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)	Year/Period of Report
The Connecticut Light and Power Company	End of: 2025/ Q4

FERC FORM NO. 1 (REV. 02-04)

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

GENERAL INFORMATION

I. **Purpose**

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

II. **Who Must Submit**

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

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

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

III. **What and Where to Submit**

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

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

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

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

The CPA Certification Statement should:

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

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

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

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

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

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

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

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

IV. **When to Submit**

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

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

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

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

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

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

3. 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

4. 'Person' means an individual or a corporation;

5. 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

7. 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; .....

11. "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

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

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

"Sec. 304.

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

"Sec. 309.

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

GENERAL PENALTIES

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

FERC FORM NO. 1 (ED. 03-07)

FERC FORM NO. 1 REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER	
IDENTIFICATION	
01 Exact Legal Name of Respondent The Connecticut Light and Power Company	02 Year/ Period of Report End of: 2025/ 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) 107 Selden Sreet, Berlin, CT 06037		
05 Name of Contact Person Meredith J. Blackburn		06 Title of Contact Person Manager Regulatory and Revenue Accounting
07 Address of Contact Person (Street, City, State, Zip Code) 107 Selden Street, Berlin, CT 06037		
08 Telephone of Contact Person, Including Area Code 413-787-1011	09 This Report is An Original / A Resubmission (1) An Original (2) A Resubmission	10 Date of Report (Mo, Da, Yr) 04/17/2026

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 Jay S. Buth	03 Signature Jay S. Buth	04 Date Signed (Mo, Da, Yr) 04/17/2026
02 Title Vice President, Controller and Chief Accounting Officer		

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.

FERC FORM No. 1 (REV. 02-04)

Page 1

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
	Identification	1	
	List of Schedules	2	
1	**General Information**	101	
2	**Control Over Respondent**	102	
3	**Corporations Controlled by Respondent**	103	
4	**Officers**	104	
5	**Directors**	105	
6	**Information on Formula Rates**	106	
7	**Important Changes During the Year**	108	
8	**Comparative Balance Sheet**	110	
9	**Statement of Income for the Year**	114	
10	**Statement of Retained Earnings for the Year**	118	
12	**Statement of Cash Flows**	120	
12	**Notes to Financial Statements**	122	
13	**Statement of Accum Other Comp Income, Comp Income, and Hedging Activities**	122a	

14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200	
15	Nuclear Fuel Materials	202	Not Applicable
16	Electric Plant in Service	204	
17	Electric Plant Leased to Others	213	Not Applicable
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224	
22	Materials and Supplies	227	
23	Allowances and Environmental Credits	228	
24	Extraordinary Property Losses	230a	Not Applicable
25	Unrecovered Plant and Regulatory Study Costs	230b	Not Applicable
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254b	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	
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272	Not Applicable
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	Not Applicable
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	

55	**Distribution of Salaries and Wages**	354	
56	**Common Utility Plant and Expenses**	356	Not Applicable
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	Not Applicable
63.1	**Renewable Generating Plant Statistics**	404	Not Applicable
64	**Hydroelectric Generating Plant Statistics**	406	Not Applicable
65	**Pumped Storage Generating Plant Statistics**	408	Not Applicable
66	**Generating Plant Statistics Pages**	410	Not Applicable
66.1	**Energy Storage Operations (Large Plants)**	414	Not Applicable
66.2	**Energy Storage Operations (Small Plants)**	419	Not Applicable
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: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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.

Jay S. Buth, Vice President,Controller and Chief Accounting Officer

107 Selden Street Berlin, CT 06037-1616

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

State of Incorporation: CT

Date of Incorporation: 1905-06-22

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.

(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.

Delivery of electricity in the State of Connecticut.

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

(2) No

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

CONTROL OVER RESPONDENT

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

Name of Controlling Organization: Eversource Energy, a Massachusetts business trust and voluntary association headquartered in Boston, Massachusetts and Hartford, Connecticut, is a public utility holding company subject to regulation by the FERC under the Public Utility Company Holding Act of 2005, which wholly and directly owns the respondent.

Manner in Which Control was Held: Ownership of Common Stock

Extent of Control: 100%

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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	Connecticut Yankee Atomic Power Company	Nuclear Electric Generation (Unit Permanently Closed)	34.5%	
2	Maine Yankee Atomic Power Company	Nuclear Electric Generation (Unit Permanently Closed)	12%	
3	Yankee Atomic Electric Company	Nuclear Electric Generation (Unit Permanently Closed)	25%	
4	Electric Power Incorporated	Not Applicable	100%	
5	The Nutmeg Power Company	Not Applicable	100%	
6	The Connecticut Steam Company	Not Applicable	100%	

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)	Date Started in Period (d)	Date Ended in Period (e)
1	Chairman and Chief Executive Officer	Paul Chodak III			
2	President and Chief Operating Officer	Stephen T. Sullivan			
3	Executive Vice President and General Counsel	Gregory B. Butler			
4	Executive Vice President, Chief Financial Officer and Treasurer	John M. Moreira			
5	Vice President, Controller and Chief Accounting Officer	Jay S. Buth			
6	Vice President- CT Electric System Operations	Christopher E. Colorio			
7	Vice President-Energy Supply	Patrick P. Smith			
8	Vice President-Supply Chain and Property Management	Craig J. Dikeman			
9	Vice President-Electric Systems Operations	Michael F. Hayhurst			
10	Vice President-Electric Field Operations	Donald J. Sacco, Jr.			
11	Assistant Treasurer-Corporate Finance and Cash Management (Retired)	Emilie G. O'Neil			2025-10-01
12	Assistant Treasurer-Corporate Finance and Cash Management	Matthew P. Fallon		2025-10-01	
13	Secretary	Florence J. Iacono			
14	Assistant Secretary	Cheri M. Sullivan			
15	Salaries are reported in officially filed copies only. All salaries disclosed are paid by the respondent. Those salaries not disclosed are either less than the threshold or are paid by Eversource Energy Service Company.				

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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	Gregory B. Butler (Executive Vice President and General Counsel)	56 Prospect Street, Hartford, CT 06103		
2	Penelope M. Conner (Executive Vice President, Customer Experience and Energy Strategy)	247 Station Drive, Westwood, MA 02090		
3	Paul Chodak III (Chairman and Chief Executive Officer)	1165 Massachusetts Avenue, Dorchester, MA 02125		
4	Chandler Howard	107 Selden Street, Berlin, CT 06037		
5	Patrick McGrath	107 Selden Street, Berlin, CT 06037		
6	John M. Moreira (Executive Vice President, Chief Financial Officer and Treasurer	800 Boylston Street, Boston, MA 02199		
7	Ian G. Nicholson	107 Selden Street, Berlin, CT 06037		
8	The Company does not have an Executive Committee.			

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	Yes No

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

Line No.	FERC Rate Schedule or Tariff Number (a)	FERC Proceeding (b)
1	ISO-NE Transmission, Markets and Services Tariff, Section II, Schedule 21-ES	ER20-2054, ER26-321
2	ISO-NE Transmission, Markets and Services Tariff, Section II, Schedule 20A-ES	ER05-754, ER18-132
3	ISO-NE Transmission, Markets and Services Tariff, Section II, Attachment F	ER20-2054, ER23-2940, ER25-1669, ER26-439, ER26-390
4	ISO-New England Inc. Transmission, Markets and Services Tariff, Schedule 22 (The University of Connecticut and Kleen Energy System, LLC)	ER05-1384, ER06-70
5	The Connecticut Light and Power Company, Rate Schedule FERC No. 517 (Green Mountain Power f/k/a Central VT Public Service Corporation)	ER00-3639, ER20-2610
6	The Connecticut Light and Power Company, Rate Schedule FERC No. 517 (Dominion Nuclear Connecticut, Inc.)	ER00-3639, ER20-2610
7	The Connecticut Light and Power Company Rate Schedule FERC No. 517 (Massachusetts Municipal Wholesale Electric Company)	ER00-3639, ER20-2610
8	The Connecticut Light and Power Company, Rate Schedule FERC No. O&M-1 (Connecticut Transmission Municipal Electric Energy Cooperative)	ER11-2404
9	The Connecticut Light and Power Company, Rate Schedule FERC No. O&M-2 (The United Illuminating Company)	ER12-2074
10	ISO-New England Inc. Transmission, Markets and Services Tariff, Schedule 22 LGIA-ISONE/CLP-21-03 (Gravel Pit Solar, LLC)	N/A
11	The Connecticut Light and Power Company, Original Service Agreement No. IA-ES-35 (Agreement for Engineering, Design, Permitting, Siting Services and Operations and Maintenance PSEG Power Connecticut, LLC)	ER16-2261
12	ISO-NE Transmission, Markets and Services Tariff, Section II, Schedule 1, Appendix C	RT04-2, ER04-116, ER21-1654
13	The Connecticut Light and Power Company, Original Service Agreement No. LGIA-ISONE/ NU-09-02 (GenConn Middletown LLC IA)	N/A
14	The Connecticut Light and Power Company, Original Service Agreement No. LGIA-ISONE/CLP-25-01 (Solar Nursery, LLC)	N/A
15	The Connecticut Light and Power Company, Original Service Agreement No. LGIA-ISONE/CLP-25-02 (Treebeard BESS Project Co, LLC)	N/A
16	The Connecticut Light and Power Company, Original Service Agreement No. LGIA-ISONE/CLP-25-03 (Saltbox Solar, LLC)	N/A
17	The Connecticut Light and Power Company, Original Service Agreement No. LGIA-ISONE/CLP-23-01 (Naugatuck Avenue Storage, LLC)	N/A
18	The Connecticut Light and Power Company, Original Service Agreement No. LGIA-ISONE/CLP-24-01 (Brookfield, LLC)	ER24-2740
19	The Connecticut Light and Power Company, Construction, Operations and Asset Demarcation Agreement (University of Connecticut)	N/A

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

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

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

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

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	20240731-5279 20240731-5278	07/31/2024	ER20-2054-000	Annual New England Participating Transmission Owners Administrative Regional Network Service Information Filing under RT04-2, et al.	ISO New England Inc. Transmission, Markets and Services Tariff, Attachment F
2	20250731-5237 20250731-5238	07/31/2025	ER20-2054-000	Annual New England Participating Transmission Owners Administrative Regional Network Service Information Filing under RT04-2, et al.	ISO New England Inc. Transmission, Markets and Services Tariff, Attachment F

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

INFORMATION ON FORMULA RATES - Formula Rate Variances

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

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
1	204-207	Electric Plant In Service (Acct 101 - 103 and 106)	g	58
2	219	Accum Provision for Depr of Electric (Account 108)	b,c	25
3	227	Materials and Supplies	c	5
4	234	Accumulated Deferred Income Taxes	b, c	18
5	262-263	Taxes Accrued, Prepaid and Charged During Year	l	10, 21
6	266	Accum Deferred Investment Tax Credit (Account 255)	h	8
7	320-323	Electric Operation and Maintenance Expenses	b	112

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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

For the quarter ended December 31, 2025, CL&P did not assume any obligations as a guarantor of another's performance.
The amount of short-term borrowings that may be incurred by CL&P is subject to periodic approval by the FERC. On December 12, 2025, the FERC granted authorization that allows CL&P to incur total short-term borrowings up to a maximum of $600 million, effective through December 31, 2027.

CL&P, Eversource parent, PSNH, NSTAR Gas, Yankee Gas, EGMA and Aquarion Water Company of Connecticut are parties to a five-year $2.0 billion revolving credit facility which terminates on October 11, 2030. The revolving credit facility serves to backstop Eversource parent's $2.0 billion commercial paper program. The facility is governed by borrowing sub-limits such that CL&P may draw up to $600 million. As of December 31, 2025, CL&P had no borrowings outstanding under this facility.

CL&P has uncommitted line of credit agreements totaling $375 million all of which expire in 2026. There were no borrowings outstanding on the uncommitted line of credit agreements as of December 31, 2025.

As of December 31, 2025, CL&P had $280.0 million in inter-company borrowings outstanding from Eversource parent.

On January 13, 2025, CL&P issued $400 million of its $4.95% First and Refunding Mortgage Bonds, 2025 Series A, due 2030. The proceeds, net of issuance costs, were used to repay outstanding short-term debt, fund capital expenditures and for working capital.

On December 1, 2025, CL&P Electric repaid at maturity the $400 million 0.75% First and Refunding Mortgage Bonds, 2020 Series A.

None

8.

Estimated Annual Effect and Nature of Important Wage Scale Changes

4th Quarter 2025

Company	Group	Effective Date	# of Employees	General Wage Increase Percent	Estimated Annualized Cost of Increase*
Connecticut Light & Power	IBEW (DSO)	10/01/25	46	3.00%	$189,954

* Rounded to the nearest thousand

For a discussion of materially important legal proceedings, see Page 123, Notes to Financial Statements, Note 13, Commitments and Contingencies

None

There were no changes in the majority security holders and voting powers of the respondent during the period.

he Connecticut Light and Power Company proprietary capital ratio is greater than 30 percent.

FERC FORM No. 1 (ED. 12-96)

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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	16,063,150,989	15,323,256,629
3	Construction Work in Progress (107)	200	562,747,082	538,272,363
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		16,625,898,071	15,861,528,992
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	3,356,020,728	3,140,449,981
6	Net Utility Plant (Enter Total of line 4 less 5)		13,269,877,343	12,721,079,011
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202	0	0

8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)			0
14	Net Utility Plant (Enter Total of lines 6 and 13)		13,269,877,343	12,721,079,011
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		11,936,325	11,813,915
19	(Less) Accum. Prov. for Depr. and Amort. (122)		323,104	323,104
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224	1,789,863	1,723,132
23	Noncurrent Portion of Allowances and Environmental Credits	228	0.00	
24	Other Investments (124)			
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		204,067,344	182,483,020
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)		0	
31	Long-Term Portion of Derivative Assets - Hedges (176)		0.00	
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		217,470,428	195,696,963
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		87,615,173	1,092,520
36	Special Deposits (132-134)		1,074,637	1,030,629
37	Working Fund (135)			
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		549,131,854	583,359,356
41	Other Accounts Receivable (143)		349,621,671	345,391,730
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		258,513,985	279,107,757
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		60,994,894	68,723,374
45	Fuel Stock (151)	227		0
46	Fuel Stock Expenses Undistributed (152)	227		0
47	Residuals (Elec) and Extracted Products (153)	227		0
48	Plant Materials and Operating Supplies (154)	227	216,241,586	240,145,837
49	Merchandise (155)	227		0

50	Other Materials and Supplies (156)	227		0
51	Nuclear Materials Held for Sale (157)	202/227		0
52	Allowances and Environmental Credits (158.1, 158.2, 158.3, and 158.4)	228		
53	(Less) Noncurrent Portion of Allowances and Environmental Credits	228	0.00	
54	Stores Expense Undistributed (163)	227	0.00	
55	Gas Stored Underground - Current (164.1)		0.00	
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0.00	
57	Prepayments (165)		(a)49,345,788	(a)36,765,472
58	Advances for Gas (166-167)		0.00	
59	Interest and Dividends Receivable (171)		9,862,153	10,842,561
60	Rents Receivable (172)		2,219,987	2,742,392
61	Accrued Utility Revenues (173)		63,508,384	59,758,567
62	Miscellaneous Current and Accrued Assets (174)		0.00	
63	Derivative Instrument Assets (175)			13,848,768
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	
65	Derivative Instrument Assets - Hedges (176)		0.00	
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		0.00	
67	Total Current and Accrued Assets (Lines 34 through 66)		1,131,102,142	1,084,593,449
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		32,348,348	33,245,433
70	Extraordinary Property Losses (182.1)	230a	0.00	
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0.00	
72	Other Regulatory Assets (182.3)	232	1,997,697,585	2,332,342,749
73	Prelim. Survey and Investigation Charges (Electric) (183)		1,911,325	2,241,185
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0.00	
75	Other Preliminary Survey and Investigation Charges (183.2)		0.00	
76	Clearing Accounts (184)		5,570,647	2,696,038
77	Temporary Facilities (185)		0.00	
78	Miscellaneous Deferred Debits (186)	233	231,143,929	233,398,057
79	Def. Losses from Disposition of Utility Plt. (187)		0.00	
80	Research, Devel. and Demonstration Expend. (188)	352	0.00	
81	Unamortized Loss on Reaquired Debt (189)		(a)2,630,244	(a)3,421,913
82	Accumulated Deferred Income Taxes (190)	234	(a)526,007,854	(a)404,489,044
83	Unrecovered Purchased Gas Costs (191)		0.00	
84	Total Deferred Debits (lines 69 through 83)		2,797,309,932	3,011,834,419
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		17,415,759,845	17,013,203,842

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: Prepayments

Note that at December 31, 2025, the total Prepayments balance in Account 165 included transmission related prepayments for the following:

	CL&P	Transmission
Prepaid Other	$ 1,844,648	$ 10,957
Prepaid Insurance	$ 3,988,693	$ 1,395,374
Prepaid Lease	$ 438,314	$ 26,088
Prepaid Workers Comp.	$ 671,790	$ —
Prepaid Agency Fees	$ 263,074	$ 131,537
Prepaid Property Taxes	$ 36,008,829	$ 13,142,764
Prepaid Vehicle Property Tax	$ 731,234	$ —
Prepaid State Regulatory	$ 4,831,707	$ —
Prepaid Vehicle Cost	$ 564,499	$ —
Prepaid Association Dues	$ 3,000	$ —
Total	$ 49,345,788	$ 14,706,720

(b) Concept: UnamortizedLossOnReacquiredDebt

Note that at December 31, 2025, the total Unamortized Loss on Reacquired Debt balance in Account 189 includes a transmission related component of $1,193,860.

(c) Concept: AccumulatedDeferredIncomeTaxes

Annual Report of CONNECTICUT LIGHT AND POWER COMPANY
Year Ended December 31, 2025
Accumulated Deferred Income Taxes (Account 190)

	Beginning Balance	Activity	Ending Balance
Account 190DGO			
ASC 740 Gross-Up (FAS 109)	318,794,786	(6,829,106)	311,965,680
Account 190DK0			
ASC 740 (FASB 109)	9,157,620	(1,510,102)	7,647,518
Account 190IT0			
ASC 740 ITC - (FAS 109)	10	1	11
Account 1904C0			
NON ADIT FIN48	(21,983,379)	353,059	(21,630,320)
Account 190480			
Reserve for Disputed Trans.	4,616,506	(74,142)	4,542,364
Account 190VA0			
Valuation Allowance	(104,128,840)	(72,515)	(104,201,355)
Account 190000			
Bad Debts	66,272,974	(3,698,926)	62,574,048
Derivative Liability	19,562,073	(19,526,792)	35,281
Regulatory Deferrals	(41,135,739)	153,564,679	112,428,940
Employee Benefits	16,604,730	686,357	17,291,087
Other	136,728,303	(1,373,703)	135,354,600
Sub-total Account 19000	198,032,341	129,651,615	327,683,956
TOTAL Account 190	404,489,044	121,518,810	526,007,854

Note that at the end of the year, the total balance of Accumulated Deferred Income Taxes in Account 190 includes a transmission related component of $99,917,478.

Note that at the end of the year, the total balance of Accumulated Deferred Income Taxes in Account 190480 (Reserve for Disputed Transactions) includes a transmission related component of $2,516,253.

Information on Formula Rates :

Page 106 Line 1, 12 calculated per company records and in accordance with Schedule 1 and Schedule 21-ES, under ISO New England Inc. Transmission, Markets and Services Tariff, Section II.

Information on Formula Rates :

Page 106 Line 3 calculated per company records and in accordance with Attachment F under ISO New England Inc. Transmission, Markets and Services Tariff, Section II.

Annual Report of CONNECTICUT LIGHT AND POWER COMPANY
Year Ended December 31, 2025
Accumulated Deferred Income Taxes (Account 190)-Transmission

	Beginning Balance	Activity	Ending Balance
Account 190DGO			
ASC 740 Gross-Up (FAS 109)	94,952,523	(2,152,158)	92,800,365
Account 190DK0			
ASC 740 (FASB 109)	—	—	—
Account 190IT0			

ASC 740 ITC - (FAS 109)	10	—	10
Account 1904C0			
NON ADIT FIN48	(11,847,333)	(134,829)	(11,982,162)
Account 190480			
Reserve for Disputed Trans.	2,487,938	28,315	2,516,253
Account 190VA0			
Valuation Allowance	(55,575,816)	(2,064,128)	(57,639,944)
Account 190000			
Bad Debts	—	—	—
Derivative Liability	—	—	—
Regulatory Deferrals	(10,351,904)	14,923,186	4,571,282
Employee Benefits	99,389	17,893	117,282
Other	65,895,300	3,639,092	69,534,392
Sub-total Account 19000	55,642,785	18,580,171	74,222,956
TOTAL Account 190	85,660,107	14,257,371	99,917,478

(d) Concept: Prepayments

Note that at December 31, 2024, the total Prepayments balance in Account 165 included transmission related prepayments for the following:

	CL&P	Transmission
Prepaid Other	$ 861,789	$ 1,357
Prepaid Insurance	$ 3,861,986	$ 1,386,177
Prepaid Lease	$ 411,661	$ 13,313
Prepaid Workers Comp.	$ 371,786	$ —
Prepaid Agency Fees	$ 274,632	$ 137,316
Prepaid Property Taxes	$ 24,689,503	$ 9,580,251
Prepaid Vehicle Property Tax	$ 1,043,001	$ —
Prepaid State Regulatory	$ 4,702,759	$ —
Prepaid Vehicle Cost	$ 548,355	$ —
Total	$ 36,765,472	$ 11,118,414

(e) Concept: UnamortizedLossOnReacquiredDebt

Note that at December 31, 2024, the total Unamortized Loss on Reacquired Debt balance in Account 189 includes a transmission related component of $1,553,277.

(f) Concept: AccumulatedDeferredIncomeTaxes

Note that at the beginning of the year, the total Accumulated Deferred Income Tax balance in Account 190 includes a transmission-related component of $85,660,107.

Note that at the beginning of the year, the total Accumulated Deferred Income Tax balance in Account 190480 (Reserve for Disputed Transactions) includes a transmission-related component of $2,487,938.

Information on Formula Rates :

Page 106 Line 1, 12 calculated per company records and in accordance with Schedule 1 and Schedule 21-ES, under ISO New England Inc. Transmission, Markets and Services Tariff, Section II.

Information on Formula Rates :

Page 106 Line 3 calculated per company records and in accordance with Attachment F under ISO New England Inc. Transmission, Markets and Services Tariff, Section II.

FERC FORM No. 1 (REV. 12-03)

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250	60,352,050	60,352,050
3	Preferred Stock Issued (204)	250	116,200,000	116,200,000
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		18,843,055	18,843,055
7	Other Paid-In Capital (208-211)	253	3,645,096,287	3,645,096,287
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118	2,956,741,046	2,840,100,468

12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	(1,538,883)	(1,605,614)
13	(Less) Reacquired Capital Stock (217)	250	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	132,096	158,555
16	Total Proprietary Capital (lines 2 through 15)		6,795,825,651	6,679,144,801
17	**LONG-TERM DEBT**			
18	Bonds (221)	256	5,130,000,000	5,130,000,000
19	(Less) Reacquired Bonds (222)	256	0	0
20	Advances from Associated Companies (223)	256	0	0
21	Other Long-Term Debt (224)	256	0	0
22	Unamortized Premium on Long-Term Debt (225)		22,734,131	25,217,925
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		10,318,964	10,855,626
24	Total Long-Term Debt (lines 18 through 23)		5,142,415,167	5,144,362,299
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		17,834,435	21,106,938
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		68,159,619	65,214,666
29	Accumulated Provision for Pensions and Benefits (228.3)		12,434,270	10,972,913
30	Accumulated Miscellaneous Operating Provisions (228.4)		13,731,707	12,295,296
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		45,423,399	42,548,073
35	Total Other Noncurrent Liabilities (lines 26 through 34)		157,583,430	152,137,886
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		637,459,674	548,087,281
39	Notes Payable to Associated Companies (233)		0	280,000,000
40	Accounts Payable to Associated Companies (234)		141,617,187	137,162,960
41	Customer Deposits (235)		10,880,540	6,828,601
42	Taxes Accrued (236)	262	165,362,035	41,654,375
43	Interest Accrued (237)		74,859,297	66,015,804
44	Dividends Declared (238)		1,763,905	1,763,951
45	Matured Long-Term Debt (239)		0	0
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		5,868,537	6,526,560
48	Miscellaneous Current and Accrued Liabilities (242)		120,125,273	105,372,045
49	Obligations Under Capital Leases-Current (243)		3,953,314	3,747,266
50	Derivative Instrument Liabilities (244)		128,208	71,089,570
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0

53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,162,017,970	1,268,248,413
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)		36,718,089	12,634,610
57	Accumulated Deferred Investment Tax Credits (255)	266	(14)	(14)
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	53,904,141	43,886,366
60	Other Regulatory Liabilities (254)	278	1,535,399,678	1,255,494,072
61	Unamortized Gain on Reacquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		[a]1,830,878,007	[a]1,746,044,213
64	Accum. Deferred Income Taxes-Other (283)		[a]701,017,726	[a]711,251,196
65	Total Deferred Credits (lines 56 through 64)		4,157,917,627	3,769,310,443
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		17,415,759,845	17,013,203,842

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

Note that at the end of the year, the total balance of Accumulated Deferred Income Taxes in Account 282 includes a transmission related component of $785,684,059.

Annual Report of THE CONNECTICUT LIGHT AND POWER COMPANY
Year Ended December 31, 2025
Accumulated Deferred Income Taxes (Account 282)

	Beginning Balance	Activity	Ending Balance
Account 282000			
ADIT - Fed Liberalized Prop	2,076,042,130	58,584,878	2,134,627,008
Account 282DK0			
ADIT Prop FAS 109	(329,997,917)	26,248,916	(303,749,001)
TOTAL ACCOUNT 282	1,746,044,213	84,833,794	1,830,878,007

Annual Report of THE CONNECTICUT LIGHT AND POWER COMPANY
Year Ended December 31, 2025
Accumulated Deferred Income Taxes (Account 282) - TRANSMISSION

	Beginning Balance	Activity	Ending Balance
Account 282000			
ADIT - Fed Liberalized Prop	958,369,368	35,242,462	993,611,830
Account 282DK0			
ADIT Prop FAS 109	(213,881,885)	5,954,114	(207,927,771)
TOTAL ACCOUNT 282	744,487,483	41,196,576	785,684,059

(b) Concept: AccumulatedDeferredIncomeTaxesOther

Annual Report of **THE CONNECTICUT LIGHT AND POWER COMPANY**
Year Ended December 31,2025
Accumulated Deferred Income Taxes (Account 283)

	Beginning Balance	Activity	Ending Balance
Account 283 DG			
FAS 109 Gross-Up	$ 200,094,958	$ 6,189,729	$ 206,284,687
Account 283DK0			
FAS 109 Regulatory Asset	23,164,821	7,574,344	30,739,165
Account 283CP0			
Comprehensive Income	197,152	(29,047)	168,105

Account 283VA0			
Valuation Allowance	3	(3)	—
Account 283990			
Derivatives - Assets	3,810,834	(3,810,834)	—
Employee Benefits	50,871,365	9,640,623	60,511,988
Property Taxes	8,842,319	954,911	9,797,230
Regulatory Deferrals	411,052,265	(32,112,507)	378,939,758
Other	13,217,479	1,359,314	14,576,793
Sub-Total Account 28399	487,794,262	(23,968,493)	463,825,769
TOTAL ACCOUNT 283	$ 711,251,196	$ (10,233,470)	$ 701,017,726

Annual Report of **THE CONNECTICUT LIGHT AND POWER COMPANY**
Year Ended December 31,2025
Accumulated Deferred Income Taxes (Account 283)-Transmission

	Beginning Balance	Activity	Ending Balance
Account 283 DG			
FAS 109 Gross-Up	$ 15,120,153	$ 38,146	$ 15,158,299
Account 283DK0			
FAS 109 Regulatory Asset	3,580,319	(9,600)	3,570,719
Account 283CP0			
Comprehensive Income	89,531	(13,186)	76,345
Account 283VA0			
Valuation Allowance	6	(2)	4
Account 283990			
Derivatives - Assets	—	—	—
Employee Benefits	5,306,494	864,716	6,171,210
Property Taxes	15,849,212	954,911	16,804,123
Regulatory Deferrals	1,748,617	413,726	2,162,343
Other	(2,949,538)	(83,239)	(3,032,777)
Sub-Total Account 28399	19,954,785	2,150,114	22,104,899
TOTAL ACCOUNT 283	$ 38,744,794	$ 2,165,472	$ 40,910,266

(c) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

Note that at the beginning of the year, the total balance of Accumulated Deferred Income Taxes in Account 282 includes a transmission related component of $744,487,483.

(d) Concept: AccumulatedDeferredIncomeTaxesOther

For the beginning of the year balance please refer to footnote b and attached table.

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

STATEMENT OF INCOME

Quarterly

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

Annual or Quarterly if applicable

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

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME											
2	Operating Revenues (400)	300	5,243,270,328	4,603,647,801	0		5,243,270,328	4,603,647,801				
3	Operating Expenses											
4	Operation Expenses (401)	320	2,489,250,188	2,600,085,157	0		2,489,250,188	2,600,085,157				
5	Maintenance Expenses (402)	320	285,294,865	220,437,263	0		285,294,865	220,437,263				
6	Depreciation Expense (403)	336	461,611,324	428,039,412	0		461,611,324	428,039,412				
7	Depreciation Expense for Asset Retirement Costs (403.1)	336										
8	Amort. & Depl. of Utility Plant (404-405)	336		6,130,533				6,130,533				
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)		628,340,782	52,649,525			628,340,782	52,649,525				
13	(Less) Regulatory Credits (407.4)		(8,410,353)	4,518,979			(8,410,353)	4,518,979				
14	Taxes Other Than Income Taxes (408.1)	262	452,959,500	420,033,849			452,959,500	420,033,849				
15	Income Taxes - Federal (409.1)	262	190,848,856	26,555,942			190,848,856	26,555,942				
16	Income Taxes - Other (409.1)	262	72,833,631	(2,143,542)			72,833,631	(2,143,542)				
17	Provision for Deferred Income Taxes (410.1)	234, 272	184,695,709	267,622,038			184,695,709	267,622,038				
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	281,249,734	110,232,738			281,249,734	110,232,738				
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)											
24.1	(Less) Gains from Disposition of Environmental Credits (411.11)											
24.2	Losses from Disposition of Environmental Credits (411.12)											
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24.2)		4,492,995,474	3,904,658,460			4,492,995,474	3,904,658,460				
27	Net Util Oper Inc (Enter Tot line 2 less 25)		750,274,854	698,989,341	0	0	750,274,854	698,989,341				
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)			252,246									
34	(Less) Expenses of Nonutility Operations (417.1)		22,780	286,049		0							
35	Nonoperating Rental Income (418)		3,500	8,600		0							
36	Equity in Earnings of Subsidiary Companies (418.1)	119	66,731	58,817		0							
37	Interest and Dividend Income (419)		12,932,318	28,332,757		0							
38	Allowance for Other Funds Used During Construction (419.1)		[a]12,915,872	[a]21,715,515		0							
39	Miscellaneous Nonoperating Income (421)		14,121,607	17,338,344		0							
40	Gain on Disposition of Property (421.1)		102,402			0							
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		40,119,650	67,420,230	0	0							
42	Other Income Deductions												
43	Loss on Disposition of Property (421.2)		7,457										
44	Miscellaneous Amortization (425)												
45	Donations (426.1)		12,314,459	11,724,832									
46	Life Insurance (426.2)												
47	Penalties (426.3)		360	35,500									
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,240,917	1,326,479									
49	Other Deductions (426.5)		[b]25,567,024	[b]9,744,572									
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		39,130,217	22,831,383	0								
51	Taxes Applic. to Other Income and Deductions												
52	Taxes Other Than Income Taxes (408.2)	262	(11,762,712)	(11,181,134)									
53	Income Taxes-Federal (409.2)	262	247,097	(695,686)									
54	Income Taxes-Other (409.2)	262	(1,907,583)	(4,681,773)									
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	16,952,990	34,483,720									
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	15,218,189	16,449,087									
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)		(11,688,397)	1,476,040	0	0							
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		12,677,830	43,112,807	0	0							
61	Interest Charges												
62	Interest on Long-Term Debt (427)		229,605,830	208,823,340									

63	Amort. of Debt Disc. and Expense (428)		5,546,408	4,519,098									
64	Amortization of Loss on Reaquired Debt (428.1)		[a]791,670	[a]865,700									
65	(Less) Amort. of Premium on Debt-Credit (429)		2,483,793	2,483,793									
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)												
67	Interest on Debt to Assoc. Companies (430)		448,180	14,199,099									
68	Other Interest Expense (431)		(8,431,597)	12,387,157									
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		[d]14,789,932	[d]7,868,798									
70	Net Interest Charges (Total of lines 62 thru 69)		210,686,766	230,441,803	0	0							
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		552,265,918	511,660,345	0	0							
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	0										
77	Extraordinary Items After Taxes (line 75 less line 76)												
78	Net Income (Total of line 71 and 77)		552,265,918	511,660,345	0	0							

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: AllowanceForOtherFundsUsedDuringConstruction
Note that for the year ended December 31, 2025, the total amount of Allowances for Other Funds Used During Construction in Account 419.1 includes a transmission related component of $3,745,812.
(b) Concept: OtherDeductions
Note that for the year ended December 31, 2025, the total amount of Public Education expenses in Account 426.5 includes a transmission related component of $0
(c) Concept: AmortizationOfLossOnReacquiredDebt
Note that for the year ended December 31, 2025, the total amount of Amortization of Loss on Reacquired Debt in Account 428.1, includes a transmission related component of $359,417.
(d) Concept: AllowanceForBorrowedFundsUsedDuringConstructionCredit
Note that for the year ended December 31, 2025, the total amount of Allowance for Borrowed Funds Used During Construction in Account 432 includes a transmission related component of $11,006,694.
(e) Concept: AllowanceForOtherFundsUsedDuringConstruction
Note that for the year ended December 31, 2024, the total amount of Allowances for Other Funds Used During Construction in Account 419.1 includes a transmission related component of $11,848,006.
(f) Concept: OtherDeductions
Note that for the year ended December 31, 2024 , the total amount of Public Education expenses in Account 426.5 includes a transmission related component of $0.
(g) Concept: AmortizationOfLossOnReacquiredDebt
Note that for the year ended December 31, 2024, the total amount of Amortization of Loss on Reacquired Debt in Account 428.1, includes a transmission related component of $393,028.
(h) Concept: AllowanceForBorrowedFundsUsedDuringConstructionCredit
Note that for the year ended December 31, 2024, the total amount of Allowance for Borrowed Funds Used During Construction in Account 432 includes a transmission related component of $3,904,657.

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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		2,840,100,468	2,667,857,549
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
4.1				0
4.2				
9	TOTAL Credits to Retained Earnings (Acct. 439)			0
10	Adjustments to Retained Earnings Debit			
10.1				0
10.2	Impact of Credit Loss Standard		0	0
15	TOTAL Debits to Retained Earnings (Acct. 439)			0
16	Balance Transferred from Income (Account 433 less Account 418.1)		552,199,187	511,601,528
17	Appropriations of Retained Earnings (Acct. 436)			
17.1				0
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			0
23	Dividends Declared-Preferred Stock (Account 437)			
23.1				0
23.2	Preferred Dividends		(5,558,609)	(5,558,609)
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		(5,558,609)	(5,558,609)
30	Dividends Declared-Common Stock (Account 438)			
30.1				0
30.2	6,035,205 Shares Outstanding at December 31, 2024 and 2023		(430,000,000)	(333,800,000)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(430,000,000)	(333,800,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			0
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,956,741,046	2,840,100,468
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
39.1				0
45	TOTAL Appropriated Retained Earnings (Account 215)			0

	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			0
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			0
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		2,956,741,046	2,840,100,468
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		(1,605,614)	(1,664,431)
50	Equity in Earnings for Year (Credit) (Account 418.1)		66,731	58,817
51	(Less) Dividends Received (Debit)			0
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
52.1				0
53	Balance-End of Year (Total lines 49 thru 52)		(1,538,883)	(1,605,614)

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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)	552,265,918	511,660,345
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	461,611,324	434,169,945
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Debt Discount, Debt Premium and Expense	3,854,285	2,901,005
5.2	Uncollectible Expense	17,949,127	17,190,352
5.3	Amortization of Regulatory (Liabilities)/Assets, Net	636,751,135	48,130,546
8	Deferred Income Taxes (Net)	(94,819,224)	175,423,933
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	(33,774,947)	(118,635,700)
11	Net (Increase) Decrease in Inventory	23,904,251	(62,935,245)
12	Net (Increase) Decrease in Allowances and Environmental Credits Inventory		291,500
13	Net Increase (Decrease) in Payables and Accrued Expenses	169,245,725	23,863,991
14	Net (Increase) Decrease in Other Regulatory Assets	(293,370,802)	(242,106,163)
15	Net Increase (Decrease) in Other Regulatory Liabilities	293,754,374	36,334,438
16	(Less) Allowance for Other Funds Used During Construction	12,915,872	21,715,515
17	(Less) Undistributed Earnings from Subsidiary Companies	66,731	58,817
18	Other (provide details in footnote):		

18.1	Pension Contrubutions		
18.2	Pension and PBOP (Income)/ Expense	(14,203,936)	(12,201,017)
18.3	Other, Net	(35,019,179)	(111,146,419)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	1,675,165,448	681,167,179
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(880,687,822)	(998,001,436)
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	(12,915,872)	(21,715,515)
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(867,771,950)	(976,285,921)
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)	0	0
45	Proceeds from Sales of Investment Securities (a)	0	0
46	Loans Made or Purchased		0
47	Collections on Loans		0
49	Net (Increase) Decrease in Receivables		0
50	Net (Increase) Decrease in Inventory		0
51	Net (Increase) Decrease in Allowances and Environmental Credits Held for Speculation		0
52	Net Increase (Decrease) in Payables and Accrued Expenses		0
53	Other (provide details in footnote):		
53.1			0
53.2	Other (provide details in footnote):		0
53.3	Other Investments, Net		
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(867,771,950)	(976,285,921)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	400,000,000	650,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Other (provide details in footnote):		
64.2	Notes Payable to Associated Companies		

66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
67.1	Other (provide details in footnote):		
67.2	Capital Contributions from Parent		300,000,000
70	Cash Provided by Outside Sources (Total 61 thru 69)	400,000,000	950,000,000
72	Payments for Retirement of:		
73	Long-term Debt (b)	(400,000,000)	(139,800,000)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Notes Payable to Associated Companies	(280,000,000)	(177,000,000)
76.2	Financing Expenses, Net of Debt Premium Received	(5,268,228)	(8,855,917)
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock	(5,558,609)	(5,558,609)
81	Dividends on Common Stock	(430,000,000)	(333,800,000)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	(720,826,837)	284,985,474
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)	86,566,661	(10,133,268)
88	Cash and Cash Equivalents at Beginning of Period	[a]2,109,240	[a]12,242,508
90	Cash and Cash Equivalents at End of Period	[b]88,675,901	[a]2,109,240

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: CashAndCashEquivalents

FERC PAGE NUMBER	LINE #	TITLE OF ACCOUNT	BALANCE
110	35	Cash (131)	$ 1,092,520
		Restricted Cash	1,016,720
		Total	$ 2,109,240

See Notes to Financial Statements, Footnote 1.

(b) Concept: CashAndCashEquivalents

FERC PAGE NUMBER	LINE #	TITLE OF ACCOUNT	BALANCE
110	35	Cash (131)	$ 87,615,173
		Restricted Cash	1,060,728
		Total	$ 88,675,901

See Notes to Financial Statements, Footnote 1.

(c) Concept: CashAndCashEquivalents

FERC PAGE NUMBER	LINE #	TITLE OF ACCOUNT	BALANCE
110	35	Cash (131)	$ 10,213,470

Restricted Cash		2,029,038
Total	$	12,242,508

See Notes to Financial Statements, Footnote 1.

(d) Concept: CashAndCashEquivalents

FERC PAGE NUMBER	LINE #	TITLE OF ACCOUNT	BALANCE
110	35	Cash (131)	$ 1,092,520
		Restricted Cash	1,016,720
		Total	$ 2,109,240

See Notes to Financial Statements, Footnote 1.

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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 Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However, where 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.

The financial statements have been prepared in accordance with the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than GAAP. CL&P's Combined Notes to Financial Statements relate to all of Eversource Energy's subsidiaries, including NSTAR Electric and PSNH, and are prepared in conformity with GAAP. Accordingly, certain footnotes are not reflective of CL&P's financial statements contained herein. Refer to the Glossary of Terms for abbreviations and acronyms used throughout the Combined Notes to Financial Statements. The following areas represent the significant differences between the Uniform System of Accounts and GAAP:

Certain regulatory assets and liabilities are reported on a gross basis in FERC accounts 182 and 254 on pages 111 and 113 in the FERC Form 1 and are reported on a net basis and separated into their current and long-term portions in other general purpose financial statements prepared in accordance with GAAP.

Certain amounts recorded as materials and supplies in FERC account 154 and special deposits in FERC account 134 are reported in aggregate as a current or long-term asset on page 110 in the FERC Form 1 and are separated into their current and long-term portions in other general purpose financial statements prepared in accordance with GAAP.

Unamortized debt expenses recorded in FERC account 181 are reported as a long-term asset on page 111 in the FERC Form 1 and are reported as a direct deduction from the carrying amount of long-term debt in other general purpose financial statements prepared in accordance with GAAP.

Cost of removal obligations are included in the accumulated provision for depreciation in FERC account 108 on page 110 in the FERC Form 1 and are reported as a regulatory liability in other general purpose financial statements prepared in accordance with GAAP.

Accumulated deferred income taxes are reported on a gross basis in FERC accounts 190, 282 and 283 on pages 111 and 113 in the FERC Form 1 and are reported on a net basis in other general purpose financial statements prepared in accordance with GAAP.

Taxes receivable and payable are reported on a gross basis in FERC accounts 143 and 236 on pages 110 and 112 and tax prepayments are reported in FERC account 165 on page 111 in the FERC Form 1. These amounts are shown on a net basis by taxing jurisdiction as a current asset or liability in other general purpose financial statements prepared in accordance with GAAP.

Long-term debt is reported in aggregate in the FERC Form 1 and is segregated between current and long-term in other general purpose financial statements prepared in accordance with GAAP.

Operating lease right-of-use assets in FERC account 101.1 are reported as Utility Plant on page 110 in the FERC Form 1 and are reported as other long-term assets in other general purpose financial statements prepared in accordance with GAAP.

Certain revenues and expenses are reported on a gross basis in FERC accounts 400, 401, 403, 404, 407, 409, 410 and 411 on pages 114 and 117 in the FERC Form 1 and are reported on a net basis in other general purpose financial statements prepared in accordance with GAAP.

Certain items that are recorded in other income and deductions reported in FERC accounts 408, 417, 421, 425 and 426 on page 117 in the FERC Form 1 are reported in operating revenues or operating expenses in other general purpose financial statements prepared in accordance with GAAP.

The nonservice components of pension, SERP and PBOP costs are reported in FERC account 926 within Operating Expenses on page 114 in the FERC Form 1 and are presented as non-operating income/(loss) in other general purpose financial statements prepared in accordance with GAAP. The capitalized portion of these nonservice components are recorded within Utility Plant on page 110 in the FERC Form 1 and are reported as a regulatory asset or liability in other general purpose financial statements prepared in accordance with GAAP.

The depreciation and interest expense components for finance leases are reported in FERC account 931 within Operating Expenses on page 114 in the FERC Form 1 and are presented as depreciation and interest expense in other general purpose financial statements prepared in accordance with GAAP.

Certain differences between allowed base distribution revenue and actual revenue collected from customers, such as the impact of revenue decoupling, is reported in FERC account 407 on page 114 in the FERC Form 1 and is reported in operating revenues in other general purpose financial statements prepared in accordance with GAAP.

GAAP requires that public entities report certain information about operating segments in complete sets of financial statements of the entity and certain information about their products and services. GAAP requires disclosure of a measure of segment profit or loss, certain specific revenue and expense items, and segment assets along with reconciliations of amounts disclosed for segments to corresponding amounts in the entity's general purpose financial statements. These disclosures are not required for FERC reporting purposes.

CL&P has evaluated events subsequent to December 31, 2025 through the issuance of the GAAP financial statements on February 17, 2026, and has updated such evaluation for disclosure purposes through April 17, 2026. See Note 28, "Subsequent Event," for further information.
See "Index to the Combined Notes to Financial Statements" for a listing of applicable notes for CL&P.

Index to the Combined Notes to Financial Statements
The notes to the financial statements that follow are a combined presentation. The following list indicates the registrants to which the footnotes apply:

Registrant	Applicable Notes
The Connecticut Light and Power Company	1 (A - I, K - O), 2 - 4, 7 – 9, 11 (A - D), 12, 13 (A - F), 14, 15, 17 - 20, 22, 26, 27, 28
NSTAR Electric Company	1 (A - E, G - I, K, L, N, O), 2 - 4, 6 - 9, 11 (A - D), 12, 13 (A - F), 14, 15, 17 - 20, 22, 26, 27, 28
Public Service Company of New Hampshire	1 (A - E, G, H, K, L, N, O), 2, 3, 7 - 10, 11 (A - D), 12, 13 (A - F), 14, 15, 17, 18, 22, 26, 27, 28

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. About Eversource, CL&P, NSTAR Electric and PSNH
Eversource Energy is a public utility holding company primarily engaged, through its wholly-owned regulated utility subsidiaries, in the energy delivery business. Eversource Energy's wholly-owned regulated utility subsidiaries consist of CL&P, NSTAR Electric and PSNH (electric utilities), Yankee Gas, NSTAR Gas and EGMA (natural gas utilities), and Aquarion (water

utilities). Eversource provides energy delivery and/or water service to approximately 4.6 million electric, natural gas and water customers through twelve regulated utilities in Connecticut, Massachusetts and New Hampshire.

Eversource, CL&P, NSTAR Electric and PSNH are reporting companies under the Securities Exchange Act of 1934. Eversource Energy is a public utility holding company under the Public Utility Holding Company Act of 2005. Arrangements among the regulated electric companies and other Eversource companies, outside agencies and other utilities covering interconnections, interchange of electric power and sales of utility property are subject to regulation by the FERC. Eversource's regulated companies are subject to regulation of rates, accounting and other matters by the FERC and/or applicable state regulatory commissions (the PURA for CL&P, Yankee Gas and Aquarion, the DPU for NSTAR Electric, NSTAR Gas, EGMA and Aquarion, and the NHPUC for PSNH and Aquarion).

CL&P, NSTAR Electric and PSNH furnish franchised retail electric service in Connecticut, Massachusetts and New Hampshire, respectively. NSTAR Gas and EGMA are engaged in the distribution and sale of natural gas to customers within Massachusetts and Yankee Gas is engaged in the distribution and sale of natural gas to customers within Connecticut. Aquarion is engaged in the collection, treatment and distribution of water in Connecticut, Massachusetts and New Hampshire. CL&P, NSTAR Electric and PSNH's results include the operations of their respective distribution and transmission businesses. The distribution business also includes the results of NSTAR Electric's solar power facilities.

Eversource Service, Eversource's service company, and several wholly-owned real estate subsidiaries of Eversource, provide support services to Eversource, including its regulated companies.

B. Basis of Presentation

The consolidated financial statements of Eversource, NSTAR Electric and PSNH include the accounts of each of their respective subsidiaries. Intercompany transactions have been eliminated in consolidation. The accompanying consolidated financial statements of Eversource, NSTAR Electric and PSNH and the financial statements of CL&P are herein collectively referred to as the "financial statements."

The preparation of the financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

CYAPC and YAEC are inactive regional nuclear power companies engaged in the long-term storage of their spent nuclear fuel. Eversource consolidates the operations of CYAPC and YAEC because CL&P's, NSTAR Electric's and PSNH's combined ownership and voting interests in each of these entities is greater than 50 percent. Intercompany transactions between CL&P, NSTAR Electric, PSNH and the CYAPC and YAEC companies have been eliminated in consolidation of the Eversource financial statements.

Eversource holds equity ownership interests that are not consolidated and are accounted for under the equity method. During 2024, Eversource sold its 50 percent ownership interests in three offshore wind projects that had been accounted for under the equity method. See Note 6, "Investments in Unconsolidated Affiliates," for further information.

