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) Central Maine Power Company	Year/Period of Report End of: 2022/ Q4

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

GENERAL INFORMATION

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.

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:

one million megawatt hours of total annual sales,

100 megawatt hours of annual sales for resale,

500 megawatt hours of annual power exchanges delivered, or

500 megawatt hours of annual wheeling for others (deliveries plus losses).

What and Where to Submit

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.

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

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

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:

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

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

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.

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.

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.

When to Submit

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

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.

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.

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).

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.

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

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

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.

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

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.

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:

'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;

'Person' means an individual or a corporation;

'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;

'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; ......

"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

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

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

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

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.

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.

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."

"Sec. 304.

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 Central Maine Power Company	02 Year/ Period of Report End of: 2022/ 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) 83 Edison Drive, Augusta, ME 04336	
05 Name of Contact Person Jack E. Jessop	06 Title of Contact Person Director, Networks Accounting
07 Address of Contact Person (Street, City, State, Zip Code) One City Center, 5th Floor, Portland, ME 04101	

08 Telephone of Contact Person, Including Area Code (207) 629-1288	09 This Report is An Original / A Resubmission (1) ☑ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 03/31/2023

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 Peter C. Cohen	03 Signature Peter C. Cohen	04 Date Signed (Mo, Da, Yr) 03/31/2023
02 Title Vice President - Regulatory		

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: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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".

31	Other Paid-in Capital	253	
32	Capital Stock Expense	254b	None
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	None
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272	None
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	None
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	Not Applicable
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	None
55	Distribution of Salaries and Wages	354	
56	Common Utility Plant and Expenses	356	None
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	Not Applicable
61	Electric Energy Account	401a	
62	Monthly Peaks and Output	401b	
63	Steam Electric Generating Plant Statistics	402	None
64	Hydroelectric Generating Plant Statistics	406	None
65	Pumped Storage Generating Plant Statistics	408	None
66	Generating Plant Statistics Pages	410	None
0	Energy Storage Operations (Large Plants)	414	None
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: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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.

Peter C. Cohen

83 Edison Drive, Augusta, ME 04336

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.

Organized July 20, 1905 as Messalonskee Electric Company under Chapter 129, Private and Special Laws of 1905 of the State of Maine.

State of Incorporation:

Date of Incorporation:

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.

N/A

(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.

The Respondent was primarily engaged in the business of transmitting and distributing electric energy generated by others to retail customers in southern and central Maine.

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

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.

Since September 1, 1998, CMP Group, Inc., a Maine corporation, has held control over the Respondent through direct ownership of 100% of its common stock. In addition, CMP Group, Inc., holds 533 of 5,713 shares (9.33%) of Respondent's 6% Preferred Stock, which votes with Respondent's common stock as a single class on ordinary matters. Effective September 1, 2000, Energy East Corporation, a New York corporation, has held control over CMP Group, Inc., and the Respondent through direct ownership, after a merger, of 100% of the voting stock of CMP Group, Inc.

The merger between Energy East Corporation and Green Acquisition Capital, Inc., a wholly-owned subsidiary of Iberdrola, S.A., (Iberdrola) became effective on September 16, 2008. As a result of the merger, Iberdrola holds through direct ownership, 100% of the voting stock of CMP Group, Inc. On December 1, 2009, Iberdrola USA, Inc. changed its legal and operating name to Iberdrola USA, Inc. from Energy East Corporation.

On November 20, 2013, Iberdrola USA Networks, Inc. was formed when Iberdrola USA, Inc. was reorganized to become the parent company of Iberdrola USA Networks, Inc. Iberdrola USA Networks, Inc. was a wholly-owned subsidiary of Iberdrola USA, Inc. In late 2015, Avangrid, Inc., formerly Iberdrola USA, Inc., was reorganized to become the parent company of Avangrid Networks, Inc., formerly Iberdrola USA Networks Inc.

Avangrid, Inc. is a wholly-owned subsidiary of Iberdrola S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain. As a result of the reorganization, Avangrid Networks, Inc. holds through direct ownership 100% of the voting stock of CMP Group, Inc.

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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	NORVARCO	Owns a 50% interest in Chester SVC Partnership, which owns a static var compensator facility	100	
2	Maine Yankee Atomic Power Company	Owns and has completed the decommissioning of a nuclear facility in Maine	[(a)]38	footnote
3	Maine Electric Power Company, Inc.	Owns and operates a transmission line and related equipment including microwave communication facilities	[(b)]78.3	footnote
4	Yankee Atomic Electric Company	Owns and has completed the decommissioning of a nuclear facility in Massachusetts	[(c)]9.5	footnote
5	Connecticut Yankee Atomic Power Company	Owns and has completed the decommissioning of a nuclear facility in Connecticut	[(d)]6	footnote

FOOTNOTE DATA

(a) Concept: VotingStockOwnedByRespondentPercentage

Central Maine Power owns 38% of the outstanding common stock of Maine Yankee Atomic Power Company. The remainder of the outstanding common stock of Maine Yankee Atomic Power Company is owned by the following non-associated utilities: Emera Maine, Cambridge Electric Light Company, Western Massachusetts Electric Company, Connecticut Light and Power Company, Central Vermont Public Service Corporation, Public Service Company of New Hampshire and New England Power Company.

(b) Concept: VotingStockOwnedByRespondentPercentage

Central Maine Power Company owns 78.3% of the outstanding common stock of Maine Electric Power Company, Inc. The remainder of the outstanding common stock of Maine Electric Power Company, Inc. is owned by the following non-associated utility: Emera Maine.

(c) Concept: VotingStockOwnedByRespondentPercentage

Central Maine Power owns 9.5% of the outstanding common stock of Yankee Atomic Electric Company. The remainder of the outstanding common stock of Yankee Atomic Electric Company is owned by the following non-associated utilities: Boston Edison Company, New England Power Company, Green Mountain Power Company, Western Massachusetts Electric Company, Public Service Company of New Hampshire, Connecticut Light and Power Company, Commonwealth Energy System and Cambridge Electric Light Company.

(d) Concept: VotingStockOwnedByRespondentPercentage

Central Maine Power owns 6% of the outstanding common stock of Connecticut Yankee Atomic Power Company. The United Illuminating Company owns 9.5% of the outstanding common stock of Connecticut Atomic Power Company. Central Maine Power Company and the United Illuminating Company are wholly-owned subsidiaries of Avangrid Networks, Inc. See Note 1 to the Notes to the Financial Statements on Page 123. The remainder of the outstanding common stock of Connecticut Yankee Atomic Power Company is owned by the following non-associated utilities: Boston Edison Company, New England Power Company, Connecticut Light and Power Company, Western Massachusetts Electric Company, Public Service Company of New Hampshire, Green Mountain Power Company and Cambridge Electric Light Company.

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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	President and CEO	Joseph A. Purington	335,000	2022-01-01	2022-12-31
2	Vice President - Regulatory	Peter Cohen	216,000	2022-01-01	2022-12-31
3	General Counsel, Secretary & Clerk, Vice President	Carlisle Tuggey	208,969	2022-01-01	2022-12-31
4	VP - Customer Service	Linda Ball	195,000	2022-01-01	2022-12-31
5	VP - Electric Operations	Adam Derosiers	208,969	2022-01-01	2022-12-31
6	Controller and Treasurer	Andrea VanLuling	303,000	2022-01-01	2022-12-31

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ Q4

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	Joseph A. Purington	Augusta, Maine	false	false
2	Catherine Stempien	Orange, Connecticut	false	false
3	Noelle M. Kinsch	Albany, New York	false	false
4	Andrea Vanluling	Portland, Maine	false	false

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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	ISO New England Inc Transmission, Markets and Service Tariff, Section II	ER20-2054

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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 (Checked by default - Not explicitly defined)

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	20220419-5135	04/19/2022	ZZ22-3-000	Central Maine Power Company submits 2021 FERC Form 730 – Report of Transmission Investment Activity under ZZ22-3.	ISO New England, Transmission Markets & Services Tariff
2	20220729-5370	07/29/2022	ER20-2054RT04-2-000, ER09-1532-000	Annual New England Participating Transmission Owner Administrative Regional Network Service Information Filing under RT04-2, et al	ISO New England, Transmission Markets & Services Tariff

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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)
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Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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.

None.

None.

None.

None.

None.

CMP had $46.0 million of notes payable at December 31, 2022 and $1.1 million at December 31, 2021. CMP funds short-term liquidity needs through an agreement among Avangrid's regulated utility subsidiaries (the "Virtual Money Pool Agreement"), a bi-lateral intercompany credit agreement with Avangrid (the "Bi-Lateral Intercompany Facility") and a bank provided credit facility to which CMP is a party (the "AGR Credit Facility"), each of which are described below.

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published
by the Federal Reserve. CMP has a lending/borrowing limit of $100 million under this agreement. CMP had $7.0 million outstanding under this agreement at December 31, 2022 and no debt outstanding under this agreement at December 31, 2021.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $500 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. CMP had $39.0 million outstanding under this agreement at December 31, 2022 and $1.1 million outstanding at December 31, 2021.

On November 23, 2021, Avangrid and its investment-grade rated utility subsidiaries (New York State Electric & Gas Corporation ("NYSEG"), Rochester Gas and Electric Corporation ("RG&E"), CMP, The United Illuminating Company ("UI"), Connecticut Natural Gas Corporation ("CNG"), The Southern Connecticut Gas Company ("SCG") and The Berkshire Gas Company ("BGC")) executed a new credit facility with an aggregate limit of $3,575 million and a termination date of November 23, 2026. Under the terms of the AGR Credit Facility, each borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit contained in the agreement. NYSEG has a maximum sublimit of $700 million, RG&E has $300 million, CMP has $200 million, UI has $250 million, CNG and SCG have maximum sublimits of $150 million and BGC has a maximum sublimit of $50 million. Effective on November 23, 2021, the AGR Credit Facility was amended to increase Avangrid's maximum sublimit to $2,500 million and to establish minimum sublimits of $500 million for NYSEG, $200 million for RG&E, $100 million for CMP, $150 million for UI, $50 million for CNG and SCG and $25 million for BGC. Under the AGR Credit Facility, each of the borrowers are charged a facility fee that is dependent on their credit rating. The facility fees range from 10 to 22.5 basis points. CMP had not borrowed under this agreement as of both December 31, 2022 and 2021.

In the AGR Credit Facility we covenant not to permit, without the consent of the lender, our ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of indebtedness to total capitalization, the facility excludes from net worth the balance of accumulated other comprehensive loss as it appears on the balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness we may maintain. Continued un-remedied failure to comply with those covenants for five business days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity. Our ratio of indebtedness to total capitalization pursuant to the revolving credit facility was 0.38 to 1.00 at December 31, 2022. We are not in default as of December 31, 2022.

The short-term financing arrangements discussed above are authorized in FERC Docket No. ES17-34-000 and by the State of Maine Public Utilities Commission in Docket No. 2016-00029.

None.

None.

Electricity Distribution

The Maine distribution rate stipulation and the Federal Energy Regulatory Commission (FERC) Transmission Return on Equity (ROE) case are some of the most important specific regulatory processes that currently affect CMP.

The revenues of CMP are regulated, being based on tariffs established in accordance with administrative procedures set by the various regulatory bodies. The tariffs applied to regulated activities in the U.S. are approved by the regulatory commissions and are based on the cost of providing service.

The revenues of each regulated utility are set to be sufficient to cover all its operating costs, including finance costs, and the costs of equity, the last of which reflect our capital ratio and a reasonable ROE. Generally, tariff reviews cover various years and provide for a reasonable ROE and full reconciliation of exceptional costs as identified in CMP's rate plan.

Energy costs that are set on the New England wholesale markets are passed on to consumers by Competitive Energy Providers, licensed by the MPUC. Under Maine Law, transmission and distribution utilities are prohibited from providing retail energy supply. Default retail supply is provided by Standard Offer Providers periodically selected by the MPUC through a competitive procurement process.

Transmission - FERC ROE and Other FERC Matters

CMP's transmission rates are determined by a tariff regulated by the FERC and administered by ISO New England, Inc. (ISO-NE). Transmission rates are set annually pursuant to a FERC authorized formula that allows for recovery of direct and allocated transmission operating and maintenance expenses, and for a return of and on investment in assets.

On September 30, 2011, the Massachusetts Attorney General, Massachusetts Department of Public Utilities, Connecticut Public Utilities Regulatory Authority, New Hampshire Public Utilities Commission, Rhode Island Division of Public Utilities and Carriers, Vermont Department of Public Service, numerous New England consumer advocate agencies and transmission tariff customers collectively filed a joint complaint with the FERC, pursuant to sections 206 and 306 of the Federal Power Act, against several New England Transmission Owners (NETOs) claiming that the approved base ROE of 11.14% used by NETOs in calculating formula rates for transmission service under the ISO-New England Open Access Transmission Tariff (OATT) was not just and reasonable and seeking a reduction of the base ROE with refunds to customers for the 15-month refund periods beginning October 1, 2011 (Complaint I), December 27, 2012 (Complaint II), July 31, 2014 (Complaint III) and April 29, 2016 (Complaint IV).

On October 16, 2014, the FERC issued its final decision in Complaint I, setting the base ROE at 10.57% and a maximum total ROE of 11.74% (base plus incentive ROEs) for the October 2011 - December 2012 period as well as prospectively from October 16, 2014. On March 3, 2015, the FERC upheld its decision and further clarified that the 11.74% ROE cap will be applied on a project specific basis and not on a transmission owner's total transmission return. The complaints were consolidated and the administrative law judge issued an initial decision on March 22, 2016. The initial decision determined that, (1) for the fifteen month refund period in Complaint II, the base ROE should be 9.59% and that the ROE Cap (base ROE plus incentive ROEs) should be 10.42% and (2) for the fifteen month refund period in Complaint III and prospectively, the base ROE should be 10.90% and that the ROE Cap should be 12.19%. The initial decision in Complaints II and III is the administrative law judge's recommendation to the FERC Commissioners.

CMP reserved for refunds for Complaints I, II and III consistent with the FERC's Mach 3, 2015 decision in Complaint I. Refunds were provided to customers for Complaint I. The CMP total reserve associated with Complaints II and III is $27.9 million as of December 31, 2022, which has not changed since December 31, 2021, except for the accrual of carrying costs. If adopted as final by the FERC, the impact of the initial decision by the FERC administrative law judge would be an additional aggregate reserve for Complaints II and III of $12.8 million, which is based upon currently available information for these proceedings.

Following various intermediate hearings, orders and appellate decisions, on October 16, 2018, the FERC issued an order directing briefs and proposing a new methodology to calculate the NETOs ROE that is contained in NETOs' transmission formula rate on file at the FERC (the October 2018 Order). Pursuant to the October 2018 Order, the NETOs filed initial briefs on the proposed methodology in all four Complaints on January 11, 2019 and replied to the initial briefs on March 8, 2019.

On November 21, 2019, the FERC issued rulings on two complaints challenging the base return on equity for Midcontinent Independent System Operator, or MISO transmission owners. These rulings established a new zone of reasonableness based on equal weighting of the DCF and capital-asset pricing model for establishing the base return on equity. This resulted in a base return on equity of 9.88% as the midpoint of the zone of reasonableness. Various parties have requested rehearing on this decision, which was granted. On May 21, 2020, FERC issued a ruling, which, among other things, adjusted the methodology to determine the MISO transmission owners' ROE, resulting in an increase in ROE from 9.88% to 10.02% by utilizing the risk premium model in addition to the DCF model and capital-asset pricing model under both prongs of Section 206 of the FPA, and calculated the zone of reasonableness into equal thirds rather than employing the quartile approach. Parties to these orders affecting the MISO transmission owners' base ROE petitioned for their review at the D.C. Circuit Court of Appeals in January 2021. The NETO's submitted an amici curia brief in support of the MISO transmission owners on March 17, 2021. On August 9, 2022, the D.C. Circuit Court vacated FERC's orders and remanded the matter back to FERC. The D.C. Circuit Court held that FERC failed to offer a reasoned explanation for its decision to reintroduce the Risk Premium model after initially, and forcefully, rejecting it and that because FERC adopted the significant portion of its model in an arbitrary and capricious fashion, the new ROE produced by that model cannot stand. We cannot predict the potential impact the MISO transmission owners' ROE proceeding may have in establishing a precedent for the NETO's pending four Complaints.

On April 15, 2021, the FERC issued a supplemental Notice of Proposed Rulemaking (Supplemental NOPR) that proposes to eliminate the 50 basis-point ROE incentive for utilities who join Regional Transmission Organizations after three years of membership. The NETOs submitted initial comments in opposition to the Supplemental NOPR on June 25, 2021 and reply comments on July 26, 2021. If the elimination of the 50 basis-point ROE incentive adder becomes final, we estimate we would have an approximately $1 million reduction in earnings per year. We cannot predict the outcome of this proceeding.

CMP Distribution Rate Stipulation and New Renewable Source Generation

In an order issued on February 19, 2020, the MPUC authorized an increase in CMP's distribution revenue requirement of $17.4 million, or approximately 6.9%, based on an allowed ROE of 9.25% and a 50.00% equity ratio. The rate increase was effective March 1, 2020. Commencing on March 1, 2020, the MPUC also imposed a 1.00% ROE reduction (to 8.25%) for management efficiency associated with CMP's customer service performance following the implementation of its new billing system in 2017 which would be removed after demonstrating satisfactory customer service performance. In September 2021, CMP met the 18-month required rolling average satisfactory customer service benchmarks and filed with the MPUC a request for removal of the management efficiency adjustment, which was approved by the MPUC effective as of its February 18, 2022 order.

The Order provided additional funding for staffing increases, vegetation management programs and storm restoration costs, while retaining the basic tiered structure for storm cost recovery implemented in the 2014 stipulation. The MPUC Order also retained the RDM implemented in 2014. The Order denied CMP's request to increase rates for higher costs associated with services provided by its affiliates and ordered the initiation of a management audit to evaluate whether CMP's current management structure, and the management and other services from its affiliates, are appropriate and in the interest of Maine customers. The management audit was commenced in July 2020 by the MPUC's consultants and culminated with a report issued by the MPUC's consultants in July 2021. On February 18, 2022, the MPUC opened a narrowly tailored follow-on investigation examining how CMP and its customers are affected by decisions made at the CMP corporate parent level about earnings, capital budgeting, and planning. In this context, the investigation will also examine regulatory approaches and structures including ratemaking and performance mechanisms. We cannot predict the outcome of this investigation.

In accordance with Chapter 120 of MPUC Rules, on May 26, 2022, CMP filed a nonbinding notice of intent to file a distribution rate case on or after sixty days from the issuance of the letter. In the notice, CMP signaled its intent to propose a three-year rate plan, which includes a multi-year capital investment plan to fund investments needed to improve reliability and resiliency, as well as to continue to improve the customer experience and cost-effectively advance clean energy transformation. CMP's notice estimated a revenue change in the range of $45 to $50 million in the first year of the rate plan followed by increases in the range of $25 to $30 million in the second year and $20 to $25 million in the third year. We cannot predict the outcome of this matter.

On August 11, 2022, CMP filed a three-year rate plan, with adjustments to the distribution revenue requirement in each year. In its filing, CMP has set the three rate years as August 1, 2023 to July 31, 2024 ("Rate Year 1"); August 1, 2024 to July 31, 2025 ("Rate Year 2"); and August 1, 2025 to July 31, 2026 ("Rate Year 3"). The requested Rate Year revenue requirement increases for the rate years are $48 million, $28 million and $23 million, respectively. The revenue requirement adjustments are based on a test year ending December 31, 2021. The requested revenue changes for each rate year of the proposal are subject to a number of adjustment mechanisms most significantly including: (1) an annual review of plant additions with potential downward reconciliation in the event of an underspend, (2) a capital adjustment mechanism for certain incremental pole replacements, broadband work, electric vehicle work, energy storage projects, and metering system upgrades, (3) a symmetrical inflation reconciliation adjustment, and (4) symmetrical reconciliation of the Company's tax basis repair deduction. New rates are expected to take effect on or around August 2023. We cannot predict the outcome of this matter.

Pursuant to Maine law, the MPUC is authorized to conduct periodic requests for proposals seeking long-term supplies of energy, capacity or Renewable Energy Certificates, or RECs, from qualifying resources. The MPUC is further authorized to order Maine Transmission and Distribution Utilities to enter into contracts with sellers selected from the MPUC's competitive solicitation process. Pursuant to a MPUC Order dated October 8, 2009, CMP entered into a 20-year agreement with Evergreen Wind Power III, LLC, on March 31, 2010, to purchase capacity and energy from Evergreen's 60 MW Rollins wind farm in Penobscot County, Maine. CMP's purchase obligations under the Rollins contract are approximately $7 million per year. Pursuant to a MPUC Order dated December 18, 2017, CMP entered into a 20-year agreement with Dirigo Solar, LLC on September 10, 2018, to purchase capacity and energy from multiple Dirigo solar facilities throughout CMP's service territory. CMP's purchase obligations under the Dirigo contract will increase as additional solar facilities are brought on line, eventually reaching a level of approximately $4 million per year. Pursuant to a MPUC Order dated November 6, 2019, CMP entered into a 20-year agreement with Maine Aqua Ventus I GP LLC on December 9, 2019, to purchase capacity and energy from an off-shore wind farm under development near Monhegan Island, Maine. CMP's purchase obligations under the Maine Aqua Ventus contract will be approximately $12 million per year once the facility begins commercial operation. On September 11, 2020 the project was assigned to New England Aqua Ventus, LLC. Pursuant to Maine law, the MPUC conducted two competitive solicitation processes to procure, in the aggregate, an amount of energy or RECs from Class 1A resources that is equal to 14% of retail electricity sales in the State during calendar year 2018, or 1.715 Million MWh. Of that 14% total, the MPUC must acquire at least 7%, but not more than 10%. Through contracts approved in December 2020 (Tranche 1), CMP was ordered to execute 13 contracts, 2 contracts terminated in 2022 prior to achieving Commercial Operations. In October 2021 CMP executed contracts with 6 additional facilities (Tranche 2), 1 contract terminated in 2023 prior to achieving Commercial Operations. Each of the Tranche 1 and Tranche 2 are for 20-year terms. In accordance with MPUC orders, CMP either sells the purchased energy, or in one case the RECs, from these facilities in the ISO New England markets, through periodically auctioning the purchased output to wholesale buyers in the New England regional market, or through a sale to a third party for the RECs. Under Maine law, CMP is assured recovery of any differences between power purchase costs and achieved market revenues through a reconcilable component of its retail distribution rates. Although the MPUC has conducted multiple requests for proposals under Maine law, and has tentatively accepted term sheet proposals for long-term contracts from other sellers, these selections have not yet resulted in additional currently effective contracts with CMP.

Summary Investigation into Security Limits Litigation

On December 13, 2021, the MPUC issued a Notice initiating a summary investigation of certain allegations with respect to the recovery of capital expenditure costs contained in the lawsuit filed by Security Limits, Inc. and Paul Silva against the Company, Networks and Iberdrola, S.A. and several other entities and individuals in the United States District Court Southern District of New York. CMP filed a report describing any costs described in the complaint that are currently being recovered or will be recovered in rates on January 18, 2022 as directed by the Notice of Summary Investigation. In the report, CMP noted that the plaintiffs' had not yet served the complaint upon Networks or the Company. The MPUC directed CMP to submit notification to the MPUC when the Complaint has been served or when the procedural deadline for serving the Complaint has passed. On February 9, 2022, Security Limits, Inc. and Paul Silva dismissed their complaint. On February 10, 2022, CMP notified the MPUC of the dismissal and requested that the proceeding be closed. Subsequently on March 8, 2022, the MPUC issued an Order closing the investigation.

Minimum Equity Requirements for Regulated Subsidiaries

CMP is subject to a minimum equity ratio requirement that is tied to the capital structure assumed in establishing revenue requirements. Pursuant to these requirements CMP must maintain a minimum equity ratio equal to the ratio in its currently effective rate plan or decision measured using a trailing 13-month average. On a monthly basis CMP must maintain a minimum equity ratio of no less than 300 basis points below the equity ratio used to set rates. The minimum equity ratio requirement has the effect of limiting the amount of dividends that may be paid and may, under certain circumstances, require that the parent contribute equity capital. CMP is prohibited by regulation from lending to unregulated affiliates. CMP has also agreed to minimum equity ratio requirements in certain short-term borrowing agreements. These requirements are lower than the regulatory requirements. We are in compliance with these requirements.

None
None
Officers: There were two additions to Officers in 2022: Carlisle Tuggey, Vice President, and Andrea VanLuling, Controller and Treasurer. No changes to Directors in 2022.
None

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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	5,335,090,441	5,096,355,395
3	Construction Work in Progress (107)	200	233,663,593	212,840,972
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		5,568,754,034	5,309,196,367
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	1,412,281,757	1,310,848,043
6	Net Utility Plant (Enter Total of line 4 less 5)		4,156,472,277	3,998,348,324
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202		
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			
9	Nuclear Fuel Assemblies in Reactor (120.3)			
10	Spent Nuclear Fuel (120.4)			
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202		
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)			0
14	Net Utility Plant (Enter Total of lines 6 and 13)		4,156,472,277	3,998,348,324
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		25,330,437	25,331,434
19	(Less) Accum. Prov. for Depr. and Amort. (122)		1,371,631	1,369,204
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224	130,274,544	117,401,895
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)			
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)			
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)			
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		154,233,350	141,364,125
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		348,607	9,004,748

36	Special Deposits (132-134)		205,430	205,430
37	Working Fund (135)		5,180	5,180
38	Temporary Cash Investments (136)		1,007	1,192
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		147,294,599	129,143,623
41	Other Accounts Receivable (143)		94,516,947	66,570,775
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		16,935,894	19,557,567
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		63,900,315	120,855,114
45	Fuel Stock (151)	227		
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	39,512,255	35,106,059
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		
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227		
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		27,016,463	17,331,696
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)		27,933	
60	Rents Receivable (172)			
61	Accrued Utility Revenues (173)		45,781,353	46,242,612
62	Miscellaneous Current and Accrued Assets (174)			
63	Derivative Instrument Assets (175)			
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)			
65	Derivative Instrument Assets - Hedges (176)			37,513
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		401,674,195	404,946,375
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		4,993,380	4,063,506
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	461,888,925	443,688,849
73	Prelim. Survey and Investigation Charges (Electric) (183)		18,115,813	17,633,717
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			

75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)		3,487,535	265,017
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	80,177,378	80,513,529
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		165,500	258,143
82	Accumulated Deferred Income Taxes (190)	234	[(a)]158,378,813	173,766,603
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		727,207,344	720,189,364
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		5,439,587,166	5,264,848,188

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

Transmission (Excluding SFAS No. 109)	69,606,410	66,441,255
Distribution (Excluding SFAS No. 109)	104,160,193	91,937,556
SFAS No. 109, Accounting for Income Taxes	—	—
	173,766,603	158,378,811

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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	156,057,355	156,057,355
3	Preferred Stock Issued (204)	250	571,300	571,300
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)		269,813,541	269,813,541
7	Other Paid-In Capital (208-211)	253	756,307,601	680,155,181
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b		
11	Retained Earnings (215, 215.1, 216)	118	919,423,547	1,004,567,530
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	56,806,765	45,086,536
13	(Less) Reaquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(3,215,795)	(3,542,795)
16	Total Proprietary Capital (lines 2 through 15)		2,155,764,314	2,152,708,648
17	**LONG-TERM DEBT**			
18	Bonds (221)	256	1,150,000,000	1,150,000,000
19	(Less) Reaquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256	140,000,000	140,000,000
22	Unamortized Premium on Long-Term Debt (225)			
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)			
24	Total Long-Term Debt (lines 18 through 23)		1,290,000,000	1,290,000,000
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		15,376,180	14,791,288
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		885,990	2,323,201
29	Accumulated Provision for Pensions and Benefits (228.3)		59,461,488	110,920,372
30	Accumulated Miscellaneous Operating Provisions (228.4)		5,093,400	5,158,600
31	Accumulated Provision for Rate Refunds (229)		160,670,899	159,731,201
32	Long-Term Portion of Derivative Instrument Liabilities			
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		971,934	1,027,121

35	Total Other Noncurrent Liabilities (lines 26 through 34)		242,459,891	293,951,783
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)			
38	Accounts Payable (232)		262,396,791	156,953,288
39	Notes Payable to Associated Companies (233)		46,000,000	
40	Accounts Payable to Associated Companies (234)		40,520,348	37,862,336
41	Customer Deposits (235)		21,243,537	19,100,104
42	Taxes Accrued (236)	262	623,101	13,261,418
43	Interest Accrued (237)		18,393,469	19,943,587
44	Dividends Declared (238)		8,570	
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		2,277,194	1,989,028
48	Miscellaneous Current and Accrued Liabilities (242)		48,071,823	41,689,754
49	Obligations Under Capital Leases-Current (243)		1,083,477	1,160,777
50	Derivative Instrument Liabilities (244)			
51	(Less) Long-Term Portion of Derivative Instrument Liabilities			
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)		440,618,310	291,960,292
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)		60,783,469	38,691,042
57	Accumulated Deferred Investment Tax Credits (255)	266		
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	8,518,277	8,682,012
60	Other Regulatory Liabilities (254)	278	390,846,523	364,231,691
61	Unamortized Gain on Reaquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272		
63	Accum. Deferred Income Taxes-Other Property (282)		[a]711,865,829	691,398,954
64	Accum. Deferred Income Taxes-Other (283)		[b]138,730,553	133,223,766
65	Total Deferred Credits (lines 56 through 64)		1,310,744,651	1,236,227,465
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		5,439,587,166	5,264,848,188

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

	Beginning Balance	End Balance
SFAS No. 109 Accounting for Income Taxes	—	—
Transmission (excluding SFAS No. 109)	329,267,801	370,355,458
Distribution (exclduing SFAS No. 109)	362,131,153	341,510,371
	691,398,954	711,865,829