In accordance with accounting guidance on noncontrolling interests in consolidated financial statements, the Preferred Stock of CL&P and the Preferred Stock of NSTAR Electric, which are not owned by Eversource or its consolidated subsidiaries and are not subject to mandatory redemption, have been presented as noncontrolling interests in the financial statements of Eversource. The Preferred Stock of CL&P and the Preferred Stock of NSTAR Electric are considered to be temporary equity and have been classified between liabilities and permanent shareholders' equity on the balance sheets of Eversource, CL&P and NSTAR Electric due to a provision in the preferred stock agreements of both CL&P and NSTAR Electric that grant preferred stockholders the right to elect a majority of the CL&P and NSTAR Electric Boards of Directors, respectively, should certain conditions exist, such as if preferred dividends are in arrears for a specified amount of time. The Net Income reported in the statements of income and cash flows represents net income prior to apportionment to noncontrolling interests, which is represented by dividends on preferred stock of CL&P and NSTAR Electric.

Eversource's utility subsidiaries' electric, natural gas and water distribution and transmission businesses are subject to rate-regulation that is based on cost recovery and meets the criteria for application of accounting guidance for entities with rate-regulated operations, which considers the effect of regulation on the differences in the timing of the recognition of certain revenues and expenses from those of other businesses and industries. See Note 2, "Regulatory Accounting," for further information.

As of December 31, 2025 and 2024, Eversource's carrying amount of goodwill was $4.23 billion and $3.57 billion, respectively. Eversource performs an assessment for possible impairment of its goodwill at least annually and determined that no impairment existed in 2025. Eversource recorded a goodwill impairment charge of $297 million in the fourth quarter of 2024 as a result of the likely sale of Aquarion at a loss. As of December 31, 2024, the assets and liabilities of the Aquarion water distribution business, including remaining goodwill of $662.5 million, met the criteria to be classified as held for sale. Unless otherwise specified, the amounts and information in the notes presented as of and for the year ended December 31, 2024 did not include assets and liabilities that were classified as held for sale. As of December 31, 2025, the criteria to be classified as held for sale was no longer met and Aquarion's assets and liabilities, including goodwill, were reclassified as held and used on the Eversource balance sheet as of December 31, 2025. See Note 24, "Assets Held for Sale," and Note 25, "Goodwill," for further information.

Certain reclassifications of prior year data were made in the accompanying financial statements to conform to the current year presentation.

C. Accounting Standards

Accounting Standards Recently Adopted: On January 1, 2025, the Company retrospectively adopted Accounting Standards Update (ASU) 2023-07, *Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures*, which requires entities to disclose significant segment expenses, other segment items, and the title and position of the chief operating decision maker (CODM). Additionally, the ASU requires entities to disclose how the CODM assesses segment performance and allocates resources, among certain other required disclosures. Furthermore, disclosures are required in interim periods. The modified disclosures are included in Note 23, "Segment Information."

On January 1, 2026, the Company prospectively adopted ASU 2023-09, *Income Taxes (Topic 740) - Improvements to Income Tax Disclosures*, which requires enhanced income tax disclosures, primarily requiring consistent categories and greater detailed disclosure information in the tax rate reconciliation as well as income taxes paid disaggregated by jurisdiction. The modified disclosures are included in Note 12, "Income Taxes."

Accounting Standards Issued but Not Yet Adopted: In September 2025, the Financial Accounting Standards Board issued ASU 2025-06, *Intangibles — Goodwill and Other — Internal-Use Software (Subtopic 350-40) - Targeted Improvements to the Accounting for Internal-Use Software*, to modernize and clarify the accounting for software costs. The ASU's provisions change the criteria for capitalization of software development costs by eliminating consideration of "project development stages" and instead requiring consideration of the probability of software project completion for its intended use. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2027, with early adoption permitted. Entities are permitted to apply one of three transition approaches: prospective, modified transition that is based on the status of the project and whether software costs were capitalized before the date of adoption, or retrospective. Eversource is currently reviewing the requirements of ASU 2025-06.

D. Cash

Cash includes cash on hand. At the end of each reporting period, any overdraft amounts are reclassified from Cash to Accounts Payable on the balance sheets.

E. Allowance for Uncollectible Accounts

Receivables, Net on the balance sheets primarily includes trade receivables from retail customers and customers related to wholesale transmission contracts, wholesale market sales, sales of RECs, and property rentals. Receivables, Net also includes customer receivables for the purchase of electricity from a competitive third-party supplier, the current portion of customer energy efficiency loans, property damage receivables and other miscellaneous receivables. There is no material concentration of receivables.

Receivables are recorded at amortized cost, net of a credit loss provision (or allowance for uncollectible accounts). The current expected credit loss (CECL) model is applied to receivables for purposes of calculating the allowance for uncollectible accounts. This model is based on expected losses and results in the recognition of estimated expected credit losses, including uncollectible amounts for both billed and unbilled revenues, over the life of the receivable at the time a receivable is recorded.

The allowance for uncollectible accounts is determined based upon various judgments and factors, including an aging-based quantitative assessment that applies an estimated uncollectible percentage to each receivable aging category. Factors in determining credit loss include historical collection, write-off experience, analysis of delinquency statistics, and management's assessment of collectability from customers, including current economic conditions, customer payment trends, the impact on customer bills because of energy usage trends and changes in rates, flexible payment plans and financial hardship arrearage management programs offered to customers, reasonable forecasts, and expectations of future collectability and collection efforts. Management continuously assesses the collectability of receivables and adjusts estimates based on actual experience and future expectations based on economic conditions, collection efforts and other factors. Management also monitors the aging analysis of receivables to determine if there are changes in the collections of accounts receivable. Receivable balances are written off against the allowance for uncollectible accounts when the customer accounts are no longer in service and these balances are deemed to be uncollectible. Management concluded that the reserve balance as of December 31, 2025 adequately reflected the collection risk and net realizable value for its receivables.

The PURA allows CL&P and Yankee Gas to accelerate the recovery of accounts receivable balances attributable to qualified customers under financial or medical duress (uncollectible hardship accounts receivable) outstanding for greater than 180 days and 90 days, respectively. The DPU allows NSTAR Electric, NSTAR Gas and EGMA to recover in rates amounts associated with certain uncollectible hardship accounts receivable. These uncollectible hardship customer account balances are included in Regulatory Assets or Other Long-Term Assets on the balance sheets. Hardship customers are protected from shut off in certain circumstances, and historical collection experience has reflected a higher default risk as compared to the rest of the receivable population. Management uses a higher credit risk profile for this pool of trade receivables as compared to non-hardship receivables. The allowance for uncollectible hardship accounts is included in the total uncollectible allowance balance.
The total allowance for uncollectible accounts is included in Receivables, Net on the balance sheets. The activity in the allowance for uncollectible accounts by portfolio segment is as follows:

	Eversource			CL&P			NSTAR Electric			PSNH
(Millions of Dollars)	Hardship Accounts	Retail (Non-Hardship), Wholesale, and Other	Total Allowance	Hardship Accounts	Retail (Non-Hardship), Wholesale, and Other	Total Allowance	Hardship Accounts	Retail (Non-Hardship), Wholesale, and Other	Total Allowance	Total Allowance [3]
Balance as of January 1, 2023	$ 284.4	$ 201.9	$ 486.3	$ 188.9	$ 36.4	$ 225.3	$ 43.7	$ 51.3	$ 95.0	$ 29.2
Uncollectible Expense	—	72.5	72.5	—	11.7	11.7	—	22.8	22.8	4.0
Uncollectible Costs Deferred [1]	137.0	21.2	158.2	114.4	12.0	126.4	1.5	16.0	17.5	(8.7)
Write-Offs	(55.9)	(122.2)	(178.1)	(44.7)	(28.5)	(73.2)	(1.6)	(41.7)	(43.3)	(10.9)
Recoveries Collected	1.3	14.3	15.6	1.1	4.7	5.8	—	5.0	5.0	0.7
Balance as of December 31, 2023	$ 366.8	$ 187.7	$ 554.5	$ 259.7	$ 36.3	$ 296.0	$ 43.6	$ 53.4	$ 97.0	$ 14.3
Uncollectible Expense	—	74.1	74.1	—	17.2	17.2	—	33.6	33.6	4.7
Uncollectible Costs Deferred [1]	71.4	48.3	119.7	35.5	11.3	46.8	16.2	21.5	37.7	5.1
Write-Offs	(74.3)	(129.5)	(203.8)	(55.1)	(30.9)	(86.0)	(4.6)	(52.4)	(57.0)	(10.9)
Recoveries Collected	0.7	13.3	14.0	0.6	4.5	5.1	—	3.6	3.6	0.9
Reclassified as Held for Sale [2]	—	(2.3)	(2.3)	—	—	—	—	—	—	—
Balance as of December 31, 2024	$ 364.6	$ 191.6	$ 556.2	$ 240.7	$ 38.4	$ 279.1	$ 55.2	$ 59.7	$ 114.9	$ 14.1
Uncollectible Expense	—	101.1	101.1	—	17.9	17.9	—	41.4	41.4	12.0
Uncollectible Costs Deferred [1]	62.4	57.6	120.0	32.0	11.1	43.1	8.3	28.8	37.1	7.2
Write-Offs	(61.9)	(154.2)	(216.1)	(48.5)	(39.1)	(87.6)	(2.9)	(63.7)	(66.6)	(10.5)
Recoveries Collected	2.1	14.9	17.0	1.5	4.5	6.0	0.1	5.7	5.8	0.7
Reclassified from Held for Sale [2]	—	2.3	2.3	—	—	—	—	—	—	—
Balance as of December 31, 2025	$ 367.2	$ 213.3	$ 580.5	$ 225.7	$ 32.8	$ 258.5	$ 60.7	$ 71.9	$ 132.6	$ 23.5

[1] These expected credit losses are deferred as regulatory costs on the balance sheets, as these amounts are ultimately recovered in rates. Amounts include uncollectible costs for hardship accounts and other customer receivables, including uncollectible amounts related to uncollectible energy supply costs.

[2] As of December 31, 2025 and 2023, the allowance for uncollectible accounts attributable to the Aquarion water distribution business are recorded within Receivables, Net on the Eversource balance sheet. As of December 31, 2024, this balance was classified as Assets Held for Sale on the Eversource balance sheet. For further information, see Note 24, "Assets Held for Sale."

[3] In connection with PSNH's pole purchase agreement on May 1, 2023, the purchase price included the forgiveness of previously reserved receivables for reimbursement of operation and maintenance and vegetation management costs.

F. Transfer of Energy Efficiency Loans

CL&P transferred a portion of its energy efficiency customer loan portfolio to outside lenders in order to make additional loans to customers. CL&P remains the servicer of the loans and will transmit customer payments to the lenders, with a maximum amount outstanding under this program of $50 million as of December 31, 2025 and $70 million as of December 31, 2024. The amounts of the loans are included in Receivables, Net and Other Long-Term Assets, and are offset by Other Current Liabilities and Other Long-Term Liabilities on CL&P's balance sheet. The current and long-term portions totaled $8.9 million and $21.8 million, respectively, as of December 31, 2025, and $9.4 million and $17.3 million, respectively, as of December 31, 2024.

G. Materials, Supplies, Natural Gas and REC Inventory

Materials, Supplies, Natural Gas and REC Inventory include materials and supplies purchased primarily for construction or operation and maintenance purposes, natural gas purchased for delivery to customers, and RECs. Inventory is valued at the lower of cost or net realizable value. RECs are purchased from suppliers of renewable sources of generation and are used to meet state mandated Renewable Portfolio Standards requirements. The carrying amounts of materials and supplies, natural gas inventory, and RECs, which are included in Current Assets on the balance sheets, were as follows:

	As of December 31,							
	2025				2024			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Materials and Supplies	$ 400.7	$ 133.9	$ 172.8	$ 55.8	$ 498.6	$ 217.3	$ 177.8	$ 72.1
Natural Gas	49.7	—	—	—	49.5	—	—	—

RECs	41.2	—	38.1	3.1	46.5	—	42.8	3.7
Total	$ 491.6	$ 133.9	$ 210.9	$ 58.9	$ 594.6	$ 217.3	$ 220.6	$ 75.8

As of December 31, 2024, the materials and supplies attributable to the Aquarion water distribution business were classified as Assets Held for Sale on the Eversource balance sheet. As of December 31, 2025, these assets were reclassified as materials and supplies on the Eversource balance sheet. For further information, see Note 24, "Assets Held for Sale."

H. Fair Value Measurements

Fair value measurement guidance is applied to derivative contracts that are not elected or designated as "normal purchases" or "normal sales" (normal) and to marketable securities held in trusts. Fair value measurement guidance is also applied to valuations of the investments used to calculate the funded status of pension and PBOP plans, the nonrecurring fair value measurements of nonfinancial assets such as goodwill, long-lived assets, equity method investments, AROs, and in the valuation of business combinations and asset acquisitions. The fair value measurement guidance was also applied in estimating the fair value of preferred stock, long-term debt and RRBs.

Fair Value Hierarchy: In measuring fair value, Eversource uses observable market data when available in order to minimize the use of unobservable inputs. Inputs used in fair value measurements are categorized into three fair value hierarchy levels for disclosure purposes. The entire fair value measurement is categorized based on the lowest level of input that is significant to the fair value measurement. Eversource evaluates the classification of assets and liabilities measured at fair value on a quarterly basis.

The levels of the fair value hierarchy are described below:

Level 1 - Inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 - Inputs are quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations in which all significant inputs are observable.

Level 3 - Quoted market prices are not available. Fair value is derived from valuation techniques in which one or more significant inputs or assumptions are unobservable. Where possible, valuation techniques incorporate observable market inputs that can be validated to external sources such as industry exchanges, including prices of energy and energy-related products.

Uncategorized - Investments that are measured at net asset value are not categorized within the fair value hierarchy.

Determination of Fair Value: The valuation techniques and inputs used in Eversource's fair value measurements are described in Note 4, "Derivative Instruments," Note 5, "Marketable Securities," Note 6, "Investments in Unconsolidated Affiliates," Note 7, "Asset Retirement Obligations," Note 11A, "Employee Benefits – Pension Benefits and Postretirement Benefits Other Than Pension," Note 15, "Fair Value of Financial Instruments," and Note 25, "Goodwill," to the financial statements.

I. Derivative Accounting

The electric and natural gas companies enter into contracts to purchase and procure energy and energy-related products for their customers, the costs of which are recoverable from customers in future rates. The accounting treatment for energy contracts entered into varies and depends on the intended use of the particular contract and on whether or not the contract is a derivative. Many of the electric and natural gas companies' contracts for the purchase and sale of energy or energy-related products for delivery to customers in the normal course of business are derivatives that are designated as "normal purchases" or "normal sales" and follow accrual accounting. If a contract is a derivative and the energy is settled in the energy market rather than delivered to customers, it is recorded at fair value on the balance sheet.

The application of derivative accounting is complex and requires management judgment in the following respects: identification of derivatives and embedded derivatives, election and designation of a contract as normal, and determination of the fair value of derivative contracts. All of these judgments can have a significant impact on the financial statements. The judgment applied in the election of a contract as normal (and resulting accrual accounting) includes the conclusion that it is probable at the inception of the contract and throughout its term that it will result in physical delivery of the underlying product and that the quantities will be used or sold by the business in the normal course of business. If facts and circumstances change and management can no longer support this conclusion, then a contract cannot be considered normal, accrual accounting is terminated, and fair value accounting is applied prospectively.

The fair value of derivative contracts is based upon the contract terms and conditions and the underlying market price or fair value per unit. When quantities are not specified in the contract, the Company determines whether the contract has a determinable quantity by using amounts referenced in default provisions and other relevant sections of the contract. The fair values of derivative contracts are estimated based on the best market information available, including valuation models that estimate future energy and energy-related prices. Fair value estimates involve assumptions, uncertainties and matters of judgment. The fair value of derivative assets and liabilities with the same counterparty are offset and recorded as a net derivative asset or liability on the balance sheets.

Regulatory assets or regulatory liabilities are recorded to offset the fair values of these derivative contracts related to energy and energy-related products, as contract settlements are recovered from, or refunded to, customers in future rates. All changes in the fair value of these derivative contracts are recorded as regulatory assets or liabilities on the balance sheets and do not impact net income.

For further information regarding derivative contracts, see Note 4, "Derivative Instruments," to the financial statements.

J. Operating Expenses

The cost of natural gas included in Purchased Power, Purchased Natural Gas and Transmission on the statements of income was as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	2025	2024	2023
Eversource - Cost of Natural Gas	$ 857.0	$ 689.6	$ 792.2

K. Allowance for Funds Used During Construction

AFUDC represents the cost of borrowed and equity funds used to finance construction and is included in the cost of the electric, natural gas and water companies' utility plant on the balance sheet. The portion of AFUDC attributable to borrowed funds is recorded as a reduction of Interest Expense, and the AFUDC related to equity funds is recorded as Other Income, Net on the statements of income. AFUDC costs are recovered from customers over the service life of the related plant in the form of increased revenue collected as a result of higher depreciation expense.

The average AFUDC rate is based on a FERC-prescribed formula using the cost of a company's short-term financings and capitalization (preferred stock, long-term debt and common equity), as appropriate. The average rate is applied to average eligible CWIP amounts to calculate AFUDC.

As part of the annual FERC Transmission Formula Rate protocols process, the AFUDC calculation methodology utilized in formula transmission rates was updated effective January 1, 2025. This calculation methodology resulted in an adjustment to the AFUDC equity and AFUDC debt amounts recognized on the statement of income in the third quarter of 2025 in accordance with the AFUDC policy.

AFUDC costs and the weighted-average AFUDC rates were as follows:

Eversource	For the Years Ended December 31,		
(Millions of Dollars, except percentages)	2025	2024	2023
Borrowed Funds	$ 64.1	$ 64.4	$ 44.6
Equity Funds	99.0	97.8	78.1
Total AFUDC	$ 163.1	$ 162.2	$ 122.7
Average AFUDC Rate	6.4 %	6.5 %	5.8 %

	For the Years Ended December 31,								
	2025			2024			2023		
(Millions of Dollars, except percentages)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Borrowed Funds	$ 14.5	$ 28.9	$ 5.7	$ 8.1	$ 27.2	$ 8.9	$ 7.7	$ 17.2	$ 6.1
Equity Funds	12.2	58.4	13.0	22.4	58.8	7.0	20.0	45.7	5.4
Total AFUDC	$ 26.7	$ 87.3	$ 18.7	$ 30.5	$ 86.0	$ 15.9	$ 27.7	$ 62.9	$ 11.5
Average AFUDC Rate	6.0 %	6.7 %	7.3 %	6.7 %	7.0 %	5.5 %	6.7 %	5.9 %	5.1 %

L. Other Income, Net

The components of Other Income, Net on the statements of income were as follows:

Eversource	For the Years Ended December 31,		
(Millions of Dollars)	2025	2024	2023
Pension, SERP and PBOP Non-Service Income Components, Net of Deferred Portion [1]	$ 139.3	$ 115.4	$ 132.9
AFUDC Equity	99.0	97.8	78.1
Equity in Earnings of Unconsolidated Affiliates [2]	19.9	51.9	15.5
Investment (Loss)/Income	(5.4)	0.6	(4.9)
Interest Income	125.5	138.2	94.2
Other [2]	0.6	6.6	32.3
Total Other Income, Net	$ 378.9	$ 410.5	$ 348.1

	For the Years Ended December 31,								
	2025			2024			2023		
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Pension, SERP and PBOP Non-Service Income Components, Net of Deferred Portion [1]	$ 36.2	$ 61.4	$ 17.6	$ 28.2	$ 52.8	$ 14.9	$ 34.9	$ 57.4	$ 16.2
AFUDC Equity	12.2	58.4	13.0	22.4	58.8	7.0	20.0	45.7	5.4
Investment (Loss)/Income	(1.7)	(1.6)	(0.7)	(1.4)	1.9	(0.5)	(2.4)	(0.2)	(0.7)
Interest Income	12.9	72.7	13.0	28.3	77.0	9.6	9.0	60.6	5.3
Other	0.1	1.7	0.1	0.1	0.9	0.1	0.1	0.6	0.4
Total Other Income, Net	$ 59.7	$ 192.6	$ 43.0	$ 77.6	$ 191.4	$ 31.1	$ 61.6	$ 164.1	$ 26.6

[1] See Note 11A, "Employee Benefits – Pension Benefits and Postretirement Benefits Other Than Pension," for the components of net periodic benefit income/expense for the Pension, SERP and PBOP Plans. The non-service related components of pension, SERP and PBOP benefit income/expense, after capitalization or deferral, are presented as non-operating income and recorded in Other Income, Net on the statements of income.

[2] Equity in Earnings of Unconsolidated Affiliates includes $23.4 million of pre-tax income recorded at Eversource in the second quarter of 2024 from Eversource's previously-held wind equity method investment, North East Offshore, as a result of a vendor settlement agreement payment received by the joint venture. In the third quarter of 2024, Eversource sold its equity method investments in three offshore wind projects. In March 2023, Eversource's equity method investment in a renewable energy fund was liquidated. Liquidation proceeds in excess of the carrying value were recorded in 2023 within Other in the table above. See Note 6, "Investments in Unconsolidated Affiliates," for further information on the 2024 sales of the offshore wind investments and the 2023 liquidation of the renewable energy fund.

M. Other Taxes

Eversource's companies that serve customers in Connecticut collect gross receipts taxes levied by the state of Connecticut from their customers. These gross receipts taxes are recorded separately with collections in Operating Revenues and with payments in Taxes Other Than Income Taxes on the statements of income as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	2025	2024	2023
Eversource	$ 232.4	$ 209.4	$ 202.9
CL&P	203.8	185.1	174.9

As agents for state and local governments, Eversource's companies that serve customers in Connecticut and Massachusetts collect certain sales taxes that are recorded on a net basis with no impact on the statements of income.

N. Supplemental Cash Flow Information

Eversource *(Millions of Dollars)*	As of and For the Years Ended December 31, 2025	2024	2023
Cash Paid During the Year for:			
Interest, Net of Amounts Capitalized	$ 1,182.6	$ 1,014.4	$ 783.2
Non-Cash Investing Activities:			
Plant Additions Included in Accounts Payable (As of)	508.2	472.5	564.1

	As of and For the Years Ended December 31,								
	2025			2024			2023		
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Cash Paid During the Year for:									
Interest, Net of Amounts Capitalized	$ 208.4	$ 232.4	$ 83.9	$ 216.8	$ 215.1	$ 78.4	$ 176.8	$ 182.8	$ 62.8
Non-Cash Investing Activities:									
Plant Additions Included in Accounts Payable (As of)	143.2	160.5	59.2	95.8	155.4	77.7	139.8	178.9	65.9

The following table reconciles cash as reported on the balance sheets to the cash and restricted cash balance as reported on the statements of cash flows:

	As of December 31,							
	2025				2024			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Cash as reported on the Balance Sheets	$ 135.4	$ 87.6	$ 8.3	$ 13.7	$ 26.7	$ 1.1	$ 0.9	$ 1.4
Restricted cash included in:								
Special Deposits	93.6	1.1	17.6	38.3	75.8	1.0	8.1	32.7
Assets Held for Sale, Current	—	—	—	—	5.8	—	—	—
Marketable Securities	14.0	—	—	—	10.0	—	—	—
Other Long-Term Assets	3.2	—	—	3.2	9.0	—	—	3.1
Cash and Restricted Cash as reported on the Statements of Cash Flows	$ 246.2	$ 88.7	$ 25.9	$ 55.2	$ 127.3	$ 2.1	$ 9.0	$ 37.2

Special Deposits represent cash collections related to the PSNH RRB customer charges that are held in trust, required ISO-NE cash deposits, cash held in escrow accounts, and CYAPC and YAEC cash balances. Special Deposits are included in Current Assets on the balance sheets. Restricted cash included in Marketable Securities represents money market funds held in restricted trusts to fund CYAPC and YAEC's spent nuclear fuel storage obligations.

Eversource's restricted cash also includes an Energy Relief Fund for energy efficiency and clean energy measures in the Merrimack Valley established under the terms of an EGMA 2020 settlement agreement. This restricted cash held in escrow accounts included $21.4 million and $20.0 million recorded as short-term in Special Deposits as of December 31, 2025 and December 31, 2024, respectively and $5.9 million recorded in Other Long-Term Assets on the balance sheets as of December 31, 2024.

O. Related Parties

Eversource Service, Eversource's service company, provides centralized accounting, administrative, engineering, financial, information technology, legal, operational, planning, purchasing, tax, and other services to Eversource's companies. The Rocky River Realty Company and Properties, Inc., two other Eversource subsidiaries, construct, acquire or lease some of the property and facilities used by Eversource's companies.

Included in the CL&P, NSTAR Electric and PSNH balance sheets as of December 31, 2025 and 2024 were Accounts Receivable from Affiliated Companies and Accounts Payable to Affiliated Companies relating to transactions between CL&P, NSTAR Electric and PSNH and other subsidiaries that are wholly-owned by Eversource. These amounts have been eliminated in consolidation on the Eversource financial statements.
Included in the PSNH balance sheets as of December 31, 2025 and 2024 and the CL&P balance sheet as of December 31, 2024 were Notes Payable to Eversource Parent. These amounts have been eliminated in consolidation on the Eversource financial statements. See Note 8, "Short-Term Debt" for intercompany borrowing amounts.

The Eversource Energy Foundation is an independent not-for-profit charitable entity and is not included in the consolidated financial statements of Eversource as the Company does not have title to, and cannot receive contributions back from, the Eversource Energy Foundation's assets. Eversource made contributions to the Eversource Energy Foundation of $7.0 million in 2025, and $20.0 million in 2023. Eversource did not make any contributions in 2024.

2. REGULATORY ACCOUNTING

Eversource's utility companies are subject to rate regulation that is based on cost recovery and meets the criteria for application of accounting guidance for rate-regulated operations, which considers the effect of regulation on the timing of the recognition of certain revenues and expenses. The regulated companies' financial statements reflect the effects of the rate-making process. The rates charged to the customers of Eversource's regulated companies are designed to collect each company's costs to provide service, including a return on investment.

The application of accounting guidance for rate-regulated enterprises results in recording regulatory assets and liabilities. Regulatory assets represent the deferral of incurred costs that are probable of future recovery in customer rates. Regulatory assets are amortized as the incurred costs are recovered through customer rates. Regulatory liabilities represent either revenues received from customers to fund expected costs that have not yet been incurred or probable future refunds to customers.

Management believes it is probable that each of the regulated companies will recover its respective investments in long-lived assets and the regulatory assets that have been recorded. If management were to determine that it could no longer apply the accounting guidance applicable to rate-regulated enterprises, or if management could not conclude it is probable that costs would be recovered from customers in future rates, the applicable costs would be charged to net income in the period in which the determination is made.

Regulatory Assets: The components of regulatory assets were as follows:

	As of December 31,							
	2025				2024			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Storm Costs, Net	$ 1,959.3	$ 991.3	$ 499.6	$ 468.4	$ 2,039.4	$ 971.1	$ 609.8	$ 458.5
Regulatory Tracking Mechanisms	1,573.8	206.5	705.6	93.2	1,781.6	507.7	650.0	162.8
Income Taxes, Net	1,044.5	546.1	161.5	23.3	968.4	521.0	145.4	20.7
Benefit Costs	992.8	173.7	300.0	61.7	967.4	168.8	293.6	65.6
Derivative Contracts	753.2	0.1	753.1	—	57.2	57.2	—	—
Securitized Stranded Costs	306.1	—	—	306.1	349.3	—	—	349.3
Cost of Removal	262.5	—	8.1	—	198.4	—	8.5	—
Goodwill-related	230.4	—	197.8	—	247.2	—	212.3	—
Asset Retirement Obligations	162.8	44.2	84.6	5.4	150.2	41.2	78.3	5.1
Environmental Remediation Costs	136.1	—	—	—	116.2	—	—	—
EGMA Acquisition and Integration Costs	82.3	—	—	—	—	—	—	—
Other Regulatory Assets	189.9	19.5	92.0	3.0	195.4	58.5	109.2	3.7
Total Regulatory Assets	7,693.7	1,981.4	2,802.3	961.1	7,070.7	2,325.5	2,107.1	1,065.7
Less: Current Portion	1,975.1	265.2	978.8	119.9	2,189.7	638.5	902.8	173.3
Total Long-Term Regulatory Assets	$ 5,718.6	$ 1,716.2	$ 1,823.5	$ 841.2	$ 4,881.0	$ 1,687.0	$ 1,204.3	$ 892.4

As of December 31, 2024, the Regulatory Assets attributable to the Aquarion water distribution business were classified as Assets Held for Sale on the Eversource balance sheet. As of December 31, 2025, these assets were reclassified as Regulatory Assets on the Eversource balance sheet. For further information, see Note 24, "Assets Held for Sale."
Storm Costs, Net: The storm cost deferrals relate to costs incurred for storm events at CL&P, NSTAR Electric and PSNH that each company expects to recover from customers. A storm must meet certain criteria to qualify for deferral and recovery with the criteria specific to each state jurisdiction and utility company. Once a storm qualifies for recovery, all qualifying expenses incurred during storm restoration efforts are deferred and recovered from customers. Costs for storms that do not meet the specific criteria are expensed as incurred. In addition to storm restoration costs, CL&P and PSNH are each allowed to recover pre-staging storm costs. Management believes storm costs deferred were prudently incurred and meet the criteria for specific cost recovery in Connecticut, Massachusetts and New Hampshire, and that recovery from customers is probable through the applicable regulatory recovery processes. For CL&P, under the current regulatory construct, the unamortized regulatory asset balance earns a return once authorized for recovery in rates. NSTAR Electric recovers a carrying charge on its deferred storm cost regulatory asset balance. PSNH earns a return on the regulatory asset balance.

Multiple tropical and severe storms over the past several years have caused extensive damage to Eversource's electric distribution systems resulting in significant numbers and durations of customer outages, along with significant pre-staging costs. Storms in 2025 that qualified for future recovery resulted in deferred storm restoration costs and pre-staging costs totaling $129 million at Eversource, including $82 million at CL&P, $25 million at NSTAR Electric, and $22 million at PSNH. Management believes that all of these storm costs were prudently incurred and meet the criteria for specific cost recovery. Of Eversource's total deferred storm costs, $2.06 billion either have yet to be filed with the applicable regulatory commission, are pending regulatory approval, or are subject to prudency review (including $1.19 billion at CL&P, $409 million at NSTAR Electric and $456 million at PSNH) as of December 31, 2025. These storm cost totals exclude storm funding amounts that are collected in rates, which are recorded as a reduction to the deferred storm cost regulatory asset balance. CL&P, NSTAR Electric and PSNH are seeking approval of their deferred storm restoration costs through the applicable regulatory recovery process.

CL&P Storm Filings: On March 28, 2024, PURA established a prudency review proceeding for the purpose of receiving and reviewing evidence of the costs reported by CL&P in response to catastrophic storms and pre-staging events totaling approximately $634 million that occurred between January 1, 2018 and December 31, 2021. On December 31, 2024, CL&P filed a supplement to its March 2024 prudency review application to request that PURA evaluate the prudence of its costs for nine additional catastrophic storms and two additional pre-staging events for the period January 1, 2022 through January 31, 2023 totaling approximately $173 million. On July 10, 2025, CL&P filed a second supplement to its March 2024 prudency review application to request that PURA evaluate the prudence of its costs for ten additional catastrophic storms for the period February 1, 2023 through December 31, 2023 totaling approximately $171 million. On July 25, 2025, CL&P filed a third supplement in this application to include carrying charges calculated at the weighted average cost of capital on the deferred storm costs totaling $246 million, which reflects CL&P's actual financing costs on the unpaid storm costs from the date the deferred storm costs first began to accrue through May 2025. These carrying charges have not been deferred on the balance sheet. On December 13, 2025, PURA opened a new proceeding for the prudency determination of CL&P's 2018 to 2023 storm costs either by a settled or litigated process and a separate future docket will be needed to consider CL&P's application to issue rate reduction bonds for the securitization of approved storm costs. A final decision is expected on or about July 29, 2026. Although we cannot predict the ultimate outcome of these storm proceedings, we continue to believe these deferred storm restoration costs were

prudently incurred and are probable of recovery.

CL&P's storm events include the August 4, 2020 Tropical Storm Isaias, which resulted in deferred storm restoration costs of approximately $232 million at CL&P as of December 31, 2025. Although in 2021 PURA found that CL&P's performance in its preparation for, and response to, Tropical Storm Isaias fell below applicable performance standards in certain instances, CL&P believes it presented in its 2023 storm filing credible evidence demonstrating there is no reasonably close causal connection between the alleged sub-standard performance and the storm costs incurred. While it is possible that some amount of storm costs may be disallowed by PURA, any such amount cannot be estimated at this time. CL&P continues to believe that these storm restoration costs associated with Tropical Storm Isaias were prudently incurred and meet the criteria for cost recovery.

Regulatory Tracking Mechanisms: The regulated companies' approved rates are designed to recover costs incurred to provide service to customers. The regulated companies recover certain of their costs on a fully-reconciling basis through regulatory commission-approved tracking mechanisms. The differences between the costs incurred (or the rate recovery allowed) and the actual revenues are recorded as regulatory assets (for undercollections) or as regulatory liabilities (for overcollections) to be included in future customer rates each year. Carrying charges are recovered in rates on all material regulatory tracking mechanisms.

The electric and natural gas distribution companies recover, on a fully reconciling basis, the costs associated with the procurement of energy and natural gas supply, state mandated energy purchase agreements and other energy-related costs, electric transmission related costs from FERC-approved transmission tariffs, energy efficiency programs, low income assistance programs, certain uncollectible accounts receivable for hardship customers, restructuring and stranded costs as a result of deregulation (including securitized RRB charges), certain capital tracking mechanisms for infrastructure improvements, and additionally for the Massachusetts utilities, pension and PBOP benefits, net metering for distributed generation, and solar-related programs. CL&P, NSTAR Electric, Yankee Gas, NSTAR Gas, EGMA and the Aquarion Water Company of Connecticut each have a regulatory commission approved revenue decoupling mechanism. Distribution revenues are decoupled from customer sales volumes, where applicable, which breaks the relationship between sales volumes and revenues. Each company reconciles its annual base distribution rate recovery amount to the pre-established levels of baseline distribution delivery service revenues. Any difference between the allowed level of distribution revenue and the actual amount realized during a 12-month period is adjusted through rates in the following period.

Income Taxes, Net: The tax effect of temporary book-tax differences (differences between the periods in which transactions affect income in the financial statements and the periods in which they affect the determination of taxable income, including those differences relating to uncertain tax positions) is accounted for in accordance with the rate-making treatment of the applicable regulatory commissions and accounting guidance for income taxes. Differences in income taxes between the accounting guidance and the rate-making treatment of the applicable regulatory commissions are recorded as regulatory assets. As these assets are offset by deferred income tax liabilities, no carrying charge is collected. The amortization period of these assets varies depending on the nature and/or remaining life of the underlying assets and liabilities. For further information regarding income taxes, see Note 12, "Income Taxes," to the financial statements.

Benefit Costs: Deferred benefit costs represent unrecognized actuarial losses and gains and unrecognized prior service costs and credits attributable to Eversource's Pension, SERP and PBOP Plans. The regulated companies record actuarial losses and gains and prior service costs and credits arising at the December 31st remeasurement date of the funded status of the benefit plans as a regulatory asset or regulatory liability in lieu of a charge to Accumulated Other Comprehensive Income/(Loss), reflecting ultimate recovery from customers through rates. The regulatory asset or regulatory liability is amortized with the recognition of actuarial losses and gains and prior service costs and credits to net periodic benefit expense/income over the estimated average future employee service period using the corridor approach. Regulatory accounting is also applied to the portions of Eversource's service company costs that support the regulated companies, as these amounts are also recoverable. As these regulatory assets or regulatory liabilities do not represent a cash outlay for the regulated companies, no carrying charge is recovered from customers. See Note 11A, "Employee Benefits - Pension Benefits and Postretirement Benefits Other Than Pension," for further information on regulatory benefit plan amounts arising and amortized during the year.

Eversource, CL&P, NSTAR Electric, and PSNH recover benefit costs related to their distribution and transmission operations from customers in rates as allowed by their applicable regulatory commissions. NSTAR Electric, NSTAR Gas and EGMA recover qualified pension and PBOP expenses related to their distribution operations through a rate reconciling mechanism that fully tracks the change in net pension and PBOP expenses each year. The electric transmission companies' rates provide for an annual true-up of estimated to actual costs, which include pension and PBOP expenses as allowed by FERC.

Derivative Contracts: For the regulated companies, regulatory assets (for losses) or regulatory liabilities (for gains) are recorded to offset the fair value of derivative contracts used to purchase energy and energy-related products that will be recovered from or refunded to customers in future rates. These regulatory assets and liabilities are excluded from rate base and contract costs are being recovered in energy supply rates over the duration of the contracts. See Note 4, "Derivative Instruments," to the financial statements for further information on these contracts.
Securitized Stranded Costs: In 2018, a subsidiary of PSNH issued $635.7 million of securitized RRBs to finance PSNH's unrecovered remaining costs associated with the divestiture of its generation assets. Securitized regulatory assets, which are not earning an equity return, are being recovered over the amortization period of the associated RRBs. The PSNH RRBs are expected to be repaid by February 1, 2033. For further information, see Note 10, "Rate Reduction Bonds and Variable Interest Entities," to the financial statements.

Cost of Removal: Eversource's regulated companies currently recover amounts in rates for future costs of removal of plant assets over the lives of the assets. The estimated cost to remove utility assets from service is recognized as a component of depreciation expense, and the cumulative amount collected from customers but not yet expended is recognized as a regulatory liability. Expended removal costs that exceed amounts collected from customers are recognized as regulatory assets, as they are probable of recovery in future rates.

Goodwill-related: The goodwill regulatory asset originated from a 1999 transaction, and the DPU allowed its recovery in NSTAR Electric and NSTAR Gas rates. This regulatory asset is currently being amortized and recovered from customers in rates without a carrying charge over a 40-year period, and as of December 31, 2025, there were 14 years of amortization remaining.

Asset Retirement Obligations: The costs associated with the depreciation of the regulated companies' ARO assets and accretion of the ARO liabilities are recorded as regulatory assets in accordance with regulatory accounting guidance. The regulated companies' ARO assets, regulatory assets, and ARO liabilities offset and are excluded from rate base. These costs are being recovered over the life of the underlying property, plant and equipment.

Environmental Remediation Costs: Recoverable costs associated with the remediation of environmental sites are recorded as regulatory assets in accordance with PURA and DPU regulation. These costs do not earn a return. For further information, see Note 13A, "Commitments and Contingencies - Environmental Matters," to the financial statements.
EGMA Acquisition and Integration Costs: As part of a DPU-approved settlement agreement on December 1, 2025, acquisition-related and integration costs incurred from the October 2020 acquisition of Columbia Gas of Massachusetts (now Eversource Gas Company of Massachusetts) are allowed for recovery over a 10-year period beginning at the time EGMA's next base distribution rate change becomes in effect. These regulatory assets are being carried with no return.

Other Regulatory Assets: Other Regulatory Assets primarily include certain uncollectible accounts receivable for hardship customers, contractual obligations associated with the spent nuclear fuel storage costs of the CYAPC, YAEC and MYAPC decommissioned nuclear power facilities, removal costs incurred that exceed amounts collected from customers, electric vehicle program costs, certain exogenous property taxes and merger-related costs allowed for recovery, losses associated with the reacquisition or redemption of long-term debt, and various other items.

Regulatory Costs in Other Long-Term Assets: Eversource's regulated companies had $244.2 million (including $127.1 million for CL&P, $51.0 million for NSTAR Electric and $5.4 million for PSNH) and $221.0 million (including $116.3 million for CL&P, $41.1 million for NSTAR Electric and $4.5 million for PSNH) of additional regulatory costs not yet specifically approved as of December 31, 2025 and 2024, respectively, that were included in Other Long-Term Assets on the balance sheets. These amounts will be reclassified to Regulatory Assets upon approval by the applicable regulatory agency. Based on regulatory policies or past precedent on similar costs, management believes it is probable that these costs will ultimately be approved and recovered from customers in rates. As of December 31, 2025 and 2024, these regulatory costs included $123.2 million (including $57.0 million for CL&P and $34.0 million for NSTAR Electric) and $92.5 million (including $47.2 million for CL&P and $24.4 million for NSTAR Electric), respectively, of deferred uncollectible hardship costs.

Equity Return on Regulatory Assets: For rate-making purposes, the regulated companies recover the carrying costs related to their regulatory assets. For certain regulatory assets, the carrying cost recovered includes an equity return component. This equity return is not recorded on the balance sheets.

Regulatory Liabilities: The components of regulatory liabilities were as follows:

	As of December 31,							
	2025				2024			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
EDIT due to Tax Cuts and Jobs Act of 2017	$ 2,423.4	$ 933.3	$ 847.9	$ 319.8	$ 2,442.7	$ 956.6	$ 877.6	$ 330.6
Regulatory Tracking Mechanisms	1,186.6	457.3	535.2	111.2	702.4	180.3	413.6	114.4
Cost of Removal	867.1	275.1	479.4	45.5	684.1	212.8	451.3	20.1
Deferred Portion of Non-Service Income Components of Pension, SERP and PBOP	509.4	72.8	252.5	48.5	427.1	61.6	211.6	42.6
AFUDC - Transmission	179.4	72.0	107.4	—	154.8	65.1	89.7	—
Derivative Contract	91.0	—	91.0	—	—	—	—	—
Benefit Costs	80.4	8.8	24.5	6.8	69.3	4.5	21.4	3.9
Other Regulatory Liabilities	200.8	43.3	15.0	4.0	184.5	39.1	14.2	4.5
Total Regulatory Liabilities	5,538.1	1,862.6	2,352.9	535.8	4,664.9	1,520.0	2,079.4	516.1
Less: Current Portion	1,264.6	417.5	650.8	118.4	632.3	124.1	436.3	121.1
Total Long-Term Regulatory Liabilities	$ 4,273.5	$ 1,445.1	$ 1,702.1	$ 417.4	$ 4,032.6	$ 1,395.9	$ 1,643.1	$ 395.0

As of December 31, 2024, the Regulatory Liabilities attributable to the Aquarion water distribution business were classified as Liabilities Held for Sale on the Eversource balance sheet. As of December 31, 2025, these liabilities were reclassified as Regulatory Liabilities on the Eversource balance sheet. For further information, see Note 24, "Assets Held for Sale."

EDIT due to Tax Cuts and Jobs Act of 2017: Pursuant to the Tax Cuts and Jobs Act of 2017, Eversource had remeasured its existing deferred federal income tax balances to reflect the decrease in the U.S. federal corporate income tax rate from 35 percent to 21 percent. The remeasurement resulted in provisional regulated excess accumulated deferred income tax (excess ADIT or EDIT) liabilities that will benefit customers in future periods and were recognized as regulatory liabilities on the balance sheet. EDIT liabilities related to property, plant, and equipment are subject to IRS normalization rules and will be returned to customers using the same timing as the remaining useful lives of the underlying assets that gave rise to the ADIT liabilities. Eversource's regulated companies are in the process of refunding the EDIT liabilities to customers based on orders issued by applicable state and federal regulatory commissions.

Deferred Portion of Non-Service Income Components of Pension, SERP and PBOP: Regulatory liabilities were recorded for the deferred portion of the non-service related components of net periodic benefit expense/(income) for the Pension, SERP and PBOP Plans. These regulatory liabilities will be amortized over the remaining useful lives of the various classes of utility property, plant and equipment.
AFUDC - Transmission: Regulatory liabilities were recorded by CL&P and NSTAR Electric for AFUDC accrued on certain reliability-related transmission projects to reflect local rate base recovery. These regulatory liabilities will be amortized over the depreciable life of the related transmission assets.

Other Regulatory Liabilities: Other Regulatory Liabilities primarily include EGMA's acquired regulatory liability as a result of the 2020 DPU-approved rate settlement agreement and the CMA asset acquisition on October 9, 2020, and various other items.

FERC ROE Complaints: As of December 31, 2025 and 2024, Eversource has a reserve established for the second ROE complaint period in the pending FERC ROE complaint proceedings, which was recorded as a regulatory liability and is reflected within Regulatory Tracking Mechanisms in the table above. The cumulative pre-tax reserve (excluding interest) as of December 31, 2025 and 2024 totaled $39.1 million for Eversource (including $21.4 million for CL&P, $14.6 million for NSTAR Electric and $3.1 million for PSNH). See Note 13E, "Commitments and Contingencies – FERC ROE Complaints," for further information on developments in the pending ROE complaint proceedings.

Regulatory Developments:

CL&P State Bonding Proceeds: On July 1, 2025, Connecticut enacted Public Act No. 25-173 (Senate Bill No. 4) (the Act). The Act authorizes the State of Connecticut to issue up to $125 million in new general obligation bonds for each fiscal year 2026 and 2027 to reduce costs of hardship protection measures charged to retail customers, of which 67 percent of each issuance will be allocated to CL&P, and $30 million for fiscal year 2026 and $20 million for fiscal year 2027 in new general obligation bonds to fund the electric vehicle charging program, of which 80 percent of each issuance will be allocated to CL&P.

On September 19, 2025, CL&P received $107.8 million in general obligation bond proceeds from the State of Connecticut, which represent reimbursement of incurred costs that were previously recognized as regulatory assets on CL&P's balance sheets. The proceeds received for the reimbursement of hardship costs and for electric vehicle charging program costs were credited against the System Benefits Charge (SBC) and Non-Bypassable Federally Mandated Congestion Charge (NBFMCC) regulatory deferrals on CL&P's balance sheet as of December 31, 2025. The proceeds from the state bond funding are presented as a cash inflow in Regulatory Recoveries within operating activities on CL&P's statement of cash flows.

Yankee Gas Distribution Rate Case: On November 12, 2024, Yankee Gas filed an application with PURA to amend its existing distribution rates for effect on November 1, 2025. Yankee Gas had subsequently amended its rate application to request approval of a distribution rate increase of $193 million. On September 22, 2025, PURA issued a proposed final (draft) decision in Yankee Gas's distribution rate case that included a distribution rate increase of $55.6 million, effective November 1, 2025.

On November 5, 2025, PURA issued a final decision in the Yankee Gas distribution rate case that included a distribution rate increase of $82.2 million and a total distribution revenue requirement of $802.2 million, effective November 1, 2025. The approved revenue requirement includes a previously recorded rate credit of $37.4 million plus carrying charges for non-firm margin credits over three years beginning November 1, 2025. Excluding the rate credit, the distribution rate increase totaled $95.7 million. The final decision also established an authorized net regulatory ROE of 9.32 percent, adopting a 9.48 percent ROE net of certain reductions totaling 16 basis points, and a 53 percent common equity ratio for Yankee Gas' capital structure. PURA declined to approve the multi-year performance-based rate making plan that would adjust rates annually as proposed by Yankee Gas. PURA also implemented an annual cap on contemporaneous cost recovery of aging infrastructure replacement spending in the Distribution Integrity Management Program (DIMP) rate tracking mechanism of $139.9 million, in which spending above the annual cap will be deferred for recovery until the next distribution rate case. The final decision resulted in a net pre-tax loss to earnings of $8.5 million in the fourth quarter of 2025, primarily for the write off of certain capitalized employee compensation costs that were disallowed from rate base. Yankee Gas filed motions to request PURA reconsider the disallowances of these capitalized costs, certain computational errors, and other issues identified in its final decision. On December 15, 2025, PURA issued a notice of reconsideration to reconsider the final decision. A final decision on the reconsideration is expected from PURA by March 15, 2026.

NSTAR Electric Distribution Rates: NSTAR Electric's performance based regulation (PBR) mechanism allows for an annual adjustment to base distribution rates for inflation, exogenous events and future capital additions based on a historical five-year average of total capital additions. On September 15, 2025, NSTAR Electric submitted its annual PBR Adjustment filing for a $55.1 million increase to base distribution rates and a total base distribution revenue requirement of $1.34 billion for effect on January 1, 2026. The requested base distribution rate increase is comprised of a $25.2 million inflation-based adjustment and a $29.9 million K-bar adjustment for capital additions based on the difference between the historical five-year average of total capital additions and the base capital revenue requirement. On December 30, 2025, the DPU approved this filing.