(b) Concept: AccumulatedDeferredIncomeTaxesOther

	Beginning Balance	End Balance
Accident and Sickness Reserve	(1,243,384)	(1,268,634)
AMI (01)	6,426,113	5,903,454
AFUDC - Amortization - Flowthrough - Gross Up	—	(175,718)
AFUDC - Equity - Flowthrough - Gross Up	—	1,322,896
Asset retirement obligation (ARO) (04)	289,546	270,801
Charitable Contribution limitation	(547,357)	—
Energy Efficiency programs (33)	1,327,632	—
Equity Earnings on Affiliates	15,475	16,369
Excess ADIT Give Back	9,586,078	—
Gross Up - Repairs	—	3,509,411
Lost Revenues Reserve	(981,915)	—
OCI - FAS 133 - Treasury Mark to Market	50,877	40,353
OCI - SERP	32,518	—
Other Cost (99) - Contra	(140,273)	—
Pension & OPEB FAS 158 (20)	34,420,378	22,206,597
Pension / OPEB COST reg (21)	—	3,297,166
Power Tax DIT´S (08)	3,793,784	3,671,467
Prepaid Insurance	245,419	264,967
Property Tax	7,668,337	7,894,376
Right of Use Assets/Capital Lease Obligations	5,379,186	5,381,877
Sales and Use Tax Audit Reserve and Interest	13,697	28,878
Storms (23)	22,705,534	34,054,961
Stranded cost (27)	1,240,333	4,066,978
Transmission reconciliation mechanisms (29)	1,821,222	—
Unamortized loss on reacquired debt -in rates (24)	72,421	46,431
Unfunded future income tax (10)	41,048,145	48,197,923
	133,223,766	138,730,553

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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

Do not report fourth quarter data in columns (e) and (f)
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.
Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
Use page 122 for important notes regarding the statement of income for any account thereof.
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.
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.
If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
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.
Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
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 Utiity 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	1,005,111,228	949,960,552			1,005,111,228	949,960,552				
3	Operating Expenses											
4	Operation Expenses (401)	320	473,923,582	430,247,733			473,923,582	430,247,733				
5	Maintenance Expenses (402)	320	139,400,836	101,003,259			139,400,836	101,003,259				
6	Depreciation Expense (403)	336	119,058,105	113,400,271			119,058,105	113,400,271				
7	Depreciation Expense for Asset Retirement Costs (403.1)	336										
8	Amort. & Depl. of Utility Plant (404-405)	336	9,558,516	9,548,860			9,558,516	9,548,860				
9	Amort. of Utility Plant Acq. Adj. (406)	336										
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)											
11	Amort. of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)											
13	(Less) Regulatory Credits (407.4)											
14	Taxes Other Than Income Taxes (408.1)	262	66,905,233	66,187,320			66,905,233	66,187,320				
15	Income Taxes - Federal (409.1)	262	9,621,472	8,184,234			9,621,472	8,184,234				
16	Income Taxes - Other (409.1)	262	2,235,180	(5,931,377)			2,235,180	(5,931,377)				
17	Provision for Deferred Income Taxes (410.1)	234, 272	383,584,572	228,433,015			383,584,572	228,433,015				
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	384,066,242	208,941,446			384,066,242	208,941,446				
19	Investment Tax Credit Adj. - Net (411.4)	266										
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)		820,221,254	742,131,869			820,221,254	742,131,869				
27	Net Util Oper Inc (Enter Tot line 2 less 25)		184,889,974	207,828,683			184,889,974	207,828,683				
28	Other Income and Deductions											
29	Other Income											
30	Nonutilty Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)											
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)											
33	Revenues From Nonutility Operations (417)											
34	(Less) Expenses of Nonutility Operations (417.1)											
35	Nonoperating Rental Income (418)		(2,427)	(2,427)								
36	Equity in Earnings of Subsidiary Companies (418.1)	119	11,720,229	11,043,227								
37	Interest and Dividend Income (419)		337,175	222,196								
38	Allowance for Other Funds Used During Construction (419.1)		12,094,111	13,273,554								
39	Miscellaneous Nonoperating Income (421)		2,563,345	3,801,726								
40	Gain on Disposition of Property (421.1)		443,320	82,888								
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		27,155,753	28,421,164								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)		35,667	464,281								
44	Miscellaneous Amortization (425)											
45	Donations (426.1)		1,055,782	1,061,497								
46	Life Insurance (426.2)											
47	Penalties (426.3)		72,500	(4,474,997)								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		563,686	302,567								
49	Other Deductions (426.5)		1,846,656	7,588,105								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		3,574,291	4,941,453								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262	351,419	294,365								
53	Income Taxes-Federal (409.2)	262	2,549,777	(964,735)								
54	Income Taxes-Other (409.2)	262	1,190,581	1,034,658								
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	1,223,297	4,354,943								
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	1,223,297									

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)		4,091,777	4,719,231								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		19,489,685	18,760,480								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		48,515,238	49,830,321								
63	Amort. of Debt Disc. and Expense (428)		500,723	470,305								
64	Amortization of Loss on Reaquired Debt (428.1)		92,643	92,643								
65	(Less) Amort. of Premium on Debt-Credit (429)											
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)											
67	Interest on Debt to Assoc. Companies (430)		173,238	28,808								
68	Other Interest Expense (431)		2,044,204	647,726								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		3,556,911	4,312,748								
70	Net Interest Charges (Total of lines 62 thru 69)		47,769,135	46,757,055								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		156,610,524	179,832,108								
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)		156,610,524	179,832,108								

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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		1,004,567,530	1,090,812,927
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		144,890,295	168,788,881
17	Appropriations of Retained Earnings (Acct. 436)			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
23.1			(34,278)	(34,278)
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		(34,278)	(34,278)
30	Dividends Declared-Common Stock (Account 438)			
30.1			(230,000,000)	(255,000,000)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(230,000,000)	(255,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		919,423,547	1,004,567,530
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)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		919,423,547	1,004,567,530
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		45,086,536	34,043,309
50	Equity in Earnings for Year (Credit) (Account 418.1)		11,720,229	11,043,227

51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
53	Balance-End of Year (Total lines 49 thru 52)		56,806,765	45,086,536

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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)	156,610,524	179,832,108
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	119,058,105	113,400,271
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Regulatory Assets and Liabilities	10,510,441	33,542,215
5.2	Amortization and Depletion of Utility Plant	9,558,516	9,548,860
5.3	Amortization of Other Assets and Liabilities	587,801	492,818
8	Deferred Income Taxes (Net)	(481,670)	23,846,512
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	8,669,305	(86,859,490)
11	Net (Increase) Decrease in Inventory	(2,987,146)	(11,051,462)
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	115,355,868	61,192,558
14	Net (Increase) Decrease in Other Regulatory Assets	(87,410,686)	(2,975,429)
15	Net Increase (Decrease) in Other Regulatory Liabilities	75,264,093	4,376,229
16	(Less) Allowance for Other Funds Used During Construction	12,094,111	13,273,554
17	(Less) Undistributed Earnings from Subsidiary Companies	11,720,229	11,043,227
18	Other (provide details in footnote):		
18.1	Other (provide details in footnote):	[a](35,809,342)	[a](1,584,069)
18.2	Pension Expense	13,673,419	17,457,893
18.3	Carrying Cost of Regulatory Assets and Liabilities	(828,141)	(4,088,080)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	357,956,747	312,814,153
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(268,280,815)	(166,149,362)
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	(12,094,111)	(13,273,554)

31	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(256,186,704)	(152,875,808)
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		
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	Notes Receivable from Associated Companies		
53.2	Investment in Subsidiary Company	(1,152,420)	(1,076,497)
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(257,339,124)	(153,952,305)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	123,569,404	199,643,804
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Equity Infusion to Subsidiary	76,152,420	126,076,497
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
67.1	Repayment of Short Term Debt Affiliates	46,000,000	(71,910,000)
70	Cash Provided by Outside Sources (Total 61 thru 69)	245,721,824	253,810,301
72	Payments for Retirement of:		
73	Long-term Debt (b)	(125,000,000)	(150,000,000)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Obligations Under Capital Leases	38,505	(253,853)
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock	(34,278)	(34,278)

81	Dividends on Common Stock	(230,000,000)	(255,000,000)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	(109,273,949)	(151,477,830)
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)	(8,656,326)	7,384,018
88	Cash and Cash Equivalents at Beginning of Period	(b)9,216,550	1,832,532
90	Cash and Cash Equivalents at End of Period	(c)560,224	(a)9,216,550

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Other Net Utility Plant	$	4,201,019
Misc Deferred Debits		249,073
Provisions for Injuries and Damages		(1,437,210)
Other Post Retirement Benefits		(51,458,884)
Environmental Provision		(65,200)
Customer Advances for Construction		22,092,427
Other Deferred Credits		(163,735)
Accumulated Other Comprehensive Income		454,512
Rate Refund		—
Prepayments		(9,684,767)
Debt Issuance Costs		—
Other		3,423
	$	(35,809,342)

(b) Concept: CashAndCashEquivalents

Cash and Cash Equivalents at End of the Period consisted of:

Cash (131)	$	9,004,748
Special Deposits (132-134)		205,430
Working Funds (135)		5,180
Temporary Cash Investments (136)		1,192
	$	9,216,550

(c) Concept: CashAndCashEquivalents

Cash and Cash Equivalents at the end of the period consisted of:

Cash (131)	$	348,607
Special Deposits (132-134)		205,430
Working Funds (135)		5,180
Temporary Cash Investments (136)		1,007
	$	560,224

(d) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Other Net Utility Plant	$	6,643,991
Misc. Deferred Debits		(74,515,055)
Provisions for Injuries and Damages		(3,465,629)
Other Post Retirement Benefits		(70,583,043)
Environmental Provision		940,100
Customer Advances for Construction		3,049,919
Other Deferred Credits		(65,499)
Accumulated Other Comprehensive Income		334,772
Rate Refund		133,000,000
Prepayments		2,516,143
Debt issuance costs		356,196
Other		204,036
	$	(1,584,069)

(e) Concept: CashAndCashEquivalents

Cash and Cash Equivalents at End of the Period consisted of:

Cash (131)	$	9,004,748
Special Deposits (132-134)		205,430
Working Funds (135)		5,180
Temporary Cash Investments (136)		1,192
	$	9,216,550

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ Q4

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 Cormmission 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.

Note 1. Summary of Significant Accounting Policies, New Accounting Pronouncements and Use of Estimates

Background and nature of operations: Central Maine Power Company and subsidiaries (CMP, the company, we, our, us) conduct regulated electricity transmission and distribution operations in Maine serving approximately 659,948 customers as of December 31, 2022, in a service territory of approximately 11,000 square miles with a population of approximately one million people. The service territory is located in the southern and central areas of Maine and contains most of Maine's industrial and commercial centers, including the city of Portland and the Lewiston-Auburn, Augusta-Waterville, Saco-Biddeford and Bath-Brunswick areas. We operate under the authority of the Maine Public Utilities Commission (MPUC) and are also subject to regulation by the Federal Energy Regulatory Commission (FERC).
CMP consists of the following subsidiaries: Maine Electric Power Company, Inc. (MEPCO) is a 78.3% owned subsidiary of CMP with the remaining 21.7% owned by Versant Power (Versant). Versant is wholly-owned by ENMAX Corp. Chester SVC Partnership (the Partnership or Chester) is a general partnership between NORVARCO, a wholly-owned subsidiary of CMP, which owns 50% interest in the Partnership and Bangor Var Co., Inc., a wholly-owned subsidiary of Versant, which owns the remaining 50% interest organized on October 9, 1990, under the Maine Uniform Partnership Act.

CMP is the principal operating utility of CMP Group, Inc. (CMP Group), a wholly-owned subsidiary of Avangrid Networks, Inc. (Networks), which is a wholly-owned subsidiary of Avangrid, Inc. (AGR), which is an 81.5% owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain.

Basis of presentation: The accompanying consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States (U.S. GAAP) and are presented on a consolidated basis, and therefore include the accounts of CMP and its consolidated subsidiaries, MEPCO and NORVARCO, and Chester. All intercompany transactions and accounts have been eliminated in consolidation in all periods presented.

Significant Accounting Policies: We consider the following policies to be the most significant in understanding the judgments that are involved in preparing our consolidated financial statements:

***Principles of consolidation*:** We consolidate the entities in which we have a controlling financial interest, after the elimination of intercompany transactions. We account for investments in common stock where we have the ability to exercise significant influence, but not control, using the equity method of accounting.

***Revenue recognition*:** We recognize revenues when we transfer control of promised goods or services to our customers in an amount that reflects the consideration we expect to be entitled to in exchange for those goods or services. Refer to Note 4 for further details.

Regulatory accounting: We account for our regulated operations in accordance with the authoritative guidance applicable to entities with regulated operations that meet the following criteria: (i) rates are established or approved by an independent, third-party regulator; (ii) rates are designed to recover the entity's specific costs of providing the regulated services or products and; (iii) there is a reasonable expectation that rates are set at levels that will recover the entity's costs and can be collected from customers. Regulatory assets primarily represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent: (i) the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates; or (ii) billings in advance of expenditures for approved regulatory programs.

We amortize regulatory assets and liabilities and recognize the related expense or revenue in our consolidated statements of income consistent with the recovery or refund included in customer rates. We believe it is probable that our currently recorded regulatory assets and liabilities will be recovered or settled in future rates.

Noncontrolling interest: The noncontrolling interest represents the portion of our net income (loss), comprehensive income (loss) and net assets that is not allocable to us and is calculated based on our ownership percentage.
***Goodwill*:** Goodwill represents future economic benefits arising from other assets acquired in a business combination that are not individually identified and separately recognized. Goodwill is initially measured at cost, being the excess of the aggregate of the consideration transferred, the fair value of any noncontrolling interest and the acquisition date fair value of any previously held equity interest in the acquiree over the fair value of the net identifiable assets acquired and liabilities assumed.

Goodwill is not amortized, but is subject to an assessment for impairment performed in the fourth quarter or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of the reporting unit to which goodwill is assigned below its carrying amount. A reporting unit is an operating segment or one level below an operating segment and is the level at which we test goodwill for impairment.

In assessing goodwill for impairment, we have the option to first perform a qualitative assessment to determine whether a quantitative assessment is necessary. If we determine, based on qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If we bypass the qualitative assessment, or perform the qualitative assessment but determine it is more likely than not that its fair value is less than its carrying amount, we perform a quantitative test to compare the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, we record an impairment loss as a reduction to goodwill and a charge to operating expenses, but the loss recognized would not exceed the total amount of goodwill allocated to the reporting unit.

Utility plant: We account for utility plant at historical cost. In cases where we are required to dismantle installations or to recondition the site on which they are located, we record the estimated cost of removal or reconditioning as an asset retirement obligation (ARO) and add an equal amount to the carrying amount of the asset.

Development and construction of our various facilities are carried out in stages. We expense project costs during early stage development activities. Once we achieve certain development milestones and it is probable that we can obtain future economic benefits from a project, we capitalize salaries and wages for persons directly involved in the project, and engineering, permits, licenses, wind measurement and insurance costs. We periodically review development projects in construction for any indications of impairment.

We transfer assets from "Construction work in progress" to "Utility plant" when they are available for service.

We determine depreciation expense for utility plant in service using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Consistent with FERC accounting requirements, we charge the original cost of utility plant retired or otherwise disposed of to accumulated depreciation. Our composite rates for depreciation were 2.5% of average depreciable property for both 2022 and 2021. We amortize our capitalized software cost, which is included in other plant, using the straight line method, based on useful lives of 5 to 15 years. Capitalized software costs were approximately $181.2 million as of December 31, 2022, and $171.3 million as of December 31, 2021. Depreciation expense was $124.1 million in 2022 and $118.3 million in 2021. Amortization of capitalized software was $9.5 million in both 2022 and 2021.
We charge repairs and minor replacements to operating expenses, and capitalize renewals and betterments, including certain indirect costs.

Allowance for funds used during construction (AFUDC) is a non-cash item that represents the allowed cost of capital, including a return on equity (ROE), used to finance construction projects. We record the portion of AFUDC attributable to borrowed funds as a reduction of interest expense and record the remainder as other income.

Our balances of major classes of utility plant and associated useful lives are shown below as of December 31:

Utility Plant	**Estimated useful life range (years)**	**2022**	**2021**
(Thousands)			
Electric			
Transmission	4-70	$ 2,814,733	$ 2,719,219
Distribution	15-82	1,813,459	1,695,279
Vehicles	4-20	70,987	64,730
Other	5-52	527,306	470,613
Total Utility Plant in Service		**5,226,485**	**4,949,841**
Total accumulated depreciation		(1,481,045)	(1,368,654)
Total Net Utility Plant in Service		**3,745,440**	**3,581,187**
Construction work in progress		240,411	243,817
Total Utility Plant		**$ 3,985,851**	**$ 3,825,004**

Leases: We determine if an arrangement is a lease at inception. We classify a lease as a finance lease if it meets any one of specified criteria that in essence transfers ownership of the underlying asset to us by the end of the lease term. If a lease does not meet any of those criteria, we classify it as an operating lease. On our consolidated balance sheets, we include, for operating leases: "Operating lease right-of-use (ROU) assets" and "Operating lease liabilities (current and non-current)"; and for finance leases: finance lease ROU assets in "Other assets" and liabilities in "Other current liabilities" and "Other liabilities."

ROU assets represent our right to use an underlying asset for the lease term and lease liabilities represent our obligation to make lease payments arising from the lease. We recognize lease ROU assets and liabilities at commencement of an arrangement based on the present value of lease payments over the lease term. We use the incremental borrowing rate based on information available at the lease commencement date to determine the present value of future payments, except when the rate implicit in the lease is determinable. A lease ROU asset also includes any lease payments made at or before commencement date, minus any lease incentives received, and includes initial direct costs incurred. We do not record leases with an initial term of 12 months or less on the balance sheet for all classes of underlying assets, and we recognize lease expense for those leases on a straight-line basis over the lease term. We include variable lease payments that depend on an index or a rate in the ROU asset and lease liability measurement based on the index or rate at the commencement date, or upon a modification. We do not include variable lease payments that do not depend on an index or a rate in the ROU asset and lease liability measurement. A lease term includes an option to extend or terminate the lease when it is reasonably certain that we will exercise that option. We recognize lease (rent) expense for operating lease payments on a straight-line basis over the lease term, or we recognize the amount eligible for recovery under our rate plan, such as actual amounts paid. We amortize finance lease ROU
assets on a straight-line basis over the lease term and recognize interest expense based on the outstanding lease liability.

We have lease agreements with lease and non-lease components, and account for lease components and associated non-lease components together as a single lease component, for all classes of underlying assets.

Impairment of long-lived assets: We evaluate utility plant and other long-lived assets for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment evaluation is based on an undiscounted cash flow analysis at the lowest level to which cash flows of the long-lived assets or asset groups are largely independent of the cash flows of other assets and liabilities. We are required to recognize an impairment loss if the carrying amount of the asset exceeds the undiscounted future net cash flows associated with that asset.

The impairment loss to be recognized is the amount by which the carrying amount of the long-lived asset exceeds the asset's fair value. Depending on the asset, fair value may be determined by use of a discounted cash flow model, with assumptions consistent with a market participant's view of the exit price of the asset.

Fair value measurement: Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants as of the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place in either the principal market for the asset or liability, or, in the absence of a principal market, in the most advantageous market for the asset or liability.

The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest. A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset according to its highest and best use, or by selling it to another market participant that would use the asset according to its highest and best use.

We use valuation techniques that are appropriate in the circumstances and for which sufficient data is available to measure fair value, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs. All assets and liabilities for which fair value is measured or disclosed in the consolidated financial statements are categorized within the fair value hierarchy based on the transparency of input to the valuation of an asset or liability as of the measurement date.

The three input levels of the fair value hierarchy are as follows:

- Level 1 - inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability either directly or indirectly, for substantially the full term of the contract.
- Level 3 - one or more inputs to the valuation methodology are unobservable or cannot be corroborated with market data.

Categorization within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. Certain investments are not categorized within the fair value hierarchy. These investments are measured based on the fair value of the underlying investments but may not be readily redeemable at that fair value.

Derivatives and hedge accounting: Derivatives are recognized on our consolidated balance sheets at their fair value. To be a derivative under the accounting standards for derivatives and hedging, an agreement would need to have a notional and an underlying, require little or no initial net investment and could be net settled. We recognize changes in the fair value of a derivative contract in earnings unless specific hedge accounting criteria are met.

Derivatives that qualify and are designated for hedge accounting are classified as cash flow hedges. We report the gain or loss on the derivative instrument as a component of Other Comprehensive Income (OCI) and later reclassify amounts into earnings when the underlying transaction occurs, which we present in the same income statement line item as the earnings effect of the hedged item. If the amounts in OCI are probable of recovery in the ratemaking process, then the OCI is reclassified as a regulatory asset or liability. For all designated and qualifying hedges, we maintain formal documentation of the hedge and effectiveness testing in accordance with the accounting standards for derivatives and hedging. If we determine that the derivative is no longer highly effective as a hedge, we will discontinue hedge accounting prospectively. For cash flow hedges of forecasted transactions, we estimate the future cash flows of the forecasted transactions and evaluate the probability of the occurrence and timing of such transactions. If we determine it is probable that the forecasted transaction will not occur, we immediately recognize in earnings hedge gains and losses previously recorded in OCI.

Changes in conditions or the occurrence of unforeseen events could require discontinuance of the hedge accounting or could affect the timing of the reclassification of gains or losses on cash flow hedges from OCI into earnings.

Cash and cash equivalents: Cash and cash equivalents include cash, bank accounts, and other highly liquid short-term investments. We consider all highly liquid investments with a maturity date of three months or less when acquired to be cash equivalents and include those investments in "Cash and cash equivalents." We classify book overdrafts representing outstanding checks in excess of funds on deposit as "Accounts payable and accrued liabilities" on our consolidated balance sheets. We report changes in book overdrafts in the operating activities section of the consolidated statements of cash flows.

Concentration of risk: We maintain our cash and cash equivalents in accounts with major financial institutions in the form of demand deposits and money market accounts. Deposits in these financial institutions may exceed the amount of federal deposit insurance provided on such deposits.

Consolidated statements of cash flows: Supplemental disclosure of cash flow information is as follows:

(Thousands)		2022	2021
Cash paid during the year ended December 31:			
Interest, net of amounts capitalized	$	46,729 $	48,146
Income taxes paid (refunded), net	$	45,224 $	(10,222)

Of the income taxes paid (refunded), substantially all was paid to (refunded by) AGR under the tax sharing agreement. Interest capitalized was $3.6 million in 2022 and $4.3 million in 2021. Accrued liabilities for utility plant additions were $35.2 million and $3.6 million as of December 31, 2022 and 2021, respectively.

***Trade receivables and unbilled revenues, net of allowance for credit losses*:** We record trade receivables at amounts billed to customers and we record unbilled revenues based on an estimate of energy delivered or services provided to customers. The estimates for unbilled revenues are determined based on various assumptions, including current month energy load requirements, billing rates by customer class and delivery loss factors. Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

The allowance for credit losses is our best estimate of the amount of probable credit losses in our existing trade receivables, determined based on experience. Each month we review our allowance for credit losses and past due accounts by age. When we believe that a receivable will not be recovered, we charge off the account balance against the allowance. Changes in assumptions about input factors and customer receivables, which are inherently uncertain and susceptible to change from period to period, could significantly affect the allowance for credit losses estimates.

Trade receivables at December 31 include unbilled revenues of $41.0 million for 2022 and $41.6 million for 2021, and are shown net of an allowance for credit losses at December 31 of $16.9 million for 2022 and $19.0 million for 2021. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $6.1 million in 2022 and $7.8 million in 2021.

Trade receivables include amounts due under deferred payment arrangements (DPAs). When a residential customer becomes delinquent in making payments, the MPUC requires us to allow the customer to enter into a DPA to settle the account balance. A DPA allows the account balance to be paid in installments over an extended period without interest, which generally exceeds one year, by negotiating mutually acceptable payment terms. Generally, we must continue to serve a customer who cannot pay an account balance in full if the customer: (i) pays a reasonable portion of the balance; (ii) agrees to pay the balance in installments; and (iii) agrees to pay future bills within 30 days until the DPA is paid in full. Failure to make payments on a DPA results in the full amount of a receivable under a DPA being due. These accounts are part of the regular operating cycle and we classify them as short term.

We establish our allowance for credit losses, including for unbilled revenue (also referred to as contract assets), by using both historical average loss percentages to project future losses, and by establishing a specific allowance for known credit issues or for specific items not considered in the historical average calculation. We consider whether we need to adjust historical loss rates to reflect the effects of current conditions and forecasted changes considering various economic indicators (e.g., Gross Domestic Product, Personal Income, Consumer Price Index, Unemployment Rate) over the contractual life of the trade receivables. We write off amounts when we have exhausted reasonable collection efforts. The allowance for credit losses for DPAs at December 31 was $9.7 million for 2022 and $11.4 million for 2021. DPA receivable balances at December 31 were $28.0 million for 2022 and $32.1 million for 2021.

Debentures, bonds and bank borrowings: We record bonds, debentures and bank borrowings as a liability equal to the proceeds of the borrowings. We treat the difference between the proceeds and the face amount of the issued liability as discount or premium and accrete the amounts as interest expense or income over the life of the instrument. We defer incremental costs associated with the issuance of the debt instruments and amortize them over the same period as debt discount or premium. We present bonds, debentures and bank borrowings net of unamortized discount, premium and debt issuance costs on our consolidated balance sheets.

Inventory: Inventory comprises materials and supplies that we use for construction of new facilities and repairs of existing facilities. These inventories are carried and withdrawn at the lower of cost and net realizable value and reported on the consolidated balance sheets within "Materials and supplies."

***Government grants*:** We record government grants as a reduction to the related utility plant to be recovered through rate base, in accordance with the prescribed FERC accounting.

In accounting for government grants related to operating and maintenance costs, we recognize amounts receivable as an offset to expenses in the consolidated statements of income in the period in which we incur the expenses.

The changes in government grants recorded as a reduction to the related utility plant as of December 31, 2022 and 2021 consisted of:

(Thousands)		Government grants	Total
As of December 31, 2020	**$**	**37,525 $**	**37,525**
Disposals		—	—
Recognized in income		(3,495)	(3,495)
As of December 31, 2021		**34,030**	**34,030**
Disposals		—	—
Recognized in income		(3,578)	(3,578)

As of December 31, 2022	**$**	**30,452**	**$**	**30,452**

We are required to comply with certain terms and conditions applicable to each grant and, if a disqualifying event should occur as specified in the grant's terms and conditions, we are required to repay the grant funds to the government. We believe we are in compliance with each grant's terms and conditions as of December 31, 2022 and 2021.

Asset retirement obligations: We record the fair value of the liability for an asset retirement obligation (ARO) and a conditional ARO in the period in which it is incurred, capitalizing the cost by increasing the carrying amount of the related long-lived asset. The ARO is associated with our long-lived assets and primarily consists of obligations related to removal or retirement of asbestos and polychlorinated biphenyl-contaminated equipment. We adjust the liability periodically to reflect revisions to either the timing or amount of the original estimated undiscounted cash flows over time. We accrete the liability to its present value each period and depreciate the capitalized cost over the useful life of the related asset. Upon settlement we will either settle the obligation at its recorded amount or incur a gain or a loss. We defer any timing differences between rate recovery and depreciation expense and accretion as either a regulatory asset or a regulatory liability.

The term conditional ARO refers to an entity's legal obligation to perform an asset retirement activity in which the timing or method of settlement are conditional on a future event that may or may not be within the entity's control. If an entity has sufficient information to reasonably estimate the fair value of the liability for a conditional ARO, it must recognize that liability at the time the liability is incurred.
The following table reconciles the beginning and ending aggregate carrying amount of the ARO, including our conditional ARO, which is recorded in Other Non-current Liabilities for the years ended December 31, 2022 and 2021.

Years Ended December 31,		**2022**		**2021**
(Thousands)				
ARO, beginning of year	$	1,027	$	975
Liabilities settled during the year		(109)		—
Accretion expenses		54		52
ARO, end of year	**$**	**972**	**$**	**1,027**

We have AROs for which we have not recognized a liability because the fair value cannot be reasonably estimated due to indeterminate settlement dates, including the removal of property upon termination of an easement, right-of-way or franchise.

Accrued removal obligations: We meet the requirements concerning accounting for regulated operations and recognize a regulatory liability for the difference between removal costs collected in rates and actual costs incurred. We classify those amounts as accrued removal obligations.
Environmental remediation liability: In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. We record our environmental liabilities on an undiscounted basis. We expect to pay our environmental liability accruals through the year 2054.

Post-employment and other employee benefits: We sponsor defined benefit pension plans that cover the majority of our employees. We also provide health care and life insurance benefits through various postretirement plans for eligible retirees.

We evaluate our actuarial assumptions on an annual basis and consider changes based on market conditions and other factors. All of our qualified defined benefit plans are funded in amounts calculated by independent actuaries, based on actuarial assumptions proposed by management.

We account for defined benefit pension or other postretirement plans, recognizing an asset or liability for the overfunded or underfunded plan status. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. We generally reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in OCI, as management believes it is probable that such items will be recoverable through the ratemaking process. Certain nonqualified plan expenses are not recoverable through the ratemaking process and we present the unrecognized prior service costs and credits and unrecognized actuarial gains and losses in accumulated other comprehensive loss. If a plan meets settlement or curtailment accounting criteria, we recognize a regulatory asset or liability if these costs are probable of recovery from ratepayers. We use a December 31st measurement date for our benefits plans.

We amortize prior service costs for both the pension and other postretirement benefits plans on a straight-line basis over the average remaining service period of participants expected to receive
benefits. We amortize unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans in excess of 10% of the greater of periodic benefit obligation or market-related value of assets over average remaining service. Our policy is to calculate the expected return on plan assets using the market related value of assets. We determine that value by recognizing the difference between actual returns and expected returns over a five-year period.

Income taxes: In August 2022, the Inflation Reduction Act of 2022 ("IRA") was signed into law in the United States. The IRA created a new corporate alternative minimum tax ("CAMT") of 15% on adjusted financial statement income and an excise tax of 1% on the value of certain stock repurchases. Based on initial guidance, CMP currently expects to be subject to the CAMT starting in 2023 but does not expect it to have a material impact on earnings, financial condition, or cash flow. Given the complexity and uncertainty around the applicability of the legislation to our specific facts and circumstances, the company continues to analyze the IRA provisions while waiting on pending Department of Treasury regulatory guidance.

AGR, the parent company of Networks, files a consolidated federal income tax return and various state income tax returns, some of which are unitary as required or permitted, including all of the activities of its subsidiaries. Each subsidiary company is treated as a member of the consolidated group and determines its current and deferred taxes based on the separate return with benefits for loss method. As a member, CMP settles its current tax liability or benefit each year directly with AGR pursuant to a tax allocation agreement between AGR and its members.

The aggregate amount of the related party income tax receivable balance due from AGR at December 31, 2022 was $13.3 million. The aggregate amount of the related party income tax payable balance due to AGR at December 31, 2021 was $12.3 million which is recorded in Taxes accrued in our consolidated balance sheets.

We use the asset and liability method of accounting for income taxes. Deferred tax assets and liabilities reflect the expected future tax consequences, based on enacted tax laws, of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts. In accordance with U.S. GAAP for regulated industries, we have established regulatory assets and liabilities for the net revenue requirements to be recovered from or refunded to customers for the related future tax expense or benefit associated with certain of these temporary differences. We defer investment tax credits when earned and amortize them over the estimated lives of the related assets. We also recognize the income tax consequences of intra-entity transfers of assets other than inventory when the transfer occurs. We had no intra-entity transfers of assets other than inventory during the years ended December 31, 2022 and 2021.

Deferred tax assets and liabilities are measured at the expected tax rate for the period in which the asset or liability will be realized or settled, based on legislation enacted as of the balance sheet date. We charge or credit changes in deferred income tax assets and liabilities that are associated with components of OCI directly to OCI. Significant judgment is required in determining income tax provisions and evaluating tax positions. Our tax positions are evaluated under a more-likely-than-not recognition threshold before they are recognized for financial reporting purposes. We record valuation allowances to reduce deferred tax assets when it is more likely than not that we will not realize all or a portion of a tax benefit. We consider the effect of the alternative minimum tax system in determining the need for a valuation allowance for deferred taxes. Deferred tax assets and liabilities are netted and classified as non-current on our consolidated balance sheets.
We record the excess of state franchise tax computed as the higher of a tax based on income or a tax based on capital in "Taxes other than income taxes" and "Taxes accrued" in our consolidated financial statements.

Positions taken or expected to be taken on tax returns, including the decision to exclude certain income or transactions from a return, are recognized in the financial statements when it is more likely than not the tax position can be sustained based solely on the technical merits of the position. The amount of a tax return position that is not recognized in the financial statements is disclosed as an unrecognized tax benefit. Changes in assumptions on tax benefits may also impact interest expense or interest income and may result in the recognition of tax penalties. Interest and penalties related to unrecognized tax benefits are recorded within "Interest expense, net of capitalization" and "Other income" and "Other deductions" in our consolidated statements of income.

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the consolidated statements of income.

Our income tax expense, deferred tax assets and liabilities, and liabilities for unrecognized tax benefits reflect management's best assessment of estimated current and future taxes to be paid. Significant judgments and estimates are required in determining the consolidated income tax components of the financial statements.

Stock-based compensation: Stock-based compensation represents costs related to AGR stock-based awards granted to employees. We account for stock-based payment transactions based on the estimated fair value of awards reflecting forfeitures when they occur. The recognition period for these costs begins at either the applicable service inception date or grant date and continues throughout the requisite service period, or until the employee becomes retirement eligible, if earlier.

Adoption of New Accounting Pronouncements

Although we are not a public business entity, our parent company is a public business entity; therefore, we adopt new accounting standards based on the effective date for public entities as permitted.

(a) Disclosures by business entities about government assistance

In November 2021, the FASB issued guidance that requires an entity to provide certain annual disclosures about government assistance received and accounted for by applying a grant or contribution accounting model by analogy. As the guidance is disclosure only, it did not have an impact to the consolidated financial results

Accounting Pronouncements Issued But Not Yet Adopted

There have been no accounting pronouncements issued but not yet adopted that are expected to have a material impact on CMP's consolidated financial statements.

Use of estimates and assumptions: The preparation of our consolidated financial statements in conformity with U.S. GAAP requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the reporting periods. Significant estimates and assumptions are used for, but not limited to: (1) allowance for credit losses and unbilled revenues; (2) asset impairments, including goodwill; (3) depreciable lives of assets; (4) income tax valuation allowances; (5) uncertain tax positions; (6) reserves for professional, workers' compensation, and comprehensive general insurance liability risks; (7) contingency and litigation reserves; (8) fair value measurements; (9) environmental remediation liabilities; (10) AROs; (11) pension and other postretirement employee benefits (OPEB); and (12) noncontrolling interest balances. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our consolidated financial statements will change as new events occur, as more experience is acquired, as additional information is obtained, and as our operating environment changes. We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside specialists to assist in our evaluations, as considered necessary. Actual results could differ from those estimates.

Union collective bargaining agreements: Approximately 66% of our employees are covered by a collective bargaining agreement. We have no agreements that will expire within the coming year.

Note 2. Industry Regulation

Our revenues are regulated, being based on tariffs established in accordance with administrative procedures set by the various regulatory bodies. Distribution rates are established by the Maine Public Utilities Commission (MPUC) and transmission rates are established by the Federal Energy Regulatory Commission (FERC). The tariffs are applied based on the cost of providing service.

Electricity Distribution

The Maine distribution rate stipulation and the Federal Energy Regulatory Commission (FERC) Transmission Return on Equity (ROE) case are some of the most important specific regulatory processes that currently affect CMP.

The revenues of CMP are regulated, being based on tariffs established in accordance with administrative procedures set by the various regulatory bodies. The tariffs applied to regulated activities in the U.S. are approved by the regulatory commissions and are based on the cost of providing service. The revenues of each regulated utility are set to be sufficient to cover all its operating costs, including finance costs, and the costs of equity, the last of which reflect our capital ratio and a reasonable ROE. Generally, tariff reviews cover various years and provide for a reasonable ROE and full reconciliation of exceptional costs as identified in CMP's rate plan.

Energy costs that are set on the New England wholesale markets are passed on to consumers by Competitive Energy Providers, licensed by the MPUC. Under Maine Law, transmission and distribution utilities are prohibited from providing retail energy supply. Default retail supply is provided by Standard Offer Providers periodically selected by the MPUC through a competitive procurement process.

Transmission - FERC ROE and Other FERC Matters

CMP's transmission rates are determined by a tariff regulated by the FERC and administered by ISO New England, Inc. (ISO-NE). Transmission rates are set annually pursuant to a FERC authorized formula that allows for recovery of direct and allocated transmission operating and maintenance expenses, and for a return of and on investment in assets.
On September 30, 2011, the Massachusetts Attorney General, Massachusetts Department of Public Utilities, Connecticut Public Utilities Regulatory Authority, New Hampshire Public Utilities Commission, Rhode Island Division of Public Utilities and Carriers, Vermont Department of Public Service, numerous New England consumer advocate agencies and transmission tariff customers collectively filed a joint complaint with the FERC, pursuant to sections 206 and 306 of the Federal Power Act, against several New England Transmission Owners (NETOs) claiming that the approved base ROE of 11.14% used by NETOs in calculating formula rates for transmission service under the ISO-New England Open Access Transmission Tariff (OATT) was not just and reasonable and seeking a reduction of the base ROE with refunds to customers for the 15-month refund periods beginning October 1, 2011 (Complaint I), December 27, 2012 (Complaint II), July 31, 2014 (Complaint III) and April 29, 2016 (Complaint IV).

On October 16, 2014, the FERC issued its final decision in Complaint I, setting the base ROE at 10.57% and a maximum total ROE of 11.74% (base plus incentive ROEs) for the October 2011 - December 2012 period as well as prospectively from October 16, 2014. On March 3, 2015, the FERC upheld its decision and further clarified that the 11.74% ROE cap will be applied on a project specific basis and not on a transmission owner's total transmission return. The complaints were consolidated and the administrative law judge issued an initial decision on March 22, 2016. The initial decision determined that, (1) for the fifteen month refund period in Complaint II, the base ROE should be 9.59% and that the ROE Cap (base ROE plus incentive ROEs) should be 10.42% and (2) for the fifteen month refund period in Complaint III and prospectively, the base ROE should be 10.90% and that the ROE Cap should be 12.19%. The initial decision in Complaints II and III is the administrative law judge's recommendation to the FERC Commissioners.

CMP reserved for refunds for Complaints I, II and III consistent with the FERC's Mach 3, 2015 decision in Complaint I. Refunds were provided to customers for Complaint I. The CMP total reserve associated with Complaints II and III is $27.9 million as of December 31, 2022, which has not changed since December 31, 2021, except for the accrual of carrying costs. If adopted as final by the FERC, the impact of the initial decision by the FERC administrative law judge would be an additional aggregate reserve for Complaints II and III of $12.8 million, which is based upon currently available information for these proceedings.

Following various intermediate hearings, orders and appellate decisions, on October 16, 2018, the FERC issued an order directing briefs and proposing a new methodology to calculate the NETOs ROE that is contained in NETOs' transmission formula rate on file at the FERC (the October 2018 Order). Pursuant to the October 2018 Order, the NETOs filed initial briefs on the proposed methodology in all four Complaints on January 11, 2019 and replied to the initial briefs on March 8, 2019.

On November 21, 2019, the FERC issued rulings on two complaints challenging the base return on equity for Midcontinent Independent System Operator, or MISO transmission owners. These rulings established a new zone of reasonableness based on equal weighting of the DCF and capital-asset pricing model for establishing the base return on equity. This resulted in a base return on equity of 9.88% as the midpoint of the zone of reasonableness. Various parties have requested rehearing on this decision, which was granted. On May 21, 2020, FERC issued a ruling, which, among other things, adjusted the methodology to determine the MISO transmission owners' ROE, resulting in an increase in ROE from 9.88% to 10.02% by utilizing the risk premium model in addition to the DCF model and capital-asset pricing model under both prongs of Section 206 of the FPA, and calculated the zone of reasonableness into equal thirds rather than employing the quartile approach. Parties to these orders affecting the MISO transmission owners' base ROE petitioned for their review at the D.C. Circuit Court of Appeals in January 2021. The NETO's submitted an amici curia brief in support of the MISO transmission owners on March 17, 2021. On August 9, 2022, the D.C. Circuit Court vacated FERC's orders and remanded the matter back to FERC. The D.C. Circuit Court held that FERC failed to offer a reasoned explanation for its decision to reintroduce the Risk Premium model after initially, and forcefully, rejecting it and that because FERC adopted the significant portion of its model in an arbitrary and capricious fashion, the new ROE produced by that model cannot stand. We cannot predict the potential impact the MISO transmission owners' ROE proceeding may have in establishing a precedent for the NETO's pending four Complaints.

On April 15, 2021, the FERC issued a supplemental Notice of Proposed Rulemaking (Supplemental NOPR) that proposes to eliminate the 50 basis-point ROE incentive for utilities who join Regional Transmission Organizations after three years of membership. The NETOs submitted initial comments in opposition to the Supplemental NOPR on June 25, 2021 and reply comments on July 26, 2021. If the elimination of the 50 basis-point ROE incentive adder becomes final, we estimate we would have an approximately $1 million reduction in earnings per year. We cannot predict the outcome of this proceeding.

CMP Distribution Rate Stipulation and New Renewable Source Generation

In an order issued on February 19, 2020, the MPUC authorized an increase in CMP's distribution revenue requirement of $17.4 million, or approximately 6.9%, based on an allowed ROE of 9.25% and a 50.00% equity ratio. The rate increase was effective March 1, 2020. Commencing on March 1, 2020, the MPUC also imposed a 1.00% ROE reduction (to 8.25%) for management efficiency associated with CMP's customer service performance following the implementation of its new billing system in 2017 which would be removed after demonstrating satisfactory customer service performance. In September 2021, CMP met the 18-month required rolling average satisfactory customer service benchmarks and filed with the MPUC a request for removal of the management efficiency adjustment, which was approved by the MPUC effective as of its February 18, 2022 order.

The Order provided additional funding for staffing increases, vegetation management programs and storm restoration costs, while retaining the basic tiered structure for storm cost recovery implemented in the 2014 stipulation. The MPUC Order also retained the RDM implemented in 2014. The Order denied CMP's request to increase rates for higher costs associated with services provided by its affiliates and ordered the initiation of a management audit to evaluate whether CMP's current management structure, and the management and other services from its affiliates, are appropriate and in the interest of Maine customers. The management audit was commenced in July 2020 by the MPUC's consultants and culminated with a report issued by the MPUC's consultants in July 2021. On February 18, 2022, the MPUC opened a narrowly tailored follow-on investigation examining how CMP and its customers are affected by decisions made at the CMP corporate parent level about earnings, capital budgeting, and planning. In this context, the investigation will also examine regulatory approaches and structures including ratemaking and performance mechanisms. We cannot predict the outcome of this investigation.

In accordance with Chapter 120 of MPUC Rules, on May 26, 2022, CMP filed a nonbinding notice of intent to file a distribution rate case on or after sixty days from the issuance of the letter. In the notice, CMP signaled its intent to propose a three-year rate plan, which includes a multi-year capital investment plan to fund investments needed to improve reliability and resiliency, as well as to continue to improve the customer experience and cost-effectively advance clean energy transformation. CMP's notice estimated a revenue change in the range of $45 to $50 million in the first year of the rate plan followed by increases in the range of $25 to $30 million in the second year and $20 to $25 million in the third year. We cannot predict the outcome of this matter.

On August 11, 2022, CMP filed a three-year rate plan, with adjustments to the distribution revenue requirement in each year. In its filing, CMP has set the three rate years as August 1, 2023 to July 31, 2024 ("Rate Year 1"); August 1, 2024 to July 31, 2025 ("Rate Year 2"); and August 1, 2025 to July 31, 2026 ("Rate Year 3"). The requested Rate Year revenue requirement increases for the rate years are $48 million, $28 million and $23 million, respectively. The revenue requirement adjustments are based on a test year ending December 31, 2021. The requested revenue changes for each rate year of the proposal are subject to a number of adjustment mechanisms most significantly including: (1) an annual review of plant additions with potential downward reconciliation in the event of an underspend, (2) a capital adjustment mechanism for certain incremental pole replacements, broadband work, electric vehicle work, energy storage projects, and metering system upgrades, (3) a symmetrical inflation reconciliation adjustment, and (4) symmetrical reconciliation of the Company's tax basis repair deduction. New rates are expected to take effect on or around August 2023. We cannot predict the outcome of this matter.

Pursuant to Maine law, the MPUC is authorized to conduct periodic requests for proposals seeking long-term supplies of energy, capacity or Renewable Energy Certificates, or RECs, from qualifying resources. The MPUC is further authorized to order Maine Transmission and Distribution Utilities to enter into contracts with sellers selected from the MPUC's competitive solicitation process. Pursuant to a MPUC Order dated October 8, 2009, CMP entered into a 20-year agreement with Evergreen Wind Power III, LLC, on March 31, 2010, to purchase capacity and energy from Evergreen's 60 MW Rollins wind farm in Penobscot County, Maine. CMP's purchase obligations under the Rollins contract are approximately $7 million per year. Pursuant to a MPUC Order dated December 18, 2017, CMP entered into a 20-year agreement with Dirigo Solar, LLC on September 10, 2018, to purchase capacity and energy from multiple Dirigo solar facilities throughout CMP's service territory. CMP's purchase obligations under the Dirigo contract will increase as additional solar facilities are brought on line, eventually reaching a level of approximately $4 million per year. Pursuant to a MPUC Order dated November 6, 2019, CMP entered into a 20-year agreement with Maine Aqua Ventus I GP LLC on December 9, 2019, to purchase capacity and energy from an off-shore wind farm under development near Monhegan Island, Maine. CMP's purchase obligations under the Maine Aqua Ventus contract will be approximately $12 million per year once the facility begins commercial operation. On September 11, 2020 the project was assigned to New England Aqua Ventus, LLC. Pursuant to Maine law, the MPUC conducted two competitive solicitation processes to procure, in the aggregate, an amount of energy or RECs from Class 1A resources that is equal to 14% of retail electricity sales in the State during calendar year 2018, or 1.715 Million MWh. Of that 14% total, the MPUC must acquire at least 7%, but not more than 10%. Through contracts approved in December 2020 (Tranche 1), CMP was ordered to execute 13 contracts, 2 contracts terminated in 2022 prior to achieving Commercial Operations. In October 2021 CMP executed contracts with 6 additional facilities (Tranche 2), 1 contract terminated in 2023 prior to achieving Commercial Operations. Each of the Tranche 1 and Tranche 2 are for 20-year terms. In accordance with MPUC orders, CMP either sells the purchased energy, or in one case the RECs, from these facilities in the ISO New England markets, through periodically auctioning the purchased output to wholesale buyers in the New England regional market, or through a sale to a third party for the RECs. Under Maine law, CMP is assured recovery of any differences between power purchase costs and achieved market revenues through a reconcilable component of its retail distribution rates. Although the MPUC has conducted multiple requests for proposals under Maine law, and has tentatively accepted term sheet proposals for long-term contracts from other sellers, these selections have not yet resulted in additional currently effective contracts with CMP.

Summary Investigation into Security Limits Litigation
On December 13, 2021, the MPUC issued a Notice initiating a summary investigation of certain allegations with respect to the recovery of capital expenditure costs contained in the lawsuit filed by Security Limits, Inc. and Paul Silva against the Company, Networks and Iberdrola, S.A. and several other entities and individuals in the United States District Court Southern District of New York. CMP filed a report describing any costs described in the complaint that are currently being recovered or will be recovered in rates on January 18, 2022 as directed by the Notice of Summary Investigation. In the report, CMP noted

that the plaintiffs' had not yet served the complaint upon Networks or the Company. The MPUC directed CMP to submit notification to the MPUC when the Complaint has been served or when the procedural deadline for serving the Complaint has passed. On February 9, 2022, Security Limits, Inc. and Paul Silva dismissed their complaint. On February 10, 2022, CMP notified the MPUC of the dismissal and requested that the proceeding be closed. Subsequently on March 8, 2022, the MPUC issued an Order closing the investigation.

Minimum Equity Requirements for Regulated Subsidiaries

CMP is subject to a minimum equity ratio requirement that is tied to the capital structure assumed in establishing revenue requirements. Pursuant to these requirements CMP must maintain a minimum equity ratio equal to the ratio in its currently effective rate plan or decision measured using a trailing 13-month average. On a monthly basis CMP must maintain a minimum equity ratio of no less than 300 basis points below the equity ratio used to set rates. The minimum equity ratio requirement has the effect of limiting the amount of dividends that may be paid and may, under certain circumstances, require that the parent contribute equity capital. CMP is prohibited by regulation from lending to unregulated affiliates. CMP has also agreed to minimum equity ratio requirements in certain short-term borrowing agreements. These requirements are lower than the regulatory requirements. We are in compliance with these requirements.

Note 3. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations we capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric rates. We base our assessment of whether recovery is probable on the existence of regulatory orders that allow for recovery of certain costs over a specific period or allow for reconciliation or deferral of certain costs. When costs are not treated in a specific order we use regulatory precedent to determine if recovery is probable. We also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs. Of the total regulatory assets net of regulatory liabilities, approximately $212.7 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

Details of other regulatory assets and other regulatory liabilities are shown in the tables below. They result from various regulatory orders that allow for the deferral and/or reconciliation of specific costs. Regulatory assets and regulatory liabilities are classified as current when recovery or refund in the coming year is allowed or required through a specific order or when the rates related to a specific regulatory asset or regulatory liability are subject to automatic annual adjustment.

Regulatory assets at December 31, 2022 and 2021 consisted of:

As of December 31,		**2022**		**2021**
(Thousands)				
Transmission revenue reconciliation mechanism	$	10,890	$	15,369
Deferred meter replacement costs		21,043		22,906
Environmental remediation costs		318		380
Energy efficiency programs		—		4,732
Federal tax depreciation normalization adjustment		13,087		13,523
Storm costs		121,388		80,933
Unamortized losses on reacquired debt		166		258
Pension and other postretirement benefits costs		90,907		122,690
Unfunded future income taxes		189,008		173,834
Asset retirement obligation		965		1,032
Other		17,210		10,324
Total regulatory assets		**464,982**		**445,981**
Less: current portion		60,653		49,860
Total non-current regulatory assets	$	**404,329**	$	**396,121**

Deferred meter replacement costs represent the deferral of the net book value of retired meters which were replaced by advanced metering infrastructure meters. This amount is being amortized at the related existing depreciation amounts.

Energy efficiency programs represents the difference between revenue billed to customers through an energy efficiency charge and the costs of our energy efficiency programs as approved by the state authorities.

Environmental remediation costs include spending that has occurred and is eligible for future recovery in customer rates. The amortization period will be established in future proceedings and will depend upon the timing of spending for the remediation costs.

Federal tax depreciation normalization adjustment represents the deferral of the normalization of change impacts in book lives and the pass back of theoretical reserves associated with Power Tax deferred income tax.

Pension and other postretirement represents the actuarial losses on the pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future pension expenses. Because no funds have yet been expended for this regulatory asset, it does not accrue carrying costs and is not included within the rate base. As of 2022, this also includes pension deferral which represents the distribution related portion of lump-sum pension settlement expense to be amortized in future rates.

Storm costs are allowed in rates based on an estimate of the routine costs of service restoration. CMP is also allowed to defer unusually high levels of service restoration costs resulting from major storms when they meet certain criteria for severity and duration. CMP's total deferral, including carrying costs, was $121.4 million at December 31, 2022 and $80.9 million at December 31, 2021.

Transmission revenue reconciliation mechanism reflects any differences in actual costs in the rate year from those used to set rates. The ATU (Annual Transmission True Up) portion is recovered over the subsequent June to May period. When the ATU is known we record it as a regulatory asset (regulatory liability), with an offset to revenues, and amortize it over the twelve-month period as the related revenues are collected (refunded).

Unamortized losses on reacquired debt represent deferred losses on debt reacquisitions that will be recovered over the remaining original amortization period of the reacquired debt.

Unfunded future income taxes represent unrecovered federal and state income taxes primarily resulting from regulatory flow through accounting treatment. The income tax benefits or charges for certain plant related timing differences, such as removal costs, are immediately flowed through to, or collected from, customers. This amount is being amortized as the amounts related to temporary differences that give rise to the deferrals are recovered in rates.

Other includes various items subject to reconciliation such as CRM&B (Billing System Costs), 2021 Pension Deferral, OPA Assessment for Non-Wire Alternatives, Net Energy Billing, Low-Income Bill Credit, 100 BP Recovery, Non-bypassable charges and Public Advocate.

Regulatory liabilities at December 31, 2022 and 2021 consisted of:

As of December 31,		**2022**		**2021**
(Thousands)				
Accrued removal obligations	$	32,434	$	41,356
Transmission revenue reconciliation mechanism		63,775		9,117
Revenue decoupling mechanism		13,314		12,603
Tax Act - remeasurement		274,691		301,520
Environmental remediation costs		1,228		795
Rate refund - FERC ROE proceeding		27,852		26,907
Other		1,723		2,222
Total regulatory liabilities		**415,017**		**394,520**
Less: current portion		86,937		37,912
Total non-current regulatory liabilities	$	**328,080**	$	**356,608**

Accrued removal obligations represent the differences between asset removal costs incurred and amounts collected in rates for those costs. The amortization period is dependent upon the asset removal costs of underlying assets and the life of the utility plant.

Environmental remediation costs include spending that has occurred and is eligible for future recovery in customer rates. The amortization period will be established in future proceedings and will depend upon the timing of spending for the remediation costs.

Rate refund - FERC ROE proceedings: see Note 2.

Revenue decoupling mechanism represents the mechanism established to disassociate the utility's profits from its delivery/commodity sales.

Tax Act – re-measurement represents the impact from re-measurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates from 35% to 21% under the provisions of the Tax Act will result in amounts previously collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates.

Transmission revenue reconciliation mechanism reflects any differences in actual costs in the rate year from those used to set rates. The ATU is recovered over the subsequent June to May period. When the ATU is known we record it as a regulatory asset (regulatory liability), with an offset to revenues, and amortize it over the twelve-month period as the related revenues are collected (refunded).

Other includes various items subject to reconciliation such as Electric Lifeline Program (ELP), removal of Disconnect Penalty, Demand Side Management and Vegetation Management.

Note 4. Revenue

We recognize revenue when we have satisfied our obligations under the terms of a contract with a customer, which generally occurs when the control of promised goods or services transfers to the customer. We measure revenue as the amount of consideration we expect to receive in exchange for providing those goods or services. Contracts with customers may include multiple performance obligations. For such contracts, we allocate revenue to each performance obligation based on its relative standalone selling price. We generally determine standalone selling prices based on the prices charged to customers. Certain revenues are not within the scope of ASC 606, such as revenues from leasing, derivatives, other revenues that are not from contracts with customers and other contractual rights or obligations, and we account for such revenues in accordance with the applicable accounting standards. We exclude from revenue amounts collected on behalf of third parties, including any such taxes collected from customers and remitted to governmental authorities. We do not have any material significant payment terms because we receive payment at or shortly after the point of sale.

The following describes the principal activities from which we generate revenue.

CMP derives its revenue primarily from tariff-based sales of electricity service to customers in the Maine area with no defined contractual term. For such revenues, we recognize revenues in an amount derived from the commodities delivered to customers. Other major sources of revenue are electricity transmission and wholesale sales of electricity.

Tariff-based sales are subject to the corresponding state regulatory authorities, which determine prices and other terms of service through the ratemaking process. Maine state law prohibits the utility from providing the electricity commodity to customers. For customers that receive their commodity from another supplier, the utility acts as an agent and delivers the electricity provided by that supplier. Revenue in those cases is only for providing the service of delivery of the commodity.

Transmission revenue results from others' use of the utility's transmission system to transmit electricity and is subject to FERC regulation, which establishes the prices and other terms of service. Long-term wholesale sales of electricity are based on individual bilateral contracts.

The performance obligation in all arrangements is satisfied over time because the customer simultaneously receives and consumes the benefits as CMP delivers or sells the electricity or provides the transmission service.

CMP records revenue from Alternative Revenue Programs (ARPs), which is not ASC 606 revenue. Such programs represent contracts between the utilities and their regulators. CMP ARPs include revenue decoupling mechanisms, other ratemaking mechanisms, annual revenue requirement reconciliations, and other demand side management programs.

CMP also has various other sources of revenue including billing, collection, other administrative charges, sundry billings, rent of utility property, and miscellaneous revenue. It classifies such revenues as other ASC 606 revenues to the extent they are not related to revenue generating activities from leasing, ARPs, or other activities.

Revenues disaggregated by major source for the years ended December 31, 2022 and 2021 are as follows:

Years Ended December 31,		2022		2021
(Thousands)				
Regulated operations – electricity	$	975,064	$	922,320
Other (a)		42,832		23,254
Revenue from contracts with customers		**1,017,896**		**945,574**
Leasing revenue		1,574		1,529
Alternative revenue programs		4,516		14,740
Other revenue		27,218		16,556
Total operating revenues	**$**	**1,051,204**	**$**	**978,399**

(a) Primarily includes certain intra-month trading activities, billing, collection, and administrative charges, sundry billings, and other miscellaneous revenue.

Note 5. Goodwill

We do not amortize goodwill, but perform our annual impairment assessment testing at least annually as described in Note 1, in the fourth quarter, as of October 1. Our qualitative assessment involves evaluating key events and circumstances that could affect the fair value of our company, as well as other factors. Events and circumstances evaluated include macroeconomic conditions, industry, regulatory and market considerations, cost factors and their effect on earnings and cash flows, overall financial performance as compared with projected results and actual results of relevant prior periods, other relevant entity-specific events, and events affecting CMP.

Our quantitative impairment testing includes various assumptions, primarily the discount rate, and forecasted cash flows. We use a discount rate that is developed using market participant assumptions, which consider the risk and nature of our cash flows and the rates of return market participants would require in order to invest their capital in CMP. We test the reasonableness of the conclusions of our quantitative impairment testing using a range of discount rates and a range of assumptions for long-term cash flows.

We had no impairment of goodwill in 2022 and 2021 as a result of our qualitative impairment testing. There were no events or circumstances subsequent to our annual impairment assessment for 2022 or 2021 that required us to update the assessment.

The carrying amount of goodwill was $324.9 million at both December 31, 2022 and 2021, with no accumulated impairment losses and no changes during 2022 and 2021.

Note 6. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,		2022		2021
(Thousands)				
Current				
Federal	$	15,256	$	10,095
State		4,813		(3,370)
Current taxes charged to expense		**20,069**		**6,725**
Deferred				
Federal		(7,797)		(284)
State		8,481		24,349
Deferred taxes charged to expense		**684**		**24,065**
Total Income Tax Expense	**$**	**20,753**	**$**	**30,790**

The differences between tax expense per the consolidated statements of income and tax expense at the 21% statutory federal tax rate for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,		2022		2021
(Thousands)				
Tax expense at federal statutory rate	$	37,924	$	44,872
Depreciation/amortization and other plant differences not normalized		(8,743)		(11,196)
State taxe expense, net of federal benefit		10,502		16,573
Excess ADIT giveback		(19,302)		(18,609)
Other, net		372		(850)
Total Income Tax Expense	**$**	**20,753**	**$**	**30,790**

Income tax expense for the year ended December 31, 2022 was $17.2 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to Excess ADIT amortization and Depreciation, amortization and other plant differences not normalized, partially offset by state taxes. This resulted in an effective tax rate of 11.5%. Income tax expense for the year ended December 31, 2021 was $14.1 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to Excess ADIT amortization and Depreciation, amortization and other plant differences not normalized, partially offset by state taxes. This resulted in an effective tax rate of 14.4%.

In 2021, CMP began refunding previously deferred Regional Transmission Excess ADITs and continued refunding previously deferred other Excess ADITs, established as a result of the 2017 Tax Act, pursuant to a regulatory order and as determined by the FERC, MPUC and IRS normalization rules.