On September 16, 2024, NSTAR Electric submitted its annual PBR Adjustment filing for a $55.8 million increase to base distribution rates, for effect on January 1, 2025. The requested base distribution rate increase is comprised of a $35.3 million inflation-based adjustment and a $20.5 million adjustment for capital additions based on the difference between the historical five-year

average of total capital additions and the base capital revenue requirement. On December 23, 2024, the DPU approved this filing.
NSTAR Gas Distribution Rates: NSTAR Gas' PBR mechanism allows for an annual adjustment to base distribution rates for inflation and exogenous events. On June 16, 2025, NSTAR Gas submitted its annual PBR Adjustment filing for rates to be effective on November 1, 2025. On September 11, 2025, NSTAR Gas updated its filing to request approval of a $162.6 million increase to base distribution rates and a total base distribution revenue requirement of $447.7 million. The base distribution rate increase is comprised of a $10.3 million inflation-based adjustment and, in accordance with the DPU's final decision in the 2020 NSTAR Gas rate case, a $152.3 million rate-base reset to incorporate capital additions for the period 2021 through 2024, which includes the transfer of GSEP revenues totaling $107.3 million into base rates, as well as other non-GSEP plant additions totaling $45.0 million.

On October 29, 2025, the DPU issued a decision determining that NSTAR Gas was not eligible to increase its distribution rates for the rate base reset because it did not achieve certain performance metrics under its PBR plan, and did not allow the base rate increase of $45.0 million for the incorporation of non-GSEP plant additions into base rates. The decision stated that those investments could be considered for inclusion in base distribution rates in NSTAR Gas's next base rate proceeding. The DPU did allow NSTAR Gas to transfer its GSEP revenues through 2024 of $107.3 million for recovery through base distribution rates effective November 1, 2025. The DPU approved the base distribution rate increase of $10.3 million for the inflation-based adjustment. The DPU also approved NSTAR Gas' mitigation proposal, in which NSTAR Gas paused recovery of the Gas System Enhancement Adjustment Factor (GSEAF) and reduced the current GSEAF to zero on November 1, 2025 in order to align this decrease with the base rate increase and to mitigate November 1, 2025 bill impacts to customers. NSTAR Gas will begin to recover the remaining 2025 GSEP revenue requirement on May 1, 2026 over 18 months. On November 4, 2025, NSTAR Gas filed a motion requesting the DPU to reconsider its decision denying the rate base reset citing legal concerns and arguing that the decision will ultimately result in higher costs for customers. NSTAR Gas also notified the DPU of its intention to file a base distribution rate case.

On December 30, 2025, NSTAR Gas and the Massachusetts Office of the Attorney General reached a joint settlement agreement that allowed for the reinstatement of the rate base reset of $45.0 million increase to base distribution rates effective January 1, 2026, for NSTAR Gas to not petition for a rate case with new rates effective December 1, 2026, and for continuation of NSTAR Gas' PBR program through November 1, 2030. The settlement agreement also required NSTAR Gas to provide a credit to customers of $10.2 million over a ten-month period beginning January 2026 as penalty for its failure to meet three performance metrics as required for eligibility for the rate base reset, pay a $2 million concession to the Office of the Attorney General to fund customer energy assistance programs, waive recovery of certain carrying charges, delay recovery of $53 million of capital pipeline investments until the next rate case, and provide bill stabilization credit deferrals. The DPU approved the settlement agreement on January 16, 2026. The settlement agreement resulted in a pre-tax charge to earnings of $12.2 million in the fourth quarter of 2025.

On September 16, 2024, NSTAR Gas submitted its annual PBR Adjustment filing for a $12.7 million increase to base distribution rates for effect on November 1, 2024. On October 30, 2024, the DPU approved this filing.

NSTAR Electric and EGMA Settlement: On November 3, 2025, EGMA, NSTAR Electric, and the Massachusetts Office of the Attorney General reached a joint settlement agreement that resolved outstanding issues in multiple open Pension Adjustment Mechanism (PAM) dockets and open Resiliency Tree Work (RTW) dockets at NSTAR Electric and allows recovery of transaction and integration costs related to Eversource's acquisition of EGMA. Certain PAM and RTW collections are being refunded to NSTAR Electric's customers over a one-year period beginning January 1, 2026 and the transaction and integration costs of $82.3 million will be collected from EGMA customers over a ten-year period from the time of the next EGMA rate case. The settlement agreement was approved by the DPU on December 1, 2025. The settlement resulted in a net pre-tax benefit to earnings of $64.8 million on the Eversource income statement in the fourth quarter of 2025 ($82.3 million benefit at Eversource Parent and Other Companies for the allowed recovery of previously expensed acquisition-related and integration costs and $17.5 million charge at NSTAR Electric) and a net increase to regulatory assets on the Eversource balance sheet.

EGMA Distribution Rates: On November 4, 2024, EGMA submitted a revised filing for its first rate base reset for rates effective November 1, 2024, in accordance with an October 7, 2020 EGMA Rate Settlement Agreement approved by the DPU. The compliance filing was ordered by the DPU on October 31, 2024. The rate base reset occurring on November 1, 2024 adjusted distribution rates to account for capital additions (including the roll-in of GSEP capital additions), depreciation expense, property taxes, and return on rate base for capital additions placed into service through December 31, 2023. The total revenue requirement calculated for the first rate base reset was an increase to base distribution rates of $147.8 million, of which $34.0 million is associated with GSEP investments through December 31, 2023. Under the terms of the Rate Settlement Agreement, EGMA applied a cap on the revenue change effective November 1, 2024, and the amount in excess of the cap was deferred for recovery through the Local Distribution Adjustment Clause (LDAC) on May 1, 2025, including carrying charges. After adjusting for the cap, the increase to base distribution rates was $85.6 million effective November 1, 2024 (of which $8.8 million is offset by a reduction in the GSEP revenue requirement and GSEP rate also taking effect on November 1, 2024 for a net distribution rate change on November 1, 2024 of $76.8 million). Base distribution rates increased effective November 1, 2025 to incorporate the $62.2 million remaining revenue requirement. On November 7, 2024, the DPU approved this filing.

PSNH Distribution Rate Case: On June 11, 2024, PSNH filed an application with the NHPUC for approval of a temporary annual base distribution rate increase. On July 31, 2024, the NHPUC approved a settlement agreement that was reached by PSNH, New Hampshire Department of Energy, and the Office of the Consumer Advocate to implement a temporary annual base distribution rate increase of $61.2 million effective August 1, 2024. Temporary rates were in effect until permanent rates were approved and took effect August 1, 2025.
Also on June 11, 2024, PSNH filed an application with the NHPUC to request an increase in permanent base distribution rates of $181.9 million, which is inclusive of the temporary rate increase. Throughout the course of the proceeding, PSNH amended the requested revenue requirement to account for developments in the case, and arrived at a final proposed rate increase of $103 million, which primarily reflects the removal of deferred storm costs that will be addressed in a separate proceeding. On July 25, 2025, the NHPUC issued its decision on permanent rates and approved a permanent rate increase of $100.7 million, effective August 1, 2025, inclusive of the temporary rate increase referenced above. The total base distribution revenue requirement effective August 1, 2025 is $519 million. The order also established an authorized regulatory ROE of 9.5 percent with a 50 percent common equity ratio for PSNH's capital structure.

This revenue requirement also contains an alternative regulation revenue requirement adjustment. This adjustment was part of the NHPUC's alternative regulatory framework that the NHPUC adopted as an alternative to PSNH's proposed performance-based regulation plan. The alternative regulatory framework authorizes formulaic annual revenue adjustments on August 1st of 2026, 2027 and 2028. PSNH is required to file its next base distribution rate case for effect in June 2029 and committed not to file its next distribution rate case until 2029. The alternative regulatory framework calculates the annual revenue adjustment using a productivity factor and an adjustment for inflation to provide PSNH with increased revenue for operations. The framework also contains an exogenous events recovery mechanism for certain unforeseen events out of PSNH's control and exceeding a specified threshold, a performance metric, and an earnings sharing mechanism where PSNH would have to return 75 percent of all revenue back to customers that exceeds 25 basis points more than the authorized ROE of 9.5 percent. Consistent with PSNH's proposal, lost base revenues for both net metering and energy efficiency were eliminated effective August 1, 2025.

To the extent permanent rates exceed the level of temporary rates, the difference will reconcile back to the date that the temporary rates took effect and the company recovers the difference over a twelve-month term. On August 11, 2025, PSNH filed its recoupment calculation, and on September 10, 2025, the NHPUC issued an order that the recoupment is $9.1 million and will be collected through the RRA regulatory tracking mechanism over a one-year period.

As part of the decision, unrecovered storm costs of $247 million were removed from the rate proceeding for consideration in a separate proceeding. Approval of the ultimate amount of storm costs to be recovered is subject to a separate prudency review that was filed in March of 2024 and is being considered by the NHPUC in a separate dedicated docket, which is at this time complete and awaiting the issuance of an order. Approved storm costs in excess of the amount approved in base rates will be recovered through the Regulatory Reconciliation Adjustment (RRA) regulatory tracking mechanism. The NHPUC increased the level of storm costs recovered in base rates from $12 million to $19 million.

The impact of the rate case decision resulted in a pre-tax benefit to earnings of $15.6 million at PSNH due primarily to the recoupment and the allowed recovery of other deferrals that will be recovered in the RRA. The majority of this amount was recorded as a reduction to amortization expense on PSNH's statement of income in 2025.

On January 30, 2026, the New Hampshire Department of Energy filed a notice of appeal with the New Hampshire Supreme Court challenging certain aspects of the PSNH distribution rate case. The appeal raises issues regarding the lawfulness of the Company's alternative regulatory framework, the adequacy of the NHPUC's findings supporting the approved revenue requirement, and whether the NHPUC sufficiently addressed required regulatory factors in its final order. The Department of Energy contends that additional findings were necessary to support the final determinations. On February 6, 2026, the Office of the Consumer Advocate filed a notice of cross-appeal with the New Hampshire Supreme Court challenging other aspects of the rate case decision. The NHPUC, as the deciding agency, is afforded the highest level of deference by the New Hampshire Supreme Court, and therefore the Department of Energy and the Office of Consumer Advocate will have a very high burden to meet to be successful on appeal. Eversource is currently evaluating the appeals and will respond consistent with applicable legal and regulatory processes.

3. PROPERTY, PLANT AND EQUIPMENT AND ACCUMULATED DEPRECIATION

Utility property, plant and equipment is recorded at original cost. Original cost includes materials, labor, construction overheads and AFUDC for regulated property. The cost of repairs and maintenance is charged to Operations and Maintenance expense as incurred.

The following tables summarize property, plant and equipment by asset category:

Eversource	As of December 31,	
(Millions of Dollars)	**2025**	**2024**
Distribution - Electric	$ 22,695.3	$ 21,144.1
Distribution - Natural Gas	9,888.0	8,922.2
Transmission - Electric	17,082.4	16,130.9
Distribution - Water [1]	2,577.3	—
Solar	206.8	201.0
Utility	52,449.8	46,398.2
Other [2]	2,476.3	2,254.1
Property, Plant and Equipment, Gross	54,926.1	48,652.3
Less: Accumulated Depreciation		
Utility	(10,911.7)	(9,636.5)
Other	(1,246.1)	(1,044.1)
Total Accumulated Depreciation	(12,157.8)	(10,680.6)
Property, Plant and Equipment, Net	42,768.3	37,971.7
Construction Work in Progress	3,162.7	3,014.9
Total Property, Plant and Equipment, Net	$ 45,931.0	$ 40,986.6

	As of December 31,					
	2025			**2024**		
(Millions of Dollars)	**CL&P**	**NSTAR Electric**	**PSNH**	**CL&P**	**NSTAR Electric**	**PSNH**
Distribution - Electric	$ 8,906.0	$ 10,635.7	$ 3,193.8	$ 8,437.9	$ 9,782.3	$ 2,964.2
Transmission - Electric	7,222.5	6,722.9	3,138.7	6,937.7	6,375.2	2,819.6
Solar	—	206.8	—	—	201.0	—
Property, Plant and Equipment, Gross	16,128.5	17,565.4	6,332.5	15,375.6	16,358.5	5,783.8
Less: Accumulated Depreciation	(3,081.3)	(4,014.2)	(1,085.4)	(2,928.0)	(3,782.0)	(1,032.3)
Property, Plant and Equipment, Net	13,047.2	13,551.2	5,247.1	12,447.6	12,576.5	4,751.5
Construction Work in Progress	576.1	1,757.7	260.6	554.6	1,461.3	338.4
Total Property, Plant and Equipment, Net	$ 13,623.3	$ 15,308.9	$ 5,507.7	$ 13,002.2	$ 14,037.8	$ 5,089.9

[1] As of December 31, 2024, the property, plant and equipment balance, net of accumulated depreciation, attributable to the Aquarion water distribution business was classified to Assets Held for Sale on the Eversource balance sheet. As of December 31, 2025, these assets were reclassified as Property, Plant and Equipment, Net on the Eversource balance sheet. For further information, see Note 24, "Assets Held for Sale."

[2] These assets are primarily comprised of computer software, hardware and equipment at Eversource Service and buildings at The Rocky River Realty Company.

Depreciation: Depreciation of utility assets is calculated on a straight-line basis using composite rates based on the estimated remaining useful lives of the various classes of property (estimated useful life for PSNH distribution and the water utilities). The composite rates, which are subject to approval by the appropriate state regulatory agency, include a cost of removal component, which is collected from customers over the lives of the plant assets and is recognized as a regulatory liability. Depreciation rates are applied to property from the time it is placed in service.

Upon retirement from service, the cost of the utility asset is charged to the accumulated provision for depreciation. The actual incurred removal costs are applied against the related regulatory liability.
The depreciation rates for the various classes of utility property, plant and equipment aggregate to composite rates as follows:

(Percent)	**2025**	**2024**	**2023**
Eversource	3.3 %	3.2 %	3.1 %
CL&P	2.9 %	2.9 %	2.8 %
NSTAR Electric	2.8 %	2.8 %	2.7 %
PSNH	3.0 %	3.0 %	3.0 %

The following table summarizes average remaining useful lives of depreciable assets:

	As of December 31, 2025			
(Years)	Eversource	CL&P	NSTAR Electric	PSNH
Distribution - Electric	33.0	34.7	32.5	30.4
Distribution - Natural Gas	32.8	—	—	—
Transmission - Electric	39.2	35.4	44.1	39.6
Distribution - Water	43.9	—	—	—
Solar	21.8	—	21.8	—
Other [1]	9.9	—	—	—

[1] The estimated useful life of computer software, hardware and equipment primarily ranges from 5 to 15 years and of buildings is 40 years.

4. DERIVATIVE INSTRUMENTS

The electric and natural gas companies enter into contracts to purchase and procure energy and energy-related products for their customers, which are subject to price volatility. The costs associated with supplying energy to customers are recoverable from customers in future rates. These regulated companies manage the risks associated with the price volatility of energy and energy-related products through the use of derivative and non-derivative contracts. Many of the derivative contracts meet the definition of, and are designated as, normal and qualify for accrual accounting under the applicable accounting guidance. The costs and benefits of derivative contracts that meet the definition of normal are recognized in Operating Expenses on the statements of income as electricity or natural gas is delivered.

Derivative contracts that are not designated as normal are recorded at fair value as derivative assets or liabilities on the balance sheets. For the electric and natural gas companies, regulatory assets or regulatory liabilities are recorded to offset the fair values of derivatives, as contract amounts are recovered from, or refunded to, customers in their respective energy supply rates. The mark to market unrealized losses or gains of these derivative contracts are deferred as regulatory assets (if the derivative is a liability) or as regulatory liabilities (if the derivative is an asset).

The gross fair values of derivative assets and liabilities with the same counterparty are offset and reported as net Derivative Assets or Derivative Liabilities, with current and long-term portions, on the balance sheets. The following table presents the gross fair values of contracts, categorized by risk type, and the net amounts recorded as current or long-term derivative assets or liabilities:

		As of December 31,					
		2025			2024		
(Millions of Dollars)	Fair Value Hierarchy	Commodity Supply and Price Risk Management	Netting [1]	Net Amount Recorded as a Derivative	Commodity Supply and Price Risk Management	Netting [1]	Net Amount Recorded as a Derivative
Current Derivative Assets:							
CL&P	Level 2	$ —	$ —	$ —	$ 14.2	$ (0.3)	$ 13.9
NSTAR Electric	Level 3	91.0	—	91.0	—	—	—
Current Derivative Liabilities:							
CL&P	Level 2	(0.1)	—	(0.1)	(71.1)	—	(71.1)
Long-Term Derivative Liabilities:							
NSTAR Electric	Level 3	(753.1)	—	(753.1)	—	—	—

[1] Amounts represent derivative assets and liabilities that Eversource elected to record net on the balance sheets. These amounts are subject to master netting agreements or similar agreements for which the right of offset exists.

Derivative Contracts at Fair Value with Offsetting Regulatory Amounts

Commodity Supply and Price Risk Management: In accordance with Massachusetts clean energy legislation and under the Massachusetts Clean Energy 83D procurement, in June 2018, NSTAR Electric entered into a 20-year power purchase agreement for the purchase of renewable hydroelectric energy and renewable energy attributes from Hydro-Québec. The agreement requires NSTAR Electric to purchase 579 MW of energy per hour through January 2046. Upon notice of commercial operation of the transmission line needed to deliver this energy, received on December 31, 2025, the power purchase agreement was marked to market on the balance sheet. The current and long-term portions of the contract were recorded as derivative assets and derivative liabilities, respectively, and were offset by current and long-term regulatory liabilities and regulatory assets, respectively, reflecting full recovery from or refund to NSTAR Electric's customers.

As required by regulation, CL&P, along with UI, has capacity-related contracts with generation facilities. CL&P has a sharing agreement with UI, with 80 percent of the costs or benefits of each contract borne by or allocated to CL&P and 20 percent borne by or allocated to UI. The combined capacities of these contracts as of December 31, 2025 and 2024 were 3 MW and 610 MW, respectively. The capacity contracts extend through 2026 and obligate both CL&P and UI to make or receive payments on a monthly basis to or from the generation facilities based on the difference between a set capacity price and the capacity market price received in the ISO-NE capacity markets.

For the years ended December 31, 2025, 2024 and 2023, losses from changes in fair value associated with these derivative contracts of $662.9 million, $3.8 million and $3.9 million, respectively, were deferred in Regulatory Assets or Regulatory Liabilities on the balance sheet.

Fair Value Measurements of Derivative Instruments

The fair value of derivative contracts utilizes both observable and unobservable inputs. The fair value is modeled using income techniques, such as discounted cash flow valuations adjusted for assumptions related to exit price. Valuations of derivative contracts using a discounted cash flow methodology include assumptions regarding future energy and energy-related prices, the timing and likelihood of scheduled payments, selection of a discount rate, and also reflect non-performance risk, including credit, using the default probability approach based on the counterparty's credit rating for assets and the Company's credit rating for liabilities. Valuations also give consideration to premiums or discounts that would be required by a market participant to arrive at an exit price. Future energy prices that are not quoted in an active market are based on available market data with assumptions of future market dynamics and inflation to address the full time period of the contract. Fair value measurements are prepared and reviewed by individuals with expertise in valuation techniques, pricing of energy-related products, and accounting requirements.

For NSTAR Electric's derivative contract, unobservable inputs for future energy prices using a forward electricity bid price curve are significant to the valuation and are classified as Level 3. As of December 31, 2025, Level 3 unobservable inputs utilized in the valuation of NSTAR Electric's power purchase agreement include energy prices ranging from $24.65 per MWh through $145.33 per MWh, or a weighted average of $53.44 per MWh, over the contractual period of 2026 through 2046.

For CL&P derivative contracts, observable inputs for energy-related product prices in future years for which quoted prices in an active market exist are significant to the valuation and are classified as Level 2.

The following table presents changes in the Level 3 category of derivative assets and derivative liabilities measured at fair value on a recurring basis. The derivative assets and liabilities are presented on a net basis.

NSTAR Electric *(Millions of Dollars)*	For the Year Ended December 31, 2025
Derivatives, Net:	
Fair Value as of Beginning of Year	$ —
Net Realized/Unrealized Losses Included in Regulatory Assets or Regulatory Liabilities	(662.1)
Settlements	—
Fair Value as of End of Year	$ (662.1)

5. MARKETABLE SECURITIES

Eversource's marketable securities include the CYAPC and YAEC legally restricted trusts that each hold equity and available-for-sale debt securities to fund the spent nuclear fuel removal obligations of their nuclear fuel storage facilities. Equity and available-for-sale debt marketable securities are recorded at fair value. CYAPC and YAEC's spent nuclear fuel trusts are restricted and are classified in long-term Marketable Securities on the balance sheets.

Eversource's water business also holds a trust. As of December 31, 2024, the securities held in this trust of $4.1 million were classified as Assets Held for Sale on the Eversource balance sheet. As of December 31, 2025, these securities held in this trust of $3.5 million were reclassified as Marketable Securities on the Eversource balance sheet. For further information, see Note 24, "Assets Held for Sale." For the years ended December 31, 2025 and 2024, there were unrealized losses of $0.7 million and unrealized gains of $0.9 million recorded in Other Income, Net, related to these equity securities, respectively.

Equity Securities: Eversource's equity securities include CYAPC's and YAEC's marketable securities held in spent nuclear fuel trusts, which had fair values of $161.8 million and $163.1 million as of December 31, 2025 and 2024, respectively. Unrealized gains and losses for these spent nuclear fuel trusts are subject to regulatory accounting treatment and are recorded in Marketable Securities with the corresponding offset to long-term liabilities on the balance sheets, with no impact on the statements of income.

Available-for-Sale Debt Securities: The following is a summary of available-for-sale debt securities, which are held in CYAPC's and YAEC's spent nuclear fuel trusts:

	As of December 31,							
	2025				2024			
Eversource *(Millions of Dollars)*	Amortized Cost	Pre-Tax Unrealized Gains	Pre-Tax Unrealized Losses	Fair Value	Amortized Cost	Pre-Tax Unrealized Gains	Pre-Tax Unrealized Losses	Fair Value
Debt Securities	$ 156.5	$ 0.7	$ (1.8)	$ 155.4	$ 163.2	$ 0.1	$ (6.1)	$ 157.2

Unrealized gains and losses for available-for-sale debt securities included in the CYAPC and YAEC spent nuclear fuel trusts are subject to regulatory accounting treatment and are recorded in Marketable Securities with the corresponding offset to long-term liabilities on the balance sheets, with no impact on the statements of income.

As of December 31, 2025, the contractual maturities of available-for-sale debt securities were as follows:

Eversource *(Millions of Dollars)*	Amortized Cost	Fair Value
Less than one year	$ 15.7	$ 15.8
One to five years	39.9	40.6
Six to ten years	26.0	26.1
Greater than ten years	74.9	72.9
Total Debt Securities	$ 156.5	$ 155.4

Realized Gains and Losses: Realized gains and losses are offset in long-term liabilities for CYAPC and YAEC and are recorded in Other Income, Net for Eversource's benefit trusts. Eversource utilizes the average cost basis method for the CYAPC and YAEC spent nuclear fuel trusts.

Fair Value Measurements: The following table presents the marketable securities recorded at fair value on a recurring basis by the level in which they are classified within the fair value hierarchy:

	As of December 31,	
Eversource *(Millions of Dollars)*	2025	2024
Level 1:		
Mutual Funds and Equities	$ 165.3	$ 163.1
Money Market Funds	14.0	10.0

Total Level 1	$ 179.3	$ 173.1
Level 2:		
U.S. Government Issued Debt Securities (Agency and Treasury)	$ 82.0	$ 92.0
Corporate Debt Securities	37.9	32.5
Asset-Backed Debt Securities	6.4	7.8
Municipal Bonds	7.2	6.8
Other Fixed Income Securities	7.9	8.1
Total Level 2	$ 141.4	$ 147.2
Total Marketable Securities	$ 320.7	$ 320.3

U.S. government issued debt securities are valued using market approaches that incorporate transactions for the same or similar bonds and adjustments for yields and maturity dates. Corporate debt securities are valued using a market approach, utilizing recent trades of the same or similar instruments and also incorporating yield curves, credit spreads and specific bond terms and conditions. Asset-backed debt securities include collateralized mortgage obligations, commercial mortgage backed securities, and securities collateralized by auto loans, credit card loans or receivables. Asset-backed debt securities are valued using recent trades of similar instruments, prepayment assumptions, yield curves, issuance and maturity dates, and tranche information. Municipal bonds are valued using a market approach that incorporates reported trades and benchmark yields. Other fixed income securities are valued using pricing models, quoted prices of securities with similar characteristics, and discounted cash flows.

6. INVESTMENTS IN UNCONSOLIDATED AFFILIATES

Investments in entities that are not consolidated are included in long-term assets on the balance sheets. Investments in affiliates where Eversource has the ability to exercise significant influence, but not control, over an investee are initially recognized as an equity method investment at cost. Earnings impacts from these equity investments are included in Other Income, Net on the statements of income. Eversource's investments accounted for under the equity method include the following:

(Millions of Dollars)	Ownership Interest	Investment Balance as of December 31, 2025	Investment Balance as of December 31, 2024
Tax Equity Investment in South Fork Wind	100%	$ 19.1	$ 22.2
Natural Gas Pipeline - Algonquin Gas Transmission, LLC	15%	110.8	112.6
Other	various	36.3	33.9
Total Investments in Unconsolidated Affiliates		$ 166.2	$ 168.7

For the years ended December 31, 2025, 2024 and 2023, Eversource had equity in earnings of unconsolidated affiliates of $19.9 million, $51.9 million, and $15.5 million, respectively. Eversource received dividends from its equity method investees (excluding proceeds received from sale or liquidation of investments) of $20.7 million, $20.5 million, and $20.1 million, respectively, for the years ended December 31, 2025, 2024 and 2023.

Tax Equity Investment in South Fork Wind: Eversource holds a noncontrolling tax equity investment in South Fork Wind through a 100 percent ownership in South Fork Wind Holdings, LLC Class A interests. In September 2023, Eversource made a $528 million investment in a tax equity interest for South Fork Wind. South Fork Wind was restructured as a tax equity investment, with Eversource purchasing 100 percent ownership of a new Class A tax equity membership interest. This investment will result in Eversource receiving cash flow benefits from investment tax credits (ITC) and other future cash flow benefits as well. During 2024, $459 million of expected investment tax credits and other expected tax benefits were reclassified from the South Fork Wind tax equity investment balance reported in Investments in Unconsolidated Affiliates as a decrease in Accumulated Deferred Income Taxes on the Eversource balance sheet, which represented a non-cash reclassification. As a result of these investment tax credits, Eversource expects lower federal income tax payments through 2028.

Offshore Wind Investments: During 2024, Eversource sold its 50 percent ownership interests in each of North East Offshore and South Fork Class B Member, LLC and in doing so, sold its interests in the Revolution Wind project, the South Fork Wind project, and the Sunrise Wind project. For more information on the sale, see Note 13G, "Commitments and Contingencies – Offshore Wind Sale and Contingent Liability," to the financial statements. Eversource recognized an aggregate pre-tax loss on the sales of its offshore wind investments of $464 million ($524 million after-tax) in 2024. In 2023, Eversource recorded pre-tax other-than-temporary impairment charges totaling $2.17 billion ($1.95 billion after-tax) in connection with the process to divest these offshore wind investments. In the impairment assessments, Eversource evaluated its investments and determined that the carrying value of the equity method offshore wind investments exceeded the fair value of the investments and that the decline in fair value was other-than-temporary. Impairment charges were recorded to reflect the investments at estimated fair value at that time. Capital contributions in the offshore wind investments in 2023 and 2024, including the 2023 contribution for the tax equity investment in South Fork Wind, were included in Investments in Unconsolidated Affiliates on the statements of cash flows. Proceeds received from the sales of the offshore wind investments of $863 million in 2024, the sale of an unused lease area to Orsted for $625 million in 2023, and an October 2023 distribution of $318 million received primarily as a result of being a 50 percent joint owner in the Class B shares of South Fork Wind which was restructured as a tax equity investment, were included in Proceeds from Unconsolidated Affiliates on the statements of cash flows. Payments made in 2025 related to Eversource's remaining offshore wind contingent obligation are reflected in investing activities on the statement of cash flows.

Liquidation of Renewable Energy Investment Fund: On March 21, 2023, Eversource's equity method investment in a renewable energy investment fund was liquidated by the fund's general partner in accordance with the partnership agreement. Proceeds received from the liquidation totaled $147.6 million and were included in Proceeds from Unconsolidated Affiliates on the statement of cash flows for the year ended December 31, 2023. A portion of the proceeds was used to make a charitable contribution to the Eversource Energy Foundation (a related party) of $20.0 million in 2023. The liquidation benefit received in excess of the investment's carrying value and the charitable contribution were included in Other Income, Net on the statement of income.

Impairments: Equity method investments are assessed for impairment when conditions exist as of the balance sheet date that indicate that the fair value of the investment may be less than book value. Eversource continually monitors and evaluates its equity method investments to determine if there are indicators of an other-than-temporary impairment. If the decline in value is considered to be other-than-temporary, the investment is written down to its estimated fair value, which establishes a new cost basis in the investment. Impairment evaluations are based on best information available at the impairment assessment date. Subsequent declines or recoveries after the reporting date are not considered in the impairment recognized. Investments that are other-than-temporarily impaired and written down to their estimated fair value cannot subsequently be written back up for increases in estimated fair value. Impairment evaluations involve a significant degree of judgment and estimation, including identifying circumstances that indicate an impairment may exist at the equity method investment level, selecting discount rates used to determine fair values, and developing an estimate of discounted future cash flows expected from investment operations or the sale of the investment.

NSTAR Electric: As of December 31, 2025 and 2024, NSTAR Electric's investments included a 14.5 percent ownership interest in two companies that transmit hydro-electricity imported from the Hydro-Quebec system in Canada of $12.2 million and $11.5 million, respectively.

7. ASSET RETIREMENT OBLIGATIONS

Eversource, including CL&P, NSTAR Electric and PSNH, recognizes a liability for the fair value of an ARO on the obligation date if the liability's fair value can be reasonably estimated, even if it is conditional on a future event. Settlement dates and future costs are reasonably estimated when sufficient information becomes available. Management has identified various categories of AROs, primarily CYAPC's and YAEC's obligation to dispose of spent nuclear fuel and high level waste, and also certain assets containing asbestos and hazardous contamination. Management has performed fair value calculations reflecting expected probabilities for settlement scenarios.

The fair value of an ARO is recorded as a long-term liability with a corresponding amount included in Property, Plant and Equipment, Net on the balance sheets. The ARO assets are depreciated, and the ARO liabilities are accreted over the estimated life of the obligation and the corresponding credits are recorded as accumulated depreciation and ARO liabilities, respectively. As the electric and natural gas companies are rate-regulated on a cost-of-service basis, these companies apply regulatory accounting guidance and both the depreciation and accretion costs associated with these companies' AROs are recorded as increases to Regulatory Assets on the balance sheets.

A reconciliation of the beginning and ending carrying amounts of ARO liabilities is as follows:

	As of December 31, 2025				As of December 31, 2024			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Balance as of Beginning of Year	$ 590.9	$ 42.5	$ 109.3	$ 5.6	$ 505.8	$ 39.9	$ 104.8	$ 5.2
Liabilities Settled During the Year	(24.2)	—	—	—	(24.6)	—	—	—
Accretion	34.0	2.9	4.7	0.3	29.5	2.6	4.5	0.4
Revisions in Estimated Cash Flows	(5.3)	—	—	—	80.2	—	—	—
Balance as of End of Year	$ 595.4	$ 45.4	$ 114.0	$ 5.9	$ 590.9	$ 42.5	$ 109.3	$ 5.6

Eversource's amounts include CYAPC and YAEC's AROs of $386.6 million and $391.7 million as of December 31, 2025 and 2024, respectively. The fair value of the ARO for CYAPC and YAEC includes uncertainties of the fuel off-load dates related to the DOE's timing of performance regarding its obligation to dispose of the spent nuclear fuel and high level waste and other assumptions, including discount rates. The incremental asset recorded as an offset to the ARO liability was fully depreciated since the plants have no remaining useful life. Any changes in the ARO liability are recorded with a corresponding offset to the related regulatory asset. The assets held in the CYAPC and YAEC spent nuclear fuel trusts are restricted for settling the ARO and all other nuclear fuel storage obligations. For further information on the assets held in the spent nuclear fuel trusts, see Note 5, "Marketable Securities," to the financial statements.

The increase in the ARO balance at Eversource for the year ended December 31, 2024 was due primarily to updated cost estimates that extended the end of life date from 2039 to 2044 for CYAPC and YAEC. These updated cost estimates were approved by FERC in November 2024.

8. SHORT-TERM DEBT

Short-Term Debt - Borrowing Limits: The amount of short-term borrowings that may be incurred by CL&P and NSTAR Electric is subject to periodic approval by the FERC. Because the NHPUC has jurisdiction over PSNH's short-term debt, PSNH is not currently required to obtain FERC approval for its short-term borrowings. On December 12, 2025, the FERC granted authorization that allows CL&P to issue total short-term borrowings in an aggregate principal amount not to exceed $600 million outstanding at any one time, through December 31, 2027. On December 12, 2025, the FERC granted authorization that allows NSTAR Electric to issue total short-term borrowings in an aggregate principal amount not to exceed $655 million outstanding at any one time, through December 31, 2027.

PSNH is authorized by regulation of the NHPUC to incur short-term borrowings up to 10 percent of net fixed plant plus an additional $60 million until further ordered by the NHPUC. As of December 31, 2025, PSNH's short-term debt authorization under the 10 percent of net fixed plant test plus $60 million totaled $572.9 million.

CL&P's certificate of incorporation contains preferred stock provisions restricting the amount of unsecured debt that CL&P may incur, including limiting unsecured indebtedness with a maturity of less than 10 years to 10 percent of total capitalization. As of December 31, 2025, CL&P had $1.19 billion of unsecured debt capacity available under this authorization.

Yankee Gas, NSTAR Gas and EGMA are not required to obtain approval from any state or federal authority to incur short-term debt.

Short-Term Debt - Commercial Paper Programs and Credit Agreements: Eversource parent has a $2.00 billion commercial paper program allowing Eversource parent to issue commercial paper as a form of short-term debt. Eversource parent, CL&P, PSNH, NSTAR Gas, Yankee Gas, EGMA and Aquarion Water Company of Connecticut are parties to a five-year $2.00 billion revolving credit facility. Effective October 11, 2025, the revolving credit facility's termination date was extended for one additional year to October 11, 2030, pursuant to the extension provisions contained in the existing credit agreement. This revolving credit facility serves to backstop Eversource parent's $2.00 billion commercial paper program.

NSTAR Electric has a $650 million commercial paper program allowing NSTAR Electric to issue commercial paper as a form of short-term debt. NSTAR Electric is also a party to a five-year $650 million revolving credit facility. Effective October 11, 2025, the revolving credit facility's termination date was extended for one additional year to October 11, 2030, pursuant to the extension provisions contained in the existing credit agreement. This revolving credit facility serves to backstop NSTAR Electric's $650 million commercial paper program.

The amount of borrowings outstanding and available under the commercial paper programs were as follows:

	Borrowings Outstanding as of December 31,		Available Borrowing Capacity as of December 31,		Weighted-Average Interest Rate as of December 31,	
(Millions of Dollars)	2025	2024	2025	2024	2025	2024
Eversource Parent Commercial Paper Program	$ 1,280.0	$ 1,538.0	$ 720.0	$ 462.0	3.98 %	4.76 %
NSTAR Electric Commercial Paper Program	245.4	504.8	404.6	145.2	3.87 %	4.55 %

There were no borrowings outstanding on the revolving credit facilities as of December 31, 2025 or 2024.

CL&P and PSNH have uncommitted line of credit agreements totaling $375 million and $250 million, respectively, all of which will expire in either May 2026, September 2026 or October 2026. There are no borrowings outstanding on either the CL&P or PSNH uncommitted line of credit agreements as of December 31, 2025.

Amounts outstanding under the commercial paper programs are included in Notes Payable and classified in current liabilities on the Eversource and NSTAR Electric balance sheets, as all borrowings are outstanding for no more than 364 days at one time.

Under the credit facilities described above, Eversource and its subsidiaries, including CL&P, NSTAR Electric, PSNH, NSTAR Gas, EGMA, Yankee Gas, and Aquarion Water Company of Connecticut, must comply with certain financial and non-financial covenants, including a consolidated debt to total capitalization ratio. As of December 31, 2025 and 2024, Eversource and its subsidiaries were in compliance with these covenants. If Eversource or its subsidiaries were not in compliance with these covenants, an event of default would occur requiring all outstanding borrowings by such borrower to be repaid, and additional borrowings by such borrower would not be permitted under its respective credit facility.

Intercompany Borrowings: Eversource parent uses its available capital resources to provide loans to its subsidiaries to assist in meeting their short-term borrowing needs. Eversource parent records intercompany interest income from its loans to subsidiaries, which is eliminated in consolidation. Intercompany loans from Eversource parent to its subsidiaries are eliminated in consolidation on Eversource's balance sheets. As of December 31, 2025 and 2024, there were intercompany loans from Eversource parent to PSNH of $49.3 million and $131.1 million, respectively. As of December 31, 2024, there were intercompany loans from Eversource parent to CL&P of $280.0 million. Eversource parent charges interest on these intercompany loans at the same weighted-average interest rate as its commercial paper program. Intercompany loans from Eversource parent are included in Notes Payable to Eversource Parent and classified in current liabilities on the respective subsidiary's balance sheets, as these intercompany borrowings are outstanding for no more than 364 days at one time.

Sources and Uses of Cash: The Company expects the future operating cash flows of Eversource, CL&P, NSTAR Electric and PSNH, along with existing borrowing availability and access to both debt and equity markets, will be sufficient to meet any working capital and future operating requirements, and capital investment forecasted opportunities.

9. LONG-TERM DEBT

Details of long-term debt outstanding are as follows:

CL&P (Millions of Dollars)	Interest Rate	As of December 31, 2025	2024
First Mortgage Bonds:			
2004 Series B due 2034	5.750 %	$ 130.0	$ 130.0
2005 Series B due 2035	5.625 %	100.0	100.0
2006 Series A due 2036	6.350 %	250.0	250.0
2007 Series B due 2037	5.750 %	150.0	150.0
2007 Series D due 2037	6.375 %	100.0	100.0
2014 Series A due 2044	4.300 %	475.0	475.0
2015 Series A due 2045	4.150 %	350.0	350.0
2017 Series A due 2027	3.200 %	500.0	500.0
2018 Series A due 2048	4.000 %	800.0	800.0
2020 Series A due 2025	0.750 %	—	400.0
2021 Series A due 2031	2.050 %	425.0	425.0
2023 Series A due 2053	5.250 %	500.0	500.0
2023 Series B due 2033	4.900 %	300.0	300.0
2024 Series A due 2029	4.650 %	350.0	350.0
2024 Series B due 2034	4.950 %	300.0	300.0
2025 Series A due 2030	4.950 %	400.0	—
Total First Mortgage Bonds		5,130.0	5,130.0
Less Amounts due Within One Year		—	(400.0)
Current Portion Classified as Long-Term Debt [1]		—	397.1
Unamortized Premiums and Discounts, Net		12.4	14.3
Unamortized Debt Issuance Costs		(32.3)	(33.2)
CL&P Long-Term Debt		$ 5,110.1	$ 5,108.2

NSTAR Electric (Millions of Dollars)	Interest Rate	As of December 31, 2025	2024
Debentures:			
2006 Debentures due 2036	5.750 %	$ 200.0	$ 200.0
2010 Debentures due 2040	5.500 %	300.0	300.0
2014 Debentures due 2044	4.400 %	300.0	300.0
2015 Debentures due 2025	3.250 %	—	250.0
2016 Debentures due 2026	2.700 %	250.0	250.0
2017 Debentures due 2027	3.200 %	700.0	700.0
2019 Debentures due 2029	3.250 %	400.0	400.0
2020 Debentures due 2030	3.950 %	400.0	400.0
2021 Debentures due 2051	3.100 %	300.0	300.0
2021 Debentures due 2031	1.950 %	300.0	300.0
2022 Debentures due 2052	4.550 %	450.0	450.0
2022 Debentures due 2052	4.950 %	400.0	400.0
2023 Debentures due 2028	5.600 %	150.0	150.0
2024 Debentures due 2034	5.400 %	600.0	600.0
2025 Debentures due 2030	4.850 %	400.0	—
2025 Debentures due 2035	5.200 %	700.0	—
Total Debentures		5,850.0	5,000.0
Notes:			
2004 Senior Notes Series B due 2034	5.900 %	50.0	50.0
2007 Senior Notes Series D due 2037	6.700 %	40.0	40.0
2016 Senior Notes Series H due 2026	2.750 %	50.0	50.0
Total Notes		140.0	140.0
Less Amounts due Within One Year		(300.0)	(250.0)
Unamortized Premiums and Discounts, Net		(8.1)	(14.0)
Unamortized Debt Issuance Costs		(36.3)	(31.1)
NSTAR Electric Long-Term Debt		$ 5,645.6	$ 4,844.9

PSNH (Millions of Dollars)	Interest Rate	As of December 31, 2025	2024
First Mortgage Bonds:			
2005 Series M due 2035	5.600 %	$ 50.0	$ 50.0
2019 Series T due 2049	3.600 %	300.0	300.0
2020 Series U due 2050	2.400 %	150.0	150.0
2021 Series V due 2031	2.200 %	350.0	350.0
2023 Series W due 2053	5.150 %	300.0	300.0
2023 Series X due 2033	5.350 %	600.0	600.0
2025 Series Y due 2028	4.400 %	300.0	—
Total First Mortgage Bonds		2,050.0	1,750.0
Unamortized Premiums and Discounts, Net		(2.8)	(2.6)
Unamortized Debt Issuance Costs		(15.9)	(15.3)
PSNH Long-Term Debt		$ 2,031.3	$ 1,732.1

OTHER (Millions of Dollars)	Interest Rate	As of December 31, 2025	2024
Eversource Parent - Senior Notes due 2026 - 2050	1.400 % - 5.950 %	$ 11,350.0	$ 11,350.0
Yankee Gas - First Mortgage Bonds due 2026 - 2051	1.380 % - 5.740 %	1,205.0	1,095.0
NSTAR Gas - First Mortgage Bonds due 2029 - 2051	2.250 % - 7.110 %	1,055.0	905.0
EGMA - First Mortgage Bonds due 2028 - 2052	2.110 % - 5.730 %	933.0	808.0
Aquarion - Unsecured Notes due 2028 - 2052	3.000 % - 6.430 %	596.6	596.8
Aquarion - Secured Debt due 2027 - 2045	1.296 % - 9.290 %	47.9	40.7
Pre-1983 Spent Nuclear Fuel Obligation (CYAPC)		5.9	5.6
Fair Value Adjustment [2]		11.6	—
Less Fair Value Adjustment - Current Portion [2]		(2.4)	—
Less Amounts due in One Year		(1,090.5)	(750.3)
Unamortized Premiums and Discounts, Net		37.8	41.7
Unamortized Debt Issuance Costs		(64.5)	(76.1)
Total Other Long-Term Debt		$ 14,085.4	$ 14,016.4
Total Eversource Long-Term Debt		$ 26,872.4	$ 25,701.6

(1) As a result of the CL&P long-term debt issuance in January 2025, $397.1 million of current portion of long-term debt was reclassified to Long-Term Debt on Eversource's and CL&P's balance sheets as of December 31, 2024.

(2) The fair value adjustment amount is the purchase price adjustments, net of amortization, required to record Aquarion's long-term debt at fair value upon the 2017 acquisition date. As of December 31, 2024, this fair value adjustment was reclassified to Liabilities Held for Sale. As of December 31, 2025, the fair value adjustment was reclassified to Long-Term Debt. For further information, see Note 24, "Assets Held for Sale."

Availability under Long-Term Debt Issuance Authorizations: On May 1, 2024, the DPU approved NSTAR Electric's request for authorization to issue up to $2.40 billion in long-term debt through December 31, 2026. On August 12, 2024, the DPU approved EGMA's request for authorization to issue up to $325 million in long-term debt through December 31, 2026. On December 18, 2024, the DPU approved NSTAR Gas' request for authorization to issue up to $475 million in long-term debt through December 31, 2027. On March 26, 2025, PURA approved Yankee Gas' request for authorization to issue up to $360 million in long-term debt through December 31, 2026. PSNH has utilized its long-term debt authorizations in place with NHPUC. CL&P has no long-term debt authorization remaining with PURA.
Long-Term Debt Issuances and Repayments: The following table summarizes long-term debt issuances and repayments:

(Millions of Dollars)	Interest Rate	Issuance/ (Repayment)	Issue Date or Repayment Date	Maturity Date	Use of Proceeds for Issuance/ Repayment Information
CL&P 2025 Series A First Mortgage Bonds	4.95 %	400.0	January 2025	January 2030	Repaid short-term debt, paid capital expenditures and working capital
CL&P 2020 Series A First Mortgage Bonds	0.75 %	(400.0)	December 2025	December 2025	Paid at maturity
NSTAR Electric Debentures	4.85 %	400.0	February 2025	March 2030	Repaid 3.25% Debentures at maturity, repaid short-term debt, paid capital expenditures and working capital
NSTAR Electric Debentures	5.20 %	400.0	February 2025	March 2035	Repaid 3.25% Debentures at maturity, repaid short-term debt, paid capital expenditures and working capital
NSTAR Electric Debentures	5.20 %	300.0	October 2025	March 2035	Repaid short-term debt, paid capital expenditures and working capital
NSTAR Electric Debentures	3.25 %	(250.0)	November 2025	November 2025	Paid at maturity
PSNH Series Y First Mortgage Bonds	4.40 %	300.0	June 2025	July 2028	Repaid short-term debt, paid capital expenditures and working capital
Eversource Parent Series HH Senior Notes	4.45 %	600.0	October 2025	December 2030	Repay Series J bonds at maturity and repaid short-term debt
Eversource Parent Series H Senior Notes	3.15 %	(300.0)	January 2025	January 2025	Paid at maturity
Eversource Parent Series Q Senior Notes	0.80 %	(300.0)	August 2025	August 2025	Paid at maturity
NSTAR Gas Series Y First Mortgage Bonds	4.86 %	205.0	June 2025	June 2030	Repaid short-term debt, paid capital expenditures and working capital
NSTAR Gas Series Z First Mortgage Bonds	5.30 %	20.0	June 2025	June 2035	Repaid short-term debt, paid capital expenditures and working capital
NSTAR Gas Series R First Mortgage Bonds	2.33 %	(75.0)	May 2025	May 2025	Paid at maturity
Yankee Gas Series Y First Mortgage Bonds	5.02 %	148.0	July 2025	January 2031	Repaid Series M bonds at maturity, repaid short-term debt, paid capital expenditures and working capital
Yankee Gas Series Z First Mortgage Bonds	5.55 %	37.0	July 2025	July 2035	Repaid Series M bonds at maturity, repaid short-term debt, paid capital expenditures and working capital
Yankee Gas Series M First Mortgage Bonds	3.35 %	(75.0)	September 2025	September 2025	Paid at maturity
EGMA Series F First Mortgage Bonds	4.77 %	125.0	September 2025	October 2030	Repaid short-term debt, paid capital expenditures and working capital

Long-Term Debt Provisions: The utility plant of CL&P, PSNH, Yankee Gas, NSTAR Gas, EGMA and a portion of Aquarion is subject to the lien of each company's respective first mortgage bond indenture. The Eversource parent, NSTAR Electric and a portion of Aquarion debt is unsecured. Additionally, the long-term debt agreements provide that Eversource and certain of its subsidiaries must comply with certain covenants as are customarily included in such agreements, including equity requirements for NSTAR Electric, NSTAR Gas and Aquarion. Under the equity requirements, NSTAR Electric's and Aquarion's senior notes must maintain a certain consolidated indebtedness to capitalization ratio as of the end of any fiscal quarter and NSTAR Gas' outstanding long-term debt must not exceed equity.

Certain secured and unsecured long-term debt securities are callable at redemption price or are subject to make-whole provisions.

No long-term debt defaults have occurred as of December 31, 2025.