Deferred tax assets and liabilities as of December 31, 2022 and 2021 consisted of:

December 31,	**2022**	**2021**
(Thousands)		
Non-current Deferred Income Tax Liabilities (Assets)		
Property related	$ 701,941	$ 668,742
Unfunded future income taxes	48,331	40,992
Pension and other postretirement benefits	13,149	8,540
Regulatory liability due to "Tax Cuts and Jobs Act"	(77,064)	(83,491)
Federal and state NOL's	(2,971)	(96)
Other	8,472	11,643
Total Non-current Deferred Income Tax Liabilities	**$ 691,858**	**$ 646,330**
Deferred tax assets	$ 80,035	$ 83,587
Deferred tax liabilities	771,893	729,917
Net Accumulated Deferred Income Tax Liabilities	**$ 691,858**	**$ 646,330**

CMP has gross Maine state net operating losses of $52.1 million for the year ended December 31, 2022. CMP had gross Maine state net operating losses of $15.5 million for the year ended December 31, 2021.

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. In 2022, we netted our liability for uncertain tax positions against all same jurisdiction deferred tax assets, net operating losses and tax credit carryforwards. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the consolidated statements of income.

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,	**2022**	**2021**
(Thousands)		
Beginning Balance	$ 15,785	$ 18,663
Reduction for tax positions related to prior years	(3,544)	(2,878)
Ending Balance	**$ 12,241**	**$ 15,785**

Unrecognized income tax benefits represent income tax positions taken on income tax returns but not yet recognized in the consolidated financial statements. The accounting guidance for uncertainty in income taxes provides that the financial effects of a tax position shall initially be recognized in the financial statements when it is more likely than not based on the technical merits that the position will be sustained upon examination, assuming the position will be audited and the taxing authority has full knowledge of all relevant information.

There were no additional accruals for interest and penalties on tax reserves as of December 31, 2022 or 2021.

Note 7. Non-current Debt

Long-term debt as of December 31, 2022 and 2021 consisted of:

As of December 31,	**2022**			**2021**	
(Thousands, except interest rates)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
First mortgage bonds (a)	2025-2052	$ 1,150,000	1.87%-5.68%	$ 1,150,000	1.87%-5.68%
Senior unsecured notes	2025-2037	140,000	5.375%-6.40%	140,000	5.375%-6.40%
Unamortized debt issuance costs and discount		(4,731)		(4,403)	
Total Debt		**1,285,269**		**1,285,597**	
Less: debt due within one year, included in current liabilities		—		124,578	
Total Non-current Debt		**$ 1,285,269**		**$ 1,161,019**	

(a) The first mortgage bonds are secured by a first mortgage lien on substantially all of Net Utility Plant In Service.

On December 15, 2022, CMP issued $75 million aggregate principal amount of Green First Mortgage Bonds maturing in 2032 at an interest rate of 4.37% and $50 million aggregate principal amount of Green First Mortgage Bonds maturing in 2052 at an interest rate of 4.76%

On December 15, 2021, CMP issued $200 million aggregate principal amount of First Mortgage Bonds maturing in 2031 at an interest rate of 2.05%.

Long-term debt, including sinking fund obligations, due during the next five years consist of:

	2023	**2024**	**2025**	**2026**	**2027**	**Total**
(Thousands)						
	$ —	$ —	$ 80,000	$ 80,000	$ —	$ 160,000

We have no debt covenant requirements related to the maintenance of financial ratios in our long-term debt agreements at December 31, 2022 and 2021.

Note 8. Bank Loans and Other Borrowings

CMP had $46.0 million of notes payable at December 31, 2022 and $1.1 million at December 31, 2021. CMP funds short-term liquidity needs through an agreement among Avangrid's regulated utility subsidiaries (the "Virtual Money Pool Agreement"), a bi-lateral intercompany credit agreement with Avangrid (the "Bi-Lateral Intercompany Facility") and a bank provided credit facility to which CMP is a party (the "AGR Credit Facility"), each of which are described below.

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. CMP has a lending/borrowing limit of $100 million under this agreement. CMP had $7.0 million outstanding under this agreement at December 31, 2022 and no debt outstanding under this agreement at December 31, 2021.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $500 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. CMP had $39.0 million outstanding under this agreement at December 31, 2022 and $1.1 million outstanding at December 31, 2021.

On November 23, 2021, Avangrid and its investment-grade rated utility subsidiaries (New York State Electric & Gas Corporation ("NYSEG"), Rochester Gas and Electric Corporation ("RG&E"), CMP, The United Illuminating Company ("UI"), Connecticut Natural Gas Corporation ("CNG"), The Southern Connecticut Gas Company ("SCG") and The Berkshire Gas Company ("BGC")) executed a new credit facility with an aggregate limit of $3,575 million and a termination date of November 23, 2026. Under the terms of the AGR Credit Facility, each borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit contained in the agreement. NYSEG has a maximum sublimit of $700 million, RG&E has $300 million, CMP has $200 million, UI has $250 million, CNG and SCG have maximum sublimits of $150 million and BGC has a maximum sublimit of $50 million. Effective on November 23, 2021, the AGR Credit Facility was amended to increase Avangrid's maximum sublimit to $2,500 million and to establish minimum sublimits of $500 million for NYSEG, $200 million for RG&E, $100 million for CMP, $150 million for UI, $50 million for CNG and SCG and $25 million for BGC. Under the AGR Credit Facility, each of the borrowers are charged a facility fee that is dependent on their credit rating. The facility fees range from 10 to 22.5 basis points. CMP had not borrowed under this agreement as of both December 31, 2022 and 2021.

In the AGR Credit Facility we covenant not to permit, without the consent of the lender, our ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of indebtedness to total capitalization, the facility excludes from net worth the balance of accumulated other comprehensive loss as it appears on the balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness we may maintain. Continued un-remedied failure to comply with those covenants for five business days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity. Our ratio of indebtedness to total capitalization pursuant to the revolving credit facility was 0.38 to 1.00 at December 31, 2022. We are not in default as of December 31, 2022.

Note 9. Redeemable Preferred Stock

We have redeemable preferred stock that contains a feature that could lead to potential redemption-triggering events that are not solely within our control.

At December 31, 2022 and 2021, our redeemable preferred stock was:

					Amount (Thousands)	
Series		**Par Value per Share**	**Redemption Price per Share**	**Shares Authorized and Outstanding(1)**	**2022**	**2021**
CMP, 6% Non-callable	$	100 $	—	5,713 $	571 $	571
Total				$	**571 $**	**571**

(1) At December 31, 2022 CMP had $2,300,000 shares of $100 par value preferred stock authorized but unissued.

CMP Group owns 3,792 shares of the 5,713 shares outstanding.

Note 10. Leases

We have operating leases for office buildings, facilities, vehicles and certain equipment. Our finance leases are primarily related to electric generation, distribution, transmission and other. Certain of our lease agreements include rental payments adjusted periodically for inflation or are based on other periodic input measures. Our leases do not contain any material residual value guarantees or material restrictive covenants. Our leases have remaining lease terms of 1 year to 61 years, some of which may include options to extend the leases for up to 10 years, and some of which may include options to terminate the leases within one year. We consider extension or termination options in the lease term if it is reasonably certain we will exercise the option.

The components of lease cost and other information related to leases were as follows:

For the Years Ended December 31,		**2022**	**2021**
(Thousands)			
Lease cost			
Finance lease cost			
Amortization of right-of-use assets	$	285 $	342
Interest on lease liabilities		(38)	6
Total finance lease cost		247	348
Operating lease cost		1,463	1,639
Short-term lease cost		50	33
Variable lease cost		37	56
Total lease cost	**$**	**1,797 $**	**2,076**

Balance sheet and other information for the years ended December 31, 2022 and 2021 was as follows:

As of December 31,		**2022**	**2021**
(Thousands, except lease term and discount rate)			
Operating Leases			
Operating lease right-of-use assets	$	15,125 $	14,774
Operating lease liabilities, current		1,071	1,161
Operating lease liabilities, long-term		15,359	14,791
Total operating lease liabilities	$	16,430 $	15,952
Finance Leases			
Other assets	$	3,764 $	4,058
Other current liabilities		13	—
Other non-current liabilities		17	—
Total finance lease liabilities	$	30 $	—
Weighted-average Remaining Lease Term (years)			
Finance leases		2.33	—
Operating leases		16.26	18.71
Weighted-average Discount Rate			
Finance leases		3.47 %	—
Operating leases		3.89 %	3.84 %

For the years ended December 31, 2022 and 2021, supplemental cash flow information related to leases was as follows:

For the Years Ended December 31,		**2022**	**2021**
(Thousands)			
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$	1,547 $	1,804
Operating cash flows from finance leases	$	(38) $	6
Financing cash flows from finance leases	$	(39) $	254
Right-of-use assets obtained in exchange for lease obligations:			
Finance leases	$	(9) $	—
Operating leases	$	1,332 $	455

As of December 31, 2022, maturities of lease liabilities were as follows:

		Finance Leases	**Operating Leases**
(Thousands)			
Year ending December 31,			
2023	$	14 $	1,566
2024		14	1,571

2025	3	1,520
2026	—	1,505
2027	—	1,034
Thereafter	—	16,166
Total lease payments	**31**	**23,362**
Less: imputed interest	(1)	(6,932)
Total	$ **30**	$ **16,430**

Most of our leases do not provide an implicit rate in the lease; thus we use our incremental borrowing rate based on the information available at the commencement date in determining the present value of lease payments.

Note 11. Commitments and Contingent Liabilities

Power purchase contracts including non-utility generator

We recognized expense of approximately $20.3 million for non-utility generator power in 2022 and $29.8 million in 2021.

Note 12. Environmental Liability

From time to time environmental laws, regulations and compliance programs may require changes in our operations and facilities and may increase the cost of electric service.

Waste sites

The EPA and various state environmental agencies, as appropriate, have notified us that we are among the potentially responsible parties that may be liable for costs incurred to remediate certain hazardous substances at five waste sites. The five sites do not include sites where coal gas was manufactured in the past, which are discussed below. With respect to the five sites, four sites are included in Maine's Uncontrolled Sites Program (MUSP), one is subject to Maine's Waste Management Program and one is included on the Massachusetts Non-Priority Confirmed Disposal Site list. Two of the sites are also included on the National Priorities list. Any liability may be joint and several for certain of those sites. We have recorded an estimated liability of $1.5 million related to the five sites at December 31, 2022.

We have recorded an estimated liability of $3.4 million at December 31, 2022, related to three additional sites where we believe it is probable that we will incur remediation costs and/or monitoring costs as a result of being regulated under State Resource Conservation and Recovery Act (RCRA) program. It is reasonably possible the ultimate cost to remediate the sites may be significantly more than the accrued amount. Our estimate for costs to remediate the 9 total sites ranges from $4.0 million to $10.3 million as of December 31, 2022. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to us. We
recorded a corresponding regulatory asset, net of insurance recoveries, because we expect to recover the net costs in rates.

Manufactured gas plants

We have a program to investigate and perform necessary remediation and/or monitoring at our three sites where coal gas was manufactured in the past. The three sites are in Maine's Voluntary Response Action Program, Brownfield Cleanup Program or MUSP.

Our estimate for costs related to investigation, remediation and/or monitoring of the sites ranges from $0.1 million to $0.3 million at December 31, 2022. The estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial action, changes in technology relating to remedial alternatives, changes due to property use and changes to current laws and regulations.

The liability to investigate and perform remediation, as necessary, at the known inactive coal gas manufacturing sites was $0.2 million and $0.6 million at December 31, 2022 and 2021, respectively. We recorded a corresponding regulatory asset because we expect to recover the net costs in rates.

Our environmental liabilities are recorded on an undiscounted basis.

Note 13. Accounting for Derivative Instruments and Hedging Activities

Note 14. Fair Value of Financial Instruments and Fair Value Measurements

The estimated fair value of debt amounted to $1,182 million and $1,491 million as of December 31, 2022 and 2021, respectively. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the electricity industry and the credit ratings of the borrowers in each case. The fair value hierarchy for the fair value of debt is considered as Level 2.

Assets and liabilities measured at fair value on a recurring basis

There were no financial instruments as of December 31, 2022. The financial instruments measured at fair value as of December 31, 2021 consist of:

Description	**Total**	**(Level 1)**	**(Level 2)**	**(Level 3)**
(Thousands)				
2021				
Assets				
Derivatives	$ 38	$ —	$ —	$ 38
Total	$ **38**	$ **—**	$ **—**	$ **38**

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2022 and 2021. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

Valuation techniques: We enter into fuel derivative contracts to hedge our unleaded and diesel fuel requirements for our fleet vehicles. Exchange based forward market prices are used but because a basis adjustment is added to the forward prices, we include the fair value measurement for these contracts in Level 3.

The reconciliation of changes in the fair value of financial instruments based on Level 3 inputs for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,	**2022**	**2021**
(Thousands)		
Beginning balance	$ 38	$ (137)
Total (losses) gains (realized/unrealized)		
Included in earnings	(803)	(259)
Included in other comprehensive income	765	434
Ending balance	$ **—**	$ **38**

The amounts of realized and unrealized gain and loss included in earnings for the period (above) are reported in Operations and maintenance of the consolidated statements of income.

Note 15. Accumulated Other Comprehensive Loss

Accumulated Other Comprehensive Loss for the years ended December 31, 2022 and 2021 consisted of:

	Balance December 31, 2020	**2021 Change**	**Balance December 31, 2021**	**2022 Change**	**Balance December 31, 2022**
(Thousands)					
Amortization of pension cost for nonqualified plans and current year actuarial gain, net of income tax expense of $33 for 2021 and $87 for 2022	$ (1,979)	$ 83	$ (1,896)	$ 224	$ (1,672)
Unrealized gain on derivatives qualified as hedges:					
Unrealized gain during period on derivatives qualified as hedges, net of income tax expense of $231 for 2021 and $214 for 2022		203		551	

Reclassification adjustment for gain included in net income, net of income tax benefit of ($138) for 2021 and ($225) for 2022			(121)		(578)	
Reclassification adjustment for loss on settled cash flow treasury hedges, net of income tax expense of $96 for 2021 and $51 for 2022			85		130	
Net unrealized gain on derivatives qualified as hedges		(1,814)	167	(1,647)	103	(1,544)
Accumulated Other Comprehensive Loss	$	**(3,793) $**	**250 $**	**(3,543) $**	**327 $**	**(3,216)**

No Accumulated Other Comprehensive Loss is attributable to the noncontrolling interest for the above periods.

Note 16. Post-Retirement and Similar Obligations

We have funded non-contributory defined benefit pension plans that cover all eligible employees. The plans provide defined benefits based on years of service and final average salary for employees hired before 2002. Most employees hired in 2002, or later based upon the plan, are covered under a cash balance plan or formula where their benefit accumulates based on a percentage of annual salary and credited interest. During 2013, we announced that we would discontinue, effective December 31, 2013, the cash balance accruals for all non-union employees covered under the cash balance plans or formula. At the same time, the plans were closed to newly-hired non-union employees. The plans had been closed to newly-hired union employees in prior years. CMP's unionized employees covered under the cash balance plans ceased to receive accruals as of December 31, 2014. Their earned balances will continue to accrue interest but will no longer be increased by a flat dollar amount or percentage of pay, as defined by the plan. Instead, they will receive a contribution to their account under their respective company's defined contribution plan. During 2022, the Company decided to freeze pension benefit accruals and contribution credits for non-union employees and transition their retirement benefits to the 401(k) Plan. Employees not participating in a defined benefit plan are eligible to receive an enhanced or core 401(k) Company matching contribution, depending on whether they are union or non-union employees, respectively.

The company maintains a 401(k) Savings and Retirement Plan (the Plan) for all eligible employees as defined in the Plan agreement. Participants in the Plan may contribute a percentage of their compensation and the company may match a predetermined percentage of the participant contributions. Expenses under the Plan for the Company totaled approximately $7.9 million for 2022 and $5.3 million for 2021.

We also have other postretirement health care benefit plans covering substantially all of our employees. The health care plans are contributory with participants' contributions adjusted annually.

Non-Qualified Retirement Benefit Plans

We also sponsor various unfunded non-qualified pension plans for certain current employees, former employees and former directors. The total liability for these plans, which is included in Other non-current liabilities on our consolidated balance sheets, was $1.2 million and $1.6 million at December 31, 2022 and 2021, respectively.

Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2022 and 2021 consisted of:

		Pension Benefits		Postretirement Benefits	
As of December 31,		**2022**	**2021**	**2022**	**2021**
(Thousands)					
Change in benefit obligation					
Benefit obligation as of January 1,	**$**	**407,423 $**	**462,706 $**	**94,024 $**	**108,172**
Service cost		4,673	6,101	537	626
Interest cost		12,447	11,603	2,491	2,402
Curtailments/Settlements		(50,326)	(21,790)	—	—
Actuarial gain		(83,071)	(34,213)	(28,899)	(11,097)
Benefits paid		(17,192)	(16,984)	(7,364)	(6,079)
Benefit obligation as of December 31,	**$**	**273,954 $**	**407,423 $**	**60,789 $**	**94,024**
Change in plan assets					
Fair value of plan assets at January 1,	**$**	**368,366 $**	**354,910 $**	**22,161 $**	**34,465**
Actual return on plan assets		(76,432)	32,230	(4,036)	3,509
Employer contributions		20,000	20,000	3,985	—
Settlements		(34,206)	(21,790)	—	—
Benefits paid		(17,192)	(16,984)	(7,364)	(15,813)
Fair value of plan assets at December 31,	**$**	**260,536 $**	**368,366 $**	**14,746 $**	**22,161**
Funded status at December 31,	**$**	**(13,418) $**	**(39,057) $**	**(46,043) $**	**(71,863)**

During 2022, the pension and postretirement benefit obligations had actuarial gains of, respectively, $83.1 million and $28.9 million, primarily due to gains from discount rate increases of $81.7 million and $15.6 million, respectively. The pension benefit obligation had a reduction of $50.3 million from settlements ($34.2 million) and curtailments ($16.1 million). The settlements were lump-sum payments made within the pension plan guidelines at the discretion of the plan participants who opted to retire. The curtailments were driven by a Company decision to freeze pension benefit accruals and contribution credits for non-union employees and transition their retirement benefits to a 401(k) plan.

During 2021, the pension benefit obligation had an actuarial gain of $34.2 million, primarily due to a $24.1 million gain from increases in discount rates. There were no significant plan design changes in 2021. There were no significant gains and losses relating to the postretirement benefit obligations.

Amounts recognized in the consolidated balance sheets as of December 31, 2022 and 2021 consisted of:

		Pension Benefits		Postretirement Benefits	
As of December 31,		**2022**	**2021**	**2022**	**2021**
(Thousands)					
Non-current liabilities	$	(13,418) $	(39,057) $	(46,043) $	(71,863)

We have determined that we are allowed to defer as regulatory assets or regulatory liabilities items that would otherwise be recorded in accumulated other comprehensive income pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans.

Amounts recognized as regulatory assets or regulatory liabilities for the years ended December 31, 2022 and 2021 consisted of:

		Pension Benefits		Postretirement Benefits	
Years Ended December 31,		**2022**	**2021**	**2022**	**2021**
(Thousands)					
Net loss (gain)	$	81,944 $	101,256 $	(2,789) $	22,071
Prior service credit	$	— $	— $	— $	(637)

Our accumulated benefit obligation (ABO) for all qualified defined benefit pension plans was $267.2 million and $377.5 million as of December 31, 2022 and 2021. Our postretirement benefits were partially funded at December 31, 2022 and 2021.

The projected benefit obligation (PBO) and ABO exceeded the fair value of pension plan assets for our qualified plans as of December 31, 2022 and 2021. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets for the relevant periods.

As of December 31,		**2022**	**2021**
(Thousands)			
Projected benefit obligation	$	273,954 $	407,423
Accumulated benefit obligation	$	267,157 $	377,500
Fair value of plan assets	$	260,536 $	368,366

As of December 31, 2022 and 2021, the accumulated postretirement benefits obligation for all the qualified plans exceeded the fair value of plan assets.

Components of net periodic benefit cost and other changes in plan assets and benefit obligations recognized in income and regulatory assets and liabilities for the years ended December 31, 2022 and 2021 consisted of:

	Pension Benefits		Postretirement Benefits	
For the years ended December 31,	**2022**	**2021**	**2022**	**2021**
(Thousands)				
Net Periodic Benefit Cost:				
Service cost	$ 4,673	$ 6,101	$ 537	$ 626
Interest cost	12,447	11,603	2,491	2,402
Expected return on plan assets	(19,483)	(23,532)	(1,323)	(1,768)
Amortization of prior service benefit	—	—	(637)	(2,013)
Settlement charge	10,096	5,421	—	—
Amortization of net loss	5,940	17,866	1,321	2,713
Net Periodic Benefit Cost	**$ 13,673**	**$ 17,459**	**$ 2,389**	**$ 1,960**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities:				
Net loss (gain)	$ 12,844	$ (42,911)	$ (23,539)	$ (12,837)
Amortization of net loss	(5,940)	(17,866)	(1,321)	(2,713)
Settlements	(10,096)	(5,421)	—	—
Curtailments	(16,120)	—	—	—
Amortization of prior service benefit	—	—	637	2,013
Total Other Changes	**(19,312)**	**(66,198)**	**(24,223)**	**(13,537)**
Total Recognized	**$ (5,639)**	**$ (48,739)**	**$ (21,834)**	**$ (11,577)**

We include the net periodic benefit cost in other operating expenses for the service component and other deductions for the non-service component. The net periodic benefit cost for postretirement benefits represents the amount expensed for providing health care benefits to retirees and their eligible dependents.

The weighted-average assumptions used to determine benefit obligations as of December 31, 2022 and 2021 consisted of:

	Pension Benefits		Postretirement Benefits	
	2022	**2021**	**2022**	**2021**
Discount rate	5.21% / 5.25% union	2.96% / 3.05% union	5.13 %	2.74 %
Rate of compensation increase	3.00 %	Age-Related Rates / 3.50% union	3.00% for union	3.50 %
Interest crediting rate	4.48% non-union / 4.50% union	2.00% non-union / 4.50% union	N/A	N/A

The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rates by developing yield curves derived from a portfolio of high grade non-callable bonds with yields that closely match the duration of the expected cash flows of our benefit obligations.
The weighted-average assumptions used to determine net periodic benefit cost for the years ended December 31, 2022 and 2021 consisted of:

	Pension Benefits		Postretirement Benefits	
Years Ended December 31,	**2022**	**2021**	**2022**	**2021**
Discount rate	2.96% / 4.15% / 3.05%	2.56 %	2.74 %	2.29 %
Expected long-term return on plan assets	6.50% / 5.00% / 6.00%	7.00 %	5.97 %	5.13 %
Rate of compensation increase (Union/Non-Union)	Age-Related Rates / 3.50% union	Age-Related Rates / 3.50% union	3.50% for union	Age-Related Rates / 3.50% union

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations, and the effect of rebalancing of plan assets discussed below. Our analysis considered current capital market conditions and projected conditions. Our policy is to calculate the expected return on plan assets using the market related value of assets. We amortize unrecognized actuarial gains and losses using the standard amortization methodology under which amounts in excess of 10% of the greater of the projected benefit obligation or market related value are amortized over the plan participants' average remaining service to retirement.

Assumed health care cost trend rates used to determine benefit obligations as of December 31, 2022 and 2021 consisted of:

As of December 31,	**2022**	**2021**
Health care cost trend rate assumed for next year	6.00% / 6.50%	6.50% / 7.25%
Rate to which cost trend rate is assumed to decline (ultimate trend rate)	4.50 %	4.50 %
Year that the rate reaches the ultimate trend rate	2029/2027	2029/2027

Contributions

We make annual contributions in accordance with our funding policy of not less than the minimum amounts as required by applicable regulations. We do not expect to contribute to our pension or other postretirement plans during 2023.

Estimated future benefit payments

Expected benefit payments and Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) subsidy receipts reflecting expected future service as of December 31, 2022 consisted of:

(Thousands)	**Pension Benefits**	**Postretirement Benefits**	**Medicare Act Subsidy Receipts**
2023	$ 23,981	$ 5,482	$ 134
2024	$ 23,412	$ 5,354	$ 135
2025	$ 23,486	$ 5,193	$ 139
2026	$ 23,200	$ 5,078	$ 139
2027	$ 23,655	$ 4,975	$ 141
2028 - 2032	$ 108,324	$ 22,711	$ 701

Plan assets

Our pension benefits plan assets are held in a master trust providing for a single trustee/custodian, a uniform investment manager lineup, and an efficient, cost-effective means of allocating expenses and investment performance to each plan under the master trust. Our primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our tolerance for risk. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. Our primary means for achieving capital preservation is through diversification of the trust's investments while avoiding significant concentrations of risk in any one area of the securities markets. Within each asset group, further diversification is achieved through utilizing multiple asset managers and systematic allocation to various asset classes and providing broad exposure to different segments of the equity, fixed income and alternative investment markets.

The asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets within broad categories of asset classes made up of Return-Seeking and Liability-Hedging investments. We currently have target allocations ranging from 25%-60% for Return-Seeking assets and 40%-75% for Liability-Hedging assets. Return-Seeking assets include investments in domestic, international and emerging equity, real estate, global asset allocation strategies and hedge funds. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the strategies and hedge funds. Liability Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of pension benefits plan assets, by asset category, as of December 31, 2022, consisted of:

As of December 31, 2022		Fair Value Measurements		
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 7,298	$ 18	$ 7,280	$ —
U.S. government securities	22,837	22,837	—	—
Common stocks	7,819	7,819	—	—
Registered investment companies	12,796	12,796	—	—
Corporate bonds	79,902	—	79,902	—
Preferred stocks	92	92	—	—
Common collective trusts	67,859	—	67,859	—
Other, principally annuity, fixed income	473	—	473	—
	$ 199,076	**$ 43,562**	**$ 155,514**	**$ —**
Other investments measured at net asset value	61,460			
Total	**$ 260,536**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2021, consisted of:

As of December 31, 2021		Fair Value Measurements		
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 11,350	$ 1,663	$ 9,687	$ —
U.S. government securities	21,896	21,896	—	—
Common stocks	15,913	15,913	—	—
Registered investment companies	34,079	34,079	—	—
Corporate bonds	97,111	—	97,111	—
Preferred stocks	104	104	—	—
Common collective trusts	125,099	—	125,099	—
Other, principally annuity, fixed income	2,687	1	2,686	—
	$ 308,239	**$ 73,656**	**$ 234,583**	**$ —**
Other investments measured at net asset value	60,127			
Total	**$ 368,366**			

Valuation Techniques

We value our pension benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities - at the closing price reported in the active market in which the security is traded.
- Common stocks - at the closing price reported in the active market in which the individual investment is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks - at the closing price reported in the active market in which the individual investment is traded.
- Common collective trusts/Registered investment companies - Level 1: at the closing price reported in the active market in which the individual investment is traded. Level 2: the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Other investments measured at net asset value (NAV) - fund shares offered to a limited group of investors and alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

Our postretirement benefits plan assets are held with trustees in multiple voluntary employees' beneficiary association (VEBA) and 401(h) arrangements and are invested among and within various asset classes to achieve sufficient diversification in accordance with our risk tolerance. This is achieved for our postretirement benefits plan assets through the utilization of multiple institutional mutual and money market funds, providing exposure to different segments of the fixed income, equity and short-term cash markets. Substantially all of the postretirement benefits plan assets are invested in VEBA and 401(h) arrangements that are not subject to income taxes with the remainder being invested in arrangements subject to income taxes.

We have established a target asset allocation policy within allowable ranges for postretirement benefits plan assets of 49%-69% for equity securities and 31%-51% for fixed income investments. Equity investments are diversified across U.S. and non-U.S. stocks, investment styles, and market capitalization ranges. Fixed income investments are primarily invested in U.S. bonds and may also include some non-U.S. bonds. We primarily minimize the risk of large losses through diversification but also through monitoring and managing other aspects of risk through quarterly investment portfolio reviews. Systematic rebalancing within target ranges increases the probability of increasing the projected expected return, while mitigating risk, should any asset categories drift outside their specified ranges.

The fair values of other postretirement benefits plan assets, by asset category, as of December 31, 2022, consisted of:

As of December 31, 2022		Fair Value Measurements		
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 602	$ 1	$ 601	$ —
U.S. government securities	259	259	—	—
Common stocks	277	277	—	—
Registered investment companies	9,656	9,656	—	—
Corporate bonds	1,188	—	1,188	—
Preferred stocks	1	1	—	—
Common collective trusts	1,938	—	1,938	—
Other, principally annuity, fixed income	18	—	18	—
	$ 13,939	**$ 10,194**	**$ 3,745**	**$ —**
Other investments measured at net asset value	807			
Total	**$ 14,746**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2021, consisted of:

As of December 31, 2021	Fair Value Measurements

(Thousands)		Total	Level 1	Level 2	Level 3
Asset Category					
Cash and cash equivalents	$	1,456 $	32 $	1,424 $	—
U.S. government securities		401	401	—	—
Common stocks		362	362	—	—
Registered investment companies		15,081	15,081	—	—
Corporate bonds		1,582	—	1,582	—
Preferred stocks		2	2	—	—
Common collective trusts		2,336	—	2,336	—
Other, principally annuity, fixed income		52	—	52	—
	$	**21,272 $**	**15,878 $**	**5,394 $**	**—**
Other investments measured at net asset value		889			
Total	**$**	**22,161**			

Valuation techniques

We value our postretirement benefits plan assets as follows:
- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities - at the closing price reported in the active market in which the security is traded.
- Common stocks and registered investment companies - at the closing price reported in the active market in which the individual investment is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Common collective trusts - the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Other investments measured at net asset value (NAV) - fund shares offered to a limited group of investors and alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

Pension and postretirement plan equity securities did not include any AGR and Iberdrola common stock as of both December 31, 2022 and 2021.

Note 17. Other Income and Other Deductions

Note 18. Related Party Transactions

Certain Networks subsidiaries, including CMP, borrow from AGR, the parent of Networks, through intercompany revolving credit agreements. For CMP, the intercompany revolving credit agreements provide access to supplemental liquidity. See Note 8 for further detail on the credit facility with AGR.