CYAPC's Pre-1983 Spent Nuclear Fuel Obligation: Under the Nuclear Waste Policy Act of 1982, the DOE is responsible for the selection and development of repositories for, and the disposal of, spent nuclear fuel and high-level radioactive waste. CYAPC is obligated to pay the DOE for the costs to dispose of spent nuclear fuel and high-level radioactive waste generated prior to April 7, 1983 (pre-1983 Spent Nuclear Fuel). CYAPC has partially paid this obligation and recorded an accrual for its remaining liability to the DOE. This liability accrues interest costs at the 3-month Treasury bill yield rate. For nuclear fuel used to generate electricity prior to April 7, 1983, payment may be made any time prior to the first delivery of spent fuel to the DOE. As of December 31, 2025 and 2024, as a result of consolidating CYAPC, Eversource has consolidated $5.9 million and $5.6 million, respectively, in pre-1983 spent nuclear fuel obligations to the DOE. The obligation includes accumulated interest costs of $4.6 million and $4.3 million as of December 31, 2025 and 2024, respectively. CYAPC maintains a trust to fund amounts due to the DOE for the disposal of pre-1983 spent nuclear fuel. For further information, see Note 5, "Marketable Securities," to the financial statements. Fees for disposal of nuclear fuel burned on or after April 7, 1983 were billed to member companies and paid to the DOE.
Long-Term Debt Maturities: Long-term debt maturities on debt outstanding for the years 2026 through 2030 and thereafter are shown below. These amounts exclude PSNH rate reduction bonds, CYAPC pre-1983 spent nuclear fuel obligation, and unamortized premiums, discounts, and debt issuance costs as of December 31, 2025:

(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH
2026	$ 1,390.5	$ —	$ 300.0	$ —
2027	2,889.5	500.0	700.0	—
2028	2,278.8	—	150.0	300.0
2029	2,300.5	350.0	400.0	—
2030	2,904.0	400.0	800.0	—
Thereafter	16,594.2	3,880.0	3,640.0	1,750.0
Total	$ 28,357.5	$ 5,130.0	$ 5,990.0	$ 2,050.0

10. RATE REDUCTION BONDS AND VARIABLE INTEREST ENTITIES

Rate Reduction Bonds: In May 2018, PSNH Funding, a wholly-owned subsidiary of PSNH, issued $635.7 million of securitized RRBs in multiple tranches with a weighted average interest rate of 3.66 percent, and final maturity dates ranging from 2026 to 2035. The RRBs are expected to be repaid by February 1, 2033. RRB payments consist of principal and interest and are paid semi-annually, beginning on February 1, 2019. The RRBs were issued pursuant to a finance order issued by the NHPUC in January 2018 to recover remaining costs resulting from the divestiture of PSNH's generation assets.

The proceeds were used by PSNH Funding to purchase PSNH's stranded cost asset-recovery property, including its vested property right to bill, collect and adjust a non-bypassable stranded cost recovery charge from PSNH's retail customers. The collections are used to pay principal, interest and other costs in connection with the RRBs. The RRBs are secured by the stranded cost asset-recovery property. Cash collections from the stranded cost recovery charges and funds on deposit in trust accounts are the sole source of funds to satisfy the debt obligation. PSNH is not the owner of the RRBs, and PSNH Funding's assets and revenues are not available to pay PSNH's creditors. The RRBs are non-recourse senior secured obligations of PSNH Funding and are not insured or guaranteed by PSNH or Eversource Energy.

PSNH Funding was formed solely to issue RRBs to finance PSNH's unrecovered remaining costs associated with the divestiture of its generation assets. PSNH Funding is considered a VIE primarily because the equity capitalization is insufficient to support its operations. PSNH has the power to direct the significant activities of the VIE and is most closely associated with the VIE as compared to other interest holders. Therefore, PSNH is considered the primary beneficiary and consolidates PSNH Funding in its consolidated financial statements.

The following tables summarize the impact of PSNH Funding on PSNH's balance sheets and income statements:

(Millions of Dollars)	As of December 31,	
PSNH Balance Sheets:	2025	2024
Restricted Cash - Current Portion (included in Special Deposits)	$ 30.6	$ 31.0
Restricted Cash - Long-Term Portion (included in Other Long-Term Assets)	3.2	3.1
Securitized Stranded Cost (included in Regulatory Assets)	306.1	349.3
Other Regulatory Liabilities (included in Regulatory Liabilities)	7.3	6.9
Accrued Interest (included in Other Current Liabilities)	5.1	5.7
Rate Reduction Bonds - Current Portion	43.2	43.2
Rate Reduction Bonds - Long-Term Portion	280.9	324.1

(Millions of Dollars)	For the Years Ended December 31,		
PSNH Income Statements:	2025	2024	2023
Amortization of RRB Principal (included in Amortization of Regulatory Assets/(Liabilities), Net)	$ 43.2	$ 43.2	$ 43.2
Interest Expense on RRB Principal (included in Interest Expense)	12.8	14.3	15.7

Estimated principal payments on RRBs as of December 31, 2025, is summarized annually through 2030 and thereafter as follows:

(Millions of Dollars)	2026	2027	2028	2029	2030	Thereafter	Total
PSNH	$ 43.2	$ 43.2	$ 43.2	$ 43.2	$ 43.2	$ 108.1	$ 324.1

Variable Interest Entities - Other: The Company's variable interests outside of the consolidated group include contracts that are required by regulation and provide for regulatory recovery of contract costs and benefits through customer rates. Eversource, CL&P and NSTAR Electric hold variable interests in VIEs through agreements with certain entities that own single renewable energy or peaking generation power plants, with other independent power producers and with transmission businesses. Eversource, CL&P and NSTAR Electric do not control the activities that are economically significant to these VIEs or provide financial or other support to these VIEs. Therefore, Eversource, CL&P and NSTAR Electric do not consolidate these VIEs.

11. EMPLOYEE BENEFITS

A. Pension Benefits and Postretirement Benefits Other Than Pension

Eversource provides defined benefit retirement plans (Pension Plans) that cover eligible employees and are subject to the provisions of ERISA, as amended by the Pension Protection Act of 2006. Eversource's policy is to annually fund, as necessary, the Pension Plans in an amount at least equal to an amount that will satisfy all federal funding requirements. In addition to the Pension Plans, Eversource maintains non-qualified defined benefit retirement plans (SERP Plans), which provide benefits in excess of Internal Revenue Code limitations to eligible participants consisting of current and retired employees.

Eversource also provides defined benefit postretirement plans (PBOP Plans) that provide life insurance and a health reimbursement arrangement created for the purpose of reimbursing retirees and dependents for health insurance premiums and certain medical expenses to eligible employees that meet certain age and service eligibility requirements. The benefits provided under the PBOP Plans are not vested, and the Company has the right to modify any benefit provision subject to applicable laws at that time. Eversource annually funds, as necessary, postretirement costs through tax deductible contributions to external trusts.

Effective January 1, 2025, a Cash Balance Pension Plan was established, which replaced employer K-Vantage contributions. Eversource transferred into the Cash Balance Pension Plan employees who were participants in the K-Vantage plan, with the exception of one union group that voted to enter effective January 1, 2026, and will credit employees a set percentage of an employee's eligible pay based on age and years of service on the employee's behalf. This benefit is an additional obligation of the existing Pension Plan and will be funded through the existing assets of the Eversource Service Pension Plan. The liability began accruing benefits upon the effective date of January 1, 2025.
Funded Status: The Pension, SERP and PBOP Plans are accounted for under the multiple-employer approach, with each operating company's balance sheet reflecting its share of the funded status of the plans. The SERP Plans do not contain any assets. The following tables provide information on the plan benefit obligations, fair values of plan assets, and funded status:

	Pension and SERP							
	As of December 31,							
	2025				2024			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Change in Benefit Obligation:								

Benefit Obligation as of Beginning of Year	$ (4,745.7)	$ (982.9)	$ (1,003.5)	$ (521.5)	$ (5,238.4)	$ (1,048.5)	$ (1,107.0)	$ (562.3)
Service Cost	(67.9)	(15.3)	(9.7)	(6.5)	(44.3)	(12.7)	(7.7)	(4.3)
Interest Cost	(255.6)	(51.5)	(53.0)	(27.1)	(250.0)	(50.3)	(51.6)	(26.8)
Actuarial (Loss)/Gain	(190.0)	(37.8)	(54.5)	(11.7)	280.2	56.2	74.1	30.7
Benefits Paid - Pension	334.5	69.1	67.2	38.8	320.9	68.1	67.1	38.0
Benefits Paid - Lump Sum	28.5	0.1	12.9	1.3	24.0	—	7.6	0.1
Benefits Paid - SERP	18.8	0.4	0.1	0.4	19.4	0.3	0.2	0.4
Employee Transfers	(0.3)	1.2	2.8	0.1	—	4.0	13.8	2.7
Water Reclassified as Assets Held for Sale	—	—	—	—	142.5	—	—	—
Water Reclassified from Assets Held for Sale	(142.5)	—	—	—	—	—	—	—
Benefit Obligation as of End of Year	$ (5,020.2)	$ (1,016.7)	$ (1,037.7)	$ (526.2)	$ (4,745.7)	$ (982.9)	$ (1,003.5)	$ (521.5)
Change in Pension Plan Assets:								
Fair Value of Pension Plan Assets as of Beginning of Year	$ 5,514.0	$ 1,144.4	$ 1,378.2	$ 597.5	$ 5,775.0	$ 1,170.0	$ 1,411.6	$ 614.0
Employer Contributions	2.5	—	—	—	5.0	—	—	—
Actual Return on Pension Plan Assets	588.4	119.3	144.7	61.3	227.0	46.5	55.1	24.3
Benefits Paid - Pension	(334.5)	(69.1)	(67.2)	(38.8)	(320.9)	(68.1)	(67.1)	(38.0)
Benefits Paid - Lump Sum	(28.5)	(0.1)	(12.9)	(1.3)	(24.0)	—	(7.6)	(0.1)
Employee Transfers	—	(1.2)	(2.8)	(0.1)	—	(4.0)	(13.8)	(2.7)
Water Reclassified as Assets Held for Sale	—	—	—	—	(148.1)	—	—	—
Water Reclassified from Assets Held for Sale	148.1	—	—	—	—	—	—	—
Fair Value of Pension Plan Assets as of End of Year	$ 5,890.0	$ 1,193.3	$ 1,440.0	$ 618.6	$ 5,514.0	$ 1,144.4	$ 1,378.2	$ 597.5
Funded Status as of December 31st	$ 869.8	$ 176.6	$ 402.3	$ 92.4	$ 768.3	$ 161.5	$ 374.7	$ 76.0

Actuarial Gain/(Loss): For the year ended December 31, 2025, the actuarial loss was primarily attributable to a decrease in the discount rate, which resulted in an increase to Eversource's Pension and SERP Plans' projected benefit obligation of $98.2 million, a $38.1 million loss related to updated census data, and a $28 million loss related to the salary scale assumption. For the year ended December 31, 2024, the actuarial gain was primarily attributable to an increase in the discount rate, which resulted in a decrease to Eversource's Pension and SERP Plans' projected benefit obligation of $332.9 million, partially offset by an actuarial loss of $42.1 million related to updated census data.

As of December 31, 2025 and 2024, the accumulated benefit obligation for the Pension and SERP Plans is as follows:

(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH
2025	$ 4,856.5	$ 981.5	$ 992.2	$ 513.1
2024	4,617.1	953.9	969.5	507.4

	PBOP							
	As of December 31,							
	2025				2024			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Change in Benefit Obligation:								
Benefit Obligation as of Beginning of Year	$ (587.4)	$ (109.1)	$ (171.4)	$ (65.9)	$ (676.0)	$ (120.6)	$ (188.3)	$ (72.0)
Service Cost	(6.4)	(1.1)	(1.1)	(0.5)	(7.0)	(1.2)	(1.2)	(0.6)
Interest Cost	(32.0)	(5.6)	(8.7)	(3.4)	(31.9)	(5.6)	(8.8)	(3.4)
Actuarial (Loss)/Gain	(11.3)	(1.6)	(3.5)	(1.2)	41.3	8.9	10.7	3.9
Benefits Paid	51.7	9.3	16.0	6.0	51.7	9.4	15.9	6.2
Employee Transfers	—	0.1	—	0.2	—	—	0.3	—
Water Reclassified as Assets Held for Sale	—	—	—	—	34.5	—	—	—
Water Reclassified from Assets Held for Sale	(34.5)	—	—	—	—	—	—	—
Benefit Obligation as of End of Year	$ (619.9)	$ (108.0)	$ (168.7)	$ (64.8)	$ (587.4)	$ (109.1)	$ (171.4)	$ (65.9)
Change in Plan Assets:								
Fair Value of Plan Assets as of Beginning of Year	$ 1,036.3	$ 124.4	$ 519.2	$ 76.4	$ 1,024.4	$ 123.0	$ 490.4	$ 74.7
Actual Return on Plan Assets	131.9	14.9	65.0	9.3	92.3	11.2	45.8	7.6
Employer Contributions	0.7	—	—	—	0.9	—	—	—
Benefits Paid	(51.3)	(9.3)	(16.0)	(5.9)	(51.8)	(9.4)	(15.9)	(6.1)
Employee Transfers	—	(0.3)	0.6	(0.2)	—	(0.4)	(1.1)	0.2
Water Reclassified as Assets Held for Sale	—	—	—	—	(29.5)	—	—	—
Water Reclassified from Assets Held for Sale	29.5	—	—	—	—	—	—	—
Fair Value of Plan Assets as of End of Year	$ 1,147.1	$ 129.7	$ 568.8	$ 79.6	$ 1,036.3	$ 124.4	$ 519.2	$ 76.4
Funded Status as of December 31st	$ 527.2	$ 21.7	$ 400.1	$ 14.8	$ 448.9	$ 15.3	$ 347.8	$ 10.5

Actuarial Gain/(Loss): For the year ended December 31, 2025, the actuarial loss was primarily attributable to a decrease in the discount rate, which resulted in an increase to the Eversource PBOP projected benefit obligation of $11.2 million. For the year ended December 31, 2024, the actuarial gain was primarily attributable to an increase in the discount rate, which resulted in a decrease to the Eversource PBOP projected benefit obligation of $39.8 million.

A reconciliation of the prepaid assets and liabilities within the Eversource Pension, SERP and PBOP Plans' funded status to the balance sheets is as follows:

	As of December 31,							
	2025				2024			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Prepaid Pension [1]	$ 982.0	$ 182.4	$ 404.0	$ 97.0	$ 887.7	$ 167.2	$ 376.9	$ 80.5
Prepaid PBOP	529.2	21.7	400.1	14.8	448.9	15.3	347.8	10.5
Prepaid Pension and PBOP	$ 1,511.2	$ 204.1	$ 804.1	$ 111.8	$ 1,336.6	$ 182.5	$ 724.7	$ 91.0
Accrued SERP [1]	$ (112.2)	$ (5.8)	$ (1.7)	$ (4.6)	$ (119.4)	$ (5.7)	$ (2.2)	$ (4.5)
Accrued PBOP [1]	(2.0)	—	—	—	—	—	—	—
Less: Accrued SERP - current portion	13.3	0.3	—	0.4	24.0	0.4	0.2	0.4
Accrued SERP and PBOP	$ (100.9)	$ (5.5)	$ (1.7)	$ (4.2)	$ (95.4)	$ (5.3)	$ (2.0)	$ (4.1)

[1] As of December 31, 2024, the Aquarion water distribution business's prepaid pension was reclassified to Assets Held for Sale and the accrued SERP and PBOP liabilities were reclassified to Liabilities Held for Sale on the Eversource balance sheet. As of December 31, 2025, these balances were reclassified to Prepaid Pension and Accrued SERP and PBOP on the Eversource balance sheet. For further information, see Note 24, "Assets Held for Sale."

The following actuarial assumptions were used in calculating the Pension, SERP and PBOP Plans' year end funded status:

	Pension and SERP						PBOP					
	As of December 31,						As of December 31,					
	2025			2024			2025			2024		
Discount Rate	4.9%	—	5.5%	5.6%	—	5.7%	5.4%	—	5.5%		5.7%	
Compensation/Progression Rate	3.5%	—	4.0%	3.5%	—	4.0%				N/A		
Cash Balance Interest Crediting Rate		4.8%			N/A					N/A		

For the Eversource Service PBOP Plan, the health care cost trend rate is not applicable. For the Aquarion PBOP Plan, the health care cost trend rate for pre-65 retirees is 7.25 percent, with an ultimate rate of 5 percent in 2035, and for post-65 retirees, the health care trend rate and ultimate rate is 3.5 percent.

Expense: Eversource charges net periodic benefit plan expense/(income) for the Pension, SERP and PBOP Plans to its subsidiaries based on the actual participant demographic data for each subsidiary's participants. The actual investment return in the trust is allocated to each of the subsidiaries annually in proportion to the investment return expected to be earned during the year. The Company utilizes the spot rate methodology to estimate the discount rate for the service and interest cost components of benefit plan expense, which provides a relatively precise measurement by matching projected cash flows to the corresponding spot rates on the yield curve.

The components of net periodic benefit plan expense/(income) for the Pension, SERP and PBOP Plans, prior to amounts capitalized as Property, Plant and Equipment or deferred as regulatory assets/(liabilities) for future recovery or refund, are shown below. The service cost component of net periodic benefit plan expense/(income), less the capitalized portion, is included in Operations and Maintenance expense on the statements of income. The remaining components of net periodic benefit plan expense/(income), less the deferred portion, are included in Other Income, Net on the statements of income. Pension, SERP and PBOP plan expense/(income) reflected in the statements of cash flows for CL&P, NSTAR Electric and PSNH does not include intercompany allocations of net periodic benefit plan expense/(income), as these amounts are cash settled on a short-term basis.

	Pension and SERP				PBOP			
	For the Year Ended December 31, 2025				For the Year Ended December 31, 2025			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Service Cost	$ 67.9	$ 15.3	$ 9.7	$ 6.5	$ 6.4	$ 1.1	$ 1.1	$ 0.5
Interest Cost	255.6	51.5	53.0	27.1	32.0	5.6	8.7	3.4
Expected Return on Plan Assets	(454.3)	(91.8)	(110.7)	(47.8)	(84.6)	(9.6)	(42.0)	(5.7)
Actuarial Loss/(Gain)	42.9	5.1	14.3	2.1	(0.9)	—	—	—
Prior Service Cost/(Credit)	1.1	—	0.3	—	(21.6)	1.1	(17.0)	0.4
Settlement Loss	3.3	—	—	—	—	—	—	—
Total Net Periodic Benefit Plan Income	$ (83.5)	$ (19.9)	$ (33.4)	$ (12.1)	$ (68.7)	$ (1.8)	$ (49.2)	$ (1.4)
Intercompany Income Allocations	N/A	$ (1.4)	$ (0.5)	$ (0.1)	N/A	$ (2.1)	$ (2.7)	$ (0.9)

	Pension and SERP				PBOP			
	For the Year Ended December 31, 2024				For the Year Ended December 31, 2024			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Service Cost	$ 44.3	$ 12.7	$ 7.7	$ 4.3	$ 7.0	$ 1.2	$ 1.2	$ 0.6
Interest Cost	250.0	50.3	51.6	26.8	31.9	5.6	8.8	3.4
Expected Return on Plan Assets	(462.6)	(93.5)	(112.4)	(48.9)	(81.2)	(9.5)	(39.5)	(5.6)
Actuarial Loss/(Gain)	85.9	12.1	25.6	5.0	(0.4)	—	—	—
Prior Service Cost/(Credit)	1.3	—	0.3	—	(21.6)	1.1	(17.0)	0.4
Settlement Loss	4.3	—	—	—	—	—	—	—
Total Net Periodic Benefit Plan Income	$ (76.8)	$ (18.4)	$ (27.2)	$ (12.8)	$ (64.3)	$ (1.6)	$ (46.5)	$ (1.2)
Intercompany Income Allocations	N/A	$ (1.6)	$ (1.3)	$ (0.4)	N/A	$ (2.2)	$ (2.6)	$ (0.9)

	Pension and SERP				PBOP			
	For the Year Ended December 31, 2023				For the Year Ended December 31, 2023			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Service Cost	$ 43.1	$ 12.3	$ 7.8	$ 4.3	$ 7.6	$ 1.3	$ 1.2	$ 0.7
Interest Cost	254.0	50.5	53.9	27.3	33.8	6.2	9.2	3.7
Expected Return on Plan Assets	(465.0)	(94.2)	(113.8)	(49.5)	(77.1)	(9.4)	(36.9)	(5.5)
Actuarial Loss	45.8	2.5	17.1	1.5	—	—	—	—
Prior Service Cost/(Credit)	1.3	—	0.3	—	(21.6)	1.1	(17.0)	0.4
Settlement Loss	12.4	—	—	—	—	—	—	—
Total Net Periodic Benefit Plan Income	$ (108.4)	$ (28.9)	$ (34.7)	$ (16.4)	$ (57.3)	$ (0.8)	$ (43.5)	$ (0.7)
Intercompany Income Allocations	N/A	$ (4.0)	$ (3.0)	$ (0.8)	N/A	$ (1.9)	$ (2.1)	$ (0.7)

The following actuarial assumptions were used to calculate Pension, SERP and PBOP expense amounts:

	Pension and SERP						PBOP					
	For the Years Ended December 31,						For the Years Ended December 31,					
	2025		2024		2023		2025		2024		2023	
Discount Rate	5.2% — 5.8%		4.7% — 5.1%		4.9% — 5.3%		5.4% — 5.9%		4.9% — 5.2%		5.1% — 5.4%	
Expected Long-Term Rate of Return	8.25%		8.25%		8.25%		8.25%		8.25%		8.25%	
Compensation/Progression Rate	3.5% — 4.0%		3.5% — 4.0%		3.5% — 4.0%		N/A		N/A		N/A	

For the Aquarion Pension Plan, the expected long-term rate of return was 8.25 percent for the years ended December 31, 2025 and 2024 and 7.94 percent for the year ended December 31, 2023. For the Aquarion PBOP Plan, the expected long-term rate of return was 7 percent for the years ended December 31, 2025, 2024 and 2023 and the health care cost trend rate was a range of 3.5 percent to 7.5 percent for the year ended December 31, 2025, 3.5 percent to 6.75 percent for the year ended December 31, 2024 and 3.5 percent to 7 percent for the year ended December 31, 2023 .

Regulatory Assets and Accumulated Other Comprehensive Income/(Loss) Amounts: The Pension, SERP and PBOP Plans cover eligible employees, including, among others, employees of the regulated companies. The regulated companies record actuarial losses and gains and prior service costs and credits arising at the December 31st remeasurement date of the funded status of the benefit plans as a regulatory asset or regulatory liability in lieu of a charge to Accumulated Other Comprehensive Income/(Loss), reflecting ultimate recovery from customers through rates. Regulatory accounting is also applied to the portions of the Eversource Service retiree benefit costs that support the regulated companies, as these costs are also recovered from customers. Adjustments to the Pension, SERP and PBOP Plans' funded status for the unregulated companies are recorded on an after-tax basis to Accumulated Other Comprehensive Income/(Loss). For further information, see Note 2, "Regulatory Accounting," and Note 16, "Accumulated Other Comprehensive Income/(Loss)," to the financial statements.

The difference between the actual return and calculated expected return on plan assets for the Pension and PBOP Plans, as well as changes in actuarial assumptions impacting the projected benefit obligation, are recorded as unamortized actuarial gains or losses arising during the year in Regulatory Assets or Accumulated Other Comprehensive Income/(Loss). Unamortized actuarial gains or losses are amortized as a component of pension and PBOP expense over the estimated average future employee service period using the corridor approach.

The following is a summary of the changes in plan assets and benefit obligations recognized in Regulatory Assets and Other Comprehensive Income (OCI) as well as amounts in Regulatory Assets and OCI that were reclassified as net periodic benefit expense during the years presented:

	Pension and SERP				PBOP			
	Regulatory Assets		OCI		Regulatory Assets		OCI	
	For the Years Ended December 31,				For the Years Ended December 31,			
(Millions of Dollars)	2025	2024	2025	2024	2025	2024	2025	2024
Actuarial Loss/(Gain) Arising During the Year	$ 57.0	$ (49.2)	$ —	$ 2.3	$ (36.8)	$ (50.9)	$ —	$ (0.6)
Actuarial (Loss)/Gain Reclassified as Net Periodic Benefit (Expense)/Income	(38.7)	(79.1)	(4.2)	(6.8)	0.9	0.4	—	—
Actuarial (Loss)/Gain Reclassified as Held for Sale	—	(16.6)	—	—	—	7.1	—	—
Actuarial Loss/(Gain) Reclassified from Held for Sale	16.6	—	—	—	(7.1)	—	—	—
Settlement Loss	—	—	(3.3)	(4.3)	—	—	—	—
Prior Service Cost Arising During the Year	0.1	1.3	—	—	—	—	—	—
Prior Service (Cost)/Credit Reclassified as Net Periodic Benefit (Expense)/Income	(1.3)	(1.2)	0.2	(0.1)	21.8	21.8	(0.2)	(0.2)
Prior Service Cost Reclassified as Held for Sale	—	(1.2)	—	—	—	(0.6)	—	—
Prior Service Cost Reclassified from Held for Sale	1.2	—	—	—	0.6	—	—	—

The following is a summary of the remaining Regulatory Assets and Accumulated Other Comprehensive Income amounts that have not been recognized as components of net periodic benefit expense as of December 31, 2025 and 2024:

	Regulatory Assets as of December 31,		AOCI as of December 31,	
(Millions of Dollars)	2025	2024	2025	2024
Pension and SERP				
Actuarial Loss	$ 991.0	$ 956.1	$ 40.2	$ 47.7
Prior Service Cost	1.8	1.8	0.4	0.2
PBOP				
Actuarial (Gain)/Loss	$ (36.6)	$ 6.4	$ 1.8	$ 1.8
Prior Service (Credit)/Cost	(43.8)	(66.2)	0.3	0.5

Estimated Future Benefit Payments: The following benefit payments, which reflect expected future service, are expected to be paid by the Pension, SERP and PBOP Plans:

(Millions of Dollars)	2026	2027	2028	2029	2030	2031 - 2035
Pension and SERP	$ 375.4	$ 383.3	$ 387.3	$ 390.9	$ 394.0	$ 1,969.3
PBOP	53.0	52.3	51.5	50.6	49.6	232.1

Eversource Contributions: Based on the current status of the Pension Plans and federal pension funding requirements, for the Eversource Service Pension Plan there is no minimum funding requirement in 2026 and Eversource does not expect to make pension contributions in 2026. Eversource does not expect to make any contributions to the Eversource Service PBOP Plan in 2026.

Eversource contributed $2.5 million and $0.7 million to the Aquarion Pension and PBOP Plans, respectively, in 2025. Eversource currently estimates contributing $2.5 million and $2.8 million to the Aquarion Pension and PBOP Plans, respectively, in 2026.

Fair Value of Pension and PBOP Plan Assets: Pension and PBOP funds are held in external trusts. Trust assets, including accumulated earnings, must be used exclusively for Pension and PBOP payments. Eversource's investment strategy for its Pension and PBOP Plans is to maximize the long-term rates of return on these plans' assets within an acceptable level of risk. The investment guidelines for each asset category includes a diversification of asset types, fund strategies and fund managers and it establishes target asset allocations that are routinely reviewed and periodically rebalanced. PBOP assets are comprised of assets held in the PBOP Plan trust, as well as specific assets within the Pension Plan trust (401(h) assets). The investment policy and strategy of the 401(h) assets is consistent with that of the defined benefit pension plan. Eversource's expected long-term rates of return on Pension and PBOP Plan assets are based on target asset allocation assumptions and related expected long-term rates of return. In developing its expected long-term rate of return assumptions for the Pension and PBOP Plans, Eversource evaluated input from consultants, as well as long-term inflation assumptions and historical returns. Management has assumed long-term rates of return of 8.25 percent for the Eversource Service Pension Plan assets and the Eversource Service PBOP Plan assets, and a 7 percent long-term rate of return for the Aquarion Pension Plan assets and the Aquarion PBOP Plan assets, to estimate its 2026 Pension and PBOP costs.
These long-term rates of return are based on the assumed rates of return for the target asset allocations as follows:

	As of December 31,					
	2025			2024		
	Target Asset Allocation		Assumed Rate of Return	Target Asset Allocation		Assumed Rate of Return
	Eversource Pension Plan	Eversource PBOP Plan	Eversource Pension Plan and PBOP Plan	Eversource Pension Plan	Eversource PBOP Plan	Eversource Pension Plan and PBOP Plan
Equity Securities:						
United States	— %	20.0 %	8.5 %	— %	20.0 %	8.5 %
Global	20.0 %	— %	8.8 %	20.0 %	— %	8.8 %
Non-United States	— %	11.0 %	8.5 %	— %	11.0 %	8.5 %
Emerging Markets	— %	6.0 %	10.0 %	— %	6.0 %	10.0 %
Debt Securities:						
Fixed Income	16.0 %	17.0 %	5.5 %	16.0 %	17.0 %	5.5 %
High Yield Fixed Income	5.0 %	— %	7.5 %	5.0 %	— %	7.5 %
United States Treasuries	11.0 %	— %	4.5 %	11.0 %	— %	4.5 %
Private Debt	10.0 %	13.0 %	10.0 %	10.0 %	13.0 %	10.0 %
Private Equity	23.0 %	18.0 %	12.0 %	23.0 %	18.0 %	12.0 %
Real Assets	15.0 %	15.0 %	7.5 %	15.0 %	15.0 %	7.5 %

The following tables present, by asset category, the Pension and PBOP Plan assets recorded at fair value on a recurring basis by the level in which they are classified within the fair value hierarchy:

	Pension Plan							
	Fair Value Measurements as of December 31,							
(Millions of Dollars)	2025 [1]				2024 [2]			
Asset Category:	Level 1	Level 2	Uncategorized	Total	Level 1	Level 2	Uncategorized	Total
Equity Securities	302.8	110.9	816.2	1,229.9	323.6	—	826.0	1,149.6
Fixed Income	340.4	502.1	1,325.6	2,168.1	314.3	344.7	1,329.6	1,988.6
Private Equity	—	—	1,799.1	1,799.1	—	—	1,710.9	1,710.9
Real Assets	158.3	127.5	638.9	924.7	243.8	—	652.2	896.0
Total	$ 801.5	$ 740.5	$ 4,579.8	$ 6,121.8	$ 881.7	$ 344.7	$ 4,518.7	$ 5,745.1
Less: 401(h) PBOP Assets [3]				(231.8)				(231.1)
Total Pension Assets				$ 5,890.0				$ 5,514.0

	PBOP Plan							
	Fair Value Measurements as of December 31,							
(Millions of Dollars)	2025 [2]				2024 [2]			
Asset Category:	Level 1	Level 2	Uncategorized	Total	Level 1	Level 2	Uncategorized	Total
Equity Securities	132.7	48.3	214.4	395.4	184.8	—	166.3	351.1
Fixed Income	45.5	41.5	185.9	272.9	61.8	44.6	127.5	233.9
Private Equity	—	—	120.1	120.1	—	—	99.0	99.0
Real Assets	79.0	6.3	41.6	126.9	83.7	—	37.5	121.2
Total	$ 257.2	$ 96.1	$ 562.0	$ 915.3	$ 330.3	$ 44.6	$ 430.3	$ 805.2
Add: 401(h) PBOP Assets [4]				231.8				231.1
Total PBOP Assets				$ 1,147.1				$ 1,036.3

[1] Fixed Income and Equity Securities classified as Level 2 as of December 31, 2025 include pending redemption settlements of $37.2 million and $15.4 million, respectively.

[2] Equity Securities classified as Level 2 as of December 31, 2025 include pending redemption settlements of $46.8 million.

[3] As of December 31, 2024, the funded status of the Aquarion water distribution business's Pension and PBOP benefit plans were reclassified as held for sale presentation on the Eversource balance sheet. Therefore, these Pension and PBOP asset balances were excluded from the tables above as of December 31, 2024. As of December 31, 2025, the funded status of the Aquarion water distribution business' Pension and
PBOP benefit plans was no longer classified as held for sale in the Eversource balance sheet and the asset balances are included in the tables above. See Note 24, "Assets Held for Sale," for further information.

[4] The assets of the Pension Plan include a 401(h) account that has been allocated to provide health and welfare postretirement benefits under the PBOP Plan.

The Company values assets based on observable inputs when available. Equity securities, fixed income exchange traded funds and real asset futures contracts classified as Level 1 in the fair value hierarchy are priced based on the closing price on the primary exchange as of the balance sheet date.

Fixed income securities, such as government issued securities and corporate bonds, are included in Level 2 and are valued using pricing models, quoted prices of securities with similar characteristics or discounted cash flows. The pricing models utilize observable inputs such as recent trades for the same or similar instruments, yield curves, discount margins and bond structures. Swaps are valued using pricing models that incorporate interest rates and equity and fixed income index closing prices to determine a net present value of the cash flows.

Certain investments, such as commingled funds, private equity investments, fixed income funds, real asset funds and hedge funds are valued using the net asset value (NAV) as a practical expedient. Assets valued at NAV are uncategorized in the fair value hierarchy. These investments are structured as investment companies offering shares or units to multiple investors for the purpose of providing a return. Commingled funds are recorded at NAV provided by the asset manager, which is based on the market prices of the underlying equity securities. Private Equity investments, Fixed Income partnership funds and Real Assets are valued using the NAV provided by the partnerships, which are based on discounted cash flows of the underlying investments, real estate appraisals or public market comparables of the underlying investments, or the NAV of underlying assets held in hedge funds. Equity Securities investments in United States, Global, Non-United States and Emerging Markets that are uncategorized include investments in commingled funds and hedge funds that are overlaid with equity index swaps and futures contracts. Fixed Income investments that are uncategorized include investments in commingled funds, fixed income funds that invest in a variety of opportunistic credit and private debt strategies, and hedge funds that are overlaid with fixed income swaps and futures contracts.

B. Defined Contribution Plans

Eversource maintains defined contribution plans on behalf of eligible participants. The Eversource 401k Plan provides for employee and employer contributions up to statutory limits. For the year ended December 31, 2025, for eligible employees, the Eversource 401k Plan provided employer matching contributions of 100 percent up to a maximum of six percent of eligible compensation. For the years ended December 31, 2024 and 2023, for eligible employees, the Eversource 401k Plan provided employer matching contributions of either 100 percent up to a maximum of three percent of eligible compensation or 50 percent up to a maximum of eight percent of eligible compensation.

In 2024 and 2023, the Eversource 401k Plan also contained a K-Vantage feature for the benefit of eligible participants, which provided an additional annual employer contribution based on age and years of service. K-Vantage participants were not eligible to actively participate in the Eversource Service Pension Plan. Effective January 1, 2025, with the exception of one union group that voted to enter effective January 1, 2026, Eversource replaced employer K-Vantage contributions with the Cash Balance Pension Plan. See Note 11A, "Employee Benefits – Pension Benefits and Postretirement Benefits Other Than Pension," for further information.

The total Eversource 401k Plan employer matching contributions, including the K-Vantage contributions, were as follows:

(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH
2025	$ 68.6	$ 9.3	$ 15.7	$ 5.1
2024	76.2	10.6	15.4	6.0
2023	67.3	9.0	13.7	5.4

C. Share-Based Payments

Share-based compensation awards are recorded using a fair-value based method at the date of grant. Eversource, CL&P, NSTAR Electric and PSNH record compensation expense related to these awards, as applicable, for shares issued to their respective employees and officers, as well as for the allocation of costs associated with shares issued to Eversource's service company employees and officers that support CL&P, NSTAR Electric and PSNH.

Eversource Incentive Plans: Eversource maintains long-term equity-based incentive plans in which Eversource, CL&P, NSTAR Electric and PSNH employees, officers and board members are eligible to participate. The incentive plans authorize Eversource to grant up to 7,400,000 new shares for various types of awards, including RSUs and performance shares, to eligible employees, officers, and board members. As of December 31, 2025 and 2024, Eversource had 3,051,466 and 3,790,353 common shares, respectively, available for issuance under these plans.
Eversource accounts for its various share-based plans as follows:

- RSUs - Eversource records compensation expense, net of estimated forfeitures, on a straight-line basis over the requisite service period based upon the fair value of Eversource's common shares at the date of grant. The par value of RSUs is reclassified to Common Stock from Capital Surplus, Paid In as RSUs become issued as common shares.
- Performance Shares - Eversource records compensation expense, net of estimated forfeitures, over the requisite service period. Performance shares vest based upon the extent to which Company goals are achieved. Vesting of outstanding performance shares is based upon the Company's EPS growth over the requisite service period and level of payout is determined based on the total shareholder return as compared to the Edison Electric Institute (EEI) Index during the requisite service period. The fair value of performance shares is determined at the date of grant using a lattice model. Compensation expense is subject to volatility until payout is established.

RSUs: Eversource granted RSUs under the annual long-term incentive programs that are subject to three-year graded vesting schedules for employees, and one-year graded vesting schedules, or immediate vesting, for board members. RSUs are paid in shares, reduced by amounts sufficient to satisfy withholdings for income taxes, subsequent to vesting. A summary of RSU

transactions is as follows:

	RSUs (Units)	Weighted Average Grant-Date Fair Value
Outstanding as of December 31, 2024	715,442	$ 61.95
Granted	345,870	$ 57.63
Shares Issued	(306,679)	$ 65.99
Forfeited	(23,452)	$ 63.23
Outstanding as of December 31, 2025	731,181	$ 58.17

The weighted average grant-date fair value of RSUs granted for the years ended December 31, 2025, 2024 and 2023 was $57.63, $57.93 and $76.42, respectively. As of December 31, 2025 and 2024, the number and weighted average grant-date fair value of unvested RSUs was 534,754 and $59.50 per share, and 455,620 and $65.29 per share, respectively. During 2025, there were 239,469 RSUs at a weighted average grant-date fair value of $68.77 per share that vested during the year and were either paid or deferred. As of December 31, 2025, 196,427 RSUs were fully vested and deferred and an additional 508,017 are expected to vest.

Performance Shares: Eversource granted performance shares under the annual long-term incentive programs that vest based upon the extent to which Company goals are achieved at the end of three-year performance measurement periods. Performance shares are paid in shares, after the performance measurement period. A summary of performance share transactions is as follows:

	Performance Shares (Units)	Weighted Average Grant-Date Fair Value
Outstanding as of December 31, 2024	864,192	$ 71.48
Granted	409,471	$ 57.82
Shares Issued	(163,335)	$ 88.50
Forfeited	(91,885)	$ 83.96
Outstanding as of December 31, 2025	1,018,443	$ 62.13

The weighted average grant-date fair value of performance shares granted for the years ended December 31, 2025, 2024 and 2023 was $57.82, $55.87 and $83.39, respectively. As of December 31, 2025 and 2024, the number and weighted average grant-date fair value of unvested performance shares was 941,243 and $61.77 per share, and 737,738 and $69.12 per share, respectively. During 2025, there were 113,252 performance shares at a weighted average grant-date fair value of $77.29 per share that vested during the year and were either paid or deferred. As of December 31, 2025, 77,200 performance shares were fully vested and deferred.

Compensation Expense: The total compensation expense and associated future income tax benefits recognized by Eversource, CL&P, NSTAR Electric and PSNH for share-based compensation awards were as follows:

Eversource (Millions of Dollars)	For the Years Ended December 31, 2025	2024	2023
Compensation Expense	$ 33.6	$ 30.0	$ 27.8
Future Income Tax Benefit	8.8	7.8	7.3

	For the Years Ended December 31, 2025			2024			2023		
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Compensation Expense	$ 10.5	$ 11.6	$ 4.3	$ 9.3	$ 9.6	$ 3.6	$ 8.7	$ 8.7	$ 3.0
Future Income Tax Benefit	2.7	3.0	1.1	2.4	2.5	0.9	2.3	2.3	0.8

As of December 31, 2025, there was $30.9 million of total unrecognized compensation expense related to nonvested share-based awards for Eversource, including $5.3 million for CL&P, $9.5 million for NSTAR Electric, and $1.9 million for PSNH. This cost is expected to be recognized ratably over a weighted-average period of 1.75 years for Eversource, CL&P, NSTAR Electric, and PSNH.

An income tax rate of 26 percent was used to estimate the tax effect on total share-based payments determined under the fair-value based method for all awards. The Company issues treasury shares to settle fully vested RSUs and performance shares under the Company's incentive plans.

For the years ended December 31, 2025, 2024, and 2023, a tax deficiency associated with the distribution of stock compensation awards increased income tax expense by $2.8 million and $2.3 million, $0.5 million respectively, which decreased cash flows from operating activities on the statements of cash flows.

D. Other Retirement Benefits

Eversource provides retirement and other benefits for certain current and past company officers. These benefits are accounted for on an accrual basis and expensed over a period equal to the service lives of the employees. The actuarially-determined liability for these benefits is included in Other Current and Long-Term Liabilities on the balance sheets. The related expense, which includes the allocation of expense associated with Eversource's service company officers that support CL&P, NSTAR Electric and PSNH, is included in Operations and Maintenance Expense on the income statements. The liability and expense amounts are as follows:

Eversource (Millions of Dollars)	As of and For the Years Ended December 31, 2025	2024	2023
Actuarially-Determined Liability	$ 29.9	$ 30.2	$ 32.6
Other Retirement Benefits Expense	2.3	2.4	2.6

	As of and For the Years Ended December 31, 2025			2024			2023		
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Actuarially-Determined Liability	$ 0.1	$ —	$ 1.0	$ 0.1	$ —	$ 1.0	$ 0.2	$ —	$ 1.1
Other Retirement Benefits Expense	0.8	0.8	0.3	0.8	0.8	0.3	0.8	0.8	0.4

12. INCOME TAXES

The components of income tax expense are as follows:

Eversource (Millions of Dollars)	For the Years Ended December 31, 2025	2024	2023
Current Income Taxes:			
Federal	$ 77.5	$ (23.4)	$ 75.8
State	37.5	14.3	0.6
Total Current	115.0	(9.1)	76.4
Deferred Income Taxes, Net:			
Federal	63.7	266.3	(0.9)
State	(36.4)	169.6	86.3
Total Deferred	27.3	435.9	85.4
Investment Tax Credits, Net	(2.0)	(2.1)	(2.1)
Income Tax Expense	$ 140.3	$ 424.7	$ 159.7

	For the Years Ended December 31, 2025			2024			2023		
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Current Income Taxes:									
Federal	$ 191.1	$ 118.9	$ 57.3	$ 25.9	$ 65.9	$ (1.7)	$ (10.8)	$ 50.7	$ (40.0)
State	70.9	37.2	23.5	(6.8)	15.2	(5.2)	(2.3)	7.8	(20.0)
Total Current	262.0	156.1	80.8	19.1	81.1	(6.9)	(13.1)	58.5	(60.0)
Deferred Income Taxes, Net:									
Federal	(66.5)	10.0	3.7	107.9	63.9	50.8	130.3	50.1	81.2
State	(28.3)	25.6	7.6	67.5	47.3	26.3	53.7	46.1	37.8
Total Deferred	(94.8)	35.6	11.3	175.4	111.2	77.1	184.0	96.2	119.0
Investment Tax Credits, Net	—	(1.7)	—	—	(1.7)	—	—	(1.7)	—
Income Tax Expense	$ 167.2	$ 190.0	$ 92.1	$ 194.5	$ 190.6	$ 70.2	$ 170.9	$ 153.0	$ 59.0

A reconciliation between income tax expense and the expected tax expense at the statutory rate is as follows:

	For the Year Ended December 31, 2025							
	Eversource		CL&P		NSTAR Electric		PSNH	
(Millions of Dollars)	Amount	Percent	Amount	Percent	Amount	Percent	Amount	Percent
Income Before Income Tax Expense	$ 1,840.2	N/A	$ 718.5	N/A	$ 820.7	N/A	$ 361.5	N/A
U.S. Federal Statutory Income Tax Expense at 21%	386.4	21 %	150.9	21 %	172.3	21 %	75.9	21 %
Tax Effect of Differences:								
State and Local Income Tax Effects, Net of Federal Impact (1)	2.4	0.1	39.6	5.5	49.6	6.0	24.6	6.8
Federal Tax Credits								
Research and Development Tax Credits	(22.6)	(1.2)	—	—	—	—	—	—

Changes in Valuation Allowances	(241.6)	(13.1)	(6.2)	(0.9)	—	—	—	—
Nontaxable or Nondeductible Items:								
Depreciation	(23.4)	(1.3)	2.5	0.3	(10.6)	(1.3)	(2.2)	(0.6)
EDIT Amortization	(50.6)	(2.7)	(17.0)	(2.4)	(21.7)	(2.6)	(8.1)	(2.2)
Loss on Offshore Wind	59.5	3.2	—	—	—	—	—	—
Other	30.2	1.6	(2.6)	(0.4)	0.4	—	1.9	0.5
Income Tax Expense/Effective Tax Rate	$ 140.3	7.6 %	$ 167.2	23.3 %	$ 190.0	23.2 %	$ 92.1	25.5 %

(1) State taxes in Connecticut (for CL&P), Massachusetts (for NSTAR Electric) and New Hampshire (for PSNH) made up the majority of the tax effects in this category for Eversource.

Eversource maintains a valuation allowance recorded on deferred tax assets associated with the loss recorded from the offshore wind investments. In the third quarter of 2025, as part of filing its 2024 tax return to provision process, Eversource partially reversed this valuation allowance by $294 million and also recorded a charge of $129 million as it reconciled the positions on the tax return to what was estimated as of December 31, 2024, resulting in a net benefit of $165 million to tax expense. The adjustment to the valuation allowance was required based on the reconciling of previously recorded tax losses to amounts included in applicable partnership income tax returns. Both adjustments resulted from changes in tax estimates based on information from the partnership tax returns received in the third quarter of 2025. Eversource also recognized state tax benefits and certain tax credits of $118 million as part of the 2024 tax return to provision process. These benefits totaling $283 million were recorded as a reduction to income tax expense on the statement of income in 2025. The Loss on Offshore Wind in the table above of $59.5 million reflects the federal impacts of the $129 million charge, partially offset by the tax benefit of $44 million recorded from the pre-tax increase of $284 million to the offshore wind contingent liability recorded in the third quarter of 2025.

	For the Years Ended December 31,							
	2024				2023			
(Millions of Dollars, except percentages)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Income/(Loss) Before Income Tax Expense	$ 1,243.8	$ 707.1	$ 826.9	$ 285.1	$ (275.0)	$ 689.6	$ 697.5	$ 254.7
Statutory Federal Income Tax Expense at 21%	261.2	148.5	173.7	59.9	(57.7)	144.9	146.5	53.5
Tax Effect of Differences:								
Depreciation	(22.6)	0.4	(10.9)	(1.0)	(25.8)	(5.6)	(8.8)	(1.0)
Investment Tax Credit Amortization	(2.1)	—	(1.7)	—	(2.1)	—	(1.7)	—
Other Federal Tax Credits	(67.0)	—	—	—	(42.5)	—	—	—
State Income Taxes, Net of Federal Impact	43.2	(2.8)	49.4	16.7	(11.4)	(10.7)	42.5	14.1
Dividends on ESOP	(5.5)	—	—	—	(5.3)	—	—	—
Tax Asset Valuation Allowance/Reserve Adjustments	278.6	50.8	—	—	295.8	51.3	—	—
Share-Based Payment Tax Deficiency	2.3	0.8	0.8	0.3	0.5	0.2	0.2	0.1
EDIT Amortization	(37.0)	(9.2)	(20.0)	(6.5)	(51.5)	(10.5)	(28.4)	(6.8)
Other, Net	(26.4)	6.0	(0.7)	0.8	59.7	1.3	2.7	(0.9)
Income Tax Expense	$ 424.7	$ 194.5	$ 190.6	$ 70.2	$ 159.7	$ 170.9	$ 153.0	$ 59.0
Effective Tax Rate	34.1 %	27.5 %	23.0 %	24.6 %	(58.1)%	24.8 %	21.9 %	23.2 %

Eversource, CL&P, NSTAR Electric and PSNH file a consolidated federal income tax return and unitary, combined and separate state income tax returns. These entities are also parties to a tax allocation agreement under which taxable subsidiaries do not pay any more taxes than they would have otherwise paid had they filed a separate company tax return, and subsidiaries generating tax losses, if any, are paid for their losses when utilized.
Deferred tax assets and liabilities are recognized for the future tax effects of temporary differences between the carrying amounts and the tax basis of assets and liabilities. The tax effect of temporary differences is accounted for in accordance with the rate-making treatment of the applicable regulatory commissions and relevant accounting authoritative literature. The tax effects of temporary differences that give rise to the net accumulated deferred income tax obligations are as follows:

	As of December 31,							
	2025				2024			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Deferred Tax Assets:								
Employee Benefits	$ 273.0	$ 37.3	$ 92.5	$ 16.1	$ 266.9	$ 33.7	$ 83.5	$ 14.5
Derivative Liabilities	205.8	—	205.8	—	19.6	19.6	—	—
Regulatory Deferrals - Liabilities	716.7	212.7	402.5	48.3	508.7	128.0	316.7	19.6
Allowance for Uncollectible Accounts	151.9	70.2	30.7	6.2	145.3	75.4	26.5	3.8
Tax Effect - Tax Regulatory Liabilities	696.0	310.7	201.1	90.5	720.8	317.6	214.3	93.2
Net Operating Loss Carryforwards	314.0	—	—	—	198.2	—	—	1.5
Purchase Accounting Adjustment	48.2	—	—	—	52.1	—	—	—
Equity Method Wind Investments	760.3	—	—	—	1,098.6	—	—	—
Other	229.6	133.3	30.9	19.7	267.1	134.7	31.5	24.1
Total Deferred Tax Assets	3,395.5	764.2	963.5	180.8	3,277.3	709.0	672.5	156.7
Less: Valuation Allowance (1)	293.4	104.2	—	—	558.2	104.1	—	—
Net Deferred Tax Assets	$ 3,102.1	$ 660.0	$ 963.5	$ 180.8	$ 2,719.1	$ 604.9	$ 672.5	$ 156.7
Deferred Tax Liabilities:								
Accelerated Depreciation and Other Plant-Related Differences	$ 5,880.4	$ 1,925.0	$ 1,963.2	$ 673.3	$ 5,493.3	$ 1,820.3	$ 1,845.2	$ 618.4
Property Tax Accruals	118.3	56.8	47.5	7.0	107.4	49.8	44.5	6.5
Regulatory Amounts:								
Regulatory Deferrals - Assets	1,837.0	405.1	725.3	263.4	1,709.1	522.9	519.9	277.8
Tax Effect - Tax Regulatory Assets	308.5	199.6	9.6	10.3	294.5	194.7	10.0	9.4
Goodwill-related Regulatory Asset - 1999 Merger	62.9	—	54.0	—	67.5	—	58.0	—
Employee Benefits	404.1	60.5	194.7	31.0	353.0	51.0	175.4	23.5
Derivative Assets	24.9	—	24.9	—	3.8	3.8	—	—
Other	113.2	18.9	31.6	2.1	101.7	15.2	24.9	2.7
Total Deferred Tax Liabilities	$ 8,749.3	$ 2,665.9	$ 3,050.8	$ 987.1	$ 8,130.3	$ 2,657.7	$ 2,677.9	$ 938.3

(1) As of December 31, 2025 and 2024, the Eversource Valuation Allowance of $293.4 million and $558.2 million, includes $162.4 million and $427.0 million, respectively, related to Eversource's share of offshore wind investments.