AGR, through its affiliates, provides administrative and management services to Networks operating utilities, including CMP, pursuant to service agreements. The cost of those services is allocated in accordance with methodologies set forth in the service agreements. The cost allocation methodologies vary depending on the type of service provided. Management believes such allocations are reasonable. The charge for operating and capital services provided to CMP by AGR and its affiliates was $44.9 million and $42.3 million for 2022 and 2021, respectively. Cost for services includes amounts capitalized in utility plant, which was approximately $9.5 million in 2022 and $8.4 million in 2021. The remainder was primarily recorded as operations and maintenance expense. The charges for services provided by CMP to AGR and its subsidiaries were approximately $9.4 million for 2022 and $5.1 million for 2021. All charges for services are at cost. All of the charges associated with services provided are recorded as revenues to offset other operating expenses on the financial statements.

The balance in accounts payable to affiliates of $40.9 million at December 31, 2022 and the balance of $38.3 million at December 31, 2021 is mostly payable to Avangrid Service Company.
The balance in accounts receivable from affiliates of $6.9 million at December 31, 2022 and the balance of $63.9 million at December 31, 2021 is mostly receivable from New England Clean Energy Connect.

The $0.2 million of notes receivable from affiliates at December 31, 2022 is from Avangrid, Inc. There were no notes receivable from affiliates at December 31, 2021. Notes receivable from affiliates relate to the Virtual Money Pool Agreement as discussed in Note 8 of these financial statements.

In 2018, the New England Clean Energy Connect, or NECEC, transmission project, proposed in a joint bid by CMP and Hydro-Québec, was selected by the Massachusetts electric distribution utilities and the Massachusetts Department of Energy Resources in the Commonwealth of Massachusetts' 83D clean energy Request for Proposal. The NECEC transmission project includes a 145-mile transmission line linking the electrical grids in Québec, Canada and New England.

On January 4, 2021, in connection with certain stipulation agreements (Stipulations), CMP transferred the NECEC project to NECEC Transmission LLC pursuant to the terms of a transfer agreement dated November 3, 2020. At that time, NECEC Transmission LLC reimbursed to CMP approximately $101 million in construction and other costs CMP had incurred in connection with the NECEC through the date of transfer.

As consideration for the transfer of the NECEC project, NECEC Transmission LLC agreed to pay CMP the sum total of $60 million, payable in one hundred and sixty equal installments of $375,000 each, due the first business day of each January, April, July and October, to be included in CMP's NECEC Rate Relief Fund as established by the Stipulations. CMP received $1.5 million in such payments from NECEC Transmission LLC in 2021. Similarly and in connection with the Stipulations, CMP will receive $80 million, payable in one hundred and sixty equal installments of $500,000, due the first business day of each January, April, July and October, from funding provided by H.Q. Energy Services (U.S.) Inc., an unaffiliated entity, which will be included in CMP's NECEC Rate Relief Fund. Pursuant to the terms of the Stipulations, all these payments were suspended in December 2021 following the stoppage of construction of the NECEC project and remained suspended as of December 31, 2022. Payments will remain suspended until construction resumes. In addition, as of December 31, 2021, CMP accrued $61.4 million of contributions in aid of construction within Construction work in progress related to NECEC Transmission LLC paying for CMP-owned assets which CMP is improving related to the NECEC interconnection. The accrued amount was paid to CMP in January 2022.

Note 19. Subsequent Events

The company has performed a review of subsequent events through March 30, 2023, which is the date these consolidated financial statements were available to be issued.

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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		(1,894,736)			(1,798,936)	(99,224)	(3,792,896)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income					38,808	(189,879)	(151,071)		
3	Preceding Quarter/Year to Date Changes in Fair Value		83,392				317,780	401,172		
4	Total (lines 2 and 3)		83,392			38,808	127,901	250,101	179,832,108	180,082,209
5	Balance of Account 219 at End of Preceding Quarter/Year		(1,811,344)			(1,760,128)	28,677	(3,542,795)		
6	Balance of Account 219 at Beginning of Current Year		(1,811,344)			(1,760,128)	28,677	(3,542,795)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income					132,160	(613,675)	(481,515)		
8	Current Quarter/Year to Date Changes in Fair Value		223,517				584,998	808,515		
9	Total (lines 7 and 8)		223,517			132,160	(28,677)	327,000	156,610,524	156,937,524
10	Balance of Account 219 at End of Current Quarter/Year		(1,587,827)			(1,627,968)		(3,215,795)		

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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)	4,442,614,211	4,442,614,211					
4	Property Under Capital Leases	18,889,592	18,889,592					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	538,081,657	538,081,657					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	4,999,585,460	4,999,585,460					
9	Leased to Others							
10	Held for Future Use	3,528,884	3,528,884					
11	Construction Work in Progress	233,663,593	233,663,593					
12	Acquisition Adjustments	331,976,097	331,976,097					
13	Total Utility Plant (8 thru 12)	5,568,754,034	5,568,754,034					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	1,412,281,757	1,412,281,757					
15	Net Utility Plant (13 less 14)	4,156,472,277	4,156,472,277					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	1,279,628,697	1,279,628,697					
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	121,277,543	121,277,543					
22	Total in Service (18 thru 21)	1,400,906,240	1,400,906,240					
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							
27	Held for Future Use							
28	Depreciation	2,291	2,291					
29	Amortization							
30	Total Held for Future Use (28 & 29)	2,291	2,291					
31	Abandonment of Leases (Natural Gas)							

32	Amortization of Plant Acquisition Adjustment	11,373,226	11,373,226					
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,412,281,757	1,412,281,757					

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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					
3	Nuclear Materials					
4	Allowance for Funds Used during Construction					
5	(Other Overhead Construction Costs, provide details in footnote)					
6	SUBTOTAL (Total 2 thru 5)					
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)					
9	In Reactor (120.3)					
10	SUBTOTAL (Total 8 & 9)					
11	Spent Nuclear Fuel (120.4)					
12	Nuclear Fuel Under Capital Leases (120.6)					
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)					
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	0				
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: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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						
3	(302) Franchise and Consents	52,330					52,330
4	(303) Miscellaneous Intangible Plant	153,651,700	3,287,359			3,587,931	160,526,990
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	153,704,030	3,287,359			3,587,931	160,579,320
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights						
9	(311) Structures and Improvements						
10	(312) Boiler Plant Equipment						
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units						
13	(315) Accessory Electric Equipment						
14	(316) Misc. Power Plant Equipment						
15	(317) Asset Retirement Costs for Steam Production						
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)						
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights						
19	(321) Structures and Improvements						
20	(322) Reactor Plant Equipment						
21	(323) Turbogenerator Units						
22	(324) Accessory Electric Equipment						
23	(325) Misc. Power Plant Equipment						
24	(326) Asset Retirement Costs for Nuclear Production						
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)						
26	C. Hydraulic Production Plant						

27	(330) Land and Land Rights						
28	(331) Structures and Improvements						
29	(332) Reservoirs, Dams, and Waterways						
30	(333) Water Wheels, Turbines, and Generators						
31	(334) Accessory Electric Equipment						
32	(335) Misc. Power Plant Equipment						
33	(336) Roads, Railroads, and Bridges						
34	(337) Asset Retirement Costs for Hydraulic Production						
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)						
36	D. Other Production Plant						
37	(340) Land and Land Rights						
38	(341) Structures and Improvements						
39	(342) Fuel Holders, Products, and Accessories						
40	(343) Prime Movers						
41	(344) Generators						
42	(345) Accessory Electric Equipment						
43	(346) Misc. Power Plant Equipment						
44	(347) Asset Retirement Costs for Other Production						
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)						
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)						
47	3. Transmission Plant						
48	(350) Land and Land Rights	71,553,643	358,089				71,911,732
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	109,989,587	260,942				110,250,529
50	(353) Station Equipment	800,387,259	18,469,371			47,570	818,904,200
51	(354) Towers and Fixtures	12,420,598					12,420,598
52	(355) Poles and Fixtures	514,494,293		659,849		11,653,444	525,487,888
53	(356) Overhead Conductors and Devices	971,757,448	39,735,310	840		(13,519,605)	997,972,313
54	(357) Underground Conduit	2,671,127					2,671,127
55	(358) Underground Conductors and Devices	7,346,794	82,886	26,618		1,813,827	9,216,889
56	(359) Roads and Trails	599,757		12,184			587,573
57	(359.1) Asset Retirement Costs for Transmission Plant	12,184					12,184
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	2,491,232,690	58,906,598	699,491		(4,764)	[(a)] 2,549,435,033
59	4. Distribution Plant						
60	(360) Land and Land Rights	4,689,642	6,480				4,696,122
61	(361) Structures and Improvements	12,756,727					12,756,727
62	(362) Station Equipment	287,680,774	6,683,861			4,764	294,369,399
63	(363) Energy Storage Equipment – Distribution						

64	(364) Poles, Towers, and Fixtures	453,446,670	112,977	2,433,261		43,797,620	494,924,006
65	(365) Overhead Conductors and Devices	408,369,720	100,553,089	378,494		(51,444,341)	457,099,974
66	(366) Underground Conduit	8,380,954				29,663	8,410,617
67	(367) Underground Conductors and Devices	64,565,176	870,001	72,868		827,003	66,189,312
68	(368) Line Transformers	283,667,405	8,401,077	1,637,351		756,690	291,187,821
69	(369) Services	82,473,039	24,805	337,458		6,033,157	88,193,543
70	(370) Meters	81,167,613	2,733,735	503,679			83,397,669
71	(371) Installations on Customer Premises	190,500	48,000				238,500
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	14,850,971	458,697	313,866			14,995,802
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,702,239,191	119,892,722	5,676,977		4,556	1,816,459,492
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	1,564,054					1,564,054
87	(390) Structures and Improvements	100,448,531	3,893,991				104,342,522
88	(391) Office Furniture and Equipment	33,563,402	2,665,280	1,145,133			35,083,549
89	(392) Transportation Equipment	64,712,214	6,612,225	354,680			70,969,759
90	(393) Stores Equipment	1,051,769		159,116			892,653
91	(394) Tools, Shop and Garage Equipment	15,021,248	1,865,982	156,208			16,731,022
92	(395) Laboratory Equipment	2,783,434		169,875			2,613,559
93	(396) Power Operated Equipment						
94	(397) Communication Equipment	97,009,415	42,145,216	513,445			138,641,186
95	(398) Miscellaneous Equipment	78,587,039	4,732,470	37,226			83,282,283
96	SUBTOTAL (Enter Total of lines 86 thru 95)	394,741,106	61,915,164	2,535,683			454,120,587
97	(399) Other Tangible Property						
98	(399.1) Asset Retirement Costs for General Plant	101,436					101,436
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	394,842,542	61,915,164	2,535,683			454,222,023
100	TOTAL (Accounts 101 and 106)	4,742,018,453	244,001,843	8,912,151		3,587,723	4,980,695,868
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)	4,742,018,453	244,001,843	8,912,151		3,587,723	4,980,695,868

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FOOTNOTE DATA

(a) Concept: TransmissionPlant
Includes $71,222,436 of Pool Transmission Facility (PTF) investments included in the Regional System Plan and placed in service on or after January 1, 2004 ("Post-2003 PTF Investment"), and $1,318,113,267 of PTF and $43,081,639 of Non-PTF investments associated with the Maine Power Reliability Program (MPRP)

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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						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
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36						
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38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL					

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Original Costs of Property Less than $240,000 Per: Transmission Lines	01/01/1914	12/31/9999	3,207,720
23	Transmission Substations	01/01/1914	12/31/9999	111,367
24	Distribution Substations	01/01/1914	12/31/9999	195,476
25	Distribution Lines	01/01/1970	12/31/9999	3,079
26	General	01/01/1974	12/31/9999	11,242
47	TOTAL			3,528,884

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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	Transmission Property-Bulk Electric System Program - Portland Area Non-PTF	8,637,154
2	Transmission Property-Transmission Line 1 Rebuild Non-PTF	5,939,396
3	Transmission Property-Substation Modernization Projects - Forest Avenue	2,430,714
4	Transmission Property-Lakes Region Reinforcement Line Rebuild Non-PTF	2,648,482
5	Transmission Property-Transmission Line 49 Rebuild Non-PTF	4,796,204
6	Transmission Property-Transmission Lines Non-PTF	3,469,813
7	Transmission Property-Substation Modernization Projects - Forest Avenue Non-PTF	7,915,305
8	Transmission Property-Bulk Electric System Program - Brunswick Area Non-PTF	2,669,477
9	Transmission Property-Substation Modernization Projects - Deer Rips	3,386,856
10	Transmission Property-Substation Modernization Projects - Deer Rips Non-PTF	2,741,548
11	Transmission Property-Midcoast Non-Transmission Alternative Project PTF	3,477,658
12	Transmission Property-Bulk Electric System Program - Southern Maine Non-PTF	2,334,798
13	Transmission Property-Bulk Electric System Program - Biddeford Area Non-PTF	2,252,803
14	Transmission Property-Transmission Line 31 Rebuild Non-PTF	2,199,875
15	Transmission Property-Remote Terminal Unit Replacement Program	6,531,664
16	Transmission Property-Bulk Electric System Program - Portland Area PTF	1,397,408
17	Transmission Property-Bulk Electric System Program - Augusta Area Non PTF T	1,014,838
18	Transmission Property-Substation Project Non PTF	2,326,851
19	Transmission Property-Telecomm Infrastructure	2,025,491
20	Transmission Property-Security Modernization Project	1,217,570
21	Transmission Property-Transmission Section 113 Corridor Project	1,269,343
22	Distribution Property-Substation Modernization Projects	39,980,136
23	Distribution Property-Line Inspections	9,720,849
24	Distribution Property-Distribution Lines	8,112,501
25	Distribution Property-Goosefare Substation Second Circuit	7,477,693
26	Distribution Property-Biddeford Pump Substation Second Circuit	8,302,774
27	Distribution Property-Resiliency Plan Projects	5,417,054
28	Distribution Property-Factory Island Transformer	5,101,157
29	Distribution Property-Distributed Generation	8,861,116
30	Distribution Property-Electric Betterments	4,167,903
31	Distribution Property-Bulk Electric System Program - Portland Area Non PTF	1,512,903
32	Distribution Property-Substation Minor Capital Projects	2,573,545

33	Distribution Property-Energy Manager		1,374,505
34	Distribution Property-Remote Terminal Unit Replacement Program		1,295,915
35	Distribution Property-Supervisory Control and Data Acquisition/Automation Projects		1,171,772
36	Distribution Property-Storms Projects		10,373,032
37	General Property-Building Planning and Space Management Projects		3,595,271
38	General Property-Recloser Automation		2,457,307
39	General Property-IT CAPEX Network Applications		3,019,463
40	General Property-Telecom Automation		1,553,315
41	General Property-Telecom Infrastructure		2,849,943
42	General Property-Facilities Management Projects - AMC		2,466,855
43	General Property-Advanced Metering Infrastructure		1,904,009
44	General Property-Advanced Metering Infrastructure HE System		3,028,536
45	General Property-Cybersecurity Project		2,356,455
46	Minor Projects-Transmission Property <$1 Million		7,374,010
47	Minor Projects-Distribution Property <$1 Million		13,440,482
48	Minor Projects-General Property <$1 Million		3,491,844
43	Total		233,663,593

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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	1,187,641,195	1,187,638,997	2,198	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	119,058,105	119,058,105		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	5,504,158	5,504,158		
7	Other Clearing Accounts	483,462	483,462		
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):	93		93	
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	125,045,818	125,045,725	93	
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(8,913,148)	(8,913,148)		
13	Cost of Removal	(25,829,483)	(25,829,483)		
14	Salvage (Credit)				
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(34,742,631)	(34,742,631)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	1,686,606	[a]1,686,606		
17.2	Transfer to Other Business				
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,279,630,988	1,279,628,697	2,291	
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production				
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production				
25	Transmission	602,737,635	[b]602,737,635		
26	Distribution	507,476,136	507,473,845	2,291	
27	Regional Transmission and Market Operation				
28	General	169,417,217	169,417,217		

29	TOTAL (Enter Total of lines 20 thru 28)	1,279,630,988	1,279,628,697	2,291	

(a) Concept: OtherAdjustmentsToAccumulatedDepreciation

Credit item represents the difference on the Reserve Ledger to the Retirements reported on the Plant Ledger. The Reserve Ledger reports Accumulated Depreciation for the asset only in the disposal with a post depreciation adjustment fo [1] r the remaining difference [2] .

(b) Concept: AccumulatedDepreciationTransmission

Includes $22,784,867 of Pool Transmission Facility (PTF) accumulated depreciation reserve balances included in the Regional System Plan and placed in service on or after January 1, 2004 ("Post-2003 PTF accumulated depreciation reserve"), and $263,775,287 of PTF and $7,372,072 of Non-PTF accumulated depreciation reserve associated with the Maine Power Reliability Program (MPRP).

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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	Maine Yankee Atomic Power Co.	09/01/1969						
2	Common Stock - 1,900 shares	09/01/1969		190,000			190,000	
3	Respondent's Share of Equity	09/01/1969		350,880	53,560		404,440	
4	10% Return During Construction	09/01/1969		61,400			61,400	
5	Subtotal	09/01/1969		602,280	53,560		655,840	
6	Connecticut Yankee Atomic Power Co.	06/01/1967						
7	Common Stock - 1,105 shares	06/01/1967		110,525			110,525	
8	Respondent's Share of Equity	06/01/1967		17,985	6,822		24,807	
9	Capital Contributions	06/01/1967		12,080			12,080	
10	Subtotal	06/01/1967		140,590	6,822		147,412	
11	Yankee Atomic Electric Company	01/01/1962						
12	Common Stock - 729 shares	01/01/1962		72,900			72,900	
13	Respondent's Share of Equity	01/01/1962		85,108	(2,036)		83,072	
14	Subtotal	01/01/1962		158,008	(2,036)		155,972	
15	Maine Electric Power Company, Inc.	02/01/1972						
16	Common Stock - 6,877 shares	02/01/1972		687,700			687,700	
17	Respondent's Share of Equity	02/01/1972		46,351,274	11,631,972		57,983,246	
18	Equity Infusion	02/01/1972		62,287,134			62,287,134	
19	Cost of Acquisition	02/01/1972		3,507,937			3,507,937	
20	Subtotal	02/01/1972		112,834,045	11,631,972		124,466,017	
21	NORVARCO	01/01/1990						
22	Common Stock - 5,000 shares	01/01/1990		500,000			500,000	
23	Equity Infusion	01/01/1990		4,885,682		1,152,420	6,038,102	
24	Respondent's Share of Equity	01/01/1990		(1,718,710)	29,911		(1,688,799)	
25	Subtotal	01/01/1990		3,666,972	29,911	1,152,420	4,849,303	
42	Total Cost of Account 123.1 $		Total	117,401,895	11,720,229	1,152,420	130,274,544	

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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)			—
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)	32,362,705	34,933,969	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)			—
8	Transmission Plant (Estimated)	1,629,755	2,673,460	Electric
9	Distribution Plant (Estimated)	1,113,599	1,904,826	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			—
11	Assigned to - Other (provide details in footnote)			—
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	35,106,059	39,512,255	
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				—
20	TOTAL Materials and Supplies	[(a)]35,106,059	[(b)]39,512,255	

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FOOTNOTE DATA

(a) Concept: MaterialsAndOperatingSupplies

Functional Allocation of Account 154, Plant Materials and Operating Supplies (Estimated):

Balance End of Year:		
Distribution:	$	14,250,462
Transmission:	$	20,855,598
	$	35,106,059

* Allocation based upon the relationship of Transmission and Distribution investment as of 12/31/21 per pages 207 lines 58 and 75.

(b) Concept: MaterialsAndOperatingSupplies

Functional Allocation of Account 154, Plant Materials and Operating Supplies (Estimated):

Balance End of Year:		
Distribution:	$	16,439,337
Transmission:	$	23,072,918
	$	39,512,255

*Allocation based upon the relationship to transmission to distribution investment as of year-end per pages 207 lines 58 and 75 Col (g)

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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.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year												
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)												
5	Returned by EPA												
6													
7													
8	Purchases/Transfers												
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												
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													

27													
28	Total												
29	Balance-End of Year												
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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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												
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)												
5	Returned by EPA												
6													
7													
8	Purchases/Transfers												
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												
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													

27													
28	Total												
29	Balance-End of Year												
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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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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	None					
20	TOTAL					

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21	None					
49	TOTAL					

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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	Detroit Projects	195,457	561.6		—
3	Kimball Projects	179,295	561.6		—
4	Sturtev Projects	171,261	561.6		—
5	Raymond Projects	168,848	561.6		—
6	Sanford Projects	156,784	561.6		—
7	Lewiston Projects	156,780	561.6		—
8	Roxbury Projects	153,966	561.6		—
9	Midcoast Projects	104,614	561.6		—
10	CMP Projects Interconnect	48,767	561.6		—
11	Augusta Projects	48,166	561.6		—
12	Winslow Projects	38,958	561.6		—
13	Western Maine Wind	34,712	561.6		—
14	Emery Meadow Solar	22,694	561.6		—
15	Three Corners Solar	16,629	561.6		—
16	Felt Road Solar	13,899	561.6		—
17	Warren Meadow Solar	13,209	561.6		—
18	Sanford Landfill Solar	10,143	561.6		—
19	Other	129,231	561.6		—
20	Total	1,663,413			
21	**Generation Studies**				
22	Emery Meadow Solar		561.7	2,809	456
23	Sanford Landfill Solar		561.7	1,286	456
24	Electric transmission - Generator interconnection	2,162,424	561.7		456
25	Keay Brook		561.7	539	456
26	Sweden Solar		561.7	2,146	456
27	Madison Solar		561.7	5,318	456
28	Old Mill Solar		561.7	808	456
29	CDG Saco Solar		561.7	1,740	456
30	NECC ETU		561.7	1,479	456

31	Cross Town Interconnection		561.7	2,145	456
39	Total	2,162,424		18,270	
40	Grand Total	3,825,837		18,270	

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Advanced Meter Infrastructure - Carrying Cost; Docket Nos. 2007-215, 2008-111 ,2010-051 (II) (Amortization period ending 06/2033)	8,319,324		456	723,519	7,595,805
2	One Month Lag for Distribution Level Customers; Docket No. RT04-2, ER09-938 (Amortization period ending 05/2022)	11,522,956	441,958	456	24,380	11,940,534
3	Advanced Meter Infrastructure - O&M Cost; Docket Nos. 2007-215, 2008-111, 2010-051(II) (Amortization period ending 06/2033)	7,607,143		905	661,919	6,945,224
4	Non-Wire Alternative Docket 2021-00036, 2022-00041 (Amortization period ending 06/2022, 06/2023)	1,095,954	735,956	456	739,182	1,092,728
5	Advanced Meter Infrastructure - Cost Savings; Docket Nos. 2007-215, 2008-111, 2010-051(II) (Amortization period ending 06/2033)	(3,488,581)		456	(301,430)	(3,187,151)
6	Pension Cost Deferral Docket 2013-168, ASC 715	4,102,937	7,649,696	—		11,752,633
7	Advanced Meter Infrastructure - Early Retirement of Legacy Meter Tax Impact; Docket Nos. 2007-215, 2008-111, 2010-051(II) (Amortization period ending 06/2033)	4,917,147		456	427,578	4,489,569
8	Public Advocate Cost Recovery; Docket No. 2021-00036 (Amortization period ending 06/2022)	52,983		456	52,983	
9	Advanced Meter Infrastructure - AMI Meter Depreciation Deferral; Docket Nos. 2007-215, 2008-111, 2010-051(II) (Amortization period ending 06/2033)	6,057,762		403/404	526,762	5,531,000
10	SFAS 143 - Asset Retirement Obligation; Docket 97-580	1,032,076	(66,815)	—		965,261
11	Advanced Meter Infrastructure - Legacy Meter Grant Carrying Costs; Docket Nos. 2007-215, 2008-111, 2010-051(II) (Amortization period ending 06/2033)	(610,051)		456	(53,048)	(557,003)
12	SFAS No. 109 - Deferred Income Taxes; Docket No. 93-140	171,799,818	15,038,533	—		186,838,351
13	Advanced Meter Infrastructure - Opt-Out Program; Docket Nos. 2021-00036, 2022-00041 (Amortization period ending 06/2022, 06/2023)	(23,142)	108,394	456	(13,911)	99,163
14	SFAS No. 158 - Postretirement Benefits Other Than Pension; Docket No. 2007-215	21,434,267	(23,539,714)	926	683,742	(2,789,189)
15	Advanced Meter Infrastructure - Legal & Health Cost; Docket Nos. 2010-051(II), 2013-168, 2018-069	2,823		456		2,823
16	SFAS No. 158 - Pension Benefits; Docket No. 2007-215	101,255,971	(13,371,558)	926	5,940,586	81,943,827
17	Advanced Meter Infrastructure - PUC Audit Cost; Docket No. 2010-051(II)	123,231		—		123,231
18	Storm Costs; Docket Nos. 2021-00036, 2022-00041 (Amortization period ending 06/2022, 06/2023)	80,933,083	82,913,703	923/905	42,459,062	121,387,724
19	100 Basis Points Recovery; Docket 2022-00041 (Amortization period ending 06/2023)		2,450,389	456	1,225,195	1,225,194
20	Stranded LGS-ST and T Docket No.2020-065 (Amortization period ending 06/2022)	179,424		456	179,424	
21	Arrears Forgiveness Program Costs; Docket No.2021-00036, 2022-00041 (Amortization period ending 06/2022, 06/2023)	86,934	49,446	903	59,288	77,092

22	Stranded Cost Revenue Reconciliation Over/Under; Docket No. 2021-037, 2022-00042 (Amortization period ending 06/2022, 06/2023)	4,949,777	12,923,067	456	3,376,242	14,496,602
23	Customer Relationship Management and Billing System (CRM&B); Docket No. 2015-040, 2018-069 (Amortization period ending 06/2032)	161,737	13,048	923	28,452	146,333
24	Transmission credits for distribution customers Docket Nos. RT04-2, ER09-938		(3,392,456)	456		(3,392,456)
25	Delay of Rate Implementation Docket No. 2014-056	4,920	(4,920)	—		
26	Transmission Annual True-up & Trans Rev Forecast; Docket Nos. RT04-2, ER09-938 (Amortization period ending 05/2022)	3,845,780	(3,373,367)	456	472,413	
27	Energy Efficiency Programs (DSM) Customers Docket No. 2021-00036 (Amortization period ending 06/2022)	4,732,296	(4,408,551)	456	323,745	
28	Vegetation Management Docket 2018-00194, 2021-00036		7,049	—		7,049
29	Environmental Clean-Up; Docket Nos. 97-580	373,700	(62,700)	923		311,000
30	Yankee Department of Energy Phase IV proceeds Docket ER13, 2019-00310	(708,076)	708,076	—		
31	Environmental Clean-Up Costs at F. O'Connor Site; Docket Nos. 2021-00036, 2022-00041 (Amortization period ending 06/2022, 06/2023)	6,322	14,162	923	13,404	7,080
32	Electric Thermal Storage (ETS) Costs; Docket No. 2012-325	174,628	(11,496)	—		163,132
33	Funded Deferred Income Tax - Power-tax Normalization; Docket 2013-168,2016-035,2020-065 (Amortization period ending 12/2051)	13,522,812		456	435,996	13,086,816
34	Low-Income Bill Credit; Docket 2022-00043, 2022-00041 (Amortization period ending 06/2023)		4,745	456	2,374	2,371
35	Management Audit; Docket 2018-00194			—		
36	Net Energy Billing; Docket 2019-00197, 2021-037) (Amortization period ending 06/2022)	222,894	(156,149)	456	66,745	
37	Large General Service Transmission and Sub-Trans; Docket Nos. RT04-2, ER09-938		1,584,182	—		1,584,182
44	TOTAL	443,688,849	76,254,678		58,054,602	461,888,925

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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 Credits Account Charged (d)	CREDITS Credits Amount (e)	Balance at End of Year (f)
1	City of Lewiston Tax Increment Financing	2,483,990	275,571	143	435,575	2,323,986
2	ISO New England, Inc. Deposit	8,608	98	447		8,706
3	Revolver Fees (Amortization)	426,726		431	87,042	339,684
4	Long-term Advances	1,594,205	638,358	403	727,561	1,505,002
5	HQUS NECEC Rate relief Fund	76,000,000		—		76,000,000
47	Miscellaneous Work in Progress					
48	Deferred Regulatroy Comm. Expenses (See pages 350 - 351)					
49	TOTAL	80,513,529				80,177,378

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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	—		
7	Other	173,766,603	[(a)]158,378,813
8	TOTAL Electric (Enter Total of lines 2 thru 7)	173,766,603	158,378,813
9	Gas		
10	—		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17.1	Other (Specify)		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	173,766,603	[(b)]158,378,813

Notes

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

	Beginning Balance	End Balance
Accrued Payroll	1,358,772	929,009
AFUDC - Amortization - Flowthrough - Gross Up	148,721	—
ARO - Other Liab	288,156	272,673
Bad Debts Reserve	5,131,460	4,674,028
Capital Lease Obligations	4,546,522	4,609,328
Embedded cost of removal (13)	11,496,980	10,865,468
Environmental	1,447,230	1,428,938
Excess DIT (28)	92,301,414	76,330,356
FAS 112 Post Employment Benefits	216,792	94,601
Hedges OCI	635,421	645,945
Injuries and Damages	651,767	248,562
Long Term Executive Incentive Plan	1,058,193	1,926,413
OCI - FAS 133 - Mark to Market	(38,432)	—
OCI - SERP	—	619,165
OPEB	16,680,264	9,436,499
Other Cost (99)	(1,172,947)	(790,026)
Pension	8,579,836	1,405,986
Regular NOL (Non-SRLY)	1,522,316	1,522,317
S_NOL_SYS	832,771	921,938
SERP	435,940	441,937
State UTP - Fed Only	265,650	—
Adjustment to Tie (after tax)	271,547	—
Directors Share Plan	—	356,418
Transmission reconciliation mechanisms (29)	—	15,049,342
Rate refund (31)	7,499,358	7,762,988
Energy Efficiency programs (33)	—	511,821
Enviromental reg (14)	116,495	255,356
Gross Up - Property - State Only	110,033	110,033
Property Flowthrough - Federal Only	327,540	327,541
Revenue Decoupling Mechanism (37)	3,535,665	3,735,311
State Regular Non-SRLY NOL	—	2,445,952
UTP Reserve Adjustment	15,519,139	12,240,914
Total Other	173,766,603	158,378,813

(b) Concept: AccumulatedDeferredIncomeTaxes

Transmission (Excluding SFAS No. 109)	69,606,410	66,441,255
Distribution (Excluding SFAS No. 109)	104,160,193	91,937,556
SFAS No. 109, Accounting for Income Taxes	—	—
	173,766,603	158,378,811

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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	Common Stock	80,000,000	5.00		31,211,471	156,057,355				
7	Total	80,000,000			31,211,471	156,057,355				
8	Preferred Stock (Account 204)									
9	6% Preferred Stock, NonCallable, Traded O.T.C.	5,713	100.00		5,713	571,300				
14	Total	5,713			5,713	571,300				
1	Capital Stock (Accounts 201 and 204) - Data Conversion									
2										
3										
4										
5	Total									

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2023-03-31	Year/Period of Report End of: 2022/ Q4

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.

Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
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.
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.
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	
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	11,754
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	11,754
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	680,143,427
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	76,152,420
16	Ending Balance Amount	[a]756,295,847
17	**Historical Data - Other Paid in Capital**	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	756,307,601

FOOTNOTE DATA

(a) Concept: MiscellaneousPaidInCapital

Ending balance Acct 211:		
Excess value attributed to Respondent resulting from acquisition by Energy East Corporation, net of $190,000,000 liquidating dividend	$	215,482,960
Accumulated amortization of capital stock expense - preferred stock		(2,929,399)
Equity infusions		545,740,231
Investment in subsidiary		(4,485,513)
Other compensation expense		2,487,568
	$	756,295,847
Ferc Form 1 Page 200		
row 12 Acquisition Adjustments	$	331,976,097
row 32 Amort of Plant Acquisition Adj:		(11,373,225)
Net Acquisition Adjustment		320,602,872
Change in Control		19,145,013
Workforce Management Plan		4,344,475
MY Replacement Power Plan		7,121,692
Pre-Merger Pension Actuarial Adjustment		(48,999)
Pre-Merger Income Tax Adjustment		(6,719,513)
Amortization through 2001		(1,034,021)
		22,808,647
Acquisition Adjustment Related to Common Equity	$	297,794,225

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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	None	
22	TOTAL	

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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	Series C First Mortgage Bond 5.68%	—	100,000,000		561,130			01/15/2012	01/04/2042	01/15/2012	01/04/2042	100,000,000	5,701,311
3	Series D First Mortgage Bond 3.07%	—	125,000,000		678,063			06/13/2012	06/15/2022	01/03/1907	06/15/2022		1,754,754
4	Series E First Mortgage Bond 4.45%	—	225,000,000		1,196,128			01/15/2013	01/15/2043	01/15/2013	01/15/2043	225,000,000	10,050,069
5	Series F First Mortgage Bond 3.15%	—	65,000,000		400,767			01/15/2015	01/15/2025	01/15/2015	01/15/2025	65,000,000	2,055,182
6	Series G First Mortgage Bond 3.37%	—	20,000,000		119,955			01/15/2015	01/15/2030	01/15/2015	01/15/2030	20,000,000	676,529
7	Series H First Mortgage Bond 4.07%	—	65,000,000		389,853			01/15/2015	01/15/2045	01/15/2015	01/15/2045	65,000,000	2,655,426
8	Series I First Mortgage Bond 3.95%	—	60,000,000		410,297			12/27/2018	12/27/2028	12/27/2018	12/27/2028	60,000,000	2,378,892
9	Series J First Mortgage Bond 3.87%	—	80,000,000		400,000			06/03/2019	06/03/2026	06/03/2019	06/03/2026	80,000,000	3,107,616
10	Series K First Mortgage Bond 4.05%	—	80,000,000		400,000			06/03/2019	01/15/2030	06/03/2019	01/15/2030	80,000,000	3,252,156
11	Series L First Mortgage Bond 4.20%	—	80,000,000		400,000			06/03/2019	06/05/2034	06/03/2019	06/05/2034	80,000,000	3,372,607
12	Series M First Mortgage Bond 1.87%	—	50,000,000		351,209			12/15/2020	12/15/2020	12/15/2020	12/15/2020	50,000,000	938,508
13	Series N First Mortgage Bond 2.05%	—	200,000,000		1,088,837			12/15/2021	12/15/2031	12/15/2021	12/15/2031	200,000,000	4,115,383
14	Series O First Mortgage Bond 4.37%	—	75,000,000		418,773			12/15/2022	12/15/2032	12/15/2022	12/15/2032	75,000,000	146,213
15	Series P First Mortgage Bond 4.76%	—	50,000,000		279,182			12/15/2022	12/15/2032	12/15/2022	12/15/2032	50,000,000	106,175
16	Subtotal		1,275,000,000		7,094,194							1,150,000,000	40,310,821
17	Reacquired Bonds (Account 222)												
18													
19													
20													
21	Subtotal												
22	Advances from Associated Companies (Account 223)												
23													
24													

25													
26	Subtotal												
27	Other Long Term Debt (Account 224)												
28	Medium Term Notes 5.78%	—	25,000,000		218,032			04/11/2005	04/11/2035	04/11/2005	04/11/2035	25,000,000	1,450,422
29	Medium Term Notes 5.375%	—	20,000,000		165,897			06/10/2005	06/10/2035	06/10/2005	06/10/2035	20,000,000	1,079,033
30	Medium Term Notes 5.43%	—	25,000,000		207,549			07/18/2005	07/18/2035	07/18/2005	07/18/2035	25,000,000	1,362,593
31	Medium Term Notes 5.7%	—	15,000,000		142,958			10/25/2005	11/01/2025	10/25/2005	11/01/2025	15,000,000	858,208
32	Medium Term Notes 5.875%	—	15,000,000		140,383			10/25/2005	10/25/2035	10/25/2005	10/25/2035	15,000,000	884,556
33	Medium Term Notes 6.4%	—	40,000,000		330,556			09/17/2007	09/15/2037	09/17/2007	09/15/2037	40,000,000	2,569,605
34	Subtotal		140,000,000		1,205,375							140,000,000	8,204,417
33	TOTAL		1,415,000,000									1,290,000,000	48,515,238

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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)	156,610,524
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5		[a]15,674,672
9	Deductions Recorded on Books Not Deducted for Return	
10		[b]285,437,806
14	Income Recorded on Books Not Included in Return	
15		[c]27,311,311
19	Deductions on Return Not Charged Against Book Income	
20		[d]393,005,890
27	Federal Tax Net Income	37,405,801
28	Show Computation of Tax:	
29	Federal Tax Payable	7,855,218
30	Provision for Prior Year Federal Income Tax	4,523,866
31	Other Activity in Current Tax Accounts	(207,835)
32	Net Federal Income Tax Provision	12,171,249
33	—	

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: TaxableIncomeNotReportedOnBooks

Taxable Income Not Reported on Books	
Contributions in Aid of Construction (CIAC)	12,117,761
Capitalized Interest	3,556,911
	15,674,672

(b) Concept: DeductionsRecordedOnBooksNotDeductedForReturn

Deductions Recorded on Books Not Deducted for Return	
Accident and Sickness Reserve	90,000
AFUDC - Amortization - Flowthrough	1,606,223
AMI (01)	1,862,995
Asset retirement obligation (ARO) (04)	66,815
Directors Share Plan	1,270,412
Disallowed Fringe Benefit Parking	23,100
Energy Efficiency programs (33)	6,556,663
Enviromental reg (14)	494,964
Lobbying and Political Expenses	62,771
Long Term Executive Incentive Plan	3,094,742
Meals and Entertainment	620,817
Net Book Value	146,063,945
Other Cost (99)	864,918
Penalties	72,500
Pension & OPEB FAS 158 (20)	43,535,600
Power Tax DIT´S (08)	435,996
Rate refund (31)	939,698
Revenue Decoupling Mechanism (37)	711,631
Transmission reconciliation mechanisms (29)	60,134,535
Unamortized loss on reacquired debt -in rates (24)	92,643
Federal Current Income Tax Provision	12,171,248
Federal and State Deferred Income Tax Provision	(481,666)
Capital Lease Obligations	477,725
481(a) Adjustments	4,669,531
	285,437,806

(c) Concept: IncomeRecordedOnBooksNotIncludedInReturn

Income Recorded on Books Not Included in Return	
AFUDC - Equity - Flowthrough	12,092,517
Allowance for Funds Used During Construction - Debt	3,556,911
Equity Earnings on Affiliates	11,661,883
	27,311,311

(d) Concept: DeductionsOnReturnNotChargedAgainstBookIncome

Deductions on Return Not Charged Against Book Income

Accrued Payroll	1,531,877
ARO - Other Liab	55,187
Bad Debts Reserve	1,990,497
Cost of Removal	25,841,752
Embedded cost of removal (13)	2,251,000
Environmental	65,200
Equity Earnings on Affiliates	58,346
FAS 112 Post Employment Benefits	297,867
Injuries and Damages	1,437,210
Mixed Service Costs	31,584,246
OPEB	25,820,160
Pension	25,638,724
Pension / OPEB COST reg (21)	11,752,633
Prepaid Insurance	69,682
Property Tax	805,703
Property-Plant	9,604,363
Repair - Flow Through	48,271,042
Retired Non-Mass Asset Property Fed Only	272,902
Sales and Use Tax Audit Reserve and Interest	54,111
SERP	21,480
Storms (23)	40,454,640
Stranded cost (27)	10,075,477
Tax Depreciation Fed Only	115,562,236
Unit of Property	28,342,615
Other	4,085,696
Other Property-Plant	6,709,691
Right of Use Assets	351,553
	393,005,890

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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 Accrued (Account 236) (e)	BALANCE AT BEGINNING OF YEAR: Prepaid Taxes (Include in Account 165) (f)	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR: Taxes Accrued (Account 236) (j)	BALANCE AT END OF YEAR: Prepaid Taxes (Included in Account 165) (k)	DISTRIBUTION OF TAXES CHARGED: Electric (Account 408.1, 409.1) (l)	DISTRIBUTION OF TAXES CHARGED: Extraordinary Items (Account 409.3) (m)	DISTRIBUTION OF TAXES CHARGED: Adjustment to Ret. Earnings (Account 439) (n)	DISTRIBUTION OF TAXES CHARGED: Other (o)
1		Other Taxes	Maine	2022	0	0	16,407	16,407		0	0	16,407			
2	**Subtotal Other Tax**				0	0	16,407	16,407		0	0	16,407			
3	Property Taxes Prepaid	Property Tax			0					0					
4	Property Taxes Accrued	Property Tax			724,249	1,992,273	67,238,562	68,179,158	(7,021,712)	374,055	9,604,387	66,887,143			351,419
5	**Subtotal Property Tax**				724,249	1,992,273	67,238,562	68,179,158	[(a)](7,021,712)	374,055	9,604,387	66,887,143[(e)]			351,419
6	Federal	Unemployment Tax	Maine	2022	0	0	49,903	48,720	[(b)](1,183)	0	0				[(f)]49,903
7	State	Unemployment Tax	Maine	2022	0	0	111,000	108,368	[(c)](2,632)	0	0				[(g)]111,000
8	**Subtotal Unemployment Tax**				0	0	160,903	157,088	(3,815)	0	0				160,903
9		Sales And Use Tax	Maine	2022	205,324	0		1,153,590	1,197,312	249,046	0				
10	**Subtotal Sales And Use Tax**				205,324	0		1,153,590	[(d)]1,197,312	249,046	0				
11	Federal	Income Tax	Maine	2022	11,889,803		12,171,249	34,564,227	(368,282)		10,871,457	9,621,472			2,549,777[(h)]
12	State	Income Tax	Maine	2022	442,042		3,425,761	6,525,261	368,282		2,289,176	2,235,180			1,190,581[(i)]
13	**Subtotal Income Tax**				12,331,845		15,597,010	41,089,488			13,160,633	11,856,652			3,740,358
14		Excise Tax	Maine	2022	0	0	1,683	1,683		0		1,683			
15	**Subtotal Excise Tax**				0	0	1,683	1,683		0	0	1,683			
16	Social Security	Payroll Tax	Maine	2022	0	0	6,890,125	6,726,725	(163,400)	0	0				6,890,125[(j)]
17	Other Medicare	Payroll Tax	Maine	2022	0	0	1,682,250	1,642,355	(39,895)	0	0				1,682,250[(k)]
18	**Subtotal Payroll Tax**				0	0	8,572,375	8,369,080	(203,295)	0	0				8,572,375
40	TOTAL				13,261,418	1,992,273	91,586,940	118,966,494	(6,031,510)	623,101	22,765,020	78,761,885			12,825,055

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: TaxAdjustments

Adjustments due to year end timing differences attributed to time of accrual and time of payment.

(b) Concept: TaxAdjustments

Adjustments due to year end timing differences attributed to time of accrual and time of payment.

(c) Concept: TaxAdjustments

Adjustments due to year end timing differences attributed to time of accrual and time of payment.

(d) Concept: TaxAdjustments

Adjustments due to year end timing differences attributed to time of accrual and time of payment.

(e) Concept: TaxesAccruedPrepaidAndCharged

.Account 408.2 - Taxes Other Than Income Taxes, Other Income and Deductions - Property Taxes.

(f) Concept: TaxesIncurredOther

Unemployment taxes are re-distributed as part of an overhead allocation to all accounts receiving direct salaries and wages.

(g) Concept: TaxesIncurredOther

Unemployment taxes are re-distributed as part of an overhead allocation to all accounts receiving direct salaries and wages.

(h) Concept: TaxesIncurredOther

Other Federal Income Taxes consisted of:
Account 409.2 Income Taxes, Other Income & Deductions

(i) Concept: TaxesIncurredOther

Other State Income Taxes consisted of:
Account 409.2 Income Taxes, Other Income & Deductions

(j) Concept: TaxesIncurredOther

Social Security taxes are re-distributed as part of an overhead allocation to all accounts receiving direct salaries and wages.

(k) Concept: TaxesIncurredOther

Other Medicare taxes are re-distributed as part of an overhead allocation to all accounts receiving direct salaries and wages.

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%									
3	4%									
4	7%									
5	10%									
8	TOTAL Electric (Enter Total of lines 2 thru 7)									
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										`
47	OTHER TOTAL									
48	GRAND TOTAL									

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Standard Offer Retainage	2,747,979	various	18,324,874	21,513,198	5,936,303
2	Customer Advances	453,727	143	1,194,244	784,459	43,942
3	SFAS No. 112 - Postemployment Benefits	635,071	various	310,950	13,083	337,204
4	Supplemental Retirement Benefit Plans	1,596,750	232	497,343	165,187	1,264,594
5	Miscellaneous	46,197				46,197
6	Deferred Compensation	3,202,288	232	2,558,257	246,006	890,037
47	TOTAL	8,682,012		22,885,668	22,721,933	8,518,277

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR: Amounts Credited to Account 411.1 (d)	CHANGES DURING YEAR: Amounts Debited to Account 410.2 (e)	CHANGES DURING YEAR: Amounts Credited to Account 411.2 (f)	ADJUSTMENTS: Debits: Account Credited (g)	ADJUSTMENTS: Debits: Amount (h)	ADJUSTMENTS: Credits: Account Debited (i)	ADJUSTMENTS: Credits: Amount (j)	Balance at End of Year (k)
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities										
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)										
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)										
18	Classification of TOTAL										
19	Federal Income Tax										
20	State Income Tax										
21	Local Income Tax										

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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	691,398,954	68,235,217	43,573,606	3,392,519	0	182/283	(3,537,928)	182/190	(11,125,183)	711,865,829
3	Gas		0	0	0	0	—	0	—	0	0
4	Other (Specify)		0	0	0	0	—	0	—	0	0
5	Total (Total of lines 2 thru 4)	691,398,954	68,235,217	43,573,606	3,392,519		—	(3,537,928)	—	(11,125,183)	711,865,829
6	—		0	0	0	0	—	0	—	0	0
9	TOTAL Account 282 (Total of Lines 5 thru 8)	691,398,954	68,235,217	43,573,606	3,392,519		—	(3,537,928)	—	(11,125,183)	711,865,829 [(a)]
10	Classification of TOTAL										
11	Federal Income Tax	557,345,495	41,222,182	28,601,521	2,312,657	0	—	(2,411,782)	—	(7,583,962)	567,106,633
12	State Income Tax	134,053,459	27,013,035	14,972,085	1,079,862	0	—	(1,126,146)	—	(3,541,221)	144,759,196
13	Local Income Tax		0	0	0	0	—	0	—	0	0

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

	Beginning Balance	End Balance
SFAS No. 109 Accounting for Income Taxes	—	—
Transmission (excluding SFAS No. 109)	329,267,801	370,355,458
Distribution (exclduing SFAS No. 109)	362,131,153	341,510,371
	691,398,954	711,865,829

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.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR: Amounts Credited to Account 411.1 (d)	CHANGES DURING YEAR: Amounts Debited to Account 410.2 (e)	CHANGES DURING YEAR: Amounts Credited to Account 411.2 (f)	ADJUSTMENTS: Debits: Account Credited (g)	ADJUSTMENTS: Debits: Amount (h)	ADJUSTMENTS: Credits: Account Debited (i)	ADJUSTMENTS: Credits: Amount (j)	Balance at End of Year (k)
1	Account 283										
2	Electric										
3	—						—		—		
4	Other	133,223,766	82,177,048	83,599,764			—		283/282	6,929,503	138,730,553[a]
9	TOTAL Electric (Total of lines 3 thru 8)	133,223,766	82,177,048	83,599,764						6,929,503	138,730,553
10	Gas										
11							—		—		
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other						—		—		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	133,223,766	82,177,048	83,599,764						6,929,503	138,730,553[b]
20	Classification of TOTAL										
21	Federal Income Tax	90,817,744	28,307,325	30,500,687			—		—	5,947,302	94,571,683
22	State Income Tax	42,406,022	53,869,723	53,099,077			—		—	982,201	44,158,870
23	Local Income Tax						—		—		

NOTES

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

	Beginning Balance	End Balance
Transmission (Excluding SFAS No. 109)	13,740,460	4,369,581
Distribution (Excluding SFAS No. 109)	119,483,306	134,360,972
SFAS No. 109 - Accounting for Income Taxes	—	—
	133,223,766	138,730,553

(b) Concept: AccumulatedDeferredIncomeTaxesOther

	Beginning Balance	End Balance
Accident and Sickness Reserve	(1,243,384)	(1,268,634)
AMI (01)	6,426,113	5,903,454
AFUDC - Amortization - Flowthrough - Gross Up	—	(175,718)
AFUDC - Equity - Flowthrough - Gross Up	—	1,322,896
Asset retirement obligation (ARO) (04)	289,546	270,801
Charitable Contribution limitation	(547,357)	—
Energy Efficiency programs (33)	1,327,632	—
Equity Earnings on Affiliates	15,475	16,369
Excess ADIT Give Back	9,586,078	—
Gross Up - Repairs	—	3,509,411
Lost Revenues Reserve	(981,915)	—
OCI - FAS 133 - Treasury Mark to Market	50,877	40,353
OCI - SERP	32,518	—
Other Cost (99) - Contra	(140,273)	—
Pension & OPEB FAS 158 (20)	34,420,378	22,206,597
Pension / OPEB COST reg (21)	—	3,297,166
Power Tax DIT´S (08)	3,793,784	3,671,467
Prepaid Insurance	245,419	264,967
Property Tax	7,668,337	7,894,376
Right of Use Assets/Capital Lease Obligations	5,379,186	5,381,877
Sales and Use Tax Audit Reserve and Interest	13,697	28,878
Storms (23)	22,705,534	34,054,961
Stranded cost (27)	1,240,333	4,066,978
Transmission reconciliation mechanisms (29)	1,821,222	—
Unamortized loss on reacquired debt -in rates (24)	72,421	46,431
Unfunded future income tax (10)	41,048,145	48,197,923
	133,223,766	138,730,553

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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	CMP Improper Notices; Docket 2020-00017	500,000	—		(500,000)	
2	Congestion Revenue Reconciliation; Docket No. 99-185	2,948,356	—		(1,563,317)	1,385,039
3	Cost of Removal; Docket No. 2007-215 (Amortization period ending 03/2040)	40,980,583	403	2,251,000		38,729,583
4	Customer Relationship Management & Billing Cost (CRMB); Docket No. 2018-069 (Amortization period ending 06/2031)		905	13,048	13,048	
5	Electric Lifeline Program (ELP) Over/Under Collection to Customers; Dockets 2021-00036, 2022-00041 (Amortization period ending 06/2022, 06/2023)	1,129,625	456	735,052	(586,950)	(192,377)
6	Environmental Cost Reserve for PCB/MGP; Docket Nos. 2007-215, 2008-111 & 2013-168	795,265	—		433,023	1,228,288
7	Revenue Decoupling Mechanism (RDM); Docket Nos. 2021-00036, 2022-00041 (Amortization period ending 06/2022, 06/2023)	12,602,754	456	7,637,422	8,349,052	13,314,384
8	Stranded Cost Revenue Reconciliation Over/Under; Docket No. 2021-037, 2022-00042 (Amortization period ending 06/2022, 06/2023)		456	1,514,339	1,514,339	
9	Stranded LGS-ST and T; Docket No. 2020-065 (Amortization period ending 06/2022)		456			
10	Transmission Revenue True Up & Trans Exp; Docket Nos. RT04-2, ER09-938 (Amortization period ending 05/2022, 12/2022)	3,875,841	456	8,183,704	66,697,938	62,390,075
11	Transmission Credits for Distribution Customers; Docket Nos. RT04-2, ER09-938 (Amortization period ending 05/2022, 12/2022)	2,052,858	456	1,035,042	(1,017,816)	
12	Vegetation Management; Docket 2021-00036, 2022-00041 (Amortization period ending 06/2022, 06/2023)	415,107	456	241,654	(83,185)	90,268
13	Yankee Department of Energy Phase IV; Dockets ER13, 2019-00310 (Amortization period ending 2/2022)		456	708,076	708,076	
14	2018 Tax Reform Impact Public Law No. 115-97 "Tax Cuts & Jobs Act"-Dist; Docket No. 2018-069, 2022-00041 Distribution (Amortization period ending 02/2030, 06/2023)	69,045,113	410	9,254,556		59,790,557
15	2018 Tax Reform Impact Public Law No. 115-97 "Tax Cuts & Jobs Act"-Trans; Docket Nos. RT04-2, ER09-938 Transmission, 2018-00194 (Amortization period ending 02/2030)	229,708,862	410	17,422,522		212,286,340
16	2019 One Time Adjustments Collected in July 2020; Docket 2021-036 (Amortization period ending 06/2022)	177,327	456	177,327		
17	Energy Efficiency Programs (DSM) Customers Docket No. 2021-00036 (Amortization period ending 06/2022)		456	479,990	2,304,356	1,824,366
41	TOTAL	364,231,691		49,653,732	76,268,564	390,846,523

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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	[a]247,896,346	234,696,580	136	103	579,793	580,180
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	[b]82,351,982	85,103,823	182	152	71,712	69,740
5	Large (or Ind.) (See Instr. 4)	[c]14,433,229	17,701,230			2,745	2,745
6	(444) Public Street and Highway Lighting	[d]3,721,572	3,802,723	1	1	558	557
7	(445) Other Sales to Public Authorities						
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales	761,144	701,337				
10	TOTAL Sales to Ultimate Consumers	349,164,273	342,005,693	319	256	654,808	653,222
11	(447) Sales for Resale	48,701,115	11,644,490	678,693	331,970		
12	TOTAL Sales of Electricity	397,865,388	353,650,183	679,012	332,226	654,808	653,222
13	(Less) (449.1) Provision for Rate Refunds						
14	TOTAL Revenues Before Prov. for Refunds	397,865,388	353,650,183	679,012	332,226	654,808	653,222
15	Other Operating Revenues						
16	(450) Forfeited Discounts	877,211	942,940				
17	(451) Miscellaneous Service Revenues	[e]5,395,402	4,345,079				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	16,706,463	17,631,878				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	[f]44,185,893	12,891,199				
22	(456.1) Revenues from Transmission of Electricity of Others	540,080,871	560,499,273				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						

26	TOTAL Other Operating Revenues	607,245,840	596,310,369				
27	TOTAL Electric Operating Revenues	1,005,111,228	949,960,552				

Line12, column (b) includes $ 1,438,727 of unbilled revenues.
Line12, column (d) includes 15,930 MWH relating to unbilled revenues

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: ResidentialSales

Residential: Reclassified items within each rate schedule represents immaterial required transfers resulting from reporting derived during the implementation of a new reporting system.

(b) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Commercial/Industrial: Reclassified items within each rate schedule represents immaterial required transfers resulting from reporting derived during the implementation of a new reporting system.

(c) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Commercial/Industrial: Reclassified items within each rate schedule represents immaterial required transfers resulting from reporting derived during the implementation of a new reporting system.

(d) Concept: PublicStreetAndHighwayLighting

Lighting: Reclassified items within each rate schedule represents immaterial required transfers resulting from reporting derived during the implementation of a new reporting system.

(e) Concept: MiscellaneousServiceRevenues

This amount represent charges for:	
Establishment of Services	1,534,034
AMI Opt Out Charges	879,778
Line Extension	110,164
Electric Revenue - Miscellaneous (CIAC)	2,867,310
Electric Revenue - Miscellaneous	4,116
Total	5,395,402

(f) Concept: OtherElectricRevenue

Schedule Page: 300 Line No.: 21 Column: b	
Advanced Meter Infrastructure IFRS/GAAP	(782,708)
Demand Side Energy Management Program IFRS/GAAP	156,244
Electric Lifeline Program Over/Under Collection IFRS/GAAP	735,052
Stranded Costs IFRS/GAAP	(1,861,903)
Power Tax IFRS/GAAP	(435,996)
OPA Non-Wire Alternative	(739,182)
Yankee DOE Phase I & Phase II IFRS/GAAP	708,076
Supply Credit - IFRS	(2,373)
Public Advocate	(52,983)
Net Energy Billing	(66,744)
Remove 100 Basis Point ROE Reduction	(1,225,195)
Other Items Less than $250K IFRS/GAAP	239,557
Regulatory Assets & Liabilities Deferrals:	
Remove 100 Basis Point ROE Reduction	2,434,739
Demand Side Energy Management Program IFRS/GAAP	(6,682,553)
Electric Lifeline Program Over/Under Collection IFRS/GAAP	591,362
Net Energy Billing IFRS/GAAP	—
Vegetation Management (D) IFRS/GAAP	46,147
Non-Wire Alternative IFRS/GAAP	735,956
Stranded Costs IFRS/GAAP	11,513,750
Customer Supply Credit	—
Other Items Less than $250K IFRS/GAAP	(61,695)
Mechanisms:	
Electric Lifeline Program re: Maine State Housing Assoc	742,915
Revenue Decoupling Mechanism IFRS/GAAP	(556,967)
Other Distribution Revenue >$250K:	
Billing and Collection Charges	1,892,324
Field Survey Billings	534,240
Net Energy Billing Capacity	321,045
Renewable Energy Certificate Sales	718,599
ISO NE ICAP HQ	4,026,147
Interconnection CIAC	625,956
LT Contract Reallocation	9,176,572
Misc Electric Ops	916,445
Interconnection fees	2,654,452
Mutual Aid - Nova Scotia	977,694
MGS Rate Relief LD	5,803,032
Energy Supply Relief Credit	4,687,020
NEB Capacity Buyout	366,028
Other Services to Third Party	(2,195,642)
Other Items Less than $250K	205,465
Other Transmission Revenue >$250K:	
Interconnection Support Charge Sched 14-	3,049,523
Interconnection Fees	3,526,464
Misc Project Billing	854,090
Other Items Less than $250K	610,940
TOTAL	**44,185,893**

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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	None				
46	TOTAL				

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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)
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41	TOTAL Billed Residential Sales	136	248,876,284	579,793		
42	TOTAL Unbilled Rev. (See Instr. 6)		(979,938)			
43	TOTAL	136	[a]247,896,346	579,793		

FOOTNOTE DATA

(a) Concept: ResidentialSales

Residential: Reclassified items within each rate schedule represents immaterial required transfers resulting from reporting derived during the implementation of a new reporting system.

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ Q4

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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)
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41	TOTAL Billed Small or Commercial	182	82,311,795	71,712		
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)		40,187			
43	TOTAL Small or Commercial	182	[a]82,351,982	71,712		

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Commercial/Industrial: Reclassified items within each rate schedule represents immaterial required transfers resulting from reporting derived during the implementation of a new reporting system.

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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)
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41	TOTAL Billed Large (or Ind.) Sales		13,923,238	2,745		
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)		509,991			
43	TOTAL Large (or Ind.)		[a]14,433,229	2,745		

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: LargeOrIndustrialSalesElectricOperatingRevenue
Commercial/Industrial: Reclassified items within each rate schedule represents immaterial required transfers resulting from reporting derived during the implementation of a new reporting system.

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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)
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41	TOTAL Billed Commercial and Industrial Sales					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL					

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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)
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41	TOTAL Billed Public Street and Highway Lighting	1	3,883,633	558		
42	TOTAL Unbilled Rev. (See Instr. 6)		(162,061)			
43	TOTAL	1	[a]3,721,572	558		

FOOTNOTE DATA

(a) Concept: PublicStreetAndHighwayLighting

Lighting: Reclassified items within each rate schedule represents immaterial required transfers resulting from reporting derived during the implementation of a new reporting system.