Income Taxes Paid: The following tables present income taxes paid, net of refunds received, disaggregated by jurisdiction. The jurisdictions presented include federal, state, and any individual jurisdictions where the amount of income taxes paid equals or exceeds five percent of the total income taxes paid during the reporting period.

Eversource (Millions of Dollars)	For the Years Ended December 31, 2025	2024	2023
Cash Paid/(Received) for Income Taxes, Net of Refunds:			
Federal Income Taxes	$ (48.8)		
State Income Taxes:			
Connecticut	6.2		
Massachusetts	(8.7)		
Other	2.9		
State Income Taxes	0.4		
Total Cash Paid/(Received) for Income Taxes, Net of Refunds	$ (48.4)		
Total Cash Paid/(Received) for Income Taxes (Prior to ASU 2023-09)		$ (69.6)	$ 39.2

	For the Years Ended December 31,								
	2025			2024			2023		
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Cash Paid for Income Taxes, Net of Refunds:									
Federal Income Taxes	$ 113.1	$ 124.5	$ 60.0						
State Income Taxes:									
Connecticut	22.4	—	—						
Massachusetts	(a)	40.3	(a)						
New Hampshire	—	—	22.9						
Other	0.2	—	0.1						
State Income Taxes	22.6	40.3	23.0						
Total Cash Paid for Income Taxes, Net of Refunds	$ 135.7	$ 164.8	$ 83.0						
Total Cash Paid/(Received) for Income Taxes (Prior to ASU 2023-09)				$ (47.4)	$ 118.7	$ (36.0)	$ (44.1)	$ 31.3	$ (59.9)

(a) Did not meet the five percent threshold required for separate disclosure.

Carryforwards: The following table provides the amounts and expiration dates of state tax credit and loss carryforwards and federal tax credit and net operating loss carryforwards:

	As of December 31,									
	2025					2024				
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Expiration Range	Eversource	CL&P	NSTAR Electric	PSNH	Expiration Range
Federal Net Operating Loss	$ 1,079.4	$ —	$ —	$ —	—	$ 877.7	$ —	$ —	$ 7.1	—
Federal Tax Credit	397.4	0.3	—	—	2044	404.1	—	—	—	2044
Federal Charitable Contribution	1.1	—	—	—	2029	—	—	—	—	—
Federal Capital Loss	1,044.6	—	—	—	2025 - 2029	2,700.0	—	—	—	2024 - 2029
State Net Operating Loss	1,447.8	—	—	—	2040 - 2044	214.1	—	—	—	2024 - 2044
State Tax Credit	236.7	153.9	—	—	2025 - 2030	238.3	157.7	—	—	2024 - 2029
State Capital Loss	1,044.6	—	—	—	2025 - 2029	2,700.0	—	—	—	2024 - 2029
State Charitable Contribution	13.2	—	—	—	2026 - 2029	15.2	—	—	—	2024 - 2028

In 2025, the Company decreased its valuation allowance reserve for state credits by $0.2 million (increased by $0.1 million for CL&P), net of tax, and in 2024, the Company increased its valuation allowance reserve for state credits by $27.3 million ($23.5 million for CL&P), net of tax.

For 2025 and 2024, state credit and federal and state capital loss carryforwards have been partially reserved by a valuation allowance of $293.4 million and $558.2 million (net of tax), respectively.

Unrecognized Tax Benefits: A reconciliation of the activity in unrecognized tax benefits, all of which would impact the effective tax rate if recognized, is as follows:

(Millions of Dollars)	Eversource	CL&P
Balance as of January 1, 2023	$ 67.1	$ 25.5
Gross Increases - Current Year	23.4	4.0
Gross Increases - Prior Year	0.1	0.1
Gross Decreases - Prior Year	(0.1)	—
Lapse of Statute of Limitations	(9.2)	(3.8)
Balance as of December 31, 2023	81.3	25.8
Gross Increases - Current Year	14.2	2.9
Gross Increases - Prior Year	11.0	—
Gross Decreases - Prior Year	(0.2)	(0.2)
Lapse of Statute of Limitations	(12.6)	(6.6)
Balance as of December 31, 2024	93.7	21.9
Gross Increases - Current Year	11.9	3.2
Gross Increases - Prior Year	5.9	1.1
Lapse of Statute of Limitations	(13.3)	(4.6)
Balance as of December 31, 2025	$ 98.2	$ 21.6

Interest and Penalties: Interest on uncertain tax positions is recorded and generally classified as a component of Other Interest Expense on the statements of income. However, when resolution of uncertainties results in the Company receiving interest income, any related interest benefit is recorded in Other Income, Net on the statements of income. No penalties have been recorded. The amount of interest expense recognized on uncertain tax positions was $2.4 million, $1.3 million and $0.3 million for the years ended December 31, 2025, 2024, and 2023, respectively. Accrued interest payable was $4.1 million and $1.7 million as of December 31, 2025 and 2024, respectively.

Tax Positions: During 2025 and 2024, Eversource did not resolve any of its uncertain tax positions.

Open Tax Years: The following table summarizes Eversource, CL&P, NSTAR Electric, and PSNH's tax years that remain subject to examination by major tax jurisdictions as of December 31, 2025:

Description	Tax Years
Federal	2022 - 2025[1]
Connecticut	2022 - 2025
Massachusetts	2022 - 2025
New Hampshire	2022 - 2025

[1] The Company's Corporate Income Tax Returns for 2022 through 2024 were reviewed and closed as part of the annual IRS CAP program, with the exception for partnership investments of the Company. The Company was informed of an IRS audit of one of the partnership returns for the tax year 2022 and the IRS reserves the right to audit any years thereafter. The Company recorded in the above Unrecognized Tax Benefits a reserve associated with this Partnership audit. These years remain open in relation to those audits.

13. COMMITMENTS AND CONTINGENCIES

A. Environmental Matters

Eversource, CL&P, NSTAR Electric and PSNH are subject to environmental laws and regulations intended to mitigate or remove the effect of past operations and improve or maintain the quality of the environment. These laws and regulations require the removal or the remedy of the effect on the environment of the disposal or release of certain specified hazardous substances at current and former operating sites. Eversource, CL&P, NSTAR Electric and PSNH have an active environmental auditing and training program and each believes it is substantially in compliance with all enacted laws and regulations.

Environmental reserves are accrued when assessments indicate it is probable that a liability has been incurred and an amount can be reasonably estimated. The approach used estimates the liability based on the most likely action plan from a variety of available remediation options, including no action required or several different remedies ranging from establishing institutional controls to full site remediation and monitoring. These liabilities are estimated on an undiscounted basis and do not assume that the amounts are recoverable from insurance companies or other third parties. The environmental reserves include sites at different stages of discovery and remediation and do not include any unasserted claims. These reserve estimates are subjective in nature as they take into consideration several different remediation options at each specific site. The reliability and precision of these estimates can be affected by several factors, including new information concerning either the level of contamination at the site, the extent of Eversource's, CL&P's, NSTAR Electric's and PSNH's responsibility for remediation or the extent of remediation required, recently enacted laws and regulations or changes in cost estimates due to certain economic factors. It is possible that new information or future developments could require a reassessment of the potential exposure to required environmental remediation. As this information becomes available, management will continue to assess the potential exposure and adjust the reserves accordingly.

The amounts recorded as environmental reserves are included in Other Current Liabilities and Other Long-Term Liabilities on the balance sheets and represent management's best estimate of the liability for environmental costs, and take into consideration site assessment, remediation and long-term monitoring costs. The environmental reserves also take into account recurring costs of managing hazardous substances and pollutants, mandated expenditures to remediate contaminated sites and any other infrequent and non-recurring clean-up costs. A reconciliation of the activity in the environmental reserves is as follows:

(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH
Balance as of January 1, 2024	$ 128.2	$ 13.8	$ 5.4	$ 7.6
Additions	11.0	0.8	1.9	0.2
Payments/Reductions	(11.2)	(1.2)	(0.7)	(1.5)
Balance as of December 31, 2024	128.0	13.4	6.6	6.3
Additions	40.5	3.6	1.8	3.3
Payments/Reductions	(14.2)	(2.1)	(1.4)	(0.4)
Balance as of December 31, 2025	$ 154.3	$ 14.9	$ 7.0	$ 9.2

The number of environmental sites for which remediation or long-term monitoring, preliminary site work or site assessment is being performed are as follows:

	Eversource	CL&P	NSTAR Electric	PSNH
2025	66	15	14	8
2024	65	15	14	8

Included in the number of sites and reserve amounts above are former MGP sites that were operated several decades ago and manufactured natural gas from coal and other processes, which resulted in certain by-products remaining in the environment that may pose a potential risk to human health and the environment, for which Eversource may have potential liability. The reserve balances related to these former MGP sites were $140.9 million and $115.9 million as of December 31, 2025 and 2024, respectively, and related primarily to the natural gas business segment.

As of December 31, 2025, for 13 environmental sites (7 for CL&P) that are included in the Company's reserve for environmental costs, management cannot reasonably estimate the exposure to loss in excess of the reserve, or range of loss, as these sites are under investigation and/or there is significant uncertainty as to what remedial actions, if any, the Company may be required to undertake. As of December 31, 2025, $33.6 million (including $7.0 million for CL&P) had been accrued as a liability for these sites.

As of December 31, 2025, for 9 environmental sites (2 for CL&P and 1 for NSTAR Electric) that are included in the Company's reserve for environmental costs, the information known and the nature of the remediation options allow for the Company to estimate the range of losses for environmental costs. As of December 31, 2025, $30.9 million (including $0.7 million for CL&P) has been accrued as a liability for these sites, which represents the low end of the range of the liabilities for environmental costs. Management believes that additional losses of up to approximately $29.6 million may be incurred in executing current remediation plans for these sites.

As of December 31, 2025, for the remaining 44 environmental sites (including 6 for CL&P, 13 for NSTAR Electric and 8 for PSNH) that are included in the Company's reserve for environmental costs, the $89.8 million accrual (including $7.2 million for CL&P, $7.0 million for NSTAR Electric and $9.2 million for PSNH) represents management's best estimate of the probable liability and no additional loss is estimable at this time.

PSNH, NSTAR Gas, EGMA and Yankee Gas have rate recovery mechanisms for MGP related environmental costs, therefore, changes in their respective environmental reserves do not impact Net Income. CL&P is allowed to defer certain environmental costs for future recovery. NSTAR Electric does not have a separate environmental cost recovery regulatory mechanism.

B. Long-Term Contractual Arrangements

Estimated Future Annual Costs: The estimated future annual costs of significant executed, non-cancelable, long-term contractual arrangements in effect as of December 31, 2025 are as follows:

Eversource

(Millions of Dollars)	2026	2027	2028	2029	2030	Thereafter	Total
Renewable Energy Purchase Contracts	$ 1,113.9	$ 1,235.1	$ 1,246.2	$ 1,115.5	$ 784.1	$ 11,643.4	$ 17,138.2
Natural Gas Procurement	523.3	487.9	359.4	320.1	273.6	781.9	2,746.2
NECEC Transmission Service Agreement	94.6	96.5	98.4	100.4	102.4	1,806.4	2,298.7

Capacity and Purchased Power	2.9	2.7	2.7	2.3	1.8	0.5	12.9
Peaker CfDs	30.2	25.9	25.8	26.2	18.9	55.1	182.1
Transmission Support Commitments	20.1	21.6	22.6	24.1	24.1	24.1	136.6
Total	$ 1,785.0	$ 1,869.7	$ 1,755.1	$ 1,588.6	$ 1,204.9	$ 14,311.4	$ 22,514.7

CL&P

(Millions of Dollars)	2026	2027	2028	2029	2030	Thereafter	Total
Renewable Energy Purchase Contracts	$ 681.8	$ 774.6	$ 780.4	$ 640.0	$ 300.4	$ 3,603.2	$ 6,780.4
Capacity	0.1	—	—	—	—	—	0.1
Peaker CfDs	30.2	25.9	25.8	26.2	18.9	55.1	182.1
Transmission Support Commitments	7.9	8.5	8.9	9.5	9.5	9.5	53.8
Total	$ 720.0	$ 809.0	$ 815.1	$ 675.7	$ 328.8	$ 3,667.8	$ 7,016.4

NSTAR Electric

(Millions of Dollars)	2026	2027	2028	2029	2030	Thereafter	Total
Renewable Energy Purchase Contracts	$ 432.1	$ 460.5	$ 465.8	$ 475.5	$ 483.7	$ 8,040.2	$ 10,357.8
NECEC Transmission Service Agreement	94.6	96.5	98.4	100.4	102.4	1,806.4	2,298.7
Purchased Power	2.8	2.7	2.7	2.3	1.8	0.5	12.8
Transmission Support Commitments	7.9	8.5	8.9	9.5	9.5	9.5	53.8
Total	$ 537.4	$ 568.2	$ 575.8	$ 587.7	$ 597.4	$ 9,856.6	$ 12,723.1

PSNH

(Millions of Dollars)	2026	2027	2028	2029	2030	Thereafter	Total
Transmission Support Commitments	$ 4.3	$ 4.6	$ 4.8	$ 5.1	$ 5.1	$ 5.1	$ 29.0

The contractual obligations table above does not include CL&P's, NSTAR Electric's or PSNH's standard/basic service contracts for the purchase of energy supply, the amounts of which vary with customers' energy needs.

Renewable Energy Purchase Contracts: Renewable energy purchase contracts include non-cancellable commitments under contracts of CL&P and NSTAR Electric for the purchase of energy and capacity from renewable energy facilities. Such contracts extend through 2046 for CL&P and NSTAR Electric. There are no long-term renewable energy purchase contracts at PSNH.

In accordance with Massachusetts clean energy legislation and under the Massachusetts Clean Energy 83D procurement, in June 2018, NSTAR Electric entered into a 20-year power purchase agreement for the purchase of renewable hydroelectric energy and renewable energy attributes from Hydro-Québec. The agreement requires NSTAR Electric to purchase 579 MW of energy per hour through January 2046. On December 31, 2025, NSTAR Electric received notice of commercial operation of the transmission line needed to deliver this energy. Costs under this contract began in January 2026 following commercial operation and range between $260 million and $420 million per year under the 20-year contract, totaling approximately $6.7 billion over the total contract term. The power purchase agreement is supported by New England Clean Energy Connect (NECEC), a 1,200 MW transmission line developed to deliver the hydroelectric power from Hydro-Québec into the New England grid. As required by law, NSTAR Electric cannot use this power to satisfy its customers' supply obligations. NSTAR Electric will sell the energy purchased under this contract into the market and will use the proceeds from these energy sales to offset the contract costs. The net supply costs under this contract will be recovered from or credited to customers in future rates and do not have an impact on the net income of NSTAR Electric. This contract meets the definition of a derivative and the fair value of the contract is recorded on NSTAR Electric's balance sheet as a derivative with an offset to regulatory assets and/or liabilities. For further information, see Note 4, "Derivative Instruments," to the financial statements.
Renewable energy purchase contracts include long-term commitments of NSTAR Electric pertaining to the Vineyard Wind LLC contract awarded under the Massachusetts Clean Energy 83C procurement solicitation. NSTAR Electric, along with other Massachusetts distribution companies, entered into 20-year contracts to purchase electricity generated by this 800 megawatt offshore wind project. Construction on the Vineyard Wind project commenced in 2022. Estimated energy costs under this contract are expected to begin when the facilities are in service in 2026 and range between $100 million and $200 million per year under NSTAR Electric's 20-year contract, totaling approximately $3.2 billion.

As required by 2018 regulation, CL&P and UI each entered into PURA-approved ten-year contracts in 2019 to purchase a combined total of approximately 9 million MWh annually from the Millstone Nuclear Power Station generation facility, which represents a combined amount of approximately 50 percent of the facility's output (approximately 40 percent by CL&P). Also as required by 2018 regulation, CL&P and UI each entered into PURA-approved eight-year contracts in 2019 to purchase a combined amount of approximately 18 percent of the Seabrook Nuclear Power Plant's output (approximately 15 percent by CL&P) beginning January 1, 2022. The total estimated remaining future cost of the Millstone Nuclear Power Station and Seabrook Nuclear Power Plant energy purchase contracts are $1.6 billion and are reflected in the table above. As required by law, CL&P cannot use this power to satisfy its customers' supply obligations. CL&P sells the energy purchased under these contracts into the market and uses the proceeds from these energy sales to offset the contract costs. As the net costs under these contracts are recovered from customers in future rates, the contracts do not have an impact on the net income of CL&P. These contracts do not meet the definition of a derivative, and accordingly, the costs of these contracts are being accounted for as incurred.

The contractual obligations table above does not include long-term commitments signed by CL&P and NSTAR Electric, as required by the PURA and the DPU, respectively, for the purchase of renewable energy and related products that are contingent on the future construction of energy facilities.

NECEC Transmission Service Agreement: In June 2018, in connection with the Hydro-Québec power purchase agreement, NSTAR Electric entered into a 20-year transmission service agreement (TSA) with NECEC Transmission LLC, the developer and owner of the NECEC transmission line. Under the TSA, NSTAR Electric is obligated to purchase its proportionate share of transmission service at regulated rates, as approved by the DPU and FERC. Costs under the TSA began in January 2026 and range between $95 million and $140 million per year, totaling approximately $2.3 billion over the total contract term. NSTAR Electric's obligation under this contract are recovered from customers in rates.

Natural Gas Procurement: Eversource's natural gas distribution businesses have long-term contracts for the purchase, transportation and storage of natural gas as part of its portfolio of supplies, which extend through 2045.

Capacity and Purchased Power: These contracts include a capacity CfD with a generation facility at CL&P through 2026, and a purchase obligation for electricity which extends through 2031 for NSTAR Electric. CL&P's portion of the costs and benefits under these capacity contracts are recovered from, or refunded to, CL&P's customers.

Peaker CfDs: CL&P, along with UI, has three peaker CfDs for a total of approximately 500 MW of peaking capacity through 2042. CL&P has a sharing agreement with UI, whereby CL&P is responsible for 80 percent and UI for 20 percent of the net costs or benefits of these CfDs. The Peaker CfDs pay the generation facility owner the difference between capacity, day-ahead ancillary services and energy market revenues and a cost-of-service payment stream for 30 years. The ultimate cost or benefit to CL&P under these contracts will depend on the costs of plant operation and the prices that the projects receive for capacity and other products in the ISO-NE markets. CL&P's portion of the amounts paid or received under the Peaker CfDs are recovered from, or refunded to, CL&P's customers.

Transmission Support Commitments: Along with other New England utilities, CL&P, NSTAR Electric and PSNH have entered into agreements to support the costs of, and receive rights to use, transmission and terminal facilities that import electricity from the Hydro-Québec system in Canada. CL&P, NSTAR Electric and PSNH are obligated to pay, over a 20-year period ending in 2040, their proportionate shares of the annual operation and maintenance expenses and capital costs of those facilities.

The total costs incurred under these agreements were as follows:

Eversource	For the Years Ended December 31,		
(Millions of Dollars)	2025	2024	2023
Renewable Energy Purchase Contracts	$ 631.3	$ 591.4	$ 581.4
Natural Gas Procurement	888.0	695.0	695.8
Capacity and Purchased Power	67.2	70.5	69.0
Peaker CfDs	19.6	23.1	20.1
Transmission Support Commitments	17.4	16.7	14.2

	For the Years Ended December 31,								
	2025			2024			2023		
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Renewable Energy Purchase Contracts	$ 567.4	$ 63.9	$ —	$ 529.0	$ 62.4	$ —	$ 474.1	$ 60.0	$ 47.3
Capacity and Purchased Power	64.4	2.8	—	67.6	2.9	—	65.5	2.9	0.6
Peaker CfDs	19.6	—	—	23.1	—	—	20.1	—	—
Transmission Support Commitments	6.9	6.8	3.7	6.6	6.6	3.5	5.6	5.6	3.0

C. Spent Nuclear Fuel Obligations - Yankee Companies
CL&P, NSTAR Electric and PSNH have plant closure and fuel storage cost obligations to the Yankee Companies, which have each completed the physical decommissioning of their respective nuclear power facilities and are now engaged in the long-term storage of their spent fuel. The Yankee Companies fund these costs through litigation proceeds received from the DOE and, to the extent necessary, through wholesale, FERC-approved rates charged under power purchase agreements with several New England utilities, including CL&P, NSTAR Electric and PSNH. CL&P, NSTAR Electric and PSNH, in turn recover these costs from their customers through state regulatory commission-approved retail rates. The Yankee Companies collect amounts that management believes are adequate to recover the remaining plant closure and fuel storage cost estimates for the respective plants. Management believes CL&P and NSTAR Electric will recover their shares of these obligations from their customers. PSNH has recovered its total share of these costs from its customers.

Spent Nuclear Fuel Litigation:
The Yankee Companies have filed complaints against the DOE in the Court of Federal Claims seeking monetary damages resulting from the DOE's failure to accept delivery of, and provide for a permanent facility to store, spent nuclear fuel pursuant to the terms of the 1983 spent fuel and high-level waste disposal contracts between the Yankee Companies and the DOE. The court previously awarded the Yankee Companies damages for Phases I, II, III and IV of litigation resulting from the DOE's failure to meet its contractual obligations. These Phases covered damages incurred in the years 1998 through 2016, and the awarded damages have been received by the Yankee Companies with certain amounts of the damages refunded to their customers.

DOE Phase V Damages - On March 25, 2021, each of the Yankee Companies filed a fifth set of lawsuits against the DOE in the Court of Federal Claims resulting from the DOE's failure to begin accepting spent nuclear fuel for disposal covering the years from 2017 to 2020. The Yankee Companies filed claims seeking monetary damages totaling $120.4 million for CYAPC, YAEC and MYAPC. Pursuant to a June 2, 2022 court order, the Yankee Companies were subsequently permitted to include monetary damages relating to the year 2021 in the DOE Phase V complaint. The Yankee Companies submitted a supplemental filing to include these costs of $33.1 million on June 8, 2022. In September 2024, the parties reached an agreement in principle to settle the Phase V complaint totaling $145 million for CYAPC, YAEC, and MYAPC. The settlement was approved on November 19, 2024 and the Department of Justice filed a Notice of Appeal on January 17, 2025 on an issue outside the scope of the settlement. Oral arguments are expected to be scheduled in 2026.

D. Guarantees and Indemnifications
In the normal course of business, Eversource parent provides credit assurances on behalf of its subsidiaries, including CL&P, NSTAR Electric and PSNH, in the form of guarantees. Management does not anticipate a material impact to net income or cash flows as a result of these various guarantees and indemnifications.

Guarantees issued on behalf of unconsolidated entities, including equity method ownership interests, for which Eversource parent is the guarantor, are recorded at fair value as a liability on the balance sheet at the inception of the guarantee. The fair value of guarantees issued on behalf of unconsolidated entities are recorded within Other Long-Term Liabilities on the balance sheet, and were $1.3 million and $1.2 million as of December 31, 2025 and 2024, respectively. Eversource regularly reviews performance risk under these guarantee arrangements, and believes the likelihood of payments being required under the guarantees is remote. In the event it becomes probable that Eversource parent will be required to perform under the guarantee, the amount of probable payment will be recorded.

On September 30, 2024, Eversource completed the sale of its 50 percent ownership share in the South Fork Wind and Revolution Wind projects to affiliates of Global Infrastructure Partners (GIP). Under the agreement with GIP, Eversource's existing and certain additional credit support obligations for Revolution Wind are expected to roll off as the project completes construction. On July 9, 2024, Eversource completed the sale of its 50 percent ownership share of Sunrise Wind to Orsted. Under the agreement with Orsted, Eversource's existing credit support obligations for Sunrise Wind were either terminated or indemnified by Orsted as a result of the sale.

The following table summarizes Eversource parent's exposure to guarantees and indemnifications of its subsidiaries and affiliates to external parties, and primarily relates to its previously-owned offshore wind investments:

	As of December 31, 2025	
Company (Obligor)	Description	Maximum Exposure (in millions)
	(1)	

Revolution Wind, LLC and TurbineCo, LLC	Offshore wind construction-related purchase agreements with third-party contractors	$ 127.0
Eversource Investment LLC, Eversource Investment Service Company LLC and South Fork Class B Member, LLC	Offshore wind funding and indemnification obligations [2]	176.7
Eversource TEI LLC	South Fork Wind Tax Equity [3]	50.0
South Fork Wind, LLC	Power Purchase Agreement Security [4]	7.1
Various Eversource subsidiaries	Surety bonds [5]	34.1

[1] Eversource parent issued guarantees on behalf of its previously 50 percent-owned affiliate, Revolution Wind, LLC, and on behalf of TurbineCo, LLC (successor in interest to North East Offshore, LLC (NEO)), under which Eversource parent agreed to guarantee each entity's performance of obligations under certain construction-related purchase agreements with third-party contractors, in an aggregate amount not to exceed $693.0 million. Eversource parent's obligations under the guarantees expire upon the earlier of (i) dates ranging between December 2026 and November 2027 and (ii) full performance of the guaranteed obligations.

[2] Eversource parent issued guarantees on behalf of its wholly-owned subsidiary Eversource Investment LLC (EI), which held Eversource's previous investments in offshore wind-related equity method investments until sale, and on behalf of its previously 50 percent-owned affiliate, South Fork Class B Member, LLC, whereby Eversource parent will guarantee each entity's performance of certain funding obligations of the South Fork and Revolution Wind projects. Eversource parent also guaranteed certain indemnification obligations of EI associated with third-party credit support for EI's investment in NEO. On September 30, 2024, Eversource parent issued a guaranty on behalf of its wholly-owned subsidiary, Eversource Investment Service Company LLC, whereby Eversource parent will guarantee Eversource Investment Service Company LLC's performance of certain indemnification obligations during the onshore construction phase of the Revolution Wind project, in an amount not to exceed $100.0 million. These guarantees will not exceed $1.62 billion and expire upon the full performance of the guaranteed obligations.

[3] Eversource parent issued a guarantee on behalf of its wholly-owned subsidiary, Eversource TEI LLC, whereby Eversource parent will guarantee Eversource TEI LLC's performance of certain obligations, in an amount not to exceed $50.0 million, in connection with any remaining obligations under the LLC agreement. Eversource parent's obligations expire upon the full performance of the guaranteed obligations.

[4] Eversource parent issued a guarantee on behalf of its previously 50 percent-owned affiliate, South Fork Wind, LLC, whereby Eversource parent will guarantee South Fork Wind, LLC's performance of certain obligations, in an amount not to exceed $7.1 million, under a Power Purchase Agreement between the Long Island Power Authority and South Fork Wind, LLC (the Agreement). The guarantee expires upon the later of (i) the end of the Agreement term, January 2044, with the option to extend to January 2049 and (ii) full performance of the guaranteed obligations.

[5] Surety bonds expire in 2026. Expiration dates reflect termination dates, the majority of which will be renewed or extended. Certain surety bonds contain credit ratings triggers that would require Eversource parent to post collateral in the event that the unsecured debt credit ratings of Eversource parent are downgraded.

Eversource parent entered into a guarantee on behalf of EI, under which Eversource parent would guarantee EI's obligations under a letter of credit facility with a financial institution that EI may request in an aggregate amount of up to approximately $25 million. As of December 31, 2025, there are no letters of credit issued under this guarantee. The guarantee will remain in effect until full performance of the guaranteed obligations.

On September 30, 2024, Eversource entered into an agreement with GIP and Ørsted to contingently provide future credit support up to a maximum of $850 million in guarantees, if required, to support third-party tax equity financing for Revolution Wind.

In January 2026, Eversource parent issued a guaranty on behalf of EI totaling $900 million to GIP in order to support certain tax positions related to the Revolution Wind project through June 30, 2035.

E. FERC ROE Complaints

Four separate complaints were filed at the FERC by combinations of New England state attorneys general, state regulatory commissions, consumer advocates, consumer groups, municipal parties and other parties (collectively, the Complainants). In each of the first three complaints, filed on October 1, 2011, December 27, 2012, and July 31, 2014, respectively, the Complainants challenged the NETOs' base ROE of 11.14 percent that had been utilized since 2005 and sought an order to reduce it prospectively from the date of the final FERC order and for the separate 15-month complaint periods. In the fourth complaint, filed April 29, 2016, the Complainants challenged the NETOs' base ROE billed of 10.57 percent and the maximum ROE for transmission incentive (incentive cap) of 11.74 percent, asserting that these ROEs were unjust and unreasonable.
The ROE originally billed during the period October 1, 2011 (beginning of the first complaint period) through October 15, 2014 consisted of a base ROE of 11.14 percent and incentives up to 13.1 percent. On October 16, 2014, FERC issued Opinion No. 531-A and set the base ROE at 10.57 percent and the incentive cap at 11.74 percent for the first complaint period. This was also effective for all prospective billings to customers beginning October 16, 2014. This FERC order was vacated on April 14, 2017 by the U.S. Court of Appeals for the D.C. Circuit (the Court).
All amounts associated with the first complaint period have been refunded, which totaled $38.9 million (pre-tax and excluding interest) at Eversource and reflected both the base ROE and incentive cap prescribed by the FERC order. The refund consisted of $22.4 million for CL&P, $13.7 million for NSTAR Electric and $2.8 million for PSNH.

Eversource has recorded a reserve of $39.1 million (pre-tax and excluding interest) for the second complaint period as of both December 31, 2025 and 2024. This reserve represents the difference between the billed rates during the second complaint period and a 10.57 percent base ROE and 11.74 percent incentive cap. The reserve consisted of $21.4 million for CL&P, $14.6 million for NSTAR Electric and $3.1 million for PSNH as of both December 31, 2025 and 2024.

On October 16, 2018, FERC issued an order on all four complaints describing how it intends to address the issues that were remanded by the Court. FERC proposed a new framework to determine (1) whether an existing ROE is unjust and unreasonable and, if so, (2) how to calculate a replacement ROE. Initial briefs were filed by the NETOs, Complainants and FERC Trial Staff on January 11, 2019 and reply briefs were filed on March 8, 2019. The NETOs' brief was supportive of the overall ROE methodology determined in the October 16, 2018 order provided the FERC does not change the proposed methodology or alter its implementation in a manner that has a material impact on the results.

The FERC order included illustrative calculations for the first complaint using FERC's proposed frameworks with financial data from that complaint. Those illustrative calculations indicated that for the first complaint period, the preliminary just and reasonable base ROE for the NETOs, which FERC concludes are of average financial risk, is 10.41 percent and the preliminary incentive cap on total ROE is 13.08 percent. If the results of the illustrative calculations were included in a final FERC order for each of the complaint periods, then a 10.41 percent base ROE and a 13.08 percent incentive cap would not have a significant impact on our financial statements for all of the complaint periods. These preliminary calculations are not binding and do not represent what we believe to be the most likely outcome of a final FERC order.

On November 21, 2019, FERC issued Opinion No. 569 affecting the two pending transmission ROE complaints against the Midcontinent ISO (MISO) transmission owners, in which FERC adopted a new methodology for determining base ROEs. Various parties sought rehearing. On December 23, 2019, the NETOs filed supplementary materials in the NETOs' four pending cases to respond to this new methodology because of the uncertainty of the applicability to the NETOs' cases. On May 21, 2020, the FERC issued its order in Opinion No. 569-A on the rehearing of the MISO transmission owners' cases, in which FERC again changed its methodology for determining the MISO transmission owners' base ROEs. On November 19, 2020, the FERC issued Opinion No. 569-B denying rehearing of Opinion No. 569-A and reaffirmed the methodology previously adopted in Opinion No. 569-A. The new methodology differs significantly from the methodology proposed by FERC in its October 16, 2018 order to determine the NETOs' base ROEs in their four pending cases. FERC Opinion Nos. 569-A and 569-B were appealed to the Court. On August 9, 2022, the Court issued its decision vacating MISO ROE FERC Opinion Nos. 569, 569-A and 569-B and remanded to FERC to reopen the proceedings. The Court found that FERC's development of the new return methodology was arbitrary and capricious due to FERC's failure to offer a reasonable explanation for its decision to reintroduce the risk-premium financial model in its new methodology for calculating a just and reasonable return.

On October 17, 2024, FERC issued an order on the remand of the MISO ROE proceedings. The order addressed the Court's decision that the reintroduction of the risk-premium financial model in the ROE methodology was arbitrary and capricious by removing the risk-premium financial model from the ROE methodology. The removal of the risk-premium financial model was the only revision to FERC's ROE methodology and resulted in a two-model approach utilizing the two-step discounted cash flow model and the capital asset pricing model. MISO transmission owners were directed to provide refunds for the period November 12, 2013 to February 11, 2015 (the first MISO ROE complaint refund period) and for the period from September 28, 2016 (the date of FERC's order on the first MISO ROE complaint) to October 17, 2024 by December 1, 2025. The order also stated that FERC does not preclude the use of the risk-premium financial model in future proceedings if the parties can demonstrate that FERC's stated concerns around the inclusion of the model have been addressed. On March 25, 2025, FERC issued an order addressing arguments raised on rehearing, sustaining the result, and denying rehearing.

On November 13, 2024, the NETOs filed a supplemental brief in their four pending ROE proceedings to explain to FERC that it cannot apply the reasoning and methodologies of the MISO ROE case to the NETOs' cases due to the entirely different set of facts in the MISO and NETOs ROE proceedings. Doing so would violate the substance of the Court's April 14, 2017 order and would violate the legal standard required by the Federal Power Act.

On February 4, 2025, the MISO transmission owners submitted a petition for review with the Court requesting review of the October 17, 2024 MISO ROE order on remand and a December 19, 2024 notice of denial of rehearing. The petition requests review of FERC's decision to retroactively backdate the MISO transmission owners' base ROE to the date of an earlier order that FERC abandoned when it issued Order No. 569, treat an underlying unlawful complaint as if it were legitimate, and order eight years of interest as part of the directed refunds. On August 21,
2025, the NETOs submitted a brief in support of the MISO transmission owners with the Court. Final briefs in the Court proceeding were submitted on January 26, 2026 and oral argument is scheduled for March 17, 2026.

Given the significant uncertainty regarding the applicability of the FERC order in the MISO transmission owners' two complaint cases to the NETOs' pending four complaint cases due to the complex differences between the cases, Eversource concluded that there is no reasonable basis for a change to the reserve or recognized ROEs for any of the complaints or subsequent periods at this time and Eversource cannot reasonably estimate any potential range of loss for any of the four complaint proceedings at this time. The resolution of these proceedings could have a material impact on the financial condition, results of operations, and cash flows.

Eversource, CL&P, NSTAR Electric and PSNH currently record revenues at the 10.57 percent base ROE and incentive cap at 11.74 percent established in the October 16, 2014 FERC order.

A change of 10 basis points to the base ROE used to establish the reserves would impact Eversource's after-tax earnings by an average of approximately $3 million for each of the four 15-month complaint periods.

F. Litigation and Legal Proceedings

Eversource, including CL&P, NSTAR Electric and PSNH, are involved in legal, tax and regulatory proceedings regarding matters arising in the ordinary course of business, which involve management's assessment to determine the probability of whether a loss will occur and, if probable, its best estimate of probable loss. The Company records and discloses losses when these losses are probable and reasonably estimable, and discloses matters when losses are probable but not estimable or when losses are reasonably possible. Legal costs related to the defense of loss contingencies are expensed as incurred.

G. Offshore Wind Sale and Contingent Liability

On July 9, 2024, Eversource completed the sale of its 50 percent ownership share of Sunrise Wind to Ørsted for adjusted proceeds of $152 million. Ørsted paid Eversource $118 million at the closing of the sale transaction and remaining proceeds of $34 million will be paid after onshore construction is completed and certain other construction milestones are achieved. With completion of the sale, Eversource does not have any ongoing financial obligations associated with Sunrise Wind.

On September 30, 2024, Eversource completed the sale of its 50 percent ownership share in the South Fork Wind and Revolution Wind projects to GIP for adjusted gross proceeds of $745 million, which were received at closing. As part of the sale, Eversource and GIP agreed to make certain post-closing purchase price adjustment payments that will impact the final purchase price. The post-closing purchase price adjustment payments include cost sharing obligations that require Eversource to share equally in GIP's funding obligations up to an effective cap of approximately $240 million of incremental capital expenditure overruns incurred during the construction phase for Revolution Wind, after which Eversource will have responsibility for GIP's obligations for any additional capital expenditure overruns in excess of this amount. The purchase price is also subject to post-closing adjustments as a result of final project economics, which includes Eversource's obligation to maintain GIP's internal rate of return through the construction period for each project as specified in the agreement. For Revolution Wind, purchase price adjustment payments are expected to be completed in late 2026. South Fork Wind has achieved commercial operation, and Eversource made a purchase price adjustment payment related to this project in June 2025. In January 2026, disputes with respect to this purchase price adjustment and all matters relating to South Fork Wind have now been resolved with no material impacts.

Upon the completion of the sales in 2024, Eversource recorded a contingent liability of $365.0 million, reflecting its estimate of the future obligations under the terms of the sale to GIP. The total sales proceeds were compared to the carrying value of the investments, including the estimate of liability for post-closing adjustment payments to GIP, and Eversource recognized an aggregate after-tax loss on the sales of its offshore wind investments of $524 million, which included a net $60 million increase in income tax expense including an increase in the valuation allowance for unused capital losses, in 2024.

In the third quarter of 2025, Eversource received an updated report from GIP on the construction status of Revolution Wind, which included revised projections of total construction costs. The revised cost projections reflected known and quantifiable cost increases, including those associated with the impacts of damage to the wind turbine installation vessel, insurance costs, tariff impacts, and costs incurred as a result of the stop-work order for Revolution Wind received on August 22, 2025 from the Bureau of Ocean Energy Management that halted all offshore wind construction activities through September 22, 2025. Based on those developments, Eversource recognized a pre-tax charge of $284.0 million in the third quarter of 2025 as a result of the aggregate impact of these items to increase the liability for purchase price adjustments associated with the offshore wind projects.

Payments made in 2025 reduced the contingent liability and are reflected within investing activities on the statement of cash flows. These payments included cost overruns for the Revolution Wind project paid to GIP, insurance payments, and the purchase price adjustment payment related to the South Fork Wind project paid to GIP.

Eversource continually evaluates the contingent liability and will reassess the balance as new information becomes available. Based on most recent updates from GIP on the construction status of Revolution Wind, factoring in estimated costs incurred as a result of a second stop-work
order for Revolution Wind received on December 22, 2025 and removed on January 12, 2026, revised insurance costs, and other information currently available, Eversource believes that the contingent liability balance as of December 31, 2025 is a reasonable estimate to cover this contingent liability for purchase price adjustments. As of December 31, 2025, the contingent liability totaled $448.2 million and is recorded as a current liability on Eversource's balance sheet, based upon the timing of expected payments to GIP. The contingent liability totaled $365.0 million as of December 31, 2024.

Eversource relies on information that it receives from the project owners for the construction-related, delay-related, and insurance-related costs of Revolution Wind. Eversource uses its judgment to adjust, as needed, its expected obligations to GIP while construction of Revolution Wind is completed.

New information or future developments that arise as the construction of Revolution Wind progresses will necessitate a reassessment of the estimated liability to GIP. The Company reviews available projections of total construction costs, including the latest cost estimates and project timeline, to determine if any changes to this liability are warranted.

It is reasonably possible that as additional updated cost estimates become available, and if additional cost overruns materialize or other adverse changes in facts, regulations and circumstances occur, it could result in additional losses and increases to the offshore wind contingent liability, which could be material. The Company will continue to monitor developments and evaluate potential exposures related to this contingency and will revise its estimated liability as additional information becomes available.

Contingencies are evaluated using the best information available at the time the financial statements are published, and this assessment involves judgments and assumptions about future events. Factors that could increase the obligation to GIP include construction cost overruns for Revolution Wind as well as the timing and extent of construction delays, which would impact the economics associated with the purchase price adjustment, and the eligibility for federal investment tax credits for Revolution Wind at a value lower than assumed and included in the purchase price. The purchase price of Revolution Wind included the sales value related to a 40 percent level of federal investment tax credits. A change in the expected value or qualification of investment tax credit adders could result in a significant loss in a future period.

Total net proceeds could also be adjusted for a benefit due to Eversource if there are lower operation costs or higher availability of the projects through the period that is four years following the commercial operation of Revolution Wind.

2023 Impairment of Offshore Wind Investments: In 2023, Eversource recorded pre-tax other-than-temporary impairment charges of $2.17 billion ($1.95 billion after-tax) in connection with the process to divest its offshore wind investments.

14. LEASES

Eversource, including CL&P, NSTAR Electric and PSNH, has entered into lease agreements as a lessee for the use of land, office space, service centers, vehicles, information technology, and equipment. These lease agreements are classified as either finance or operating leases and the liability and right-of-use asset are recognized on the balance sheet at lease commencement. Leases with an initial term of 12 months or less are not recorded on the balance sheet and are recognized as lease expense on a straight-line basis over the lease term.

Eversource determines whether or not a contract contains a lease based on whether or not it provides Eversource with the use of a specifically identified asset for a period of time, as well as both the right to direct the use of that asset and receive the significant economic benefits of the asset. Eversource has elected the practical expedient to not separate non-lease components from lease components and instead to account for both as a single lease component, with the exception of the information technology asset class where the lease and non-lease components are separated.

The provisions of Eversource, CL&P, NSTAR Electric and PSNH lease agreements contain renewal options. The renewal options range from one year to twenty years. The renewal period is included in the measurement of the lease liability if it is reasonably certain that Eversource will exercise these renewal options.

For leases entered into or modified after the January 1, 2019 implementation date of the leases standard under Topic 842, the discount rate utilized for classification and measurement purposes as of the inception date of the lease is based on each company's collateralized incremental interest rate to borrow over a comparable term for an individual lease because the rate implicit in the lease is not determinable.

CL&P and PSNH entered into certain contracts for the purchase of energy that qualify as leases. These contracts do not have minimum lease payments and therefore are not recognized as a lease liability on the balance sheet and are not reflected in the future minimum lease payments table below. Expense related to these contracts is included as variable lease cost in the table below. The expense and long-term obligation for these contracts are also included in Note 13B, "Commitments and Contingencies - Long-Term Contractual Arrangements," to the financial statements. In 2024, these contracts at PSNH were terminated.

The components of lease cost, prior to amounts capitalized, are as follows:

Eversource	For the Years Ended December 31,		
(Millions of Dollars)	2025	2024	2023
Finance Lease Cost:			
Amortization of Right-of-use-Assets	$ 9.5	$ 6.4	$ 4.8
Interest on Lease Liabilities	2.9	2.7	2.0
Total Finance Lease Cost	12.4	9.1	6.8
Operating Lease Cost	13.0	15.2	11.4
Variable Lease Cost	18.6	18.3	69.2
Total Lease Cost	$ 44.0	$ 42.6	$ 87.4

	For the Years Ended December 31,								
	2025			2024			2023		
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Finance Lease Cost:									
Amortization of Right-of-use-Assets	$ 2.0	$ 0.2	$ 0.1	$ 1.7	$ 0.2	$ —	$ —	$ 0.2	$ —
Interest on Lease Liabilities	0.9	0.6	—	0.8	0.6	—	—	0.6	—
Total Finance Lease Cost	2.9	0.8	0.1	2.5	0.8	—	—	0.8	—
Operating Lease Cost	2.8	5.1	1.9	2.6	5.3	1.8	0.7	3.0	0.4
Variable Lease Cost	18.6	—	—	18.9	—	(0.6)	21.9	—	47.3
Total Lease Cost	$ 24.3	$ 5.9	$ 2.0	$ 24.0	$ 6.1	$ 1.2	$ 22.6	$ 3.8	$ 47.7

Operating lease cost, net of the capitalized portion, is included in Operations and Maintenance (or Purchased Power, Purchased Natural Gas and Transmission expense for transmission leases) on the statements of income. Amortization of finance lease assets is included in Depreciation on the statements of income. Interest expense on finance leases is included in Interest Expense on the statements of income.

Supplemental balance sheet information related to leases is as follows:

		As of December 31, 2025				As of December 31, 2024			
(Millions of Dollars)	Balance Sheet Classification	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Operating Leases:									
Right-of-use-Assets, Net	Other Long-Term Assets	$ 47.4	$ 6.1	$ 27.2	$ 1.5	$ 56.1	$ 7.7	$ 29.4	$ 3.3
Operating Lease Liabilities									
Current Portion	Other Current Liabilities	$ 10.0	$ 2.3	$ 3.9	$ 1.5	$ 10.4	$ 2.2	$ 3.7	$ 1.7
Long-Term	Other Long-Term Liabilities	37.4	3.8	23.3	—	45.7	5.5	25.7	1.6
Total Operating Lease Liabilities		$ 47.4	$ 6.1	$ 27.2	$ 1.5	$ 56.1	$ 7.7	$ 29.4	$ 3.3
Finance Leases:									
Right-of-use-Assets, Net	Property, Plant and Equipment, Net	$ 76.6	$ 14.6	$ 2.6	$ 0.6	$ 61.9	$ 16.6	$ 2.8	$ —
Finance Lease Liabilities									
Current Portion	Other Current Liabilities	$ 24.5	$ 1.6	$ —	$ 0.1	$ 5.6	$ 1.5	$ —	$ —
Long-Term	Other Long-Term Liabilities	57.2	14.0	4.9	0.4	62.1	15.6	4.9	—
Total Finance Lease Liabilities		$ 81.7	$ 15.6	$ 4.9	$ 0.5	$ 67.7	$ 17.1	$ 4.9	$ —

The finance lease payments that NSTAR Electric will make over the next twelve months are entirely interest-related, due to escalating payments. As such, none of the finance lease payments over the next twelve months will reduce the finance lease liability.

As of December 31, 2024, the operating lease balances attributable to the Aquarion water distribution business were classified as Assets Held for Sale on the Eversource balance sheet. As of December 31, 2025, these assets were reclassified as Other Long-Term Assets on the Eversource balance sheet. For further information, see Note 24, "Assets Held for Sale."

Other information related to leases is as follows:

	As of December 31,							
	2025				2024			
	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Weighted-Average Remaining Lease Term (Years):								
Operating Leases	9	3	12	2	9	4	12	2
Finance Leases	9	7	16	4	12	8	17	—
Weighted-Average Discount Rate (Percentage):								
Operating Leases	4.1 %	5.3 %	4.2 %	5.1 %	4.1 %	5.2 %	4.2 %	5.2 %
Finance Leases	3.5 %	5.3 %	2.9 %	4.6 %	3.3 %	5.3 %	2.9 %	— %

(Millions of Dollars)				
For the Year Ended December 31, 2025	Eversource	CL&P	NSTAR Electric	PSNH
Cash Paid for Amounts Included in the Measurement of Lease Liabilities:				
Operating Cash Flows from Operating Leases	$ 12.8	$ 2.8	$ 5.0	$ 1.9
Operating Cash Flows from Finance Leases	2.8	0.9	0.7	—
Financing Cash Flows from Finance Leases	5.7	1.5	—	0.2
Supplemental Non-Cash Information on Lease Liabilities:				
Right-of-use-Assets Obtained in Exchange for New Operating Lease Liabilities	1.4	0.8	0.1	0.1
Right-of-use-Assets Obtained in Exchange for New Finance Lease Liabilities	19.7	—	—	0.7

(Millions of Dollars)				
For the Year Ended December 31, 2024	Eversource	CL&P	NSTAR Electric	PSNH
Cash Paid for Amounts Included in the Measurement of Lease Liabilities:				
Operating Cash Flows from Operating Leases	$ 14.5	$ 2.5	$ 4.9	$ 1.8
Operating Cash Flows from Finance Leases	2.6	0.7	0.7	—
Financing Cash Flows from Finance Leases	5.2	1.2	—	—
Supplemental Non-Cash Information on Lease Liabilities:				
Right-of-use-Assets Obtained in Exchange for New Operating Lease Liabilities	15.3	7.8	5.7	0.3
Right-of-use-Assets Obtained in Exchange for New Finance Lease Liabilities	0.3	—	—	—

(Millions of Dollars)				
For the Year Ended December 31, 2023	Eversource	CL&P	NSTAR Electric	PSNH
Cash Paid for Amounts Included in the Measurement of Lease Liabilities:				

Operating Cash Flows from Operating Leases	$	10.5	$	0.7	$	2.5	$	0.4
Operating Cash Flows from Finance Leases		2.0		—		0.6		—
Financing Cash Flows from Finance Leases		3.9		—		—		—
Supplemental Non-Cash Information on Lease Liabilities:								
Right-of-use-Assets Obtained in Exchange for New Operating Lease Liabilities		12.8		0.6		7.0		5.0
Right-of-use-Assets Obtained in Exchange for New Finance Lease Liabilities		18.5		18.3		—		—

As of December 31, 2025, there are no lease agreements for Eversource, CL&P, NSTAR Electric or PSNH which have been executed but have yet to commence and have not been recorded as right-of-use assets.
Future minimum lease payments, excluding variable costs, under long-term leases, as of December 31, 2025 are as follows:

	Operating Leases				Finance Leases			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Year Ending December 31,								
2026	$ 11.5	$ 2.6	$ 5.0	$ 1.5	$ 27.9	$ 2.4	$ 0.7	$ 0.2
2027	7.1	2.0	2.8	0.1	8.2	2.5	0.7	0.2
2028	6.8	1.9	2.8	—	7.5	2.6	0.7	0.2
2029	4.7	0.1	2.5	—	7.3	2.6	0.7	—
2030	4.3	—	2.5	—	7.3	2.6	0.7	—
Thereafter	22.0	0.1	19.6	0.1	43.1	6.2	9.6	—
Future lease payments	56.4	6.7	35.2	1.7	101.3	18.9	13.1	0.6
Less amount representing interest	9.0	0.6	8.0	0.2	19.6	3.3	8.2	0.1
Present value of future minimum lease payments	$ 47.4	$ 6.1	$ 27.2	$ 1.5	$ 81.7	$ 15.6	$ 4.9	$ 0.5

15. FAIR VALUE OF FINANCIAL INSTRUMENTS

The following methods and assumptions were used to estimate the fair value of each of the following financial instruments:

Preferred Stock, Long-Term Debt and Rate Reduction Bonds: The fair value of CL&P's and NSTAR Electric's preferred stock is based upon pricing models that incorporate interest rates and other market factors, valuations or trades of similar securities and cash flow projections. The fair value of long-term debt and RRB debt securities is based upon pricing models that incorporate quoted market prices for those issues or similar issues adjusted for market conditions, credit ratings of the respective companies and treasury benchmark yields. The fair values provided in the table below are classified as Level 2 within the fair value hierarchy. Carrying amounts and estimated fair values are as follows:

	Eversource		CL&P		NSTAR Electric		PSNH	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
As of December 31, 2025:								
Preferred Stock Not Subject to Mandatory Redemption	$ 155.6	$ 126.1	$ 116.2	$ 92.9	$ 43.0	$ 33.2	$ —	$ —
Long-Term Debt	28,265.4	27,055.5	5,110.1	4,844.7	5,945.6	5,752.6	2,031.3	1,874.8
Rate Reduction Bonds	324.1	320.2	—	—	—	—	324.1	320.2
As of December 31, 2024:								
Preferred Stock Not Subject to Mandatory Redemption	$ 155.6	$ 123.8	$ 116.2	$ 90.3	$ 43.0	$ 33.5	$ —	$ —
Long-Term Debt	26,704.8	24,791.4	5,111.1	4,705.8	5,094.9	4,759.4	1,732.1	1,529.7
Rate Reduction Bonds	367.3	352.1	—	—	—	—	367.3	352.1

Derivative Instruments and Marketable Securities: Derivative instruments and investments in marketable securities are carried at fair value. For further information, see Note 4, "Derivative Instruments," and Note 5, "Marketable Securities," to the financial statements.

See Note 1H, "Summary of Significant Accounting Policies – Fair Value Measurements," for the fair value measurement policy and the fair value hierarchy.

16. ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

The changes in accumulated other comprehensive income/(loss) by component, net of tax, are as follows:

	For the Year Ended December 31, 2025			For the Year Ended December 31, 2024		
Eversource *(Millions of Dollars)*	Qualified Cash Flow Hedging Instruments	Defined Benefit Plans	Total	Qualified Cash Flow Hedging Instruments	Defined Benefit Plans	Total
Balance as of January 1st	$ (0.4)	$ (26.1)	$ (26.5)	$ (0.4)	$ (33.3)	$ (33.7)
OCI Before Reclassifications	—	0.5	0.5	—	(2.5)	(2.5)
Amounts Reclassified from AOCI	—	5.5	5.5	—	9.7	9.7
Net OCI	—	6.0	6.0	—	7.2	7.2
Balance as of December 31st	$ (0.4)	$ (20.1)	$ (20.5)	$ (0.4)	$ (26.1)	$ (26.5)

Defined benefit plan OCI amounts before reclassifications relate to actuarial gains and losses that arose during the year and were recognized in AOCI. The unamortized actuarial gains and losses and prior service costs on the defined benefit plans are amortized from AOCI into Other Income, Net over the average future employee service period, and are reflected in amounts reclassified from AOCI. The related tax effects of the defined benefit plan OCI amounts before reclassifications recognized in AOCI was a net deferred tax liability of $0.1 million in 2025 and were net deferred tax assets of $0.4 million and $4.9 million in 2024 and 2023, respectively.

The following table sets forth the amounts reclassified from AOCI by component and the impacted line item on the statements of income:

	Amounts Reclassified from AOCI			
	For the Years Ended December 31,			
Eversource *(Millions of Dollars)*	2025	2024	2023	Statements of Income Line Item Impacted
Unrealized Loss on Marketable Securities	$ —	$ —	$ (1.6)	Other Income, Net
Tax Effect	—	—	0.4	Income Tax Expense
Unrealized Loss on Marketable Securities, Net of Tax	—	—	(1.2)	
Defined Benefit Plan Costs:				
Amortization of Actuarial Losses	(4.2)	(6.8)	(7.0)	Other Income, Net [1]
Amortization of Prior Service Cost	—	(0.3)	(0.3)	Other Income, Net [1]
Settlement Losses	(3.3)	(4.3)	(12.4)	Other Income, Net [1]
Total Defined Benefit Plan Costs	(7.5)	(11.4)	(19.7)	
Tax Effect	2.0	1.7	6.4	Income Tax Expense
Defined Benefit Plan Costs, Net of Tax	(5.5)	(9.7)	(13.3)	
Total Amounts Reclassified from AOCI, Net of Tax	$ (5.5)	$ (9.7)	$ (14.5)	

[1] These amounts are included in the computation of net periodic Pension, SERP and PBOP costs. See Note 1L, "Summary of Significant Accounting Policies – Other Income, Net" and Note 11A, "Employee Benefits – Pension Benefits and Postretirement Benefits Other Than Pension," for further information.

17. DIVIDEND RESTRICTIONS

Eversource parent's ability to pay dividends may be affected by certain state statutes, the ability of its subsidiaries to pay common dividends and the leverage restriction tied to its consolidated total indebtedness to total capitalization ratio requirement in its revolving credit agreements. Pursuant to the joint revolving credit agreement of Eversource, CL&P, PSNH, NSTAR Gas, Yankee Gas, EGMA and Aquarion Water Company of Connecticut, and to the NSTAR Electric revolving credit agreement, Eversource is required to maintain consolidated total indebtedness to total capitalization ratio of no greater than 70 percent at the end of each fiscal quarter and each other company is required to maintain consolidated total indebtedness to total capitalization ratio of no greater than 65 percent at the end of each fiscal quarter. As of December 31, 2025, all companies were in compliance with such covenant and in compliance with all such provisions of the revolving credit agreements that may restrict the payment of dividends as of December 31, 2025.

The Retained Earnings balances subject to dividend restrictions were $4.50 billion for Eversource, $2.93 billion for CL&P, $3.32 billion for NSTAR Electric and $903.0 million for PSNH as of December 31, 2025.
CL&P, NSTAR Electric and PSNH are subject to Section 305 of the Federal Power Act that makes it unlawful for a public utility to make or pay a dividend from any funds "properly included in its capital account." Management believes that this Federal Power Act restriction, as applied to CL&P, NSTAR Electric and PSNH, would not be construed or applied by the FERC to prohibit the payment of dividends from retained earnings for lawful and legitimate business purposes. In addition, certain state statutes may impose additional limitations on such companies and, including but not limited to, on NSTAR Gas, Yankee Gas, EGMA, and Aquarion's operating companies. Such state law restrictions do not restrict the payment of dividends from retained earnings or net income.

18. COMMON SHARES

The following table sets forth the Eversource parent common shares and the shares of common stock of CL&P, NSTAR Electric and PSNH that were authorized and issued, as well as the respective per share par values:

	Shares			
			Issued as of December 31,	
	Par Value	Authorized as of December 31, 2025 and 2024	2025	2024
Eversource	$ 5	410,000,000	382,854,501	375,724,367
CL&P	$ 10	24,500,000	6,035,205	6,035,205
NSTAR Electric	$ 1	100,000,000	200	200
PSNH	$ 1	100,000,000	301	301

Common Share Issuances: On May 30, 2025, Eversource entered into an equity distribution agreement pursuant to which it may offer and sell up to $1.2 billion of its common shares from time to time through an "at-the-market" (ATM) equity offering program. Eversource may issue and sell its common shares through its sales agents during the term of this agreement. Shares were offered in transactions on the New York Stock Exchange, in the over-the-counter market, through negotiated transactions or otherwise. Sales may be made at either market prices prevailing at the time of sale, at prices related to such prevailing market prices or at negotiated prices. In 2025, Eversource issued 7,130,134 common shares, which resulted in proceeds of $465.4 million, net of issuance costs. Eversource used the net proceeds received for general corporate purposes.

On May 11, 2022, Eversource entered into an equity distribution agreement pursuant to which it could offer and sell up to $1.2 billion of its common shares from time to time through an ATM equity offering program. In 2024, Eversource issued 15,740,294 common shares, which resulted in proceeds of $989.4 million, net of issuance costs. Eversource used the net proceeds received for general corporate purposes. Eversource completed the program in October 2024.

Treasury Shares: As of December 31, 2025 and 2024, there were 7,437,621 and 9,116,315 Eversource common shares held as treasury shares, respectively. As of December 31, 2025 and 2024, there were 375,416,880 and 366,608,052 Eversource common shares outstanding, respectively.

Eversource issues treasury shares to satisfy awards under the Company's incentive plans, shares issued under the dividend reinvestment and share purchase plan, and matching contributions under the Eversource 401k Plan. The issuance of treasury shares represents a non-cash transaction, as the treasury shares were used to fulfill Eversource's obligations that require the issuance of common shares.

19. PREFERRED STOCK NOT SUBJECT TO MANDATORY REDEMPTION

The CL&P and NSTAR Electric preferred stock is not subject to mandatory redemption and is presented as a noncontrolling interest of a subsidiary in Eversource's financial statements.

CL&P is authorized to issue up to 9,000,000 shares of preferred stock, par value $50 per share, and NSTAR Electric is authorized to issue 2,890,000 shares of preferred stock, par value $100 per share. Holders of preferred stock of CL&P and NSTAR Electric are entitled to receive cumulative dividends in preference to any payment of dividends on the common stock. Upon liquidation, holders of preferred stock of CL&P and NSTAR Electric are entitled to receive a liquidation preference before any distribution to holders of common stock in an amount equal to the par value of the preferred stock plus accrued and unpaid dividends. If the net assets were to be insufficient to pay the liquidation preference in full, then the net assets would be distributed ratably to all holders of preferred stock. The preferred stock of CL&P and NSTAR Electric is subject to optional redemption by the CL&P and NSTAR Electric Boards of Directors at any time.
Details of preferred stock not subject to mandatory redemption are as follows (in millions, except in redemption price and shares):

Series			Redemption Price Per Share	Shares Outstanding as of December 31, 2025	Shares Outstanding as of December 31, 2024	As of December 31, 2025	As of December 31, 2024
CL&P							
	$1.90	Series of 1947	$ 52.5	163,912	163,912	$ 8.2	$ 8.2
	$2.00	Series of 1947	$ 54.0	336,088	336,088	16.8	16.8
	$2.04	Series of 1949	$ 52.0	100,000	100,000	5.0	5.0
	$2.20	Series of 1949	$ 52.5	200,000	200,000	10.0	10.0
	3.90%	Series of 1949	$ 50.5	160,000	160,000	8.0	8.0
	$2.06	Series E of 1954	$ 51.0	200,000	200,000	10.0	10.0
	$2.09	Series F of 1955	$ 51.0	100,000	100,000	5.0	5.0
	4.50%	Series of 1956	$ 50.8	104,000	104,000	5.2	5.2
	4.96%	Series of 1958	$ 50.5	100,000	100,000	5.0	5.0
	4.50%	Series of 1963	$ 50.5	160,000	160,000	8.0	8.0
	5.28%	Series of 1967	$ 51.4	200,000	200,000	10.0	10.0
	$3.24	Series G of 1968	$ 51.8	300,000	300,000	15.0	15.0
	6.56%	Series of 1968	$ 51.4	200,000	200,000	10.0	10.0
Total CL&P				2,324,000	2,324,000	116.2	116.2
NSTAR Electric							
	4.25%	Series of 1956	$ 103.6	180,000	180,000	18.0	18.0
	4.78%	Series of 1958	$ 102.8	250,000	250,000	25.0	25.0
Total NSTAR Electric				430,000	430,000	43.0	43.0
Fair Value Adjustment due to Merger with NSTAR						(3.6)	(3.6)
Total Eversource - Noncontrolling Interest - Preferred Stock of Subsidiaries						$ 155.6	$ 155.6

20. COMMON SHAREHOLDERS' EQUITY AND NONCONTROLLING INTERESTS

Dividends on the preferred stock of CL&P and NSTAR Electric totaled $7.5 million for each of the years ended December 31, 2025, 2024 and 2023. These dividends were presented as Net Income Attributable to Noncontrolling Interests on the Eversource statements of income. Noncontrolling Interest – Preferred Stock of Subsidiaries on the Eversource balance sheets totaled $155.6 million as of December 31, 2025 and 2024. On the Eversource balance sheets, Common Shareholders' Equity was fully attributable to Eversource parent and Noncontrolling Interest – Preferred Stock of Subsidiaries was fully attributable to the noncontrolling interest.

For the years ended December 31, 2025, 2024 and 2023, there was no change in ownership of the common equity of CL&P and NSTAR Electric.

21. EARNINGS/(LOSS) PER SHARE

Basic earnings/(loss) per share is computed based upon the weighted average number of common shares outstanding during each period. Diluted earnings/(loss) per share is computed on the basis of the weighted average number of common shares outstanding plus the potential dilutive effect of certain share-based compensation awards as if they were converted into outstanding common shares. The dilutive effect of unvested RSU and performance share awards is calculated using the treasury stock method. RSU and performance share awards are included in basic weighted average common shares outstanding as of the date that all necessary vesting conditions have been satisfied.

For the years ended December 31, 2025, 2024 and 2023, there were no antidilutive share awards excluded from the computation of diluted EPS.
The following table sets forth the components of basic and diluted earnings per share:

Eversource *(Millions of Dollars, except share information)*	For the Years Ended December 31, 2025	2024	2023
Net Income/(Loss) Attributable to Common Shareholders	$ 1,692.4	$ 811.7	$ (442.2)
Weighted Average Common Shares Outstanding:			
Basic	370,852,601	357,482,965	349,580,638
Dilutive Effect	406,663	296,443	259,843
Diluted	371,259,264	357,779,408	349,840,481
Basic Earnings/(Loss) Per Common Share	$ 4.56	$ 2.27	$ (1.27)
Diluted Earnings/(Loss) Per Common Share	$ 4.56	$ 2.27	$ (1.26)

22. REVENUES

Revenue is recognized when promised goods or services (referred to as performance obligations) are transferred to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. A five-step model is used for recognizing and measuring revenue from contracts with customers, which includes identifying the contract with the customer, identifying the performance obligations promised within the contract, determining the transaction price (the amount of consideration to which the company expects to be entitled), allocating the transaction price to the performance obligations and recognizing revenue when (or as) the performance obligation is satisfied.

The following tables present operating revenues disaggregated by revenue source:

Eversource *(Millions of Dollars)*	For the Year Ended December 31, 2025: Electric Distribution	Natural Gas Distribution	Electric Transmission	Water Distribution	Other	Eliminations	Total
Revenues from Contracts with Customers							
Retail Tariff Sales							
Residential	$ 5,215.5	$ 1,474.9	$ —	$ 167.8	$ —	$ —	$ 6,858.2
Commercial	3,273.4	716.3	—	71.1	—	(8.9)	4,051.9
Industrial	421.6	210.0	—	4.8	—	(26.1)	610.3
Total Retail Tariff Sales Revenues	8,910.5	2,401.2	—	243.7	—	(35.0)	11,520.4
Wholesale Transmission Revenues	—	—	2,452.1	—	—	(1,786.8)	665.3
Wholesale Market Sales Revenues	1,004.7	184.0	—	4.4	—	—	1,193.1
Other Revenues from Contracts with Customers	88.3	5.8	14.4	2.6	1,732.7	(1,729.5)	114.3
Total Revenues from Contracts with Customers	10,003.5	2,591.0	2,466.5	250.7	1,732.7	(3,551.3)	13,493.1
Alternative Revenue Programs	17.2	40.8	(183.7)	(15.0)	—	171.2	30.5
Other Revenues	18.9	3.0	0.5	1.2	—	—	23.6
Total Operating Revenues	$ 10,039.6	$ 2,634.8	$ 2,283.3	$ 236.9	$ 1,732.7	$ (3,380.1)	$ 13,547.2

Eversource *(Millions of Dollars)*	For the Year Ended December 31, 2024: Electric Distribution	Natural Gas Distribution	Electric Transmission	Water Distribution	Other	Eliminations	Total
Revenues from Contracts with Customers							
Retail Tariff Sales							
Residential	$ 4,904.8	$ 1,129.1	$ —	$ 150.4	$ —	$ —	$ 6,184.3
Commercial	2,973.3	588.0	—	70.3	—	(7.7)	3,623.9
Industrial	389.0	172.5	—	4.7	—	(22.4)	543.8
Total Retail Tariff Sales Revenues	8,267.1	1,889.6	—	225.4	—	(30.1)	10,352.0
Wholesale Transmission Revenues	—	—	2,032.4	—	—	(1,529.3)	503.1
Wholesale Market Sales Revenues	658.9	161.9	—	4.2	—	—	825.0
Other Revenues from Contracts with Customers	92.2	5.1	13.9	3.8	1,701.3	(1,694.6)	121.7

Total Revenues from Contracts with Customers	9,018.2	2,056.6	2,046.3	233.4	1,701.3	(3,254.0)	11,801.8
Alternative Revenue Programs	28.7	44.5	74.2	(5.3)	—	(67.2)	74.9
Other Revenues	19.6	2.8	0.5	1.2	—	—	24.1
Total Operating Revenues	$ 9,066.5	$ 2,103.9	$ 2,121.0	$ 229.3	$ 1,701.3	$ (3,321.2)	$ 11,900.8

	For the Year Ended December 31, 2023						
Eversource (Millions of Dollars)	Electric Distribution	Natural Gas Distribution	Electric Transmission	Water Distribution	Other	Eliminations	Total
Revenues from Contracts with Customers							
Retail Tariff Sales							
Residential	$ 5,054.2	$ 1,145.4	$ —	$ 144.7	$ —	$ —	$ 6,344.3
Commercial	2,893.2	637.7	—	69.8	—	(4.8)	3,595.9
Industrial	352.4	186.8	—	4.5	—	(19.7)	524.0
Total Retail Tariff Sales Revenues	8,299.8	1,969.9	—	219.0	—	(24.5)	10,464.2
Wholesale Transmission Revenues	—	—	1,777.5	—	—	(1,310.5)	467.0
Wholesale Market Sales Revenues	625.0	206.7	—	3.9	—	—	835.6
Other Revenues from Contracts with Customers	82.6	5.6	18.9	8.1	1,636.6	(1,628.0)	123.8
Total Revenues from Contracts with Customers	9,007.4	2,182.2	1,796.4	231.0	1,636.6	(2,963.0)	11,890.6
Alternative Revenue Programs	(54.3)	35.5	118.9	0.4	—	(106.5)	(6.0)
Other Revenues	20.4	4.0	0.6	1.1	—	—	26.1
Total Operating Revenues	$ 8,973.5	$ 2,221.7	$ 1,915.9	$ 232.5	$ 1,636.6	$ (3,069.5)	$ 11,910.7

	For the Years Ended December 31,								
	2025			2024			2023		
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Revenues from Contracts with Customers									
Retail Tariff Sales									
Residential	$ 2,716.1	$ 1,802.6	$ 696.8	$ 2,493.7	$ 1,771.8	$ 639.3	$ 2,597.8	$ 1,691.0	$ 765.4
Commercial	1,263.9	1,650.0	361.7	1,164.8	1,466.7	343.6	1,082.1	1,442.3	369.6
Industrial	175.4	143.3	102.9	164.2	118.1	106.7	137.2	123.2	92.0
Total Retail Tariff Sales Revenues	4,155.4	3,595.9	1,161.4	3,822.7	3,356.6	1,089.6	3,817.1	3,256.5	1,227.0
Wholesale Transmission Revenues	1,037.8	901.1	513.2	870.8	794.1	367.5	794.7	692.0	290.8
Wholesale Market Sales Revenues	801.3	169.6	33.8	491.9	131.1	35.9	429.1	131.8	64.1
Other Revenues from Contracts with Customers	36.1	46.5	22.5	36.7	50.2	21.2	36.7	49.1	18.1
Total Revenues from Contracts with Customers	6,030.6	4,713.1	1,730.9	5,222.1	4,332.0	1,514.2	5,077.6	4,129.4	1,600.0
Alternative Revenue Programs	(79.2)	(4.9)	(82.4)	45.4	36.7	20.8	66.8	(52.0)	49.8
Other Revenues	6.8	9.7	2.9	9.0	8.5	2.6	9.6	8.4	3.0
Eliminations	(717.2)	(731.3)	(275.0)	(661.5)	(656.3)	(243.1)	(575.2)	(570.3)	(204.9)
Total Operating Revenues	$ 5,241.0	$ 3,986.6	$ 1,376.4	$ 4,615.0	$ 3,720.9	$ 1,294.5	$ 4,578.8	$ 3,515.5	$ 1,447.9

Retail Tariff Sales: Regulated utilities provide products and services to their regulated customers under rates, pricing, payment terms and conditions of service, regulated by each state regulatory agency. The arrangement whereby a utility provides commodity service to a customer for a price approved by the respective state regulatory commission is referred to as a tariff sale contract, and the tariff governs all aspects of the provision of regulated services by utilities. The majority of revenue for Eversource, CL&P, NSTAR Electric and PSNH is derived from regulated retail tariff sales for the sale and distribution of electricity, natural gas and water to residential, commercial and industrial retail customers.

The utility's performance obligation for the regulated tariff sales is to provide electricity, natural gas or water to the customer as demanded. The promise to provide the commodity represents a single performance obligation, as it is a promise to transfer a series of distinct goods or services that are substantially the same and that have the same pattern of transfer to the customer. Revenue is recognized over time as the customer simultaneously receives and consumes the benefits provided by the utility, and the utility satisfies its performance obligation. Revenue is recognized based on the output method as there is a directly observable output to the customer (electricity, natural gas or water units delivered to the customer and immediately consumed). Each Eversource utility is entitled to be compensated for performance completed to date (service taken by the customer) until service is terminated.

In regulated tariff sales, the transaction prices are the rates approved by the respective state regulatory commissions. In general, rates can only be changed through formal proceedings with the state regulatory commissions. These rates are designed to recover the costs to provide service to customers and include a return on investment. Regulatory commission-approved tracking mechanisms are included in these rates and are also used to recover, on a fully-reconciling basis, certain costs, such as the procurement of energy supply, state mandated energy purchase agreements, retail transmission charges, energy efficiency program costs, net metering for distributed generation, and restructuring and stranded costs, among others. These tracking mechanisms result in rates being changed periodically to ensure recovery of actual costs incurred and the refund of any overcollection of costs.

Electric customers may elect to purchase electricity from each Eversource electric utility or may contract separately with a competitive third-party supplier. Certain eligible natural gas customers may elect to purchase natural gas from each Eversource natural gas utility or may contract separately with a gas supply operator. Revenue is not recorded for the sale of the electricity or the natural gas commodity to customers who have contracted separately with these suppliers, only the delivery to a customer, as the utility is acting as an agent on behalf of the supplier.

Wholesale Transmission Revenues: The Eversource electric transmission-owning companies (CL&P, NSTAR Electric and PSNH) each own and maintain transmission facilities that are part of an interstate power transmission grid over which electricity is transmitted throughout New England. CL&P, NSTAR Electric and PSNH, as well as most other New England utilities, are parties to a series of agreements that provide for coordinated planning and operation of the region's transmission facilities and the rules by which they acquire transmission services. The Eversource electric transmission-owning companies have a combination of FERC-approved regional and local formula rates that are designed to work in tandem to recover all their transmission costs. These rates are part of the ISO-NE Tariff. Regional rates recover the costs of higher voltage transmission facilities that benefit the region and are collected from all New England transmission customers, including the Eversource distribution businesses. Eversource's local rates generally recover the costs of transmission facilities that do not provide a benefit to the region, and are collected from Eversource's distribution businesses and other transmission customers. The distribution businesses of Eversource, in turn, recover the FERC approved charges from retail customers through annual tracking mechanisms, which are retail tariff sales.

The utility's performance obligation for regulated wholesale transmission sales is to provide transmission services to the customer as demanded. The promise to provide transmission service represents a single performance obligation. The transaction prices are the transmission rate formulas as defined by the ISO-NE Tariff and are regulated and established by FERC. Wholesale transmission revenue is recognized over time as the performance obligation is completed, which occurs as transmission services are provided to customers. The revenue is recognized based on the output method. Each Eversource utility is entitled to be compensated for performance completed to date (e.g., use of the transmission system by the customer).

Wholesale Market Sales Revenues: Wholesale market sales transactions include sales of energy and energy-related products into the ISO-NE wholesale electricity market, sales of natural gas to third-party marketers, and the sale of RECs to various counterparties. ISO-NE oversees the region's wholesale electricity market and administers the transactions and terms and conditions, including payment terms, which are established in the ISO-NE tariff, between the buyers and sellers in the market. Pricing is set by the wholesale market. The wholesale transactions in the ISO-NE market occur on a day-ahead basis or a real-time basis (daily) and are, therefore, short-term. Transactions are tracked and reported by ISO-NE net by the hour, which is the net hourly position of energy sales and purchases by each market participant. The performance obligation for ISO-NE energy transactions is defined to be the net by hour transaction. Revenue is recognized when the performance obligation for these energy sales transactions is satisfied, which is when the sale occurs and the energy is transferred to the customer. For sales of natural gas, transportation, and natural gas pipeline capacity to third-party marketers, revenue is recognized when the performance obligation is satisfied at the point in time the sale occurs and the natural gas or related product is transferred to the marketer. RECs are sold to various counterparties, and revenue is recognized when the performance obligation is satisfied upon transfer of title to the customer through the New England Power Pool Generation Information System. Wholesale transactions also include the sale of CL&P's, NSTAR Electric's and PSNH's transmission rights associated with their proportionate equity ownership share in the transmission lines of the Hydro-Québec system in Canada.

Other Revenues from Contracts with Customers: Other revenues from contracts with customers primarily include property rentals that are not deemed leases. These revenues are generally recognized on a straight-line basis over time as the service is provided to the customer. Other revenues also include revenues from Eversource's service company, which is eliminated in consolidation.

Alternative Revenue Programs: In accordance with accounting guidance for rate-regulated operations, certain of Eversource's utilities' rate making mechanisms qualify as alternative revenue programs (ARPs) if they meet specified criteria, in which case revenues may be recognized prior to billing based on allowed levels of collection in rates. Eversource's utility companies recognize revenue and record a regulatory asset or liability once the condition or event allowing for the automatic adjustment of future rates occurs. ARP revenues include both the recognition of the deferral adjustment to ARP revenues, when the regulator-specified condition or event allowing for additional billing or refund has occurred, and an equal and offsetting reversal of the ARP deferral to revenues as those amounts are reflected in the price of service in subsequent periods.
Eversource's ARPs include the revenue decoupling mechanism, the annual reconciliation adjustment to transmission formula rates, and certain capital tracker mechanisms. Certain Eversource electric, natural gas and water companies, including CL&P and NSTAR Electric, have revenue decoupling mechanisms approved by a regulatory commission (decoupled companies). Decoupled companies' distribution revenues are not directly based on sales volumes. The decoupled companies reconcile their annual base distribution rate recovery to pre-established levels of baseline distribution delivery service revenues, with any difference between the allowed level of distribution revenue and the actual amount realized adjusted through subsequent rates. The transmission formula rates provide for the annual reconciliation and recovery or refund of estimated costs to actual costs. The financial impacts of differences between actual and estimated costs are deferred for future recovery from, or refund to, transmission customers. This transmission deferral reconciles billed transmission revenues to the revenue requirement for our transmission businesses.

Other Revenues: Other Revenues include certain fees charged to customers that are not considered revenue from contracts with customers. Other revenues also include lease revenues under lessor accounting guidance of $3.1 million ($0.5 million at CL&P and $1.8 million at NSTAR Electric), $2.5 million ($0.5 million at CL&P and $1.2 million at NSTAR Electric), and $4.6 million, ($0.7 million at CL&P and $2.5 million at NSTAR Electric) for the years ended December 31, 2025, 2024 and 2023, respectively.

Intercompany Eliminations: Intercompany eliminations are primarily related to the Eversource electric transmission revenues that are derived from ISO-NE regional transmission charges to the distribution businesses of CL&P, NSTAR Electric and PSNH that recover the costs of the wholesale transmission business, and revenues from Eversource's service company. Intercompany revenues and expenses between the Eversource wholesale transmission businesses and the Eversource distribution businesses and from Eversource's service company are eliminated in consolidation and included in "Eliminations" in the tables above.

Receivables: Receivables, Net on the balance sheet primarily includes trade receivables from retail customers and customers related to wholesale transmission contracts, wholesale market sales, sales of RECs, and property rentals. In general, retail tariff customers and wholesale transmission customers are billed monthly, and the payment terms are generally due and payable upon receipt of the bill.

Unbilled Revenues: Unbilled Revenues on the balance sheet represent estimated amounts due from retail customers for electricity, natural gas or water delivered to customers but not yet billed. The utility company has satisfied its performance obligation and the customer has received and consumed the commodity as of the balance sheet date, and therefore, the utility company records revenue for those services in the period the services were provided. Only the passage of time is required before the company is entitled to payment for the satisfaction of the performance obligation. Payment from customers is due monthly as services are rendered and amounts are billed. Actual amounts billed to customers when meter readings become available may vary from the estimated amount.

Unbilled revenues are recognized by allocating estimated unbilled sales volumes to the respective customer classes, and then applying an estimated rate by customer class to those sales volumes. Unbilled revenue estimates reflect seasonality, weather, customer usage patterns, customer rates in effect for customer classes, and the timing of customer billing. The companies that have a decoupling mechanism record a regulatory deferral to reflect the actual allowed amount of revenue associated with their respective decoupled distribution rate design.

Practical Expedients: Eversource has elected practical expedients in the accounting guidance that allow the company to record revenue in the amount that the company has a right to invoice, if that amount corresponds directly with the value to the customer of the company's performance to date, and not to disclose related unsatisfied performance obligations. Retail and wholesale transmission tariff sales fall into this category, as these sales are recognized as revenue in the period the utility provides the service and completes the performance obligation, which is the same as the monthly amount billed to customers. There are no other material revenue streams for which Eversource has unsatisfied performance obligations.

23. SEGMENT INFORMATION

Eversource is organized into the Electric Distribution, Electric Transmission, Natural Gas Distribution and Water Distribution reportable segments and Other based on a combination of factors, including the characteristics of each segments' services, the sources of operating revenues and expenses and the regulatory environment in which each segment operates. The Electric Distribution segment consists of the rate-regulated distribution businesses of CL&P, NSTAR Electric and PSNH, and includes the results of NSTAR Electric's solar power facilities. The Electric Transmission segment consists of the rate-regulated electric transmission businesses of CL&P, NSTAR Electric and PSNH. The Natural Gas Distribution segment consists of the rate-regulated businesses of Yankee Gas, NSTAR Gas and EGMA. The Water Distribution segment consists of the rate-regulated business of Aquarion. These reportable segments represent substantially all of Eversource's total consolidated revenues. Revenues from the sale of electricity, natural gas and water primarily are derived from residential, commercial and industrial customers and are not dependent on any single customer.

Eversource's reportable segments are determined based upon the level at which Eversource's chief operating decision maker assesses performance and makes decisions about the allocation of company resources. The chief operating decision maker uses the net income of each reportable segment to evaluate return generated from assets and decide how to reinvest profits and allocate resources, to monitor budget-to-actual results, in the planning and forecasting process, in determining compensation achievement, and in benchmarking to Eversource's peers. Eversource's chief operating decision maker is its chief executive officer. The accounting policies of the segments are the same as those described in the summary of significant accounting policies.

The remainder of Eversource's operations is presented as Other in the tables below and primarily consists of 1) the equity in earnings of Eversource parent from its subsidiaries and intercompany interest income, both of which are eliminated in consolidation, and interest expense related to the debt of Eversource parent, 2) the revenues and expenses of Eversource Service, most of which are eliminated in consolidation, 3) the operations of CYAPC and YAEC, 4) the results of other unregulated subsidiaries, which are not part of its core business, and 5) Eversource parent's equity ownership interests that are not consolidated, which primarily included the offshore wind investments until sale of the three offshore wind projects in 2024 and a natural gas pipeline owned by Enbridge, Inc.

In the ordinary course of business, Yankee Gas, NSTAR Gas and EGMA purchase natural gas transmission services from the Enbridge, Inc. natural gas pipeline project described above. These affiliate transaction costs total $77.7 million annually and are classified as Purchased Power, Purchased Natural Gas and Transmission on the Eversource statements of income.

Each of Eversource's subsidiaries, including CL&P, NSTAR Electric and PSNH, has one reportable segment.

Cash flows used for investments in plant included in the segment information below are cash capital expenditures that do not include amounts incurred on capital projects but not yet paid, cost of removal, AFUDC related to equity funds, and the capitalized and deferred portions of pension and PBOP income/expense. Eversource's segment information is as follows:

	For the Year Ended December 31, 2025						
Eversource *(Millions of Dollars)*	Electric Distribution	Natural Gas Distribution	Electric Transmission	Water Distribution	Other	Eliminations	Total
Operating Revenues	$ 10,039.6	$ 2,634.8	$ 2,283.3	$ 236.9	$ 1,732.7	$ (3,380.1)	$ 13,547.2
Depreciation and Amortization	(1,435.1)	(279.7)	(437.1)	(46.8)	(220.1)	14.3	(2,404.5)
Operations and Maintenance [1]							
Operations, Excluding Storm Costs	(432.8)	(181.5)	(152.0)				
Corporate Shared Services	(443.4)	(114.2)	(77.0)				
Storm Costs	(89.2)	—	—				
Employee Benefits	(266.6)	(89.3)	(58.6)				
Uncollectible Expense	(167.2)	(74.3)	—				
Other	(170.8)	(46.6)	(79.7)				
Total Operations and Maintenance	(1,570.0)	(505.9)	(367.3)	(95.6)	(1,285.2)	1,750.2	(2,073.8)
Purchased Power, Purchased Natural Gas and Transmission, Other Taxes and Energy Efficiency [2]	(6,048.0)	(1,314.4)	(302.2)	(27.4)	(3.9)	1,615.6	(6,080.3)
Operating Income	986.5	534.8	1,176.7	67.1	223.5	—	2,988.6
Interest Expense	(386.3)	(119.4)	(171.6)	(30.8)	(701.2)	166.0	(1,243.3)
Loss on Offshore Wind	—	—	—	—	(284.0)	—	(284.0)
Interest Income	98.2	26.8	0.4	0.1	166.0	(166.0)	125.5
Other Income, Net	155.9	30.5	40.9	6.1	1,943.5	(1,923.5)	253.4
Income Tax (Expense)/Benefit	(182.6)	(112.2)	(266.8)	1.7	419.6	—	(140.3)
Net Income	671.7	360.5	779.6	44.2	1,767.4	(1,923.5)	1,699.9
Net Income Attributable to Noncontrolling Interests	(4.6)	—	(2.9)	—	—	—	(7.5)
Net Income Attributable to Common Shareholders	$ 667.1	$ 360.5	$ 776.7	$ 44.2	$ 1,767.4	$ (1,923.5)	$ 1,692.4
Total Assets (as of)	$ 34,858.1	$ 10,865.5	$ 17,193.9	$ 2,977.6	$ 29,743.3	$ (31,851.7)	$ 63,786.7
Cash Flows Used for Investments in Plant	$ 1,872.6	$ 834.6	$ 1,094.0	$ 165.3	$ 192.2	$ —	$ 4,158.7

	For the Year Ended December 31, 2024						
Eversource *(Millions of Dollars)*	Electric Distribution	Natural Gas Distribution	Electric Transmission	Water Distribution	Other	Eliminations	Total
Operating Revenues	$ 9,066.5	$ 2,103.9	$ 2,121.0	$ 229.3	$ 1,701.3	$ (3,321.2)	$ 11,900.8
Depreciation and Amortization	(934.7)	(216.6)	(405.1)	(32.3)	(198.7)	11.0	(1,776.4)
Operations and Maintenance [1]							
Operations, Excluding Storm Costs	(447.3)	(180.9)	(135.1)				
Corporate Shared Services	(457.1)	(106.1)	(74.6)				
Storm Costs	(76.8)	—	—				
Employee Benefits	(202.5)	(76.9)	(52.7)				
Uncollectible Expense	(182.8)	(48.4)	—				
Other	(135.9)	(29.2)	(71.1)				
Total Operations and Maintenance	(1,502.4)	(441.5)	(333.5)	(98.7)	(1,350.5)	1,713.7	(2,012.9)
Purchased Power, Purchased Natural Gas and Transmission, Other Taxes and Energy Efficiency [2]	(5,685.3)	(1,007.1)	(276.0)	(26.3)	(7.6)	1,596.5	(5,405.8)
Loss on Pending Sale of Aquarion	—	—	—	(297.0)	—	—	(297.0)
Operating Income/(Loss)	944.1	438.7	1,106.4	(225.0)	144.5	—	2,408.7
Interest Expense	(359.1)	(99.2)	(172.4)	(36.2)	(662.7)	218.3	(1,111.3)
Loss on Offshore Wind	—	—	—	—	(464.0)	—	(464.0)
Interest Income	114.6	23.2	0.3	0.1	218.3	(218.3)	138.2
Other Income, Net	134.7	22.4	50.5	7.2	1,416.9	(1,359.4)	272.3
Income Tax (Expense)/Benefit	(198.0)	(94.1)	(257.3)	0.2	124.5	—	(424.7)
Net Income/(Loss)	636.3	291.0	727.5	(253.7)	777.5	(1,359.4)	819.2
Net Income Attributable to Noncontrolling Interests	(4.6)	—	(2.9)	—	—	—	(7.5)
Net Income/(Loss) Attributable to Common Shareholders	$ 631.7	$ 291.0	$ 724.6	$ (253.7)	$ 777.5	$ (1,359.4)	$ 811.7
Total Assets (as of)	$ 32,031.9	$ 9,786.7	$ 16,070.9	$ 2,515.8	$ 29,041.1	$ (29,851.9)	$ 59,594.5
Cash Flows Used for Investments in Plant	$ 1,807.4	$ 934.5	$ 1,343.3	$ 161.8	$ 233.5	$ —	$ 4,480.5

	For the Year Ended December 31, 2023						
Eversource *(Millions of Dollars)*	Electric Distribution	Natural Gas Distribution	Electric Transmission	Water Distribution	Other	Eliminations	Total
Operating Revenues	$ 8,973.5	$ 2,221.7	$ 1,915.9	$ 232.5	$ 1,636.6	$ (3,069.5)	$ 11,910.7
Depreciation and Amortization	(18.2)	(214.2)	(371.2)	(56.0)	(158.8)	2.7	(815.7)
Operations and Maintenance [1]							
Operations, Excluding Storm Costs	(418.2)	(172.8)	(124.7)				
Corporate Shared Services	(397.2)	(103.0)	(62.5)				
Storm Costs	(71.1)	—	(1.3)				
Employee Benefits	(175.6)	(76.6)	(46.1)				
Uncollectible Expense	(161.9)	(64.8)	—				
Other	(167.9)	(27.5)	(57.4)				
Total Operations and Maintenance	(1,391.9)	(444.7)	(292.0)	(93.2)	(1,325.6)	1,651.7	(1,895.7)
Purchased Power, Purchased Natural Gas and Transmission, Other Taxes and Energy Efficiency [2]	(6,712.7)	(1,217.9)	(258.5)	(23.9)	(4.2)	1,417.2	(6,800.0)
Operating Income	850.7	344.9	994.2	59.4	148.0	2.1	2,399.3
Interest Expense	(291.7)	(85.7)	(163.7)	(38.5)	(425.3)	149.5	(855.4)
Loss on Offshore Wind	—	—	—	—	(2,167.0)	—	(2,167.0)
Interest Income	74.5	18.2	0.4	—	150.6	(149.5)	94.2
Other Income/(Loss), Net	136.2	20.4	41.2	5.9	(261.8)	312.0	253.9
Income Tax (Expense)/Benefit	(157.1)	(73.0)	(225.8)	6.3	289.9	—	(159.7)
Net Income/(Loss)	612.6	224.8	646.3	33.1	(2,265.6)	314.1	(434.7)
Net Income Attributable to Noncontrolling Interests	(4.6)	—	(2.9)	—	—	—	(7.5)
Net Income/(Loss) Attributable to Common Shareholders	$ 608.0	$ 224.8	$ 643.4	$ 33.1	$ (2,265.6)	$ 314.1	$ (442.2)
Cash Flows Used for Investments in Plant	$ 1,668.1	$ 844.1	$ 1,406.3	$ 167.0	$ 251.3	$ —	$ 4,336.8

(1) The significant expense categories and amounts align with the segment-level information that is regularly provided to the chief operating decision maker. Costs of the operations organization include labor and overtime, outside services, vehicles, vegetation management, employee expenses, fees and payments, regulatory assessments, and materials, partially offset by reimbursements. Corporate shared services include corporate centralized functions. Costs within these corporate functions primarily include labor, services by vendors, fees and payments, insurance, and regulatory assessments. Other includes information technology system depreciation at Eversource Service charged to the operating businesses, as well as storm funding, capitalization and various other corporate costs. The segment-level operating expense for information technology system depreciation is eliminated and reflected in depreciation in Eversource's consolidation.
For the water distribution segment, the chief operating decision maker is provided with total operations and maintenance expense information to manage its operations. Operations and maintenance expenses primarily include employee costs, benefits, and outside services.

(2) Other segment line items for the electric distribution, electric transmission and natural gas distribution segments primarily include purchased power, purchased natural gas and transmission, taxes other than income taxes including property, payroll-related and Connecticut gross earnings taxes, and energy efficiency program expenses. Other segment line items for the water distribution business primarily include taxes other than income taxes.

24. ASSETS HELD FOR SALE

In December 2024, Eversource obtained approval from its Board of Trustees to sell the Aquarion water distribution business. On January 27, 2025, Eversource entered into a definitive agreement to sell Aquarion to the Aquarion Water Authority (AWA), a quasi-public corporation and political subdivision of the State of Connecticut and a standalone, newly created water authority alongside the South Central Connecticut Regional Water Authority. In June 2024, a Connecticut law chartered AWA and enabled it to acquire, own and operate Aquarion as a not-for-profit water authority. Subject to certain closing adjustments, the aggregate enterprise value of the sale is approximately $2.4 billion in cash, which included approximately $1.6 billion for the equity and $800 million of net debt that will either be extinguished at closing or transferred to the buyer. The sale requires approval by PURA and the DPU, as well as other approvals pursuant to the Hart-Scott-Rodino Antitrust Improvements Act, for which the relevant waiting period has expired, as well as other customary closing conditions. Regulatory approvals in New Hampshire and Maine were received. Eversource plans to use the net proceeds from sale to pay down parent company debt.

On November 19, 2025, PURA denied the application to approve the sale, finding that the transaction did not meet managerial suitability and responsibility requirements due to concerns with governance and oversight structure over Aquarion and its consumer advocate. On December 2, 2025, the denial was appealed to the Connecticut Superior Court. On January 15, 2026, the Court issued its decision, sustaining the appeal and remanding back to PURA, finding that PURA acted illegally in denying the application as those disputed governance elements were mandated under Connecticut law. The Court upheld that operational aspects of the consumer advocate were within PURA's statutory authority and regulatory discretion. A final decision is expected by PURA on March 25, 2026.

The assets and liabilities of the Aquarion water distribution business had previously met the criteria to be classified as held for sale as of December 31, 2024 and were classified separately as current or long-term assets and liabilities held for sale on the Eversource balance sheet. As Eversource had concluded this was the sale of a business, all goodwill held by the water distribution reporting unit was included in the carrying amount of the business and was also classified within assets held for sale at that time. Aquarion's long-term debt was expected to be repaid by Eversource upon closing and was therefore excluded from liabilities held for sale. Assets and liabilities classified as held for sale are measured at the lower of carrying amount or fair value less costs to sell. Closing of the transaction includes the finalization of working capital and other closing adjustments as well as final closing costs, which could result in a loss recorded at the time of sale. The water distribution business did not meet the criteria to be presented as a discontinued operation.

In the fourth quarter of 2024, upon classifying the assets and liabilities as held for sale, Eversource concluded that the likely sale of Aquarion at a loss resulted in the requirement to test water distribution goodwill for impairment. Eversource performed an impairment test by comparing the fair value of the business to its carrying value and recorded a goodwill impairment of $297 million, as the estimated fair value of the business based on the anticipated sale was less than the carrying value. The fair value included future cash outflows of approximately $140 million of estimated income taxes as a result of the transaction. The goodwill impairment charge is presented separately within Operating Income on the Eversource statement of income for the year ended December 31, 2024.

Based on PURA's November 19, 2025 denial of the sale and the uncertainty of the ultimate outcome, the Aquarion water distribution business no longer met the criteria to be classified as held for sale and its assets and liabilities were reclassified as held and used on the balance sheet as of December 31, 2025. The reclassification to held and used did not result in an adjustment to Aquarion's carrying values.
As of December 31, 2024, the major classes of Aquarion's assets and liabilities presented in current and long-term Assets Held for Sale and Liabilities Held for Sale on the Eversource balance sheet, which are included in the Water Distribution reportable segment, were as follows:

(Millions of Dollars)	
Restricted Cash	$ 5.8
Receivables, Net	14.4
Unbilled Revenues	11.5
Prepayments and Other Current Assets	24.6
Total Current Assets Held for Sale	$ 56.3
Property, Plant and Equipment, Net	$ 1,885.2
Regulatory Assets	51.2
Goodwill	662.5
Other Long-Term Assets	12.2
Total Long-Term Assets Held for Sale	$ 2,611.1
Accounts Payable	$ 24.2
Other Current Liabilities	28.4
Total Current Liabilities Held for Sale	$ 52.6
Regulatory Liabilities	$ 132.2
Other Long-Term Liabilities	266.7
Total Long-Term Liabilities Held for Sale	$ 398.9

For the years ended December 31, 2024 and 2023, pre-tax income associated with the held for sale water distribution business (excluding the goodwill impairment recognized in 2024) was $43.1 million and $26.8 million, respectively.