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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)
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41	TOTAL Billed Interdepartmental Sales		761,144			
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		761,144			

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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	319	349,756,094	654,808		
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts		(591,821)			
43	TOTAL - All Accounts	319	349,164,273	654,808		

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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	New England Independent System Operator	IU	—				678,693		48,701,115		48,701,115
15	Subtotal - RQ										
16	Subtotal-Non-RQ						678,693		48,701,115		48,701,115
17	Total						678,693		48,701,115		48,701,115

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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		
5	(501) Fuel		
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses		
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)		
14	Maintenance		
15	(510) Maintenance Supervision and Engineering		
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant		
18	(513) Maintenance of Electric Plant		
19	(514) Maintenance of Miscellaneous Steam Plant		
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)		
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)		
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		

33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)		
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses		
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of Lines 62 thru 67)		
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		

71	(553) Maintenance of Generating and Electric Plant		
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)		
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)		
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	50,371,626	29,853,497
76.1	(555.1) Power Purchased for Storage Operations	0	
77	(556) System Control and Load Dispatching	952,862	697,318
78	(557) Other Expenses	3,747,088	2,179,498
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	55,071,576	32,730,313
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	55,071,576	32,730,313
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,926,748	878,844
85	(561.1) Load Dispatch-Reliability	45,257	59,705
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	3,023,968	2,350,696
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies	1,663,413	524,825
91	(561.7) Generation Interconnection Studies	2,162,424	1,183,797
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	1,158,597	3,525,604
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	312,395	1,125,458
95	(564) Underground Lines Expenses	(589)	54,861
96	(565) Transmission of Electricity by Others	218,824,644	215,222,969
97	(566) Miscellaneous Transmission Expenses	1,987,166	[a]2,238,876
98	(567) Rents	184,935	163,915
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	231,288,958	227,329,550
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	358,515	326,302
102	(569) Maintenance of Structures	736,871	441,221
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,286,233	2,271,162

107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	4,848,309	10,080,346
109	(572) Maintenance of Underground Lines	43,651	41,420
110	(573) Maintenance of Miscellaneous Transmission Plant	66,393	36,840
111	TOTAL Maintenance (Total of Lines 101 thru 110)	8,339,972	13,197,291
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	239,628,930	240,526,841
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	3,364,078	2,162,042
135	(581) Load Dispatching	1,380,935	1,087,768
136	(582) Station Expenses	2,124,798	1,782,051
137	(583) Overhead Line Expenses	5,543,590	15,414,167
138	(584) Underground Line Expenses	190,255	92,334
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	30,704	32,006
140	(586) Meter Expenses	3,462,770	2,526,799
141	(587) Customer Installations Expenses	3,109,284	643,497
142	(588) Miscellaneous Expenses	8,758,138	12,631,285
143	(589) Rents	5,103,024	5,030,273
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	33,067,576	41,402,222

145	Maintenance		
146	(590) Maintenance Supervision and Engineering	165,906	14,021
147	(591) Maintenance of Structures	1,379	539
148	(592) Maintenance of Station Equipment	1,467,627	1,189,022
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	159,185,320	65,901,261
150	(594) Maintenance of Underground Lines	1,158,981	1,082,019
151	(595) Maintenance of Line Transformers		
152	(596) Maintenance of Street Lighting and Signal Systems	53,336	81,461
153	(597) Maintenance of Meters		
154	(598) Maintenance of Miscellaneous Distribution Plant	(37,649,550)	12,685,519
155	TOTAL Maintenance (Total of Lines 146 thru 154)	124,382,999	80,953,842
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	157,450,575	122,356,064
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	2,336,270	2,327,287
160	(902) Meter Reading Expenses	2,200,637	1,496,024
161	(903) Customer Records and Collection Expenses	22,452,748	21,565,812
162	(904) Uncollectible Accounts	6,132,144	7,758,223
163	(905) Miscellaneous Customer Accounts Expenses	20,879,545	7,409,545
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	54,001,344	40,556,891
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	42,906	1,918
168	(908) Customer Assistance Expenses	38,057,652	32,579,194
169	(909) Informational and Instructional Expenses	438,249	528,081
170	(910) Miscellaneous Customer Service and Informational Expenses	356,804	336,516
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	38,895,611	33,445,709
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	53,653	90,141
175	(912) Demonstrating and Selling Expenses	863,197	1,151,358
176	(913) Advertising Expenses	11,210	17,715
177	(916) Miscellaneous Sales Expenses	99,286	(110,434)
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	1,027,346	1,148,780
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	5,162,702	7,499,090
182	(921) Office Supplies and Expenses	5,674,922	3,343,820

183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	30,814,790	28,591,241
185	(924) Property Insurance	1,687,186	1,494,008
186	(925) Injuries and Damages	1,488,239	1,350,171
187	(926) Employee Pensions and Benefits	2,100,794	7,323,479
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	8,806,748	7,731,656
190	(929) (Less) Duplicate Charges-Cr.	(2,929,883)	5,539,518
191	(930.1) General Advertising Expenses	728,530	624,873
192	(930.2) Miscellaneous General Expenses	846,153	888,851
193	(931) Rents	331,224	326,597
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	60,571,171	53,634,268
195	Maintenance		
196	(935) Maintenance of General Plant	6,677,865	6,852,126
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	67,249,036	60,486,394
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	613,324,418	531,250,992

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: MiscellaneousTransmissionExpenses
Account in credit balance due to Equipment returned to inventory of current & prior year for MEPCO section 388 and 3023.

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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	Athens Energy	IF	NUG				57,417					5,684,290		5,684,290
2	Vermont Yankee Nuclear Power Corp	LU	FPC No. 1										8,121	8,121
3	BD Solar	LU	NUG				47,680					1,639,394		1,639,394
4	Yankee Atomic Electric Company	LU	FPC No. 1										397	397
5	Brookfield Power	OS	—										(366,028)	(366,028)
6	NEB Sponsor Facility KWH	OS	N/A				240,886					29,948,865		29,948,865
7	Connecticut Yankee Atomic Power Co	LU	FPC No. 1										12,915	12,915
8	Georges River	OS	NUG				35,322					3,496,837		3,496,837
9	Helix Wind	OS	—				159,004					5,803,630 [(a)]		5,803,630
10	Hydro - Quebec	OS	N/A				268					18,302		18,302
11	ISO New England, Inc.	LU	FPC No. 2				(1,043)					(58,479)		(58,479)
12	Kennebago Hydro	LU	NUG				2,910					233,786		233,786

13	Madison Dept of Electric Works	OS	N/A				18					3,013		3,013
14	Maine Yankee Atomic Power Company	LU	FPC No. 1										86,734	86,734
15	Pittsfield Solar	LU	NUG				17,244					1,459,703[b]		1,459,703
16	Re Energy Livermore Falls	OS	N/A										(6,184,788)	(6,184,788)
17	Rollins-First Wind	LU	NUG				119,506				(733,610)	9,318,544[c]		8,584,934
15	TOTAL						679,212	0	0	0	(733,610)	57,547,885	(6,442,649)	50,371,626

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: EnergyChargesOfPurchasedPower

This expense is Central Maine Powers (CMP) portion of the Connecticut Yankee cost of service to store spent nuclear fuel insite including a return on and of equity and other investments. The generator, Connecticut Yankee must safely store the nuclear fuel until the Department of Energy (DOE) long term storage site is ready. Construction of this site is not yet started.

(b) Concept: EnergyChargesOfPurchasedPower

This expense is Central Maine Powers (CMP) portion of the Maine Yankee cost of service to store spent nuclear fuel onsite including a return on and of equity and other investments.
The generator, ME Yankee must safely store the nuclear fuel until the Department of Energy (DOE) long term storage site is ready. Construction of this site is not yet started.

(c) Concept: EnergyChargesOfPurchasedPower

This expense is Central Maine Powers (CMP) portion of the Yankee Atomic cost of service to store spent nuclear fuel onsite including a return of and of equity and other investments. The generator, Yankee Atomic must safely store the nuclear fuel until the Department of Energy (DOE) long term storage site is ready. Construction of this site is not yet started.

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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	Brookfield Energy Marketing, LP Non-Jurisdictional Sales	Not Available	Not Available	LFP	[(a)] —	New England/HVDC	HQ Phase I or II	85					24	24
2	HQ Energy Services US, Inc.	Not Available	Not Available	LFP	[(b)] —	New England/HVDC	HQ Phase I or II	93	523,927	523,927	4,260,086			4,260,086
3	HQ Energy Services US, Inc.	Not Available	Not Available	NF	[(c)] —	New England/HVDC	HQ Phase I or II	57	207,014	207,014			[(h)]86,658	86,658
4	VITOL	Not Available	Not Available	LFP	[(d)] —	New England/HVDC	HQ Phase I or II	1	8,381	8,381	50,298			50,298
5	VITOL	Not Available	Not Available	NF	[(e)] —	New England/HVDC	HQ Phase I or II		4,518	4,518			[(i)]23,483	23,483
6	MAG	Not Available	Not Available	NF	—	New England/HVDC	HQ Phase I or II		133	133			237,025	237,025
7	Nalcor	Not Available	Not Available	NF	—	New England/HVDC	HQ Phase I or II		53	53			159	159
8	ISO New England, Inc. Non-Jurisdictional Sales	ISO New England Participants	ISO New England Participants	OS	—	ISO New England, Inc	ISO New England, Inc						231,926,658	231,926,658
9	Jurisdictional Sales:	—	—	OS	—	—	—		[(f)]9,819,252	[(g)]9,819,252				
10	Residential Transmission Sales	3	—	OS	—	—	—						184,683,619	184,683,619
11	Commercial Transmission Sales	—	—	OS	—	—	—						117,104,537	117,104,537
12	Industrial Transmission Sales	—	—	OS	—	—	—						59,709,532	59,709,532
13	Lighting Transmission Sales	—	—	OS	—	—	—						549,959	549,959
14	Wholesale Transmission Sales	—	—	OS	—	—	—						1,348,862	1,348,862
15	Regulatory Transmission Revenues	—	—	OS	—	—	—						(59,900,029)[(j)]	(59,900,029)
35	TOTAL							236	10,563,278	10,563,278	4,310,384		535,770,487	540,080,871

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: RateScheduleTariffNumber

Pursuant to Part II of the ISO-NE Transmission, Markets and Services Tariff, Schedule 20A-CMP filed with the Commission on March 31, 2005 in Docket No. ER05-754-000.

(b) Concept: RateScheduleTariffNumber

Pursuant to Part II of the ISO-NE Transmission, Markets and Services Tariff, Schedule 20A-CMP filed with the Commission on March 31, 2005 in Docket No. ER05-754-000.

(c) Concept: RateScheduleTariffNumber

Non-Firm Transmission Charge.

(d) Concept: RateScheduleTariffNumber

Pursuant to Part II of the ISO-NE Transmission, Markets and Services Tariff, Schedule 20A-CMP filed with the Commission on March 31, 2005 in Docket No. ER05-754-000.

(e) Concept: RateScheduleTariffNumber

ISO-NE FERC Electric Tariff Number 3.

(f) Concept: TransmissionOfElectricityForOthersEnergyReceived

The energy received is from suppliers who serve the Respondent's customers. The energy is delivered to these customers by the Respondent. The MWHs reported are the net tie flow on an hourly basis needed to serve the Respondent's customer load.

(g) Concept: TransmissionOfElectricityForOthersEnergyDelivered

Respondent provides Local Network Transmission Service to Wholesale and Retail Customers pursuant to Part II of the ISO-NE Transmission, Markets and Services Tariff - Schedule 21-CMP filed with the Commission on December 22, 2004 in Docket Nos. ER05-374-000 and ER05-374-001. The Jurisdictional Sales revenues include unbilled transmission revenues.

(h) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Pursuant to Part II of the ISO-NE Transmission, Markets and Services Tariff, Schedule 20A-CMP filed with the Commission on March 31, 2005 in Docket No. ER05-754-000.

(i) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Payment to Respondent was made pursuant to the Rate Design and Funds Disbursement Agreement filed with the Commission on October 1, 2004 in Docket No. RTO04-2-000 et al. and Part II of the ISO-NE Transmission, Markets and Services Tariff ("ISO Tariff") filed with the Commission on December 22, 2004 in Docket Nos. ER05-374-000 and ER05-374-001.

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ISO Tariff - Part II:	
Schedule 1	223,459,197
	3,301,658
Through or Out Revenues	5,165,803
Total	231,926,658

(j) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Regulatory Assets/Liabilities Amortizations:	
Transmission Revenue True Up	(6,254,542)
One Month Billing Lag	(24,380)
Distribution Level Share - RNS Credits	1,035,042
Regulatory Assets/Liabilities Deferrals:	
Unfunded Deferred Income Tax Adjustment	—
Transmission Revenue True Up	(55,358,119)
One Month Billing Lag	—
Distribution Level Share - RNS Credits	(2,255,582)
LGS-ST-TOU & LGS-T-TOU Credit Deferral	1,584,182
Mechanisms:	
Congestion	1,373,368
Total:	(59,900,029)

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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	Not Applicable				
40	TOTAL				

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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: MegaWatt Hours Received (c)	TRANSFER OF ENERGY: MegaWatt Hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Public Service Company of New Hampshire	LFP	167,012	167,012	30,854			30,854
2	Emera Maine	LFP	40,366	40,366	367,826			367,826
3	ISO New England	OS					[a] 216,500,397	216,500,397
4	Boston Electric (AC)	OS					[b] 21,584	21,584
5	New England HQ (AC)	OS					[c] 55,015	55,015
6	New England HQ (DC)	OS					[d] 623,811	623,811
7	NHH (DC)	OS					[e] 770,632	770,632
8	New England Elect Transm (DC)	OS					[f] 48,107	48,107
9	New England Power (NEP AC)	OS					[g] 296,809	296,809
10	Vermont Electric (VETCO DC)	OS					[h] 109,609	109,609
	TOTAL		207,378	207,378	398,680	0	218,425,964	218,824,644

(a) Concept: OtherChargesTransmissionOfElectricityByOthers

ISO Tariff Part II:	
Regional Network Services	206,262,613
Schedule 1	2,600,700
Schedule 2 Expense	1,444,553
Schedule 2 RNS Expense	165,944
Schedule 3 RNS Expense	170
Schedule 16 Blackstart	2,917,046
Congestion Uplift	(279,485)
Schedule 2 Var Support	(2,563)
Load Response	—
OATT SCH 17 IROL-CIP	2,586
ISO Tariff Part IV:	
Schedule 1	3,264,131
Schedule 5 - NESCO	124,702
Total	216,500,397

(b) Concept: OtherChargesTransmissionOfElectricityByOthers

Schedule Page: 332 Line No.: 8 Column: g

(c) Concept: OtherChargesTransmissionOfElectricityByOthers

Schedule Page: 332 Line No.: 9 Column: g

(d) Concept: OtherChargesTransmissionOfElectricityByOthers

Schedule Page: 332 Line No.: 10 Column: g

(e) Concept: OtherChargesTransmissionOfElectricityByOthers

Schedule Page: 332 Line No.: 11 Column: g

(f) Concept: OtherChargesTransmissionOfElectricityByOthers

Schedule Page: 332 Line No.: 12 Column: g

(g) Concept: OtherChargesTransmissionOfElectricityByOthers

Schedule Page: 332 Line No.: 13 Column: g

(h) Concept: OtherChargesTransmissionOfElectricityByOthers

Schedule Page: 332 Line No.: 14 Column: g

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
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	Other Environmental Activities	473,294
7	Invoice Price Variance	176,124
8	Board of Directors Payments	190,754
9	Other	5,981
46	TOTAL	846,153

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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			9,408,573		9,408,573
2	Steam Production Plant					
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant					
7	Transmission Plant	63,435,363				63,435,363
8	Distribution Plant	37,872,202		114,595		37,986,797
9	Regional Transmission and Market Operation					
10	General Plant	17,750,540		35,348		17,785,888
11	Common Plant-Electric					
12	TOTAL	119,058,105		9,558,516		128,616,621

B. Basis for Amortization Charges

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)
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Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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 (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	MPUC Annual Assessments	5,174,833		5,174,833		Electric	928	5,174,833				
2	FERC Annual Assessments	943,833		943,833		Electric	928	943,833				
3	OPA Annual Assessments	1,635,379		1,635,379		Electric	928	1,635,379				
4	Formula Rate Complaints Dkt Nos. EL13-33, EL11-66, EL16-64 & EL 14-86		69,461	69,461		Electric	928	69,461				
5	2022 Regulatory Proceedings		983,242	983,242		Electric	928	983,242				
46	TOTAL	7,754,045	1,052,703	8,806,748				8,806,748				

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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:

   Electric R, D and D Performed Internally:

   Generation

   hydroelectric

   Recreation fish and wildlife
   Other hydroelectric

   Fossil-fuel steam
   Internal combustion or gas turbine
   Nuclear
   Unconventional generation
   Siting and heat rejection

   Transmission

   Overhead
   Underground
   Distribution
   Regional Transmission and Market Operation
   Environment (other than equipment)
   Other (Classify and include items in excess of $50,000.)
   Total Cost Incurred
   Electric, R, D and D Performed Externally:

   Research Support to the electrical Research Council or the Electric Power Research Institute
   Research Support to Edison Electric Institute
   Research Support to Nuclear Power Groups
   Research Support to Others (Classify)
   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	None						

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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	875,191		
4	Transmission	4,535,890		
5	Regional Market			
6	Distribution	16,734,339		
7	Customer Accounts	14,057,588		
8	Customer Service and Informational	258,503		
9	Sales	633,385		
10	Administrative and General	8,143,880		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	45,238,776		
12	Maintenance			
13	Production			
14	Transmission	2,363,836		
15	Regional Market			
16	Distribution	15,098,239		
17	Administrative and General	1,671,557		
18	TOTAL Maintenance (Total of lines 13 thru 17)	19,133,632		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	875,191		
21	Transmission (Enter Total of lines 4 and 14)	6,899,725		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	31,832,578		
24	Customer Accounts (Transcribe from line 7)	14,057,588		
25	Customer Service and Informational (Transcribe from line 8)	258,503		
26	Sales (Transcribe from line 9)	633,385		
27	Administrative and General (Enter Total of lines 10 and 17)	9,815,437		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	64,372,408	28,922,025	93,294,433
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			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
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			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
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)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	64,372,408	28,922,025	93,294,433
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	32,046,377	14,398,189	46,444,566
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	32,046,377	14,398,189	46,444,566

72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,288,231	578,792	1,867,023
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,288,231	578,792	1,867,023
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	Billable Charges	170,569	76,635	247,204
80	Other Income and Deductions	185,129	83,177	268,306
81	—			
82				
83				
84				
85				
86				
87				
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89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	355,698	159,812	515,510
96	TOTAL SALARIES AND WAGES	98,062,714	44,058,819	142,121,533

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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.

None

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ Q4

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)	(199,514)	132,331	66,482	(58,479)
3	Net Sales (Account 447)	(15,562,133)	(9,659,494)	(11,586,540)	(48,701,115)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
10					
11					
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44					
45					
46	TOTAL	(15,761,647)	(9,527,163)	(11,520,058)	(48,759,594)

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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	0	0	5,864,831	0	0	8,835,158
2	Reactive Supply and Voltage	0	0	1,608,104	0	0	0
3	Regulation and Frequency Response	0	0	0	0	0	0
4	Energy Imbalance	0	0	0	0	0	0
5	Operating Reserve - Spinning	0	0	0	0	0	0
6	Operating Reserve - Supplement	0	0	0	0	0	0
7	Other	0	0	2,917,046	0	0	0
8	Total (Lines 1 thru 7)			10,389,981			8,835,158

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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	1,591	11	18	1,591					
2	February	1,493	14	19	1,493					
3	March	1,432	3	19	1,432					
4	Total for Quarter 1				4,516	0	0			0
5	April	1,211	8	11	1,211					
6	May	1,215	22	18	1,215					
7	June	840	26	18	840					
8	Total for Quarter 2				3,266	0	0			0
9	July	1,600	21	16	1,600					
10	August	1,600	21	15	1,600					
11	September	1,381	12	18	1,381					
12	Total for Quarter 3				4,582	0	0			0
13	October	1,248	24	18	1,248					
14	November	1,384	21	18	1,384					
15	December	1,473	12	18	1,473					
16	Total for Quarter 4				4,105	0	0			0
17	Total				16,469	0	0	0	0	0

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2023-03-31	Year/Period of Report End of: 2022/ 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)	319
3	Steam		23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	678,693
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
7	Other		27	Total Energy Losses	200
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	0	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	679,212
10	Purchases (other than for Energy Storage)	679,212			
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	10,563,278			
17	Delivered	10,563,278			
18	Net Transmission for Other (Line 16 minus line 17)	0			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	679,212			

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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	50,335	49,526	1,591	11	18
30	February	43,367	53,278	1,493	14	19
31	March	70,984	62,918	1,432	3	19
32	April	68,415	64,832	1,211	8	11
33	May	54,846	57,365	1,215	22	18
34	June	57,680	58,038	840	26	18
35	July	55,538	52,490	1,600	21	16
36	August	48,507	49,205	1,600	21	15
37	September	59,320	60,246	1,381	12	18
38	October	53,427	53,971	1,248	24	18
39	November	64,903	64,526	1,384	21	18
40	December	51,890	52,298	1,473	12	18
41	Total	679,212	678,693			

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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 Mct.
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
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	
3	Year Originally Constructed	
4	Year Last Unit was Installed	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	0
7	Plant Hours Connected to Load	0
8	Net Continuous Plant Capability (Megawatts)	0
9	When Not Limited by Condenser Water	0
10	When Limited by Condenser Water	0
11	Average Number of Employees	0
12	Net Generation, Exclusive of Plant Use - kWh	0
13	Cost of Plant: Land and Land Rights	0
14	Structures and Improvements	0
15	Equipment Costs	0
16	Asset Retirement Costs	0
17	Total cost (total 13 thru 20)	0
18	Cost per KW of Installed Capacity (line 17/5) Including	0
19	Production Expenses: Oper, Supv, & Engr	0
20	Fuel	0
21	Coolants and Water (Nuclear Plants Only)	0
22	Steam Expenses	0
23	Steam From Other Sources	0
24	Steam Transferred (Cr)	0
25	Electric Expenses	0
26	Misc Steam (or Nuclear) Power Expenses	0

27	Rents	0
28	Allowances	0
29	Maintenance Supervision and Engineering	0
30	Maintenance of Structures	0
31	Maintenance of Boiler (or reactor) Plant	0
32	Maintenance of Electric Plant	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0
34	Total Production Expenses	0.0000
35	Expenses per Net kWh	

35	**Plant Name**
36	Fuel Kind
37	Fuel Unit
38	Quantity (Units) of Fuel Burned
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year
41	Average Cost of Fuel per Unit Burned
42	Average Cost of Fuel Burned per Million BTU
43	Average Cost of Fuel Burned per kWh Net Gen
44	Average BTU per kWh Net Generation

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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
1	Kind of Plant (Run-of-River or Storage)	
2	Plant Construction type (Conventional or Outdoor)	
3	Year Originally Constructed	
4	Year Last Unit was Installed	
5	Total installed cap (Gen name plate Rating in MW)	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0
7	Plant Hours Connect to Load	0
8	**Net Plant Capability (in megawatts)**	
9	(a) Under Most Favorable Oper Conditions	0
10	(b) Under the Most Adverse Oper Conditions	0
11	Average Number of Employees	0
12	Net Generation, Exclusive of Plant Use - kWh	0
13	**Cost of Plant**	
14	Land and Land Rights	0
15	Structures and Improvements	0
16	Reservoirs, Dams, and Waterways	0
17	Equipment Costs	0
18	Roads, Railroads, and Bridges	0
19	Asset Retirement Costs	0
20	Total cost (total 13 thru 20)	0
21	Cost per KW of Installed Capacity (line 20 / 5)	
22	**Production Expenses**	
23	Operation Supervision and Engineering	0
24	Water for Power	0
25	Hydraulic Expenses	0
26	Electric Expenses	0
27	Misc Hydraulic Power Generation Expenses	0
28	Rents	0
29	Maintenance Supervision and Engineering	0

30	Maintenance of Structures	0
31	Maintenance of Reservoirs, Dams, and Waterways	0
32	Maintenance of Electric Plant	0
33	Maintenance of Misc Hydraulic Plant	0
34	Total Production Expenses (total 23 thru 33)	0
35	Expenses per net kWh	0.0000

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - kWh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	0
12	**Cost of Plant**	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	0
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	**Production Expenses**	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	

28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	0
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per kWh (line 37 / 9)	
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))	0

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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: Fuel Production Expenses (i)	Production Expenses: Maintenance Production Expenses (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
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2													
3													
4													
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Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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)	Project Costs included in (p)	Production (Dollars) (q)	Transmission (Dollars) (r)	Distribution (Dollars) (s)
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Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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 (a)	To (b)	Operating (c)	Designated (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)	(i)	Land (j)	Construction Costs (k)	Total Costs (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
1	Buxton	Surowiec (374)	345	345	H.Frame	27	0	1	850.8 ACSR	515,763	5,588,108	6,103,871	0	0	0	0
2	New England Hydro-NHH MA/NH border	Sandy Pond Junction	0	0	Single Pole	0	0	0	2839.8	0	0	0	0	0	0	0
3	New England Hydro-NHH	Hudson, NH	450	450	Corten Steel	8	0	1	KcMil ACSR	0	0	0	0	0	0	0
4	Surowiec	Maine Yankee (375)	345	345	H.Frame	25	0	1	850.8 ACSR	242,584	26,599,580	26,842,164	0	0	0	0
5	Surowiec	Maine Yankee (375)	345	345	Stl. Towers	1	0	0	850.8 ACSR	0	0	0	0	0	0	0
6			0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Surowiec	Maine Yankee (375)	345	345	Stl. Towers	5	0	0	900 ACSR	0	0	0	0	0	0	0
8	Surowiec	Maine Yankee (377)	345	345	H.Frame	24	0	1	850.8 ACSR	410,122	37,154,384	37,564,506	0	0	0	0
9	New England Hydor NHH-Junction	Terminal	0	0	Lattice Steel	0	0	0	0	0	0	0	0	0	0	0
10	Surowiec	Maine Yankee (377)	345	345	Stl. Towers	6	0	0	850.8 ACSR	0	0	0	0	0	0	0
11	Mason	Maine Yankee (378)	345	345	H.Frame	3	0	1	850.8 ACSR	8,437	1,801,843	1,810,280	0	0	0	0
12	New England Hydro NHH- Hudson, NH	Monroe, NH	450	450	H-Frame	112	0	1	0	0	0	0	0	0	0	0
13	Deerfield, NH	Buxton (385)	345	345	H.Frame	31	0	1	850.8 ACSR	0	8,978,667	8,978,667	0	0	0	0
14	South Gorham	Buxton (386)	345	345	H.Frame	0	0	1	954 ACSR	273,557	4,691,298	4,964,855	0	0	0	0
15	New England Hydro-El-NEH - Sandy Pond	MA/NH	0	0	Single Pole	0	0	0	2839.8	0	0	0	0	0	0	0
16	South Gorham	Buxton (386)	345	345	Stl. Towers	7	0	0	954 ACSR	0	0	0	0	0	0	0

17	New England Hydro-El-NEH - Converter Terminal	Border	450	450	Corten Steel	12	0	1	KcMil ACSR	0	0	0	0	0	0	0
18	Scobie, NH	Buxton (391)	345	345	H.Frame	31	0	1	850.8 ACSR	223,815	7,551,173	7,774,988	0	0	0	0
19	Raven Farm	Surowiec (3020)	345	345	H.Frame	13	0	1	1590 ACSR	366,924	28,442,114	28,809,038	0	0	0	0
20	South Gorham	Maguire Road (3021)	345	345	H.Frame	21	0	1	1590 ACSR	279,696	33,947,759	34,227,455	0	0	0	0
21	Maguire Road	Three RV (3022)	345	345	H.Frame	20	0	1	1590 ACSR	967,116	34,635,881	35,602,997	0	0	0	0
22	New England Power Co-NEPAC - Milbury #3	Sandy Pond, Ayer	0	0	0	0	0	0	1113 MCM AL	0	0	0	0	0	0	0
23	New England Power Co-NEPAC	Medway Town Line	345	345	WH Frame	0	0	0	1590 MCM	0	0	0	0	0	0	0
24	Orrington	Albion Road (3023)	345	345	H.Frame	59	0	1	1590 ACSR	9,487,316	154,164,414	163,651,730	0	0	0	0
25	0	0	0	0	SPH Frame	38	0	2	0	0	0	0	0	0	0	0
26	Albion Road	Coopers Mills (3024)	345	345	H.Frame	20	0	1	1590 ACSR	2,607,897	43,034,022	45,641,919	0	0	0	0
27	Albion Road	Coopers Mills (3024)	345	345	Stl. Towers	1	0	0	0	0	0	0	0	0	0	0
28	Coopers Mills	Larrabee Road (3025)	345	345	H.Frame	35	0	1	1590 ACSR	14,289,592	108,884,898	123,174,490	0	0	0	0
29	Surowiec	Larrabee Road (3026)	345	345	H.Frame	16	0	1	1590 ACSR	58,553	47,831,266	47,889,819	0	0	0	0
30	Buxton 345 MVa	Surowiec (3038)	345	345	H.Frame	26	0	1	850.8 ACSR	0	4,570,003	4,570,003	0	0	0	0
31	Buxton	Surowiec (3038)	345	345	Stl. Towers	0	0	0	850.8 ACSR	0	0	0	0	0	0	0
32	Raven Farm 345 MVa	WF Wyman (3039)	345	345	H.Frame	0	0	1	954 ACSR	0	4,535,146	4,535,146	0	0	0	0
33	Raven Farm	WF Wyman (3039)	345	345	H.Frame	0	0	0	1590 ACSR	0	0	0	0	0	0	0
34	Raven Farm	WF Wyman (3039)	345	345	Stl. Towers	5	0	0	954 ACSR	0	0	0	0	0	0	0
35	South Gorham 345 MVa	Raven Farm (3040)	345	345	H.Frame	14	0	1	954 ACSR	0	6,319,382	6,319,382	0	0	0	0
36	South Gorham	Raven Farm (3040)	345	345	H.Frame	0	0	0	1590 ACSR	0	0	0	0	0	0	0
37	South Gorham	Raven Farm (3040)	345	345	Stl. Towers	3	0	0	954 ACSR	0	0	0	0	0	0	0
38			0	0		0	0	0		0	0	0	0	0	0	0
39	South Gorham 115 MVa OH	Raven Farm (3040)	115	115	Overhead	1,319	0	106	0	12,148,246	771,598,060	783,746,306	0	0	0	0
40	South Gorham 115 MVa UG	Raven Farm (3040)	115	115	Underground	3	0	2	0	0	0	0	0	0	0	0
41	South Gorham 34.5 MVa OH	Raven Farm (3040)	34	34	Overhead	1,036	0	169	0	14,657,673	220,228,418	234,886,091	0	0	0	0
42	South Gorham 34.5 MVa UG	Raven Farm (3040)	34	34	Underground	16	0	21	0	0	0	0	0	0	0	0
43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	TOTAL					2,937	0	320		56,537,291	1,550,556,416	1,607,093,707	0	0	0	0

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)	LINE COST					Construction
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing		Land and Land Rights	Poles, Towers and Fixtures	Conductors and Devices	Asset Retire. Costs	Total	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	None	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Overground
44	TOTAL		0		0	0	0										

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)				Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
1	Albion Road - Benton	Transmission	Unattended	345	115	0	448	1	0	0	0	0
2	Brunswick West Side - Brunswick	Distribution	Unattended	34	12	0	21	2	0	0	0	0
3	Elm Street - Yarmouth (34.5 MVa)	Distribution	Unattended	34	12	0	7	1	0	0	0	0
4	Limerick - Limerick	Distribution	Unattended	34	12	0	11	1	0	0	0	0
5	Norway - Norway	Distribution	Unattended	115	12	0	22	1	0	0	0	0
6	Sewall Street - Portland	Transmission	Unattended	115	34	0	37	1	0	0	0	0
7	Weston Hydro - Skowhegan	Distribution	Unattended	34	12	0	14	1	0	0	0	0
8	Andover - Roxbury	Distribution	Unattended	34	12	0	5	3	0	0	0	0
9	Bucksport - Bucksport	Transmission	Unattended	115	34	0	20	1	0	0	0	0
10	Emden - Emden	Distribution	Unattended	115	12	0	6	1	0	0	0	0
11	Lincolnville - Lincolnville	Distribution	Unattended	115	34	0	14	1	0	0	0	0
12	Oakland - Oakland	Distribution	Unattended	34	12	0	7	1	0	0	0	0
13	Shawmut - Shawmut	Distribution	Unattended	34	12	0	7	1	0	0	0	0
14	West Waterville - Waterville	Distribution	Unattended	34	12	0	18	2	0	0	0	0
15	Athens - Athens	Distribution	Unattended	115	12	0	22	1	0	0	0	0
16	Bucksport - Bucksport	Distribution	Unattended	34	12	0	7	1	0	0	0	0
17	Factory Island - Saco	Distribution	Unattended	34	12	0	25	2	0	0	0	0
18	Lisbon - Lisbon	Distribution	Unattended	34	12	0	11	1	0	0	0	0
19	Ogunquit - Ogunquit	Distribution	Unattended	34	12	0	21	2	0	0	0	0
20	Shaw Mills - Gorham	Distribution	Unattended	34	12	0	14	1	0	0	0	0
21	Western Avenue - South Portland	Distribution	Unattended	34	12	0	22	1	0	0	0	0
22	Augusta East Side - Augusta	Transmission	Unattended	115	34	0	37	1	0	Capacitor	1	5
23	Burnham - Pittsfield	Distribution	Unattended	34	12	0	5	1	0	0	0	0
24	Fairfield - Fairfield	Distribution	Unattended	34	12	0	21	2	0	0	0	0
25	Lisbon Falls - Lisbon Falls	Distribution	Unattended	34	12	0	12	2	0	0	0	0
26	Old Orchard - Old Orchard	Distribution	Unattended	34	12	0	28	2	0	0	0	0

27	Sheepscot - Alna	Distribution	Unattended	34	12	0	3	1	0	0	0	0
28	Williams - Embden	Transmission	Unattended	115	70	0	8	1	0	0	0	0
29	Augusta K-5 - Augusta	Distribution	Unattended	34	12	0	14	1	0	0	0	0
30	Butlers Corner - Sanford	Distribution	Unattended	34	12	0	11	1	0	0	0	0
31	Falmouth - Falmouth	Distribution	Unattended	34	12	0	11	1	0	0	0	0
32	Livermore Falls - Lisbon Falls	Distribution	Unattended	115	12	0	22	1	0	0	0	0
33	Oxford - Oxford	Distribution	Unattended	34	12	0	14	1	0	0	0	0
34	Sidney - Sidney	Distribution	Unattended	34	12	0	3	1	0	0	0	0
35	Wilton - Wilton	Distribution	Unattended	34	12	0	7	1	0	0	0	0
36	Bar Mills - Hollis	Distribution	Unattended	34	12	0	14	1	0	0	0	0
37	Camden - Camden	Distribution	Unattended	34	12	0	21	2	0	0	0	0
38	Farmington - Farmington	Distribution	Unattended	34	12	0	7	1	0	0	0	0
39	Louden - Saco	Transmission	Unattended	115	34	0	75	2	0	0	0	0
40	Park Street - Rockland	Transmission	Unattended	115	34	0	37	1	0	0	0	0
41	Skowhegan North Side - Madison	Distribution	Unattended	34	12	0	11	1	0	0	0	0
42	Winslow - Winslow	Distribution	Unattended	34	12	0	14	1	0	0	0	0
43	Bassett - Berwick	Distribution	Unattended	34	12	0	14	1	0	0	0	0
44	Cape 115kV - South Portland (34.5)	Transmission	Unattended	115	34	0	37	1	0	0	0	0
45	Fore River - Portland	Distribution	Unattended	115	12	0	45	2	0	0	0	0
46	Louden - Saco	Distribution	Unattended	34	12	0	5	1	0	0	0	0
47	Park Street - Rockland	Distribution	Unattended	34	12	0	44	3	0	Capacitor	2	5
48	Skowhegan South Side - Skowhegan	Distribution	Unattended	34	12	0	11	1	0	0	0	0
49	Winslow - Winslow	Transmission	Unattended	115	34	0	112	3	0	Capacitor	2	32
50	Bath 115KV - West Bath	Transmission	Unattended	115	34	0	74	2	0	0	0	0
51	Cape 115kV - South Portland	Transmission	Unattended	115	12	0	45	2	0	0	0	0
52	Forest Avenue - Portland	Distribution	Unattended	34	12	0	22	1	0	0	0	0
53	Lovell - Sweden	Transmission	Unattended	115	34	0	37	1	0	Capacitor	1	5
54	Philips El New - Lewiston	Distribution	Unattended	34	12	0	5	1	0	0	0	0
55	South Berwick - South Berwick	Distribution	Unattended	34	12	0	11	1	0	0	0	0
56	Winthrop - Winthrop	Distribution	Unattended	34	12	0	18	2	0	0	0	0
57	Bath 115KV - West Bath	Distribution	Unattended	34	12	0	11	1	0	0	0	0
58	Cape Elizabeth - Cape Elizabeth	Distribution	Unattended	34	12	0	18	2	0	0	0	0
59	Fort Hill - Gorham	Distribution	Unattended	34	12	0	11	1	0	0	0	0
60	Lovell - Sweden	Distribution	Unattended	34	12	0	3	1	0	0	0	0
61	Philips Old - Lewiston	Distribution	Unattended	34	4	0	9	4	0	0	0	0
62	South China - China	Distribution	Unattended	34	12	0	14	1	0	0	0	0
63	Woodstock - Woodstock	Transmission	Unattended	115	34	0	75	2	0	Capacitor	1	5
64	Bath N End - Bath	Distribution	Unattended	34	12	0	5	1	0	0	0	0
65	Capitol Street - Augusta	Distribution	Unattended	34	12	0	23	2	0	0	0	0
66	Freeport - Freeport	Distribution	Unattended	34	12	0	25	2	0	0	0	0

67	Maguire Road - Kennebunk	Transmission	Unattended	345	115	0	448	1	0	Capacitor	1	0
68	Philips Strong - Strong	Distribution	Unattended	34	12	0	7	1	0	0	0	0
69	South Gorham 345kV - Gorham	Transmission	Unattended	345	115	0	896	2	0	0	0	0
70	Woolwich -Woolwich	Distribution	Unattended	34	12	0	5	1	0	0	0	0
71	Bath Washington St - Bath	Distribution	Unattended	34	4	0	14	1	0	0	0	0
72	Carmel - Carmel	Distribution	Unattended	34	12	0	11	1	0	0	0	0
73	Fryeburg - Fryeburg	Distribution	Unattended	34	12	0	5	1	0	0	0	0
74	Maine Yankee - Wiscasset	Distribution	Unattended	115	12	0	14	1	0	0	0	0
75	Pittsfield - Pittsfield	Distribution	Unattended	34	12	0	7	1	0	0	0	0
76	South Sanford - Sanford	Distribution	Unattended	34	12	0	28	2	0	0	0	0
77	[(a)] W.F. Wyman - Yarmouth	Transmission	Unattended	115	34	0	33	1	0	0	0	0
78	Belfast 115KV - Belfast	Distribution	Unattended	34	12	0	7	1	0	Capacitor	1	0
79	Challenger Drive - Lewiston	Transmission	Unattended	115	34	0	14	1	0	0	0	0
80	Fryeburg - Fryeburg (34.5 MVa)	Distribution	Unattended	34	4	0	3	1	0	0	0	0
81	Manchester - Manchester	Distribution	Unattended	34	12	0	14	1	0	0	0	0
82	Pleasant Hill - Scarborough	Transmission	Unattended	115	34	0	37	1	0	0	0	0
83	South Waterville - Waterville	Distribution	Unattended	34	12	0	11	1	0	0	0	0
84	W.F. Wyman - Yarmouth	Distribution	Unattended	34	12	0	5	1	0	0	0	0
85	Belfast 115KV - Belfast	Transmission	Unattended	115	34	0	75	2	0	0	0	0
86	Challenger Drive - Lewiston	Distribution	Unattended	115	12	0	14	1	0	0	0	0
87	Gardiner - Gardiner	Distribution	Unattended	34	12	0	7	1	0	0	0	0
88	Manktown Rd - Waldoboro	Distribution	Unattended	34	12	0	4	3	0	0	0	0
89	Pleasant Hill - Scarborough (115 MVa)	Distribution	Unattended	115	12	0	22	1	0	0	0	0
90	Spring Street - Westbrook	Transmission	Unattended	115	34	0	128	3	0	Capacitor	1	16
91	Wyman Hydro - Moscow	Distribution	Unattended	115	12	0	6	1	0	Capacitor	2	35
92	Belfast West Side - Belfast	Distribution	Unattended	34	12	0	21	2	0	0	0	0
93	Clinton - Benton	Distribution	Unattended	34	12	0	5	1	0	0	0	0
94	Goosefare - Saco	Distribution	Unattended	115	12	0	22	1	0	0	0	0
95	Mason Corner - Wiscasset (345 MVa)	Transmission	Unattended	345	115	0	448	1	0	0	0	0
96	Pleasant Hill - Scarborough	Distribution	Unattended	34	12	0	7	1	0	0	0	0
97	Spring Street - Westbrook (115 MVa)	Distribution	Unattended	115	12	0	14	1	0	0	0	0
98	York Beach - York	Distribution	Unattended	34	12	0	14	1	0	0	0	0
99	Berwick - Berwick	Distribution	Unattended	34	12	0	11	1	0	0	0	0
100	Cony Road - Chelsea	Distribution	Unattended	34	12	0	11	1	0	0	0	0
101	Gray - Gray	Distribution	Unattended	34	12	0	18	2	0	0	0	0
102	Mason Corner - Wiscasset	Transmission	Unattended	115	34	0	37	1	0	0	0	0
103	Pratt & Whitney - North Berwick	Distribution	Unattended	115	12	0	14	1	0	0	0	0
104	Spring Street - Westbrook	Distribution	Unattended	34	12	0	11	1	0	0	0	0
105	York Harbor - York	Distribution	Unattended	34	12	0	11	1	0	0	0	0
106	Bethel - Bethel	Distribution	Unattended	34	12	0	7	1	0	0	0	0

107	Cooks Corner - Brunswick	Distribution	Unattended	34	12	0	14	1	0	Ground Bank	3	0
108	Greenville - Greenville	Distribution	Unattended	34	12	0	5	1	0	0	0	0
109	May Street - Biddeford	Distribution	Unattended	34	12	0	28	2	0	0	0	0
110	Prides Corner - Westbrook	Transmission	Unattended	115	34	0	37	1	0	0	0	0
111	Stickneys Corner - Washington	Distribution	Unattended	34	12	0	5	1	0	0	0	0
112	Keyes Wtvl	Distribution	Unattended	34	12	0	15	2	0	0	0	0
113	Biddeford IP - Biddeford	Transmission	Unattended	115	34	0	37	1	0	0	0	0
114	Coopers Mills Rd - Windsor (345 MVa)	Transmission	Unattended	345	118	0	448	1	1	0	0	0
115	Great Falls - Auburn	Distribution	Unattended	34	12	0	21	2	0	0	0	0
116	McCoys - Vassalboro	Distribution	Unattended	34	12	0	3	3	0	0	0	0
117	Prides Corner - Westbrook	Distribution	Unattended	115	12	0	14	1	0	0	0	0
118	Stratton - Eustis	Distribution	Unattended	34	12	0	3	1	0	0	0	0
119	Perrier	Distribution	Unattended	34	12	0	28	2	0	0	0	0
120	Biddeford IP - Biddeford	Distribution	Unattended	115	12	0	22	1	0	0	0	0
121	Coopers Mills Rd - Windsor	Distribution	Unattended	115	12	0	14	1	0	0	0	0
122	Guilford - Guilford	Transmission	Unattended	115	34	0	37	1	0	Capacitor	2	10
123	Meadow Road - Rockport	Transmission	Unattended	115	34	0	37	1	0	Capacitor	2	10
124	Prospect - Prospect	Distribution	Unattended	34	12	0	7	1	0	0	0	0
125	Sturtevant - Farmington	Transmission	Unattended	115	34	0	37	1	0	0	0	0
126	Biddeford Pump - Biddeford	Distribution	Unattended	34	12	0	7	1	0	0	0	0
127	Coopers Mills Rd - Windsor	Transmission	Unattended	115	34	0	37	1	0	0	0	0
128	Guilford - Guilford	Distribution	Unattended	34	12	0	11	1	0	0	0	0
129	Meadow Road - Rockport	Distribution	Unattended	34	12	0	14	1	0	0	0	0
130	Puddledock Road - Manchester	Distribution	Unattended	115	34	0	0	0	0	0	0	0
131	Sturtevant - Farmington	Distribution	Unattended	115	12	0	14	1	0	Capacitor	1	5
132	Bigelow - Carabassett Valley	Distribution	Unattended	115	34	0	22	1	0	0	0	0
133	Corinna - Corinna	Distribution	Unattended	34	12	0	7	1	0	0	0	0
134	Gulf Island 115kV - Lewiston	Transmission	Unattended	115	34	0	37	1	0	Capacitor	1	35
135	Mechanic Falls - Mechanic Falls	Distribution	Unattended	34	12	0	21	2	0	0	0	0
136	Puddledock Road - Manchester	Transmission	Unattended	115	34	0	37	1	0	0	0	0
137	Surowiec - North Pownal	Transmission	Unattended	345	115	0	448	1	0	0	0	0
138	Bishop Street - Portland	Distribution	Unattended	34	12	0	29	2	0	0	0	0
139	County Road - Oakland	Transmission	Unattended	115	34	0	112	2	0	0	0	0
140	Harris Hydro - Indian Lake Twp	Transmission	Unattended	115	12	0	17	1	1	0	0	0
141	Messina - Wiscasset	Distribution	Unattended	34	12	0	7	1	0	0	0	0
142	Quaker Hill - North Berwick	Transmission	Unattended	115	34	0	75	2	0	0	0	0
143	Swett Road - Windham	Distribution	Unattended	34	12	0	14	1	0	0	0	0
144	Blair Road - Augusta	Distribution	Unattended	34	12	0	11	1	0	0	0	0
145	County Road - Oakland	Distribution	Unattended	34	12	0	14	1	0	0	0	0

146	Harris Hydro - Indian Lake Twp	Distribution	Unattended	34	12	0	7	1	0	0	0	0
147	Middle St. - Lewiston	Distribution	Unattended	115	12	0	45	2	0	0	0	0
148	Rangeley - Rangeley	Distribution	Unattended	34	12	0	3	1	0	Capacitor /Ground Bk	4	1
149	Thomaston Creek - Thomaston	Distribution	Unattended	34	12	0	11	1	0	0	0	0
150	Bolt Hill - Eliot	Distribution	Unattended	34	12	0	14	1	0	0	0	0
151	Crowley's - Lewiston	Transmission	Unattended	115	34	0	33	1	0	0	0	0
152	Hartland - Pittsfield	Distribution	Unattended	115	12	0	14	1	0	0	0	0
153	Middle St. - Lewiston	Transmission	Unattended	115	34	0	56	1	0	0	0	0
154	Raymond 115kV - Raymond	Distribution	Unattended	115	34	0	75	2	0	Capacitor	1	5
155	Topsham 115kV - Topsham	Transmission	Unattended	115	34	0	71	2	0	0	0	0
156	Bolt Hill - Eliot	Transmission	Unattended	115	34	0	112	3	0	0	0	0
157	Crowley's - Lewiston	Distribution	Unattended	115	12	0	14	1	0	0	0	0
158	High Street - Sanford	Distribution	Unattended	34	12	0	14	2	0	0	0	0
159	Monmouth - Monmouth (115 MVa)	Distribution	Unattended	115	12	0	14	1	0	0	0	0
160	Raymond - Raymond	Distribution	Unattended	34	12	0	14	1	0	0	0	0
161	Topsham 115kV - Topsham	Distribution	Unattended	34	12	0	11	1	0	0	0	0
162	Bond Brook - Augusta	Distribution	Unattended	34	12	0	14	1	0	0	0	0
163	Damariscotta Mills - Newcastle	Distribution	Unattended	34	12	0	11	1	0	Capacitor	1	3
164	Highland - Warren	Transmission	Unattended	115	34	0	37	1	0	0	0	0
165	Monmouth - Monmouth	Distribution	Unattended	115	12	0	14	1	0	0	0	0
166	Red Brook - South Portland	Distribution	Unattended	115	34	0	37	1	0	0	0	0
167	Topsham Old - Topsham	Distribution	Unattended	34	12	0	14	1	0	0	0	0
168	Bonny Eagle - Standish	Distribution	Unattended	34	12	0	11	1	0	0	0	0
169	Deer Rips - Auburn	Distribution	Unattended	34	12	0	33	2	0	0	0	0
170	Hinkley Pond - South Portland	Distribution	Unattended	115	12	0	14	1	0	0	0	0
171	Monson - Monson	Distribution	Unattended	34	12	0	3	1	0	Ground Bank	3	0
172	Richmond - Richmond	Distribution	Unattended	34	12	0	7	1	0	0	0	0
173	Trap Corner - West Paris	Distribution	Unattended	34	12	0	3	1	0	0	0	0
174	Boothbay Harbor - Boothbay Harbor	Distribution	Unattended	34	12	0	21	2	0	Capacitor	1	5
175	Denmark - Denmark	Distribution	Unattended	34	12	0	6	1	0	0	0	0
176	Hiram - Baldwin	Distribution	Unattended	34	12	0	7	1	0	0	0	0
177	Moshers - Gorham	Distribution	Unattended	115	12	0	14	1	0	0	0	0
178	Rigby - South Portland	Distribution	Unattended	34	12	0	18	2	0	0	0	0
179	Turner - Turner	Distribution	Unattended	34	12	0	11	1	0	0	0	0
180	Bowman Street - Farmingdale	Transmission	Unattended	115	34	0	37	1	0	0	0	0
181	Detroit - Detroit	Transmission	Unattended	115	34	0	33	1	0	Capacitor	1	4
182	Hotel Road - Auburn	Distribution	Unattended	115	12	0	22	1	0	0	0	0
183	Moshers - Gorham	Transmission	Unattended	115	34	0	37	1	0	0	0	0
184	Riley - Jay	Distribution	Unattended	115	12	0	14	1	0	Capacitor	1	30

185	Union - Union	Distribution	Unattended	34	12	0	7	1	0	0	0	0
186	Bowman Street - Farmingdale	Distribution	Unattended	115	34	0	37	2	0	0	0	0
187	Detroit - Detroit	Distribution	Unattended	34	12	0	11	1	0	0	0	0
188	Hotel Road - Auburn	Transmission	Unattended	115	34	0	75	2	0	0	0	0
189	Mussey Road - Scarborough	Distribution	Unattended	115	34	0	37	1	0	0	0	0
190	Roxbury - Roxbury	Transmission	Unattended	115	34	0	22	1	0	0	0	0
191	Union Street - Portland	Distribution	Unattended	34	12	0	90	4	0	0	0	0
192	Bragdon Commons - York	Distribution	Unattended	34	12	0	14	1	0	0	0	0
193	Dexter - Dexter	Distribution	Unattended	34	12	0	14	2	0	0	0	0
194	Kennebunkport - Kennebunkport	Distribution	Unattended	34	12	0	18	2	0	0	0	0
195	Newcastle - Newcastle	Transmission	Unattended	115	34	0	75	2	0	Capacitor	1	5
196	Rumford - Rumford	Distribution	Unattended	115	12	0	28	2	0	0	0	0
197	Unity - Unity	Distribution	Unattended	34	12	0	11	1	0	0	0	0
198	Branch Brook - Kennebunk	Transmission	Unattended	115	34	0	37	1	0	0	0	0
199	Dogtown Rd - Detroit	Transmission	Unattended	115	18	0	154	2	0	0	0	0
200	Kimball Road - Harrison	Transmission	Unattended	115	34	0	37	1	0	Capacitor	2	70
201	North Anson - Anson	Distribution	Unattended	34	4	0	4	6	0	0	0	0
202	Rumford IP - Rumford	Distribution	Unattended	115	34	0	14	1	0	Capacitor	1	67
203	Vallee Lane - Old Orchard Beach	Transmission	Unattended	115	34	0	56	1	0	0	0	0
204	Branch Brook - Kennebunk (115 MVa)	Distribution	Unattended	115	12	0	22	1	0	0	0	0
205	Dover - Dover	Distribution	Unattended	34	12	0	10	2	0	0	0	0
206	Kimball Road - Harrison	Distribution	Unattended	34	12	0	11	1	0	0	0	0
207	North Limington - Limington	Distribution	Unattended	34	12	0	14	1	0	0	0	0
208	Sabattus - Sabattus	Distribution	Unattended	34	12	0	14	1	0	0	0	0
209	Vassalboro - Winslow	Distribution	Unattended	34	12	0	14	1	0	0	0	0
210	Branch Brook - Kennebunk (34.5 MVa)	Distribution	Unattended	34	12	0	11	1	0	0	0	0
211	Dunstan - Scarborough	Distribution	Unattended	34	12	0	22	1	0	0	0	0
212	Kittery - Kittery	Distribution	Unattended	34	12	0	14	1	0	0	0	0
213	Newport - Newport	Distribution	Unattended	34	12	0	14	2	0	0	0	0
214	Sanford 115kV - Sanford	Transmission	Unattended	115	34	0	75	2	0	0	0	0
215	Waldoboro - Winslow	Distribution	Unattended	34	12	0	7	1	0	0	0	0
216	Bridgton - Bridgton	Distribution	Unattended	34	12	0	14	1	0	Capacitor	2	10
217	East Deering - Portland	Distribution	Unattended	34	12	0	18	2	0	0	0	0
218	Lakewood 115kV - Madison	Transmission	Unattended	115	34	0	75	2	0	Capacitor	1	10
219	New Portland - New Portland	Distribution	Unattended	34	12	0	3	1	0	0	0	0
220	Sanford Industrial Park - Sanford	Distribution	Unattended	34	12	0	14	1	0	0	0	0
221	Warren - Warren	Distribution	Unattended	34	12	0	3	1	0	0	0	0
222	Brighton Avenue - Portland	Distribution	Unattended	34	12	0	20	1	0	0	0	0
223	East Wilton - Wilton	Distribution	Unattended	34	12	0	14	1	0	0	0	0
224	Lambert Street - Falmouth	Distribution	Unattended	34	12	0	18	2	0	0	0	0

225	New Vineyard - New Vineyard	Distribution	Unattended	34	12	0	2	3	0	0	0	0
226	Sanford Switch - Sanford	Distribution	Unattended	34	12	0	14	1	0	Capacitor	1	0
227	Waterboro - Waterboro	Distribution	Unattended	115	12	0	14	1	0	0	0	0
228	Bristol - Bristol	Distribution	Unattended	34	12	0	14	1	0	0	0	0
229	Edgecomb - Edgecomb	Distribution	Unattended	34	12	0	6	1	0	Capacitor	1	5
230	Larabee Road - Lewiston	Transmission	Unattended	345	115	0	448	1	0	Capacitor	2	0
231	North Augusta - Augusta	Distribution	Unattended	115	12	0	14	1	0	0	0	0
232	Scarborough - Scarborough	Distribution	Unattended	34	12	0	14	1	0	0	0	0
233	Westbrook - Westbrook	Distribution	Unattended	34	12	0	14	1	0	0	0	0
234	Brooks - Brooks	Distribution	Unattended	34	12	0	5	1	0	0	0	0
235	Eliot - Eloit	Distribution	Unattended	34	12	0	7	1	0	0	0	0
236	Lebanon - Labanon	Distribution	Unattended	34	12	0	14	1	0	0	0	0
237	North Augusta - Augusta	Transmission	Unattended	115	34	0	37	1	0	0	0	0
238	Searsport - Sanford	Distribution	Unattended	34	12	0	14	1	0	0	0	0
239	West Bridgton - West Bridgton	Distribution	Unattended	34	12	0	5	1	0	0	0	0
240	Browns Crossing - Farmingdale	Distribution	Unattended	115	12	0	14	1	0	0	0	0
241	Elm Street - Yarmouth	Distribution	Unattended	115	12	0	22	1	0	0	0	0
242	Leeds - Leeds	Distribution	Unattended	115	34	0	37	1	0	0	0	0
243	North Windham - Windham	Distribution	Unattended	34	12	0	21	2	0	0	0	0
244	Sewall Street - Portland (115 MVa)	Distribution	Unattended	115	12	0	22	1	0	0	0	0
245	West Buxton - Buxton	Transmission	Unattended	115	34	0	75	2	0	0	0	0
246	Brunswick Hydro - Brunswick	Distribution	Unattended	34	12	0	11	1	0	0	0	0
247	Elm Street - Yarmouth	Transmission	Unattended	115	34	0	37	1	0	0	0	0
248	Lewiston Lower - Lewiston	Distribution	Unattended	115	12	0	45	2	0	0	0	0
249	Norway - Norway	Transmission	Unattended	115	34	0	37	1	0	0	0	0
250	Sewall Street - Portland	Distribution	Unattended	34	12	0	22	1	0	0	0	0
251	West Street - Gardiner	Distribution	Unattended	34	12	0	11	1	0	0	0	0

FOOTNOTE DATA

(a) Concept: SubstationNameAndLocation

CMP Transformers 2021	Capacity Category		
substn_character	**<10,000**	**>=10,000**	**Grand Total**
Unattended D	74	177	251
Unattended T	3	76	79
Grand Total	**77**	**253**	**330**

CMP MVA 2021	Capacity Category		
substn_character	**<10,000**	**>=10,000**	**Grand Total**
Unattended D	342	2476	2818
Unattended T	120	6075	6195
Grand Total	**462**	**8551**	**9013**

CMP Substations 2021	MVA		
SS TYPE	**<10,000**	**>=10,000**	**Grand Total**
Unattended D	46	107	153
Unattended T	1	20	21
Unattended T/D	—	33	33
Grand Total	**47**	**160**	**207**

Name of Respondent: Central Maine Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/31/2023	Year/Period of Report End of: 2022/ 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	Support Services	Iberdrola Financiacion SA	various	413,755
3	Other Services	IB. Distrib. Electrica SA	various	2,343
4	Support Services	AVANGRID Service Company	various	[(a)]31,201,825
5	Support Services	New York State Electric & Gas Corporation	various	1,184,142
6	Support Services	Rochester Gas and Electric Corporation	various	385,673
7	Other Services	Avangrid Management Company	various	123,977
8	Other Services	Maine Natural Gas Corporation	various	
9	Other Services	NECEC Transmission LLC	various	
10	Other Services	UIL Holdings Corporation	various	62,674
11	Other Services	The United Illuminating Company	various	1,531,559
12	CWIP Support Services		107	[(b)]9,582,520
13	Interest		430	[(c)]173,238
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Other Services	IB. Distrib. Electrica SA	various	
22	Other Services	AVANGRID Service Company	various	595,574
23	Other Services	AVANGRID Networks, Inc.	various	3,827
24	Support Services	New York State Electric & Gas Corporation	various	2,025,634
25	Support Services	Rochester Gas and Electric Corporation	various	876,476
26	Support Services	MaineCom Services	various	559,877
27	Support Services	The Union Water Power Company	various	1,001
28	Support Services	Maine Electric Power Company, Inc.	various	27,747
29	Other Services	Avangrid Management Company	various	214,195
30	Support Services	Maine Natural Gas Corporation	various	8,470
31	Support Services	NECEC Transmission LLC	various	4,298,983
32	Other Services	The United Illuminating Company	various	412,527
33	Other Services	Connecticut Natural Gas Corporation	various	105,256
34	Other Services	The Southern Connecticut Gas Company	various	85,197
35	Other Services	Berkshire Gas Company	various	30,444
36	Interest		419	125,303

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FOOTNOTE DATA

(a) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Account	Distribution	Transmission	Total
5600	—	394,647	394,647
5700	—	98,081	98,081
5800	93,201	—	93,201
5880	97,391	—	97,391
5930	263,296	—	263,296
9010	11,260	9,775	21,035
9030	601,247	493,766	1,095,013
9120	40,398	35,072	75,470
9210	181,441	446,570	628,011
9230	12,803,937	11,115,778	23,919,715
9290	2,075,886	1,802,187	3,878,073
9301	341,456	296,436	637,892
Total	**16,509,513**	**14,692,312**	**31,201,825**

(b) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

IB. Distrib. Electrica SA	38,350
AVANGRID, Inc.	—
AVANGRID Service Company	7,242,081
New York State Electric & Gas Corporation	965,471
Rochester Gas and Electric Corporation	645,074
NECEC Transmission LLC	—
The United Illuminating Company	691,544
	9,582,520

(c) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

AVANGRID, Inc.	99,563
New York State Electric & Gas Corporation	—
Rochester Gas and Electric Corporation	10,947
The United Illuminating Company	61,708
Connecticut Natural Gas Corporation	—
The Southern Connecticut Gas Company	1,020
Berkshire Gas Company	—
	173,238