25. GOODWILL

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. The following table presents Eversource's goodwill by reportable segment:

(Millions of Dollars)	Electric Distribution	Electric Transmission	Natural Gas Distribution	Water Distribution	Total
Balance as of January 1, 2024	$ 2,543.6	$ 576.8	$ 451.0	$ 960.7	$ 4,532.1
Sale of Water Unregulated Business and Water Acquisition, net	—	—	—	(1.2)	(1.2)
Water Goodwill Impairment	—	—	—	(297.0)	(297.0)
Water Goodwill Reclassified as Held for Sale	—	—	—	(662.5)	(662.5)
Balance as of December 31, 2024	$ 2,543.6	$ 576.8	$ 451.0	$ —	$ 3,571.4
Measurement Period Adjustment	—	—	—	(0.1)	(0.1)
Water Goodwill Reclassified from Held for Sale	—	—	—	662.5	662.5
Balance as of December 31, 2025	$ 2,543.6	$ 576.8	$ 451.0	$ 662.4	$ 4,233.8

In 2024, Eversource completed the sale of its unregulated water business resulting in a reduction to goodwill of $5.4 million and completed a water acquisition resulting in the addition of $4.2 million of goodwill.

Goodwill is not amortized but is subject to an assessment for impairment at least annually and more frequently if indicators of impairment arise that would more likely than not reduce the fair value of Eversource's reporting units below their carrying amounts. Eversource's reporting units for the purpose of testing goodwill are Electric Distribution, Electric Transmission, Natural Gas Distribution and Water Distribution. These reporting units are consistent with the operating segments underlying the reportable segments identified in Note 23, "Segment Information," to the financial statements.

In assessing goodwill for impairment, an entity is permitted to first assess qualitatively whether it is more likely than not that goodwill impairment exists as of the annual impairment test date. If after performing the qualitative assessment it is determined that it is more likely than not that the fair value of a reporting unit is less than its carrying value (including goodwill), then a quantitative goodwill impairment test is performed. A quantitative impairment test is required only if it is concluded that it is more likely than not that a reporting unit's carrying value may not be recoverable. The quantitative assessment compares the estimated fair value of a reporting unit to its carrying amount, and to the extent the carrying amount exceeds the fair value, an impairment of goodwill is recognized for the excess up to the amount of goodwill allocated to the reporting unit. A resulting write-down, if any, would be charged to Operating Expenses.

In the fourth quarter of 2024, Eversource concluded that the likely sale of Aquarion at a loss resulted in the requirement to perform an interim goodwill impairment test for Water Distribution goodwill. Eversource compared the estimated fair value of the business from the anticipated transaction to its carrying value. Assumptions used in the valuation were the future cash flows from the sale, including approximately $140 million of estimated income tax impacts as a result of the transaction. Based on the interim impairment test as of December 31, 2024, Eversource recorded a goodwill impairment of $297.0 million to write down the carrying value of the Water Distribution reporting unit to its estimated fair value. The goodwill impairment charge is presented separately within Operating Income on the Eversource statement of income for the year ended December 31, 2024. The remaining goodwill held by the Water Distribution reporting unit was reclassified to Assets Held for Sale on the Eversource balance sheet as of December 31, 2024 and became part of the water distribution disposal group.

Eversource completed its annual goodwill impairment assessment for the Electric Distribution, Electric Transmission and Natural Gas Distribution reporting units as of October 1, 2025 and determined it was more likely than not that their fair value exceeded carrying value and no impairment existed. The annual goodwill assessment included a qualitative evaluation of multiple factors that impact the fair value of the reporting units, including general, macroeconomic and market conditions, and entity-specific assumptions that affect the future cash flows of the reporting units. Key considerations include discount rates, utility sector market performance and merger transaction multiples, the Company's share price and credit ratings, analyst reports, financial performance, cost and risk factors, internal estimates and projections of future cash flows and net income, long-term strategy, the timing and outcome of rate cases, and recent regulatory and legislative proceedings.

As of October 1, 2025, the goodwill of the Water Distribution reporting unit was classified within Assets Held for Sale, and the disposal group was carried at fair value less cost to sell. Based on PURA's November 19, 2025 denial of the Aquarion sale and the uncertainty of the ultimate outcome, the Aquarion water distribution business no longer met the criteria to be classified as held for sale. The goodwill held by the Water Distribution reporting unit of $662.5 million that was previously classified within Assets Held for Sale has been reclassified to Goodwill on the Eversource balance sheet as of December 31, 2025. In the fourth quarter of 2025, Eversource performed a goodwill impairment test for Water Distribution goodwill and determined that no impairment existed.

26. ADDITIONAL EXCESS ADIT DISCLOSURE REQUIREMENTS

As of December 31, 2025, of the total excess unamortized ADIT balance at CL&P of $933,329,049, the balance related to CL&P Transmission was $324,487,287.

As of December 31, 2025, of the total excess unamortized ADIT balance at NSTAR East of $633,259,674 and NSTAR West of $214,641,842, the balance related to NSTAR East Transmission was $202,815,042 and the balance related to NSTAR West Transmission was $137,563,997.

As of December 31, 2025, of the total excess unamortized ADIT balance at PSNH of $319,794,910 the balance related to PSNH Transmission was $103,063,209.

27. ADOPTION OF FERC ORDER NO. 898

Effective January 1, 2025, the Company adopted the accounting and reporting requirements of FERC Order No. 898, Accounting and Reporting Treatment of Certain Renewable Energy Assets. Order No. 898 amended the Uniform System of Accounts to establish new production plant subfunctions and related accounts for renewable generation and energy storage assets and to codify the accounting treatment for environmental credits. Upon adoption of Order No. 898, certain electric plant balances previously classified within Other Production Plant were reclassified to the applicable renewable production plant accounts. These reclassifications were recorded prospectively and did not result in any change to total electric plant balances, net income or cash flows for the period.

28. SUBSEQUENT EVENT

On March 19, 2026, FERC issued Opinion No. 594 in the NETO ROE proceedings, attempting to resolve all four pending complaints dating back to 2011 and respond to the Court's April 14, 2017 decision vacating FERC's prior decision in the first complaint, which found that the FERC had failed to (1) make an explicit, reasoned finding that the existing 11.14 percent base ROE was unjust and unreasonable before imposing a replacement ROE, and (2) adequately justify placing the ROE at the midpoint of the upper half of the zone of reasonableness. In Opinion No. 594, FERC applied a revised ROE methodology that it believes is consistent with its 2024 ROE Order on remand to the Midcontinent ISO (MISO) transmission owners, to satisfy the first step in the FERC process to revise the ROE in a Section 206 proceeding by finding the NETOs' base ROE of 11.14 percent is unjust and unreasonable. FERC then found the just and reasonable replacement base ROE to be 9.57 percent with an incentive cap of 12.09 percent for the first complaint period (October 1, 2011 – December 31, 2012) and applied this same ROE prospectively, effective October 16, 2014, the date of the first complaint order vacated by the Court. FERC directed the NETOs to issue refunds with interest for the applicable refund periods. This decision decreases the allowed base ROE of 10.57 percent with an incentive cap of 11.74 to a base ROE of 9.57 percent with an incentive cap of 12.09 percent. The second, third and fourth NETO ROE complaints were dismissed as part of the decision and FERC did not direct any refunds for the periods associated with those proceedings.
On April 14, 2026, FERC granted an extension of the refund deadline to May 20, 2027. On April 14, 2026, Eversource and Avangrid filed a joint motion requesting a stay of the retroactive refund obligation applicable to the period October 16, 2014 through March 19, 2026 (retroactive refund period) with the DC Circuit Court.

Management is currently evaluating the financial impacts to the first quarter 2026 financial statements as a result of this order. Such impacts could be material. See Note 13E, "Commitments and Contingencies - FERC ROE Complaints," for further information regarding the FERC ROE complaints.

GLOSSARY OF TERMS

The following is a glossary of abbreviations and acronyms that are found in this report:

Current or former Eversource Energy companies, segments or investments:

Eversource, ES or the Company	Eversource Energy and subsidiaries
Eversource parent or ES parent	Eversource Energy, a public utility holding company
ES parent and other companies	ES parent and other companies are comprised of Eversource parent, Eversource Service, and other subsidiaries, which primarily includes our unregulated businesses, The Rocky River Realty Company (a real estate subsidiary), the consolidated operations of CYAPC and YAEC, and Eversource parent's equity ownership interests that are not consolidated
CL&P	The Connecticut Light and Power Company
NSTAR Electric	NSTAR Electric Company
PSNH	Public Service Company of New Hampshire
PSNH Funding	PSNH Funding LLC 3, a bankruptcy remote, special purpose, wholly-owned subsidiary of PSNH
NSTAR Gas	NSTAR Gas Company
EGMA	Eversource Gas Company of Massachusetts
Yankee Gas	Yankee Gas Services Company
Aquarion	Aquarion Company and its subsidiaries
HEEC	Harbor Electric Energy Company, a wholly-owned subsidiary of NSTAR Electric
Eversource Service	Eversource Energy Service Company
CYAPC	Connecticut Yankee Atomic Power Company
MYAPC	Maine Yankee Atomic Power Company
YAEC	Yankee Atomic Electric Company
Yankee Companies	CYAPC, YAEC and MYAPC
Regulated companies	The Eversource regulated companies are comprised of the electric distribution and transmission businesses of CL&P, NSTAR Electric and PSNH, the natural gas distribution businesses of Yankee Gas, NSTAR Gas and EGMA, Aquarion's water distribution businesses, and the solar power facilities of NSTAR Electric
Regulators and Government Agencies:	
DEEP	Connecticut Department of Energy and Environmental Protection
DOE	U.S. Department of Energy
DOER	Massachusetts Department of Energy Resources
DPU	Massachusetts Department of Public Utilities
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
ISO-NE	ISO New England, Inc., the New England Independent System Operator
MA DEP	Massachusetts Department of Environmental Protection
NHPUC	New Hampshire Public Utilities Commission
PURA	Connecticut Public Utilities Regulatory Authority
SEC	U.S. Securities and Exchange Commission
Other Terms and Abbreviations:	
ADIT	Accumulated Deferred Income Taxes
AFUDC	Allowance For Funds Used During Construction
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
Bcf	Billion cubic feet
CfD	Contract for Differences
CWIP	Construction Work in Progress
EDC	Electric distribution company
EDIT	Excess Deferred Income Taxes
EPS	Earnings Per Share
ERISA	Employee Retirement Income Security Act of 1974
ESOP	Employee Stock Ownership Plan
Eversource 2024 Form 10-K	The Eversource Energy and Subsidiaries 2024 combined Annual Report on Form 10-K as filed with the SEC
Fitch	Fitch Ratings, Inc.
FMCC	Federally Mandated Congestion Charge
GAAP	Accounting principles generally accepted in the United States of America
GSEP	Gas System Enhancement Program
GWh	Gigawatt-Hours
IPP	Independent Power Producers
ISO-NE Tariff	ISO-NE FERC Transmission, Markets and Services Tariff
kV	Kilovolt
kVa	Kilovolt-ampere
kW	Kilowatt (equal to one thousand watts)
kWh	Kilowatt-Hours
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LRS	Supplier of last resort service
MG	Million gallons
MGP	Manufactured Gas Plant
MMBtu	Million British thermal units
MMcf	Million cubic feet
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
MWh	Megawatt-Hours
NETOs	New England Transmission Owners (including Eversource, National Grid and Avangrid)
OCI	Other Comprehensive Income/(Loss)
PAM	Pension and PBOP Rate Adjustment Mechanism
PBOP	Postretirement Benefits Other Than Pension
PBOP Plan	Postretirement Benefits Other Than Pension Plan
Pension Plan	Single uniform noncontributory defined benefit retirement plan
PPA	Power purchase agreement
RECs	Renewable Energy Certificates
Regulatory ROE	The average cost of capital method for calculating the return on equity related to the distribution business segment excluding the wholesale transmission segment
ROE	Return on Equity
RRBs	Rate Reduction Bonds or Rate Reduction Certificates
RSUs	Restricted share units
S&P	Standard & Poor's Financial Services LLC
SERP	Supplemental Executive Retirement Plans and non-qualified defined benefit retirement plans
SS	Standard service
UI	The United Illuminating Company
VIE	Variable Interest Entity

FERC FORM No. 1 (ED. 12-96)

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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	0				185,014		185,014		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income	0				(26,459)		(26,459)		
3	Preceding Quarter/Year to Date Changes in Fair Value	0						0		
4	Total (lines 2 and 3)	0	0	0	0	(26,459)	0	(26,459)	511,660,345	511,633,886
5	Balance of Account 219 at End of Preceding Quarter/Year	0				158,555		158,555		
6	Balance of Account 219 at Beginning of Current Year	0				158,555		158,555		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income	0				(26,459)		(26,459)		
8	Current Quarter/Year to Date Changes in Fair Value	0				0		0		
9	Total (lines 7 and 8)	0	0	0	0	(26,459)	0	(26,459)	552,265,918	552,239,459
10	Balance of Account 219 at End of Current Quarter/Year	0	0	0	0	132,096	0	132,096		

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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)	14,573,170,650	14,573,170,650					
4	Property Under Capital Leases	24,325,507	(a)24,325,507					
5	Plant Purchased or Sold							

6	Completed Construction not Classified	1,434,066,198	1,434,066,198					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	16,031,562,355	16,031,562,355					
9	Leased to Others							
10	Held for Future Use	31,588,634	31,588,634					
11	Construction Work in Progress	562,747,082	562,747,082					
12	Acquisition Adjustments							
13	Total Utility Plant (8 thru 12)	16,625,898,071	16,625,898,071					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	3,356,020,728	3,356,020,728					
15	Net Utility Plant (13 less 14)	13,269,877,343	13,269,877,343					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	3,351,178,125	3,351,178,125					
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	4,842,603	[a]4,842,603					
22	Total in Service (18 thru 21)	3,356,020,728	3,356,020,728					
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							
27	Held for Future Use							
28	Depreciation							
29	Amortization							
30	Total Held for Future Use (28 & 29)							
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment							
33	Total Accum Prov (equals 14) (22,26,30,31,32)	3,356,020,728	3,356,020,728					

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: UtilityPlantInServicePropertyUnderCapitalLeases

Company	Capital Lease	Operating Lease Net of Amortization	Total
CL&P	18,281,904	6,043,603	24,325,507

Right of Use Operating Leases	11,578,433.78
Right of Use Operating Leases - Accumulated Amortization	(5,534,830.49)

Right of Use Operating Leases - Net	6,043,603
Right of Use Capital Leases	18,281,904
Total	24,325,507

(b) Concept: AmortizationOfOtherUtilityPlantUtilityPlantInService

Amort of Other Utility Plant

111010 Accumulated Provision for Amortization	1,118,512
111020 Accumulated Provision for Amortization-Leases	3,724,091
Amort of Other Utility Plant	**4,842,603**

Acct	Date	Function	CL&P D	CL&P T	Total
Amortization of Other Utility Plant	Dec-24	Intangible	104,880,845	11,186,446	116,067,291
	Dec-24	General Plant	2,811,281	-	2,811,281
					118,878,572
Amortization of Other Utility Plant	Dec-25	Intangible	—	—	—
	Dec-25	General Plant	4,842,603	-	4,842,603
					4,842,603

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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)	0				0
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)	0				0
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	0				0
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)	0				

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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						
4	(303) Miscellaneous Intangible Plant	144,294,273				(144,294,273)	
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	144,294,273				(a)(144,294,273)	
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						
13.1	(315.1) Computer Hardware						
13.2	(315.2) Computer Software						
13.3	(315.3) Communication 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						
22.1	(324.1) Computer Hardware						
22.2	(324.2) Computer Software						
22.3	(324.3) Communication 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						
31.1	(334.1) Computer Hardware						
31.2	(334.2) Computer Software						
31.3	(334.3) Communication 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)						
35.1	D. Solar Production Plant						
35.2	(338.1) Land and Land Rights						
35.3	(338.2) Structures and Improvements						
35.5	(338.4) Solar Panels						
35.6	(338.5) Collector System						
35.7	(338.6) Generator Step-up Transformers (GSU)						
35.8	(338.7) Inverters						
35.9	(338.8) Other Accessory Electrical Equipment						
35.10	(338.9) Computer Hardware						
35.11	(338.10) Computer Software						
35.12	(338.11) Communication Equipment						
35.13	(338.12) Miscellaneous Power Plant Equipment						
35.14	(338.13) Asset Retirement Costs for Solar Production						
35.15	TOTAL Solar Production Plant (Enter Total of lines 35.2 thru 35.14)						
35.16	E. Wind Production Plant						
35.17	(338.20) Land and Land Rights						
35.18	(338.21) Structures and Improvements						
35.20	(338.23) Wind Turbines						
35.21	(338.24) Wind Towers and Fixtures						

35.23	(338.26) Collector System						
35.24	(338.27) Generator Step-up Transformers (GSU)						
35.25	(338.28) Inverters						
35.26	(338.29) Other Accessory Electrical Equipment						
35.27	(338.30) Computer Hardware						
35.28	(338.31) Computer Software						
35.29	(338.32) Communication Equipment						
35.30	(338.33) Miscellaneous Power Plant Equipment						
35.31	(338.34) Asset Retirement Costs for Wind Production						
35.32	TOTAL Wind Production Plant (Enter Total of lines 35.17 thru 35.31)						
35.33	F. Other Renewable Production Plant						
35.34	(339.1) Land and Land Rights						
35.35	(339.2) Structures and Improvements						
35.36	(339.3) Fuel Holders						
35.37	(339.4) Boilers						
35.39	(339.6) Generators						
35.41	(339.8) Other Accessory Electrical Equipment						
35.42	(339.9) Computer Hardware						
35.43	(339.10) Computer Software						
35.44	(339.11) Communication Equipment						
35.45	(339.12) Miscellaneous Power Plant Equipment						
35.46	(339.13) Asset Retirement Costs for Other Renewable Production						
35.47	TOTAL Other Renewable Production Plant (Enter Total of lines 35.34 thru 35.46)						
36	G. 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						
42.1	(345.1) Computer Hardware						
42.2	(345.2) Computer Software						
42.3	(345.3) Communication Equipment						
43	(346) Misc. Power Plant Equipment						
44	(347) Asset Retirement Costs for Other Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)						
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, 35.15, 35.32, 35.47, and 45)						
47	3. Transmission Plant						
48	(350) Land and Land Rights	114,491,366	(542,311)			92,106	114,041,161
48.2	(351.1) Computer Hardware		590,434			8,440,862	9,031,296

48.3	(351.2) Computer Software		7,671,055			12,915,740	20,586,795
48.4	(351.3) Communication Equipment		12,432,005	332,389		197,175,684	209,275,300
49	(352) Structures and Improvements	167,100,194	57,894,302	262,620		(9,403,488)	215,328,388
50	(353) Station Equipment	1,897,420,801	100,723,089	23,604,427		10,421,859	1,984,961,322
51	(354) Towers and Fixtures	32,701,764	2,765,857	1,429,946			34,037,675
52	(355) Poles and Fixtures	2,301,731,334	150,656,593	10,522,843		(112,327)	2,441,752,757
53	(356) Overhead Conductors and Devices	742,959,647	(11,662,006)	5,039,704		(906,008)	725,351,929
54	(357) Underground Conduit	490,875,177	2,132,014	11,438			492,995,753
55	(358) Underground Conductors and Devices	601,213,929	575,019				601,788,948
56	(359) Roads and Trails	251,011,378	3,494,021	37,658			254,467,741
57	(359.1) Asset Retirement Costs for Transmission Plant	936,812					936,812
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	6,600,442,402	326,730,072	41,241,025		218,624,428	7,104,555,877
59	4. Distribution Plant						
60	(360) Land and Land Rights	8,866,662	12,654	3,874		(214,516)	8,660,926
61	(361) Structures and Improvements	88,400,719	12,366,726	836,735			99,930,710
62	(362) Station Equipment	1,075,143,064	42,899,101	8,446,484		(486,403)	1,109,109,278
63.1	(363.1) Computer Hardware		4,301,921	358,420		10,686,689	14,630,190
63.2	(363.2) Computer Software		8,600,769			132,002,764	140,603,533
63.3	(363.3) Communication Equipment		(1,826,090)	610,111		100,904,800	98,468,599
64	(364) Poles, Towers, and Fixtures	842,955,164	46,214,061	7,437,650			881,731,575
65	(365) Overhead Conductors and Devices	2,217,694,705	136,707,512	35,164,214			2,319,238,003
66	(366) Underground Conduit	485,113,518	42,722,944	2,118,468			525,717,994
67	(367) Underground Conductors and Devices	1,313,997,245	82,025,813	15,714,899			1,380,308,159
68	(368) Line Transformers	844,979,287	74,749,022	10,343,432	3,567,320	(45,570)	912,906,627
69	(369) Services	438,966,624	19,167,743	17,044,333			441,090,034
70	(370) Meters	232,165,802	8,874,222	6,729,321		532,959	234,843,662
71	(371) Installations on Customer Premises	41,086,340	4,249,582	2,186,641			43,149,281
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	62,104,128	2,574,931	995,224			63,683,835
74	(374) Asset Retirement Costs for Distribution Plant	2,678,555					2,678,555
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	7,654,151,813	483,640,911	107,989,806	3,567,320	243,380,723	8,276,750,961
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)						
84.1	6. ENERGY STORAGE PLANT						
84.2	(387.1) Land and Land Rights						
84.3	(387.2) Structures and Improvements						
84.4	(387.3) Energy Storage Equipment						
84.6	(387.5) Collector System						
84.7	(387.6) Generator Step-up Transformers (GSU)						
84.8	(387.7) Inverters						
84.9	(387.8) Computer Hardware						
84.10	(387.9) Computer Software						
84.11	(387.10) Communication Equipment						
84.12	(387.11) Miscellaneous Energy Storage Equipment						
84.13	(387.12) Asset Retirement Costs for Energy Storage						
84.14	TOTAL Energy Storage Plant (Total lines 84.2 thru 84.13)						
85	7. General Plant						
86	(389) Land and Land Rights	7,264,171					7,264,171
87	(390) Structures and Improvements	228,435,719	53,471,307	2,162,274			279,744,752
88	(391) Office Furniture and Equipment	25,165,143	(2,058,827)	64,115		(16,666,191)	6,376,010
89	(392) Transportation Equipment	190,371,080	35,026,381	11,805,180		(15,292)	213,576,989
90	(393) Stores Equipment	8,866,836	2,361,785	354,057			10,874,564
91	(394) Tools, Shop and Garage Equipment	88,313,781	4,770,185	302,556		7,341	92,788,751
92	(395) Laboratory Equipment	9,068,762	101,132	137,754			9,032,140
93	(396) Power Operated Equipment	1,802,006		6,546			1,795,460
94	(397.1) Computer Hardware	31,559				(31,559)	0
94.1	(397.2) Computer Software						0
94.2	(397.3) Communication Equipment	301,861,403	2,077,292			(301,141,893)	2,796,802
95	(398) Miscellaneous Equipment	5,515,818	(1,691,397)	2,242,587			1,581,834
96	SUBTOTAL (Enter Total of lines 86 thru 95)	866,696,278	94,057,858	17,075,069		(317,847,594)	625,831,473
97	(399) Other Tangible Property						
98	(399.1) Asset Retirement Costs for General Plant	98,537					[a]98,537
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	866,794,815	94,057,858	17,075,069		(317,847,594)	[a]625,930,010
100	TOTAL (Accounts 101 and 106)	15,265,683,303	904,428,841	166,305,900	3,567,320	(136,716)	16,007,236,848
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)	15,265,683,303	904,428,841	166,305,900	3,567,320	(136,716)	16,007,236,848

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: IntangiblePlantTransfers

Note that at the end of the year 2025, the total intangible plant balance includes a transmission - related component in the beginning balance (column b) and the ending balance (column g). The Transmission related dollars by plant account are as follow:

PLANT ACCOUNT		Beginning Balance 2025	Additions	Retirements	Adjustments	Transfers	Ending Balance 2025
301	Organization	—	—	—	—	—	—
302	Franchises and Consents	—	—	—	—	—	—
303	Miscellaneous Intangible Plant	12,291,509	—	0	0	(12,291,509)	—
TOTAL INTANGIBLE PLANT		**12,291,509**	**—**	**0**	**0**	**(12,291,509)**	**—**

(b) Concept: TransmissionPlant

Calculated per company records and in accordance with Schedule 21-ES, Schedule 1 under ISO New England Inc. Transmission, Markets and Services Tariff, Section II Page 106 line 1 and 12

(c) Concept: AssetRetirementCostsForDistributionPlantDistributionPlant

Distribution related ARO - There is no Transmission related component recorded in FERC Account 374 (Distribution Plant AROs)

(d) Concept: AssetRetirementCostsForGeneralPlantGeneralPlant

For Transmission related ARO for General Plant recorded in FERC Acct 399.1, the beginning balance (b) and ending balance (g), refer to footnote on line 99.

(e) Concept: GeneralPlant

Note that at the end of the year 2025, the total general plant balance includes a transmission - related component in the beginning balance (column b) and the ending balance (column g). The Transmission related dollars by plant account are as follow:

		Beginning Balance 2025	Additions	Retirements	Adjustments	Transfers	Ending Balance 2025
389	Land and Land Rights	1,263,024	—	—	—	—	1,263,024
390	Structures and Improvements	20,092,379	(395,286)	78,600	—	—	19,618,493
391	Office Furniture and Equipment	10,647,543	(1,195,633)	—	—	(7,238,861)	2,213,049
392	Transportation Equipment	26,843,604	(258,872)	2,663,065	—	(110,447)	23,811,220
393	Stores Equipment	881,645	—	—	—	—	881,645
394	Tools, Shop and Garage Equipment	15,167,176	2,080,813	—	—	7,341	17,255,330
395	Laboratory Equipment	1,770,776	—	—	—	—	1,770,776
396	Power Operated Equipment	207,314	—	—	—	—	207,314
397.1	Computer Hardware	31,559	—	—	—	(31,559)	—
397.2	Computer Software	—	—	—	—	—	—
397.3	Communication Equipment	199,150,019	2,450,755	—	—	(198,977,735)	2,623,039
398	Miscellaneous Equipment	3,351,664	(43,312)	2,208,471	—	—	1,099,881
399.1	General Plant ARO	—	—	—	—	—	—
TOTAL TRANSMISSION RELATED GENERAL PLANT		279,406,703	2,638,465	4,950,136	—	(206,351,261)	70,743,771

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

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

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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	Land - Montville Cap Banks - Transmission	01/01/2011	01/01/2040	191,661
3				
4				
5				
6				
7				
21	Other Property:			
22	Glenbrook Cables Transmission Line Equipment (Schedule 12C)	01/01/2008	01/01/2040	31,396,973
23	Functionalized:			
24	Distribution 0			
25	Transmission 31,588,634			
26	Total 31,588,634			
47	TOTAL			31,588,634

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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	CL&P Distribution	
2	Bokum 15L Transformer & Reconfig SS	30,390,049
3	Stevenson 14A Upgrade Xfrmr & Swgr	11,025,040
4	Hopewell 22R Replace Xfrmr	10,143,046
5	Beacon Falls 11N Replace Xfrmr	9,209,653
6	Franklin Dr Replace Xfrmr	8,875,204
7	Third Party Attachment Make Ready	7,815,085
8	Southington 4C Add Transformer	6,405,020
9	DIRECT BURIED CABLE REPLACEMENT PRO	6,198,716
10	S Meadow 1A - Replace OCB's	5,391,029
11	Falls Village 9A XFMR Reliability	5,283,347
12	CL&P MAJOR STORMS 2022	5,178,653
13	Glenbrook 1K Replace Transformer	4,655,814
14	Rplc Mobile Xfrmr 71MX	4,350,262
15	Farmington1C19 Contingency Overload	3,444,515
16	ROW 006 Remediation	3,258,986
17	Greenwich Ave Structural Upgrade	2,902,288

18	Chippen Hill 15U Replace SWGR	2,794,875
19	24H6 Smart Switch & Eliminating 25R	2,782,043
20	CACS Upgrade - CL&P	2,598,210
21	E. Meriden 21P Replace SWGR	2,339,548
22	Replace Center St Bridge, Meriden	2,023,162
23	CT Electric Curriculum Development	1,999,997
24	New Road in Bristol, Relocate and S	1,959,330
25	Ridgefield 22N Add Feeders	1,954,922
26	DIST S/S OBSOLESENCE ANNUAL - GEN.	1,911,866
27	State Hwy Proj Bee St @ Rte 691&91	1,593,939
28	UConn System Upgrade #900	1,565,750
29	SYSTEM REPAIRS/OBSOL HARTFORD	1,465,357
30	Newtown - AHU Replacements (2)	1,464,765
31	Install SWGR For Meriden Common PH2	1,455,379
32	CT Interconnection Automation	1,408,292
33	2N07 PILC Cable Replacement	1,383,453
34	Ridgefield 22N Contingency Overload	1,339,160
35	Building Interior Redesign	1,228,266
36	Berlin 6A Replace Switch	1,214,805
37	CT Transit-26 Elm Ct-New Service	1,205,548
38	Hiawatha Village Westport	1,197,566
39	Berlin 6A Incr Capacity	1,062,999
40	REPAIR & REPL OF CL&P UG STRUCTURES	1,029,709
41	2023 Trip Saver Program	1,028,765
42	Eliminate 4.8 kV 12F-6X Islanded SS	1,025,776
43	NEW/EXISTING CUSTMRS NEWTOWN	1,023,326
44	SSRK33.18-22M10-81M=>500-COND.2	1,017,782
45	Projects Under $1,000,000 Distribution	114,408,085
46	CL&P Distribution Total $282,009,382	
47	CL&P Transmission	
48	1704 L UCMP Proj (SW HTFD_S Meadow)	42,347,200
49	Line 1722 UCMP Proj (Hartford, CT)	38,772,099
50	1270-1337 L UCMP Proj (Danbury, CT)	27,882,435
51	Lines 1753 &1792 UG Rbld XLPE	27,321,438
52	Falls Village 9A Reliability	11,285,010
53	Montville BPS Sep/Cable Sys Rplc	11,259,209
54	1142L SNDRP Seg 5 Christian St. Jct	8,004,421
55	1670-2 / 1771 Lines Rebuild	5,584,537
56	1580L SNDRP Seg3 W.Devon-Devon 7R	5,471,488
57	1580L SNDRP Seg 5 Christian St. Jct	5,460,229
58	Plumtree 30G-3 Phase Spare XMFR	4,853,550
59	1545L SNDRP Seg3 W.Devon-Devon 7R	4,565,812

60	1319 line SNDRP Seg 5	4,266,961
61	Line 1759 Copper Retir and STR Repl	4,121,423
62	1670-3,1820 & 1830 Rebuild	4,094,014
63	UConn 900 Line Exten Sys Upgrade	3,113,392
64	Manchester 3A-345kV Circuit Brkr Rp	2,966,185
65	Long Mt_BPS Sep & Cable Rplc	2,532,988
66	Line 3403C MOV Program Release	2,316,553
67	N Bloomfield 2A-5X Auto XFR Repl	2,298,645
68	362L Hurd St Pk &CT RCross Rebuild	2,277,844
69	Line 3403D MOV Program Release	2,192,886
70	Line 1028 Fitch Darien ACR OPWG	2,070,902
71	1146 Line Rebuild	2,062,874
72	376L Hurd St Pk &CT RCross Rebuild	1,861,708
73	Shunt Reactor Manchester 3A	1,798,549
74	Shunt Reactor Beseck 9F	1,766,729
75	Line 1773 Copperweld Retire & ACR	1,641,154
76	Line 1867/1880/1389 Line Rebuild	1,611,659
77	23K-115kV Relay & Ctrl Encl Install	1,611,615
78	1483L SNDRP Seg3 W.Devon-Devon 7R	1,563,811
79	1772L Hurd St Pk &CT RCross Rebuild	1,536,869
80	Bokum 15L Addition/Station Reconfig	1,351,351
81	Line 1772 ACR & OPGW Installation	1,278,730
82	1808L SNDRP Seg 5 Christian St. Jct	1,208,607
83	Line 348 Lattice Repl OPGW Install	1,200,545
84	Devon 7R SS SNDRP Seg 3	1,186,207
85	Physical Sec Ballistic Rnd 3 Site 4	1,106,727
86	Line 680 Rebuild	1,085,379
87	Plumtree 30G Stat Serv Transf Rpl	1,012,137
88	Projects Under $1,000,000 Transmission	[a]30,793,828
89	CL&P Transmission Total $280,737,700	
43	Total	562,747,082

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FOOTNOTE DATA

(a) Concept: ConstructionWorkInProgress

PTF and Non-PTF Breakout (both Local and localized)

Description of Project	Project Type	Amount
Projects Under $1,000,000	PTF	3,559,969
Projects Under $1,000,000	NonPTF	24,848,236
Projects Under $1,000,000	LOCAL	2,385,623
		30,793,828

1704 L UCMP Proj (SW HTFD_S Meadow)	Project is 100% PTF	
Line 1722 UCMP Proj (Hartford, CT)	Project is 100% PTF	
1270-1337 L UCMP Proj (Danbury, CT)	Project is 100% NonPTF	
Lines 1753 &1792 UG Rbld XLPE	Project is 100% NonPTF	
Falls Village 9A Reliability	Project is 100% Local	
Montville BPS Sep/Cable Sys Rplc	PTF	11,169,950
	NonPTF	89,259
		11,259,209
1142L SNDRP Seg 5 Christian St. Jct	Project is 100% PTF	
1670-2 / 1771 Lines Rebuild	Project is 100% PTF	
1580L SNDRP Seg3 W.Devon-Devon 7R	Project is 100% PTF	
1580L SNDRP Seg 5 Christian St. Jct	Project is 100% PTF	
Plumtree 30G-3 Phase Spare XMFR	Project is 100% NonPTF	
1545L SNDRP Seg3 W.Devon-Devon 7R	Project is 100% PTF	
1319 line SNDRP Seg 5	Project is 100% PTF	
Line 1759 Copper Retir and STR Repl	Project is 100% PTF	
1670-3,1820 & 1830 Rebuild	Project is 100% NonPTF	
UConn 900 Line Exten Sys Upgrade	Project is 100% NonPTF	
Manchester 3A-345kV Circuit Brkr Rp	Project is 100% PTF	
Long Mt_BPS Sep & Cable Rplc	Project is 100% PTF	
Line 3403C MOV Program Release	Project is 100% PTF	
N Bloomfield 2A-5X Auto XFR Repl	Project is 100% PTF	
362L Hurd St Pk &CT RCross Rebuild	Project is 100% PTF	
Line 3403D MOV Program Release	Project is 100% PTF	
Line 1028 Fitch Darien ACR OPWG	Project is 100% PTF	
1146 Line Rebuild	Project is 100% PTF	
376L Hurd St Pk &CT RCross Rebuild	Project is 100% PTF	
Shunt Reactor Manchester 3A	Project is 100% PTF	
Shunt Reactor Beseck 9F	Project is 100% PTF	
Line 1773 Copperweld Retire & ACR	Project is 100% PTF	
Line 1867/1880/1389 Line Rebuild	Project is 100% PTF	
23K-115kV Relay & Ctrl Encl Install	Project is 100% PTF	
1483L SNDRP Seg3 W.Devon-Devon 7R	Project is 100% PTF	
1772L Hurd St Pk &CT RCross Rebuild	Project is 100% PTF	
Bokum 15L Addition/Station Reconfig	Project is 100% Local	
Line 1772 ACR & OPGW Installation	Project is 100% PTF	
1808L SNDRP Seg 5 Christian St. Jct	Project is 100% PTF	
Line 348 Lattice Repl OPGW Install	Project is 100% PTF	
Devon 7R SS SNDRP Seg 3	Project is 100% PTF	
Physical Sec Ballistic Rnd 3 Site 4	Project is 100% PTF	
Line 680 Rebuild	Project is 100% NonPTF	
Plumtree 30G Stat Serv Transf Rpl	Project is 100% PTF	

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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	3,021,571,409	3,021,571,409		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	430,325,355	430,325,355		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	9,278,482	9,278,482		
7	Other Clearing Accounts	408,522	408,522		
8	Other Accounts (Specify, details in footnote):				

9.1	Other Accounts (Specify, details in footnote):				
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	440,012,359	440,012,359		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(166,221,028)	[a](166,221,028)		
13	Cost of Removal	(59,927,854)	(59,927,854)		
14	Salvage (Credit)	4,281,534	4,281,534		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(221,867,348)	(221,867,348)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	111,461,705	[b]111,461,705		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	3,351,178,125	3,351,178,125		
	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				
23.1	Solar Production				
23.2	Wind Production				
23.3	Other Renewable Production				
24	Other Production				
25	Transmission	1,716,152,850	[c][d][e]1,716,152,850		
26	Distribution	1,490,126,752	1,490,126,752		
27	Regional Transmission and Market Operation				
27.1	Energy Storage				
28	General	144,898,523	[f]144,898,523		
29	TOTAL (Enter Total of lines 20 thru 28)	3,351,178,125	3,351,178,125		

FOOTNOTE DATA

(a) Concept: BookCostOfRetiredPlant

BOOK COST OF PLANT RETIRED	
Retirements from Reserves	166,221,028
ARO Retirements	—
Land Retirements/Other	84,872
Retirements from 111	—
Total Retirements (ties to page 207)	166,305,900

(b) Concept: OtherAdjustmentsToAccumulatedDepreciation

OTHER DEBIT OR (CREDIT) ITEMS	
Transfers and Adjustments	(658,256)
Sundry Billing	237,476
Asset Retirement Obligation Activity	60,012
Journal Entries	(4,163,820)
Unitization	(80,998)
FERC Order 898 account 111 to 108 transfers	116,067,291
Total Other Debit or Credit Items	111,461,705

(c) Concept: AccumulatedDepreciationTransmission

Page 106 Line 1 Calculated per company records and in accordance with schedule 21-ES, Schedule 1 under ISO New England Inc. Transmission, Markets, and Services Tariff, Section II

(d) Concept: AccumulatedDepreciationTransmission

Page 106 Line 12 Calculated per company records and in accordance with Schedule 21-ES, Schedule 1 under ISO New England Inc. Transmission, Markets, and Services Tariff, Section II

(e) Concept: AccumulatedDepreciationTransmission

Page 106 Lines 5, 6, 7 Calculated per company records as stipulated per contract.

(f) Concept: AccumulatedDepreciationGeneral

The total General Plant balance in Account 108 includes a transmission related component at the end of year balance of $23,032,080.

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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	Connecticut Yankee Atomic Power Company							
2	Common Stock		07/01/1964	475,018			475,018	
3	Capital Contributions			1,035,000			1,035,000	
4	Equity and Dividends			(572,909)	46,469		(526,440)	
5	Subtotal			937,109			983,578	
6	Maine Yankee Atomic Power Company							
7	Common Stock		05/20/1968	60,000			60,000	
8	Capital Contributions			2,019,746			2,019,746	
9	Equity and Dividends			(1,683,035)	20,451		(1,662,584)	
10	Subtotal			396,711			417,162	
11	Yankee Atomic Energy Company							
12	Common Stock		12/10/1958	187,900			187,900	
13	Capital Contributions			163,333			163,333	
14	Equity and Dividends			38,078	(189)		37,889	
15	Subtotal			389,311			389,122	
42	Total Cost of Account 123.1 $3,940,997		Total	1,723,132	66,731	0	1,789,863	0

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The Connecticut Light and Power Company	(1) An Original (2) A Resubmission	04/17/2026	End of: 2025/ Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	0		
2	Fuel Stock Expenses Undistributed (Account 152)	0		
3	Residuals and Extracted Products (Account 153)	0		
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	[a]201,941,195	[b]194,058,877	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	0		
8	Transmission Plant (Estimated)	628,974	2,302,705	
9	Distribution Plant (Estimated)	37,575,668	19,880,004	
10	Regional Transmission and Market Operation Plant (Estimated)	0		
10.1	Energy Storage Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	0		
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	240,145,837	216,241,586	
13	Merchandise (Account 155)	0		
14	Other Materials and Supplies (Account 156)	0		
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)	0		
16	Stores Expense Undistributed (Account 163)		0.00	Electric
17		0		
20	TOTAL Materials and Supplies	240,145,837	216,241,586	

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FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesConstruction

Schedule Page: 227 Line No.: 5 Column: b

Note that the balance of Plant Materials and Operating Supplies assigned to Construction at December 31,2024 includes a transmission related component of $22,878,488.

Schedule Page: 227 Line No.: 5 Column: c

(b) Concept: PlantMaterialsAndOperatingSuppliesConstruction

Schedule Page: 227 Line No.: 5 Column: c

Note that the balance of Plant Materials and Operating Supplies assigned to Construction at December 31,2025 includes a transmission related component of $81,915,778.

	This report is:		

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Allowances and Environmental Credits (Accounts 158.1, 158.2, 158.3, and 158.4)

1. Report below the details related to allowances and environmental credits. Additional information about the type of allowances/environmental credits required by other regulatory bodies can be disclosed within the footnote data.
2. Report all acquisitions of allowances and environmental credits at cost.
3. Report allowances and environmental credits 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 and environmental credits transactions by the period they are first eligible for use: the current year's allowances and environmental credits in columns (b)-(c), allowances and environmental credits for the three succeeding years in columns (d)-(i), starting with the following year, and allowances and environmental credits for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 authoritative agency issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by an authoritative agency. Report on Line 39 the authoritative agency's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the authoritative agency's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances and environmental credits 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 and environmental credits 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 and environmental credits sales.

Line No.	Allowances and Environmental Credits Inventory (Accounts 158.1, 158.3, and 158.4) (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 authoritative agency												
6													
7													
8	Connecticut Renewable Energy Certificates		0										
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509, 555.2, and 555.3												
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		0										
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 authoritative agency												
38	Deduct: Returned by authoritative agency												
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						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						

15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
20	TOTAL					0.00

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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						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						

39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					0.00

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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**				
20	Total				
21	**Generation Studies**				
22	40505101 - Generator Interconnection Non-ISO	1,350	186	4,475	186
23	40505501 - Generator Interconnection Non-ISO	442,981	186	315,641	186
24	40505601 - Generator Interconnection Non-ISO	2,584,845	186	2,822,369	186
25	40560401 - Generator Interconnection Non-ISO	39,667	186	25,351	186
26	QP1058 - Generator Interconnection Study	0	186	13,098	186
27	QP1163 - Generator Interconnection Study	0	186	530	186
28	QP1192 - Generator Interconnection Study	5,419	186	7,150	186
29	QP1193 - Generator Interconnection Study	14,007	186	17,174	186
30	QP1245 - Generator Interconnection Study	16,727	186	16,403	186
31	QP1296 - Generator Interconnection Study	(1,839)	186	532	186
32	QP1319 - Generator Interconnection Study	17,396	186	19,948	186
33	QP1345 - Generator Interconnection Study	0	186	7,973	186
34	QP1357 - Generator Interconnection Study	16,080	186	15,757	186
35	QP1400 - Generator Interconnection Study	8,131	186	18,544	186
36	QP1436 - Generator Interconnection Study	1,793	186	2,764	186
37	Grand Total	3,412,338		3,541,319	

38	QP1486 - Generator Interconnection Study	0	186	86	186
39	QP924/QP925 - Generator Interconnection Study	265,781	186	253,524	186
39	Total				
40	Grand Total	3,412,338		3,541,319	

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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	Income Taxes - FASB ASC 740	[a]536,846,449	25,048,093	190,282,285	2,059,313	[a]559,835,229
2	Unrecovered Contract Obligation - CYAPC	16,724,170	86,059			16,810,229
3	Unrecovered Contract Obligation - YAEC	81,812	0		858	80,954
4	Asset Retirement Obligation	41,217,204	2,935,469	230,108	132	44,152,541
5	FASB ASC 960/962 Pension	[a]168,760,116	23,320,168	129,146	18,424,046	[a]173,656,238
6	Contract for Differences Docket 05-07-14PH02	57,240,802	78,926,713	175,244	136,039,307	128,208
7	Deferred Storm Restoration Costs Docket No. 13-03-23	978,539,079	79,738,224	407,408,593	55,681,077	1,002,596,226
8	Boiler/Furnace Program SBC Deferral Public Act 13-247	8,657,001	5,965,477	143,908	14,413,397	209,081
9	Revenue Decoupling Mechanism Deferral Docket No. 14-05-06	33,124,640	40,372,069	407	60,396,256	13,100,453
10	Electric System Improvement Deferral Docket No. 17-10-46	104,893,350	19,336,470	407,431	27,852,162	96,377,658
11	Competitive Transition Charge Deferral Docket No. 99-03-36	9,389,908	3,672,349	407	8,454,065	4,608,192
12	Deferred Tax Federal Income Tax Rate Reduction	43,717	0	283	7,272	36,445
13	Retail Transmission Deferral Docket No. 05-08-03	104,670,799	124,514,905	565,431	156,757,872	72,427,832
14	FMCC Deferral Docket No. 99-03-36	129,350,562	152,476,891	407,555	281,827,453	0
15	System Benefit Charge Deferral Docket No. 99-06-36	100,282,421	0	407	100,282,421	0
16	Transmission Sch 1 Deferral Docket No. ER03-1247	4,289,282	2,669,085	407	2,551,415	4,406,952
17	Electric Vehicle Program Docket No. DE 24-01-03	38,231,437	1,285,241	908	39,516,678	0
18	Transmission Tariff Deferral Docket No. ER03-1247	0	161,087,739	431,449,565,920	151,816,392	9,271,347
44	TOTAL	2,332,342,749	721,434,952		1,056,080,116	1,997,697,585

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

[a] Concept: OtherRegulatoryAssets

Note that the balance of FASB ASC 740 regulatory asset at December 31, 2024 includes a transmission related component of $42,597,950.

(b) Concept: OtherRegulatoryAssets

Note that the balance of FSB ASC 960/962 Pension at December 31, 2024 includes a transmission related component of $($652,941).

(c) Concept: OtherRegulatoryAssets

Note that the balance of FASB ASC 740 regulatory asset at December 31, 2025 includes a transmission related component of $42,739,625.

(d) Concept: OtherRegulatoryAssets

Note that the balance of FSB ASC 960/962 Pension at December 31, 2025 includes a transmission related component of ($689,089).

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MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Credits Account Charged (d)	Credits Amount (e)	
1	C&LM Loan Program	81,488,384	331,037,821	143,254	334,689,237	77,836,968
2	Credit Line Renewal Fees	886,810	353,833	431	403,022	837,621
3	Real Estate Transactions	724,681	108,411	142,146	8,147	824,945
4	Deferred Rate Case Costs	779,703	0		0	779,703
5	Workers Compensation/Public Liability Insurance Recoveries	15,836,298	0		0	15,836,298
6	EE Demand Response Project	28,976,470	130,602	146,555,908	5,904,173	23,202,899
7	Environmental Costs of Facility Closures	256,007	0		0	256,007
8	Minor Items (5)	4,744,584	0	232,588	3,656,484	1,088,100
9	Environmental Deferral	16,035,403	1,148,003	228	603,758	16,579,648
10	CL&P Pension Accumulated Other Comprehensive Income	333,117	0		0	333,117
11	COVID-19 Deferred Cost	13,070,371	0		0	13,070,371
12	Supplemental Hardship Reserve	47,191,997	29,013,339	144	19,169,791	57,035,545
13	Miscellaneous Work in Progress	13,637,454	32,545,681	107,580	38,204,696	7,978,439
14	Deferred Pole Make Ready Costs	9,436,778	6,275,117	407	227,627	15,484,268
47	Miscellaneous Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	233,398,057				231,143,929

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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		400,481,130	521,882,876
7	Other		0
8	TOTAL Electric (Enter Total of lines 2 thru 7)	400,481,130	521,882,876
9	Gas		
10			0
15	Other		0
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17.1	Other (Specify)	4,007,914	4,124,978
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	[a]404,489,044	[b]526,007,854

Notes

Use the below space for any notes to Schedule 234. The XBRL element to use for any applicable notes is AccumulatedDeferredIncomeTaxesTextBlock

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

Note that at the beginning of the year, the total Accumulated Deferred Income Tax balance in Account 190 includes a transmission-related component of $85,660,107.

Note that at the beginning of the year, the total Accumulated Deferred Income Tax balance in Account 190480 (Reserve for Disputed Transactions) includes a transmission-related component of $2,487,938.

Information on Formula Rates :

Page 106 Line 1, 12 calculated per company records and in accordance with Schedule 1 and Schedule 21-ES, under ISO New England Inc. Transmission, Markets and Services Tariff, Section II.

Information on Formula Rates :

Page 106 Line 3 calculated per company records and in accordance with Attachment F under ISO New England Inc. Transmission, Markets and Services Tariff, Section II.

(b) Concept: AccumulatedDeferredIncomeTaxes

Annual Report of CONNECTICUT LIGHT AND POWER COMPANY
Year Ended December 31, 2025
Accumulated Deferred Income Taxes (Account 190)

	Beginning Balance	Activity	Ending Balance
Account 190DGO			
ASC 740 Gross-Up (FAS 109)	318,794,786	(6,829,106)	311,965,680
Account 190DK0			
ASC 740 (FASB 109)	9,157,620	(1,510,102)	7,647,518
Account 190IT0			
ASC 740 ITC - (FAS 109)	10	1	11
Account 1904C0			
NON ADIT FIN48	(21,983,379)	353,059	(21,630,320)
Account 190480			
Reserve for Disputed Trans.	4,616,506	(74,142)	4,542,364
Account 190VA0			
Valuation Allowance	(104,128,840)	(72,515)	(104,201,355)
Account 190000			
Bad Debts	66,272,974	(3,698,926)	62,574,048
Derivative Liability	19,562,073	(19,526,792)	35,281
Regulatory Deferrals	(41,135,739)	153,564,679	112,428,940
Employee Benefits	16,604,730	686,357	17,291,087
Other	136,728,303	(1,373,703)	135,354,600
Sub-total Account 19000	198,032,341	129,651,615	327,683,956
TOTAL Account 190	404,489,044	121,518,810	526,007,854

Note that at the end of the year, the total balance of Accumulated Deferred Income Taxes in Account 190 includes a transmission related component of $99,917,478.

Note that at the end of the year, the total balance of Accumulated Deferred Income Taxes in Account 190480 (Reserve for Disputed Transactions) includes a transmission related component of $2,516,253.

Information on Formula Rates :

Page 106 Line 1, 12 calculated per company records and in accordance with Schedule 1 and Schedule 21-ES, under ISO New England Inc. Transmission, Markets and Services Tariff, Section II.

Information on Formula Rates :

Page 106 Line 3 calculated per company records and in accordance with Attachment F under ISO New England Inc. Transmission, Markets and Services Tariff, Section II.

Annual Report of CONNECTICUT LIGHT AND POWER COMPANY
Year Ended December 31, 2025
Accumulated Deferred Income Taxes (Account 190)-Transmission

	Beginning Balance	Activity	Ending Balance
Account 190DGO			
ASC 740 Gross-Up (FAS 109)	94,952,523	(2,152,158)	92,800,365
Account 190DK0			
ASC 740 (FASB 109)	—	—	—
Account 190IT0			
ASC 740 ITC - (FAS 109)	10	—	10
Account 1904C0			
NON ADIT FIN48	(11,847,333)	(134,829)	(11,982,162)
Account 190480			
Reserve for Disputed Trans.	2,487,938	28,315	2,516,253
Account 190VA0			
Valuation Allowance	(55,575,816)	(2,064,128)	(57,639,944)
Account 190000			
Bad Debts	—	—	—
Derivative Liability	—	—	—
Regulatory Deferrals	(10,351,904)	14,923,186	4,571,282
Employee Benefits	99,389	17,893	117,282
Other	65,895,300	3,639,092	69,534,392
Sub-total Account 19000	55,642,785	18,580,171	74,222,956
TOTAL Account 190	85,660,107	14,257,371	99,917,478

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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 - Not Publicly Traded	24,500,000	10.00		6,035,205	60,352,050				
7	Total	24,500,000			6,035,205	60,352,050				
8	Preferred Stock (Account 204)									
9	Cumulative Preferred Stock	9,000,000								
10	3.9% 1949 Series		50.00	50.50	160,000	8,000,000				

11	4.50% 1956 Series		50.00	50.75	104,000	5,200,000				
12	4.96% 1958 Series		50.00	50.50	100,000	5,000,000				
13	4.50% 1963 Series		50.00	50.50	160,000	8,000,000				
14	5.28% 1967 Series		50.00	51.43	200,000	10,000,000				
15	6.56% 1968 Series		50.00	51.44	200,000	10,000,000				
16	$2.00 1947 Series		50.00	54.00	336,088	16,804,400				
17	$1.90 1947 Series		50.00	52.50	163,912	8,195,600				
18	$2.20 1949 Series		50.00	52.50	200,000	10,000,000				
19	$2.04 1949 Series		50.00	52.00	100,000	5,000,000				
20	$2.06 E 1954 Series		50.00	51.00	200,000	10,000,000				
21	$2.09 F 1955 Series		50.00	51.00	100,000	5,000,000				
22	$3.24 G 1968 Series		50.00	51.84	300,000	15,000,000				
90	Total	9,000,000			2,324,000	116,200,000				

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 2026-04-17	Year/Period of Report End of: 2025/ 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.

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

Line No.	Item (a)	Amount (b)
1	**Donations Received from Stockholders (Account 208)**	
2	Beginning Balance Amount	0
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	0
4	Ending Balance Amount	0
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	238,521
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	0
8	Ending Balance Amount	238,521
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	58,891
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	0
12	Ending Balance Amount	58,891
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	3,644,798,875
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	0
15.2	Miscellaneous	0
15.3	Amortization Preferred Stock Expense	0

15.4	ESOP Adjustment	0
16	Ending Balance Amount	3,644,798,875
17	**Other Paid in Capital**	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	3,645,096,287

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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	0

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1	Bonds (Account 221)												
2	First Mortgage Bonds												
3	2004 Series B 5.75% Fixed Rate		130,000,000		1,477,466		937,300	09/15/2004	09/15/2034	09/01/2004	09/01/2034	130,000,000	7,475,000
4	2005 Series B 5.625% Fixed Rate		100,000,000		1,027,923		42,000	04/07/2005	04/01/2035	04/01/2005	03/01/2035	100,000,000	5,625,000
	2006 Series A 6.35% Fixed												

5	Rate		250,000,000		2,397,870		130,000	06/07/2006	06/01/2036	06/01/2006	05/01/2036	250,000,000	15,875,000
6	2007 Series B 5.75% Fixed Rate		150,000,000		1,513,165		1,452,000	03/27/2007	03/01/2037	03/01/2007	02/01/2037	150,000,000	8,625,000
7	2007 Series D 6.375% Fixed Rate		100,000,000		1,009,209		235,000	09/17/2007	09/01/2037	09/01/2007	08/01/2037	100,000,000	6,375,000
8	2014 Series A 4.30% Fixed Rate		475,000,000		4,937,064	(21,935,250)		04/24/2014	04/15/2044	04/01/2014	03/31/2044	475,000,000	20,425,000
9	2015 Series A 4.15% Fixed Rate		350,000,000		3,929,931		6,627,000	05/20/2015	06/01/2045	05/01/2015	05/01/2045	350,000,000	14,525,000
10	2017 Series A 3.20% Fixed Rate		500,000,000		4,520,382	(10,286,000)	1,020,000	03/10/2017	03/15/2027	03/01/2017	02/28/2027	500,000,000	16,000,000
11	2018 Series A 4.00% Fixed Rate		800,000,000		8,649,299	(7,956,000)	1,215,000	03/28/2018	04/01/2048	03/01/2018	03/31/2048	800,000,000	32,000,000
12	2021 Series A 2.05 Fixed Rate		425,000,000		3,849,095		1,147,500	06/30/2021	07/01/2031	06/01/2021	07/01/2031	425,000,000	8,712,500
13	2023 Series A 5.25% Fixed Rate		500,000,000		5,843,033		1,055,000	01/10/2023	01/15/2053	01/01/2023	12/01/2052	500,000,000	26,250,000
14	2023 Series B 4.90% Fixed Rate		300,000,000		2,917,815		585,000	07/06/2023	07/01/2033	07/01/2023	06/01/2033	300,000,000	14,700,000
15	2024 Series A 4.65% Fixed Rate		350,000,000		3,217,271		724,500	01/23/2024	01/01/2029	01/01/2024	12/01/2028	350,000,000	16,275,000
16	2024 Series B 4.95% Fixed Rate		300,000,000		2,946,634		1,335,000	08/13/2024	08/15/2034	08/01/2024	07/01/2034	300,000,000	14,850,001
17	2025 Series A 4.95% Fixed Rate		400,000,000		3,640,432		544,000	01/15/2025	01/15/2030	01/01/2025	12/31/2029	400,000,000	19,140,000
18	Subtotal		5,130,000,000		51,876,588	(40,177,250)	17,049,300					5,130,000,000	226,852,501
19	Reacquired Bonds (Account 222)												
20		0	0		0	0	0						
23	Subtotal		0		0	0	0					0	0
24	Advances from Associated Companies (Account 223)												
25		0	0		0	0	0						
28	Subtotal		0		0	0	0					0	0
29	Other Long Term Debt (Account 224)												
30	2020 Series A 0.75% Fixed Rate (Paid off 12/1/2025)	0	0		0	0	0					0	2,750,000
31	Additional Footnote- Other Comprehensive Income												3,329
32	Subtotal		0		0	0	0					0	2,753,329
33	TOTAL		5,130,000,000	24,564,207								5,130,000,000	229,605,830

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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 filed, 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)	552,265,918
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Employee Compensation and Benefits	(28,251,056)
11	Current and Deferred Federal and State Income Taxes	167,202,778
12	Other	(63,058,444)
14	Income Recorded on Books Not Included in Return	
15	Other	7,900,000
16	Current and Deferred Federal and State Income Taxes	
19	Deductions on Return Not Charged Against Book Income	
20	Book/Tax Property Differences	(311,935,835)
21	Amortization/Deferral of Regulatory Assets	589,871,740
22	Bad Debts	(19,050,631)
27	Federal Tax Net Income	[(a)]894,944,470
28	Show Computation of Tax:	
29	Federal Income Tax @ 21%	187,938,339
30	NNECO Taxes Billed	(216,553)
31	Prior Years Taxes & Other	3,374,167
32	Federal Income Tax	191,095,953
33	Federal Income Tax - Other Income/Deductions (Page 117, Line 53)	247,097
34	Federal Income Tax (Page 114, Line 15)	190,848,856

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: FederalTaxNetIncome

This company is a member of an affiliated group, Eversource Energy and Subsidiaries, which will file a 2025 consolidated federal Income Tax return on or before October 15, 2026.

Members of the group are:
Eversource Energy
The Connecticut Light and Power Company
The Connecticut Steam Company
Electric Power, Inc.
NGS Sub, Inc.
Harbor Electric Energy Company
Hopkinton LNG Corp.
HWP Company
North Atlantic Energy Corporation
North Atlantic Energy Service Corporation
Northeast Generation Services Company
Northeast Nuclear Energy Company

Eversource Energy Service Company
NSTAR Electric Company
NSTAR Gas Company
NU Enterprises, Inc.
Eversource Energy Transmission Ventures, Inc.
The Nutmeg Power Company
Properties, Inc.
Public Service Company of New Hampshire
Renewable Properties, Inc.
The Rocky River Realty Company
Yankee Energy System, Inc.
Yankee Gas Services Company
Eversource Holdco Corporation
Aquarion Company
Aquarion Management Services Company
Aquarion Water Company
Aquarion Water Company of New Hampshire
Aquarion Water Capital of Massachusetts, Inc.
Aquarion Water Company of Massachusetts, Inc.
Aquarion Water Company of Connecticut
Eversource Gas Company of Massachusetts
Abenaki Water Co., Inc.
New England Service Company
Torrington Water Company

The above entities are parties to a tax allocation agreement under which taxable subsidiaries do not pay any more taxes than they would have otherwise paid had they filed a separate Company tax return, and subsidiaries generating tax losses, if any, are paid for their losses when utilized.

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

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

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED			
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1	Federal Income	Federal Tax			7,867,931		191,095,953	111,855,389		87,108,495	0	190,848,856			247,097
2					0	0				0					
3	**Subtotal Federal Tax**				7,867,931	0	191,095,953	111,855,389	0	87,108,495	0	190,848,856	0	0	247,097
4	CT Gross Earnings	State Tax	CT		28,032,656	0	191,939,568	191,579,781		28,392,443		203,819,142			(11,879,574)
5	CT FIN 48	State Tax	CT		2	0				2					
6	CT Transaction Tax Reserv	State Tax	CT		0	0	1,374	1,374		0		1,374			
7	**Subtotal State Tax**				28,032,658	0	191,940,942	191,581,155	0	28,392,445	0	203,820,516	0	0	(11,879,574)
8	**Subtotal Local Tax**				0	0	0	0	0	0	0	0	0	0	0
9	**Subtotal Other Tax**				0	0	0	0	0	0	0	0	0	0	0
10	CT Property Tax	Property Tax	CT			25,732,504	238,249,032	249,256,591		0	36,740,063	237,844,806			404,226
11	**Subtotal Property Tax**				0	25,732,504	238,249,032	249,256,591	0	0	36,740,063	[a]237,844,806	0	0	[b]404,226
12		Real Estate Tax			0	0				0					
13	**Subtotal Real Estate Tax**				0	0	0	0	0	0	0	0	0	0	0

14	Federal Unemployment	Unemployment Tax			(1,353)	0	43,570	43,570		(1,353)		43,570			
15	CT Unemployment	Unemployment Tax	CT		0	0	255,864	255,864		0		255,864			
16	MA Unemployment	Unemployment Tax	MA		0	0	81,079	81,079		0		81,079			
17	NH Unemployment	Unemployment Tax	NH		0	0	(494)	(494)		0		(494)			
18	DC Unemployment	Unemployment Tax	DC		0	0				0					
19	NJ Unemployment	Unemployment Tax	NJ		0	0				0					
20	PA Unemployment	Unemployment Tax	PA		0	0				0					
21	FL Unemployment	Unemployment Tax	FL		0	0	80	80		0		80			
22	IN Unemployment	Unemployment Tax	IN		0	0	(25)	(25)		0		(25)			
23	IL Unemployment	Unemployment Tax	IL		0	0	11	11		0		11			
24	MI Unemployment	Unemployment Tax	MI		0	0				0					
25	NC Unemployment	Unemployment Tax	NC		0	0				0					
26	NY Unemployment	Unemployment Tax	NY		0	0	48	48		0		48			
27	UT Unemployment	Unemployment Tax	UT		0	0	10	10		0		10			
28	WI Unemployment	Unemployment Tax	WI		0	0				0					
29	Reserved for Future Use 1	Unemployment Tax			0	0				0					
30	Reserved for Future Use 2	Unemployment Tax			0	0				0					
31	Reserved for Future Use 3	Unemployment Tax			0	0				0					
32	Reserved for Future Use 4	Unemployment Tax			0	0				0					
33	**Subtotal Unemployment Tax**				(1,353)	0	380,143	380,143	0	(1,353)	0	380,143	0	0	0
34	CT Sales Tax	Sales And Use Tax	CT		0	0	20,411,232	20,411,232		0					20,411,232
35	**Subtotal Sales And Use Tax**				0	0	20,411,232	20,411,232	0	0	0	0	0	0	20,411,232
36	Corporation Business Profits	Income Tax	CT		5,276,666	0	70,911,237	26,823,176		49,364,727	0	72,818,820			(1,907,583)
37	MA Income	Income Tax	MA		0	0	14,811	14,811		0		14,811			
38	**Subtotal Income Tax**				5,276,666	0	70,926,048	26,837,987	0	49,364,727	0	72,833,631	0	0	(1,907,583)
39	CT Insurance Premium Excise	Excise Tax	CT		0	0	425,416	425,416		0		425,416			
40	Mass Manufacturing Excise	Excise Tax	MA		0	0	60,841	175,841	115,000	0	0	60,841			
41	**Subtotal Excise Tax**				0	0	486,257	601,257	115,000	0	0	486,257	0	0	0
42	Highway Use	Fuel Tax			0	0	9,765	9,765		0		9,765			
43	**Subtotal Fuel Tax**				0	0	9,765	9,765	0	0	0	9,765	0	0	0
44	FICA	Federal Insurance Tax			387,779	0	8,246,966	8,231,360		403,385		8,246,966			
45	Medicare	Federal Insurance Tax			90,694	0	2,160,951	2,157,309		94,336		2,160,951			
46	**Subtotal Federal Insurance Tax**				478,473	0	10,407,917	10,388,669	0	497,721	0	10,407,917	0	0	0
47	**Subtotal Franchise Tax**				0	0	0	0	0	0	0	0	0	0	0
48	**Subtotal Miscellaneous Other**				0	0	0	0	0	0	0	0	0	0	0

	Tax														
49	Other	Other Federal Tax			0	0	0	0		0		0			
50	**Subtotal Other Federal Tax**				0	0	0	0	0	0	0	0	0	0	0
51	Other MA	Other State Tax				0	0			0		0			
52	**Subtotal Other State Tax**				0	0	0	0	0	0	0	0	0	0	0
53	**Subtotal Other Property Tax**				0	0	0	0	0	0	0	0	0	0	0
54		Other Use Tax			0	0				0					
55	**Subtotal Other Use Tax**				0	0	0	0	0	0	0	0	0	0	0
56	**Subtotal Other Advalorem Tax**				0	0	0	0	0	0	0	0	0	0	0
57	**Subtotal Other License And Fees Tax**				0	0	0	0	0	0	0	0	0	0	0
58	MA Universal Health	Payroll Tax	MA		0	0	10,096	10,096		0		10,096			
59		Payroll Tax			0	0				0					
60	**Subtotal Payroll Tax**				0	0	10,096	10,096	0	0	0	10,096	0	0	0
61	**Subtotal Advalorem Tax**				0	0	0	0	0	0	0	0	0	0	0
62	**Subtotal Other Allocated Tax**				0	0	0	0	0	0	0	0	0	0	0
63	**Subtotal Severance Tax**				0	0	0	0	0	0	0	0	0	0	0
64	**Subtotal Penalty Tax**				0	0	0	0	0	0	0	0	0	0	0
65	**Subtotal Other Taxes And Fees**				0	0	0	0	0	0	0	0	0	0	0
40	TOTAL				41,654,375	25,732,504	723,917,385	611,332,284	115,000	165,362,035	36,740,063	[a]716,641,987	0	0	[a]7,275,398

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: TaxesAccruedPrepaidAndCharged

The total amount of Connecticut local property tax expense charged to the transmission business segment was $102,767,094. The total amount of Connecticut local property tax expense charged to the distribution business segment was $135,077,712.

Information on Formula Rates:
Calculated per company records and in accordance with Schedule 21-ES, Schedule 1 under ISO New England Inc. Transmission, Markets and Services Tariff, Section II.
Reference page 106, line 1.

Calculated per company records and in accordance with Schedule 21-ES, Schedule 1.
Reference page 106, line 12.

Calculated per company records as stipulated per contract.
Reference page 106, lines 5, 6 and 7.

(b) Concept: TaxesIncurredOther

Schedule Page: 262 Line No.: 9.1 Column: o

State of Connecticut local property taxes charged to other accounts includes $116,862 to account 408 and $2,254,035 to accounts 184 and 163 and $(1,966,671) to various income and expense accounts. There is a total transmission related component of $(1,307,189).

(c) Concept: TaxesAccruedPrepaidAndCharged

For the year ended December 31, 2025, the total amount of Taxes Accrued, Prepaid and Charges related to operating expenses (column l) include transmission related components as follow:

Description	Amount

Federal Income Taxes	59,242,872
State of Connecticut Gross Earnings Taxes	23,119,057
State of Connecticut Transaction Tax Reserve	1,374
Connecticut local property tax expense	102,767,094
Federal Unemployment Taxes	4,136
State of Connecticut Unemployment Taxes	19,497
Commonwealth of Massachusetts Unemployment Taxes	13,530
State of New Hampshire Unemployment Taxes	-83
State of Florida Unemployment Taxes	13
State of Indiana Unemployment Taxes	-4
State of Illinois Unemployment Taxes	2
State of New York Unemployment Taxes	8
State of Utah Unemployment Taxes	2
State of Wisconsin Unemployment Taxes	0
State of Connecticut Corporation Business Profits Taxes	26,221,593
Commonwealth of Massachusetts Income Taxes	35,406
State of Connecticut Insurance Premium Excise Taxes	136,857
Commonwealth of Massachusetts Manufacturing Excise Taxes	24,367
Federal Highway Use Taxes	0
FICA Taxes	716,818
Medicare Taxes	196,681
Commonwealth of Massachusetts Universal Health Taxes	1,685

(d) Concept: TaxesIncurredOther

For the year ended December 31, 2025, the total amount of Taxes Accrued, Prepaid and Charges related to other (column o) include transmission related components as follow:

Description	Amount
Federal Income Taxes	3,405,256
State of Connecticut Gross Earnings Taxes	0
Connecticut local property tax expense	(1,307,189)
State of Connecticut Sales and Use Taxes	6,502,814
State of Connecticut Corporation Business Profits Taxes	(555,315)

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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%	(400)			411.4			(400)		
4	7%									
5	10%	386			411.4			386		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	(a)(14)						(a)(14)		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										
47	OTHER TOTAL									
48	GRAND TOTAL	(14)						(14)		

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredInvestmentTaxCredits

Note that at the beginning of the year, the balance of Accumulated Deferred Investment Tax Credits in Account 255 includes a transmission related component of $17.

(b) Concept: AccumulatedDeferredInvestmentTaxCredits

Note that at the end of the year, the balance of Accumulated Deferred Investment Tax Credits in Account 255 includes a transmission related component of $17.

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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	Deferred Tariff Revenue (30 year amortization)	4,333,400	146/456	866,664	0	3,466,736
2	Deferred Contract Obligation-CYAPC	2,156,368	182/234	77,227	86,059	2,165,200
3	Deferred Contract Obligation-MYAPC	898,624	182/234	31,403	37,581	904,802
4	Contribution in Aid of Construction	8,667,921	186	35,223,381	35,652,663	9,097,203
5	Deposits for Transmission Inter-connection Generator Agreements	0		0	0	0
6	EE Loan Funding	17,332,128	242/254	80,937,633	85,419,536	21,814,031
7	COVID-19 FICA Deferral	0		0	0	0
8	COVID-19 Accrual	1,299,611	921	0	0	1,299,611
9	Solar (NRES) Refundable Deposits	2,617,830	232	736,459	2,471,342	4,352,713
10	Minor Items (11)	6,580,484	107/186/234/242/254/921/924	13,577,743	17,801,104	10,803,845
47	TOTAL	43,886,366		131,450,510	141,468,285	53,904,141

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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				ADJUSTMENTS				Balance at End of Year
			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)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	

											(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)	0									0
18	Classification of TOTAL										
19	Federal Income Tax										
20	State Income Tax										
21	Local Income Tax										

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
			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)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 282										
2	Electric	1,723,721,843	76,183,820	2,095,757				8,538,621		19,284,352	1,808,555,637
3	Gas	0									
4	Other (Specify)	0									
5	Total (Total of lines 2 thru 4)	1,723,721,843	76,183,820	2,095,757				8,538,621		19,284,352	1,808,555,637
6	Other Income and Deductions	22,322,370									22,322,370
7		0									
9	TOTAL Account 282 (Total of Lines 5 thru 8)	1,746,044,213	76,183,820	2,095,757				8,538,621		19,284,352	1,830,878,007

10	Classification of TOTAL										
11	Federal Income Tax	1,311,457,665	61,151,929	1,245,986				8,538,621			1,362,824,987
12	State Income Tax	434,586,548	15,031,891	849,771						19,284,352	468,053,020
13	Local Income Tax	0									

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

Note that at the beginning of the year, the total balance of Accumulated Deferred Income Taxes in Account 282 includes a transmission related component of $744,487,483.

(b) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

Note that at the end of the year, the total balance of Accumulated Deferred Income Taxes in Account 282 includes a transmission related component of $785,684,059.

Annual Report of THE CONNECTICUT LIGHT AND POWER COMPANY
Year Ended December 31, 2025
Accumulated Deferred Income Taxes (Account 282)

	Beginning Balance	Activity	Ending Balance
Account 282000			
ADIT - Fed Liberalized Prop	2,076,042,130	58,584,878	2,134,627,008
Account 282DK0			
ADIT Prop FAS 109	(329,997,917)	26,248,916	(303,749,001)
TOTAL ACCOUNT 282	1,746,044,213	84,833,794	1,830,878,007

Annual Report of THE CONNECTICUT LIGHT AND POWER COMPANY
Year Ended December 31, 2025
Accumulated Deferred Income Taxes (Account 282) - TRANSMISSION

	Beginning Balance	Activity	Ending Balance
Account 282000			
ADIT - Fed Liberalized Prop	958,369,368	35,242,462	993,611,830
Account 282DK0			
ADIT Prop FAS 109	(213,881,885)	5,954,114	(207,927,771)
TOTAL ACCOUNT 282	744,487,483	41,196,576	785,684,059

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
			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)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 283										
2	Electric										
3	Electric	686,539,422	29,003,033	51,150,930						12,213,999	676,605,524

9	TOTAL Electric (Total of lines 3 thru 8)	686,539,422	29,003,033	51,150,930						12,213,999	676,605,524
10	Gas										
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other	24,711,774			4,918	304,490					24,412,202
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	[a]711,251,196	29,003,033	51,150,930	4,918	304,490				12,213,999	[b]701,017,726
20	Classification of TOTAL										
21	Federal Income Tax	528,428,319	20,307,656	35,815,410	4,918	213,205				8,803,679	521,515,957
22	State Income Tax	182,822,877	8,695,377	15,335,520		91,285				3,410,320	179,501,769
23	Local Income Tax										

NOTES

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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

For the beginning of the year balance please refer to footnote b and attached table.

(b) Concept: AccumulatedDeferredIncomeTaxesOther

Annual Report of **THE CONNECTICUT LIGHT AND POWER COMPANY**
Year Ended December 31,2025
Accumulated Deferred Income Taxes (Account 283)

	Beginning Balance	Activity	Ending Balance
Account 283 DG			
FAS 109 Gross-Up	$ 200,094,958	$ 6,189,729	$ 206,284,687
Account 283DK0			
FAS 109 Regulatory Asset	23,164,821	7,574,344	30,739,165
Account 283CP0			
Comprehensive Income	197,152	(29,047)	168,105
Account 283VA0			
Valuation Allowance	3	(3)	—
Account 283990			
Derivatives - Assets	3,810,834	(3,810,834)	—
Employee Benefits	50,871,365	9,640,623	60,511,988
Property Taxes	8,842,319	954,911	9,797,230
Regulatory Deferrals	411,052,265	(32,112,507)	378,939,758
Other	13,217,479	1,359,314	14,576,793
Sub-Total Account 28399	487,794,262	(23,968,493)	463,825,769
TOTAL ACCOUNT 283	$ 711,251,196	$ (10,233,470)	$ 701,017,726

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Annual Report of **THE CONNECTICUT LIGHT AND POWER COMPANY**
Year Ended December 31,2025
Accumulated Deferred Income Taxes (Account 283)-Transmission

	Beginning Balance	Activity	Ending Balance
Account 283 DG			
FAS 109 Gross-Up	$ 15,120,153	$ 38,146	$ 15,158,299
Account 283DK0			
FAS 109 Regulatory Asset	3,580,319	(9,600)	3,570,719
Account 283CP0			
Comprehensive Income	89,531	(13,186)	76,345
Account 283VA0			
Valuation Allowance	6	(2)	4
Account 283990			
Derivatives - Assets	—	—	—
Employee Benefits	5,306,494	864,716	6,171,210
Property Taxes	15,849,212	954,911	16,804,123
Regulatory Deferrals	1,748,617	413,726	2,162,343
Other	(2,949,538)	(83,239)	(3,032,777)
Sub-Total Account 28399	19,954,785	2,150,114	22,104,899

TOTAL ACCOUNT 283	$ 38,744,794	$ 2,165,472	$ 40,910,266

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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	AFUDC Regulatory Liability	[a]39,013,088	407	[a]1,402,632	0	[a]37,610,456
2	FASB ASC 740 Regulatory Liability	[a]15,836,267	190,282,283	3,008,076	941,567	[a]13,769,758
3	Non-SERP Unamortized Gains	126,017	228,926	29,795	0	96,222
4	Regulatory Liability Stranded Costs Docket No. 98-01-02	771,699	254,456	771,700	751,051	751,050
5	Reserve for C&LM projects Docket No. 13-03-02	22,014,150	142,908	64,327,012	69,146,166	26,833,304
6	All Connect Commissions Deferral Docket No. 09-12-05	119,329		11,071		108,258
7	NEIL Distribution Docket No. 99-03-36	5,543,554	254	5,736,681	4,476,269	4,283,142
8	Adjustment for Rate Adj Mechanisms	13,800,389	593	13,589,637	17,352,102	17,562,854
9	Unrecovered Contract Obligation Maine Yankee	8,392,734		37,543	0	8,355,191
10	Regulatory Liability From Federal Income Tax Rate Reduction	[a]956,625,956	190,282,283,411	23,296,907	0	[a]933,329,049
11	Deferred Fee for Free Program Docket No 17-10-46	5,593,267	407	221,268	392,089	5,764,088
12	Boiler/Furnace Program Loans	80,302,681	143,186	315,116,854	306,372,177	71,558,004
13	CAM GET Deferral	22,076,490		0	4,415,298	26,491,788
14	Transmission Tariff Deferral Docket No. ER03-1247	49,287,522	431,449,565	49,287,522	0	0
15	AFUDC on Transmission	[a]24,060,616	407	[a]1,238,884	11,591,802	[a]34,413,534
16	FASB ASC 960/962 SERP	599,945	228	225,698	0	374,247
17	MedVantage APBO	151,926	228,926	30,497	63,148	184,577
18	PBOP Transmission Deferral Docket ER-20-2054-000	856,322		0	397,506	1,253,828
19	C&LM Deferral Docket No. 13-03-02	6,465,909	242,421,431,908	156,805,818	164,261,631	13,921,722
20	FASB ASC 960-962 PBOP	3,856,211		0	4,602,875	8,459,086
21	System Benefit Charge Deferral Docket No. 99-06-36	0	407	106,941,274	215,543,342	108,602,068
22	FMCC Deferral Docket No. 99-03-36	0	407,555	148,446,193	370,123,645	221,677,452
41	TOTAL	1,255,494,072		890,525,062	1,170,430,668	1,535,399,678

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: OtherRegulatoryLiabilities

Schedule Page: 278 Line No.: 1 Column: b
The balance at the end of the year, December 31, 2024, AFUDC Regulatory Liability includes a transmission related PTF amount of $39,013,088 and a transmission related non-PTF amount of $0.

(b) Concept: OtherRegulatoryLiabilities

Schedule Page: 278 Line No.: 2 Column: b

Note that the balance of FASB ASC 740 regulatory liability at December 31, 2024 includes a transmission related component of $251,466.

(c) Concept: OtherRegulatoryLiabilities

Schedule Page: 278 Line No.: 10 Column: b

As of December 31, 2024, of the total excess unamortized ADIT balance at CL&P of $956,625,956 the balance related to CL&P Transmission $332,480,430.

(d) Concept: OtherRegulatoryLiabilities

Schedule Page: 278 Line No.: 15 Column: b

The balance at the end of the year, December 31, 2024, AFUDC on Transmission includes a transmission related PTF amount of $20,679,738 and a transmission related non-PTF amount of $3,380,878.

(e) Concept: DecreaseInOtherRegulatoryLiabilities

Schedule Page: 278 Line No.: 1 Column: d
The activity of $1,402,632 for the 2025 AFUDC Regulatory Liability includes a transmission related PTF amount of $1,402,632 and a transmission related non-PTF amount of $0.

(f) Concept: DecreaseInOtherRegulatoryLiabilities

Schedule Page: 278 Line No.: 15 Column: d
The activity of $1,238,885 for 2025 includes a transmission related PTF amount of $737,710 and a transmission related non-PTF amount of $501,174.

(g) Concept: OtherRegulatoryLiabilities

Schedule Page: 278 Line No.: 1 Column: f
The balance at the end of the year, December 31, 2025, AFUDC Regulatory Liability includes a transmission related PTF amount of $37,610,456 and a transmission related non-PTF amount of $0.

(h) Concept: OtherRegulatoryLiabilities

Schedule Page: 278 Line No.: 2 Column: f

Note that the balance of FASB ASC 740 regulatory liability at December 31, 2025 includes a transmission related component of $251,466.

(i) Concept: OtherRegulatoryLiabilities

Schedule Page: 278 Line No.: 10 Column: f

As of December 31, 2025, of the total excess unamortized ADIT balance at CL&P of $933,329,049 the balance related to CL&P Transmission $324,487,287.

(j) Concept: OtherRegulatoryLiabilities

The balance at the end of the year, December 31, 2025, AFUDC on Transmission includes a transmission related PTF amount of $28,218,833.73 and a transmission related non-PTF amount of $6,194,700.

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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	2,716,060,536	2,493,675,941	10,133,998	9,853,626	1,193,581	1,174,421

3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	1,236,908,588	1,139,782,384	8,334,634	8,411,140	108,519	108,554
5	Large (or Ind.) (See Instr. 4)	175,418,190	164,225,793	1,675,394	1,660,668	2,785	2,826
6	(444) Public Street and Highway Lighting	13,103,024	12,570,670	48,583	48,550	5,053	5,076
7	(445) Other Sales to Public Authorities						
8	(446) Sales to Railroads and Railways	13,906,867	12,439,119	158,257	177,405	2	2
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	[a]4,155,397,205	[a]3,822,693,907	[a]20,350,866	[a]20,151,389	1,309,940	1,290,879
11	(447) Sales for Resale	779,806,991	464,660,155	9,632,779	9,243,225	30	30
12	TOTAL Sales of Electricity	4,935,204,196	4,287,354,062	29,983,645	29,394,614	1,309,970	1,290,909
13	(Less) (449.1) Provision for Rate Refunds	25,735,268	(17,203,302)				
14	TOTAL Revenues Before Prov. for Refunds	4,909,468,928	4,304,557,364	29,983,645	29,394,614	1,309,970	1,290,909
15	Other Operating Revenues						
16	(450) Forfeited Discounts	6,309,970	8,434,816				
17	(451) Miscellaneous Service Revenues	[b]2,363,401	[b]2,547,921				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	[c]25,564,863	[c]25,597,637				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	[d]361,796	[d]345,222				
22	(456.1) Revenues from Transmission of Electricity of Others	[e]299,201,370	262,164,841				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	333,801,400	299,090,437				
27	TOTAL Electric Operating Revenues	5,243,270,328	4,603,647,801				

Line12, column (b) includes $ 3,749,818 of unbilled revenues.
Line12, column (d) includes 80,840 MWH relating to unbilled revenues

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: SalesToUltimateConsumers

Total Revenues derived from retail customers includes $3,749,818 of unbilled revenues for the year 2025. See page 304 for details of unbilled revenues by customer class.

(b) Concept: MiscellaneousServiceRevenues

Account 451 includes $1,419,868 of Reconnection Fees and $838,920 of Returned Check Charges for the year 2025.

(c) Concept: RentFromElectricProperty

Account 454 includes $7,426,323 Rental Revenue related to transmission for the year 2025:

Billboard	62,169
Building	83,640
Fiber Optic	846,101
Land Use	6,000
Parking/Access	574,816

Wireless	5,745,968
Review Fee	20,250
Substation and Right of Way	87,379
Total	7,426,323

(d) Concept: OtherElectricRevenue

Account 456 Other Electric Revenues includes $-0- transmission related revenues for the year 2025.

(e) Concept: RevenuesFromTransmissionOfElectricityOfOthers

Refer to Pages 328-330 for details.

(f) Concept: SalesToUltimateConsumers

Total Revenues derived from retail customers includes $2,355,767 of unbilled revenues for the year 2024.

(g) Concept: MiscellaneousServiceRevenues

Account 451 includes $1,478,878 of Reconnection Fees and $1,020,700 of Returned Check Charges for the year 2024.

(h) Concept: RentFromElectricProperty

Account 454 includes $7,066,651 Rental Revenue related to transmission for the year 2024:

Billboard	48,060
Building	81,204
Fiber Optic	879,474
Land Use	(17,500)
Parking/Access	236,992
Wireless	5,819,321
Review Fee	11,000
Substation and Right of Way	8,100
Total	7,066,651

(i) Concept: OtherElectricRevenue

Account 456 Other Electric Revenues includes $-0- transmission related revenues for the year 2024.

(j) Concept: MegawattHoursSoldSalesToUltimateConsumers

Instructions 9 - Unmetered Sales:

Residential	1,713
Commercial/Industrial	55,808
Streetlights	48,547
Total	106,068

The total "Megawatt Hours Sold" to CL&P retail customers represents the delivery of energy to all distribution customers including energy for customers who have chosen third party suppliers. In addition, it includes 80,840 MWHs related to unbilled revenues for the year 2025.

(k) Concept: MegawattHoursSoldSalesToUltimateConsumers

Instructions 9 - Unmetered Sales:

Residential	1,771
Commercial/Industrial	55,825
Streetlights	48,559
Total	106,155

The total "Megawatt Hours Sold" to CL&P retail customers represents the delivery of energy to all distribution customers including energy for customers who have chosen third party suppliers. In addition, it includes 14,381 MWHs related to unbilled revenues for the year 2024.

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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	Not Applicable				
46	TOTAL				

Name of Respondent:	This report is: (1) An Original	Date of Report:	Year/Period of Report

The Connecticut Light and Power Company	(2) A Resubmission	04/17/2026	End of: 2025/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	1 Residential	8,439,497	2,304,941,939	1,056,695	7,987	0.2731
2	5 Res. Electric Heating	1,594,819	400,613,723	135,883	11,737	0.2512
3	7 Time of Day	8,300	2,107,962	602	13,787	0.2540
4	18 Controlled Water Heating	17	4,778	10	1,700	0.2811
5	30 Small Gen Service	12,413	2,028,247	347	35,772	0.1634
6	35 Intermediate Gen Service	2,156	358,636	8	269,500	0.1663
7	37 Intermediate T-O-D	6,731	892,618	8	841,375	0.1326
8	56 Intermediate T-O-D	1,742	162,850	1	1,742,000	0.0935
9	115 Unmetered	42	9,049	25	1,680	0.2155
10	116 Street Lighting and Security	1,671	1,266,466	2,420	690	0.7579
11	30A Small Gen Service Alternative	216	62,486	10	21,600	0.2893
12	EVS Electric Vehicle Small		887	2		
13	Less: Duplicate Customers col d			(2,430)		
41	TOTAL Billed Residential Sales	10,067,604	2,712,449,641	1,193,581	8,435	0.2694
42	TOTAL Unbilled Rev. (See Instr. 6)	66,394	3,610,895			0.0544
43	TOTAL	10,133,998	2,716,060,536	1,193,581	8,490	0.2680

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	1 Residential (Commercial)	20,637	5,152,239	1,117	18,475	0.2497
2	5 Com. Electric Heating (Commercial)	3	1,015	1	3,000	0.3383
3	7 Time of Day (Commercial)	577	103,045	8	72,125	0.1786
4	18 Water Heating	702	122,491	132	5,318	0.1745

5	27 Time of Day (Commercial)	136,749	19,617,309	268	510,257	0.1435
6	29 Outdoor Recreational	1,723	967,082	219	7,868	0.5613
7	30 Small Gen. Service	3,146,509	593,214,770	96,305	32,672	0.1885
8	35 Intermediate Gen. Service (Commercial)	411,700	55,472,067	1,142	360,508	0.1347
9	37 Intermediate T-O-D Electric	1,151,722	148,709,821	1,305	882,546	0.1291
10	40 Church & School	75,934	13,983,877	1,701	44,641	0.1842
11	41 Large Church & School	11,957	1,618,907	10	1,195,700	0.1354
12	55 Intermediate T-O-D Manuf.	265,716	28,112,515	118	2,251,831	0.1058
13	56 Intermediate TOD Non-Man.	1,558,625	181,678,491	569	2,739,236	0.1166
14	57 Large T-O-D Manufacturers	200,318	17,101,499	18	11,128,778	0.0854
15	58 Large T-O-D Non-Man.	1,112,046	122,777,872	65	17,108,400	0.1104
16	115 Unmetered (Commercial)	47,189	7,073,286	2,130	22,154	0.1499
17	116 Street & Security Lighting	8,231	3,446,738	8,023	1,026	0.4188
18	119 Standby & Auxillary Power	222	26,665	0		0.1201
19	27A Time of Day Alternative	7,070	1,229,253	27	261,852	0.1739
20	30A Small Gen. Service Alternative (Commercial)	139,493	30,153,770	3,415	40,847	0.2162
21	EVL Electric Vehicle Large	29,070	5,424,942	27	1,076,667	0.1866
22	EVM Electric Vehicle Medium	3,219	706,401	32	100,594	0.2194
23	EVS Electric Vehicle Small	803	216,703	47	17,085	0.2699
24	Less: Duplicate Customers col d (Commercial)			(8,160)		
41	TOTAL Billed Small or Commercial	8,330,215	1,236,910,758	108,519	76,763	0.1485
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	4,419	(2,170)			(0.0005)
43	TOTAL Small or Commercial	8,334,634	1,236,908,588	108,519	76,803	0.1484

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SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	27 Time of Day	24,491	3,643,247	59	415,102	0.1488
2	30 Small Gen. Service	97,272	20,012,665	1,833	53,067	0.2057
3	35 Intermediate Gen. Serv	37,998	6,075,430	125	303,984	0.1599
4	37 Intermediate T-O-D	157,416	21,295,635	251	627,155	0.1353
5	39 Interruptible Service	226,711	9,030,751	3	75,570,333	0.0398
6	55 Inter. T-O-D Man.	379,870	39,341,535	167	2,274,671	0.1036

7	56 Inter. T-O-D Non-Man.	105,094	11,742,893	38	2,765,632	0.1117
8	57 Large TOD Manufacturer	562,661	51,629,188	55	10,230,200	0.0918
9	58 Large T-O-D Non-Manu.	51,863	8,017,766	7	7,409,000	0.1546
10	115 Unmetered (Industrial)	1	173	3	333	0.1730
11	116 Street & Security Light	387	132,360	277	1,397	0.3420
12	119 Standby & Auxillary Pwr	1,528	685,924	3	509,333	0.4489
13	27A Time of Day Alternative	4,968	781,698	17	292,235	0.1573
14	30A Small Gen. Service Alternative (Industrial)	14,251	2,872,884	225	63,338	0.2016
15	Less: Duplicate Customers col d (Industrial)			(278)		
41	TOTAL Billed Large (or Ind.) Sales	1,664,511	175,262,149	2,785	597,670	0.1053
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	10,883	156,041			0.0143
43	TOTAL Large (or Ind.)	1,675,394	175,418,190	2,785	601,578	0.1047

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SALES OF ELECTRICITY BY RATE SCHEDULES

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3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	115 Unmetered	8,817	1,485,582	1,929	4,571	0.1685
2	116 Street & Security Lighting	17,496	8,405,608	2,307	7,584	0.4804
3	117 Partial Street Lighting	22,234	3,212,547	817	27,214	0.1445
41	TOTAL Billed Public Street and Highway Lighting	48,547	13,103,737	5,053	9,608	0.2699
42	TOTAL Unbilled Rev. (See Instr. 6)	36	(713)			(0.0198)
43	TOTAL	48,583	13,103,024	5,053	9,615	0.2697

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SALES OF ELECTRICITY BY RATE SCHEDULES

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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	Number and Title of Rate Schedule	MWh Sold	Revenue	Average Number of Customers	KWh of Sales Per Customer	Revenue Per KWh Sold

No.	(a)	(b)	(c)	(d)	(e)	(f)
1	58 Large T-O-D Non-Mfg	159,149	13,921,102	2	79,574,500	0.0875
41	TOTAL Billed Sales To Railroads and Railways	159,149	13,921,102	2	79,574,500	0.0875
42	TOTAL Unbilled Rev. (See Instr. 6)	(892)	(14,235)			0.0160
43	TOTAL	158,257	13,906,867	2	79,128,500	0.0879

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SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
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29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		25,735,268			

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
41	TOTAL Billed - All Accounts	20,270,026	4,151,647,387	1,309,940	15,474	0.2048
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	80,840	3,749,818			0.0464
43	TOTAL - All Accounts	20,350,866	4,155,397,205	1,309,940	15,536	0.2042

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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 long-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)		Megawatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	
1	Requirement Service:										
2	National Grid	RQ	(b) 1				5		1,032	624	1,656
3	(a) NSTAR Electric Company	RQ	(b) 1				41		5,684	5,820	11,504
4	Nonassociated Utilities/Companies:										
5	(a) Amerex Brokers, LLC	OS							(63,390)		(63,390)
6	(a) ICAP Energy LLC	OS							(19,300)		(19,300)
7	(a) GFI Securities, LLC	OS							(123,950)		(123,950)
8	(a) ISO New England	OS	(b) 5				9,632,733		640,491,118	33,796,593	674,287,711
9	(f) Marex Spectron	OS							(86,841)		(86,841)
10	(a) Other Purchasers								105,799,601		105,799,601
15	Subtotal - RQ						46		6,716	6,444	13,160
16	Subtotal-Non-RQ						9,632,733		745,997,238	33,796,593	779,793,831
17	Total						9,632,779		746,003,954	33,803,037	779,806,991

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale

Associated Utility.

(b) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale

Broker Fees.

(c) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale

Broker Fees.

(d) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale

Broker Fees.

(e) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale

Short-term energy and capacity sales.

(f) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale

Broker Fees.

(g) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale

Short-term renewable energy credit sales related to procurement activities.

Listing of short-term renewable energy credit sales related to procurement activities:

Line #	Name of Company or Public Authority	Statistical Classification	MegaWatt Hours Sold	Energy Charges ($)	Other Charges ($)	Total Revenue ($)	
1	3Degrees Group, Inc.	OS			1,732,268		1,732,268
2	Burlington Elec. Dept.	OS			1,460,885		1,460,885
3	Constellation Energy Generation	OS			63,317,337		63,317,337
4	Dynegy Marketing and Trade, LLC	OS			1,930,000		1,930,000
5	EDP Renewables North America LLC	OS			2,980,000		2,980,000
6	Hartree Partners LP	OS			1,128,000		1,128,000
7	Just Energy Limited	OS			536,250		536,250
8	National Grid	OS			6,637,485		6,637,485
9	NextEra Energy Marketing	OS			5,615,856		5,615,856
10	NRG Business Marketing	OS			11,138,801		11,138,801
11	OTC Flow US Inc	OS			348,300		348,300
12	Sol Systems	OS			2,134,161		2,134,161
13	Vitol Inc.	OS			6,823,526		6,823,526
14	Vermont Public Power Supply Authority	OS			16,732		16,732
				—	105,799,601	—	105,799,601

(h) Concept: RateScheduleTariffNumber

Eversource Operating Companies FERC Electric Tariff Number 1.

(i) Concept: RateScheduleTariffNumber

Eversource Operating Companies FERC Electric Tariff Number 1.

(j) Concept: RateScheduleTariffNumber

MBR Tariff, Market Based Tariff 5.0.0

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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	0	0
5	(501) Fuel	0	0
6	(502) Steam Expenses	0	0

7	(503) Steam from Other Sources	0	0
8	(Less) (504) Steam Transferred-Cr.	0	0
9	(505) Electric Expenses	0	0
10	(506) Miscellaneous Steam Power Expenses	0	0
11	(507) Rents	0	0
12	(509) Allowances	0	(28,307,132)
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	0	(28,307,132)
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	0	0
16	(511) Maintenance of Structures	0	0
17	(512) Maintenance of Boiler Plant	0	0
18	(513) Maintenance of Electric Plant	0	0
18.1	(513.1) Maintenance of Computer Hardware		0
18.2	(513.2) Maintenance of Computer Software		0
18.3	(513.3) Maintenance of Communication Equipment		0
19	(514) Maintenance of Miscellaneous Steam Plant	0	0
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	0	0
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	0	(28,307,132)
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		0
25	(518) Fuel		0
26	(519) Coolants and Water		0
27	(520) Steam Expenses		0
28	(521) Steam from Other Sources		0
29	(Less) (522) Steam Transferred-Cr.		0
30	(523) Electric Expenses		0
31	(524) Miscellaneous Nuclear Power Expenses		0
32	(525) Rents		0
33	TOTAL Operation (Enter Total of lines 24 thru 32)	0	0
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		0
36	(529) Maintenance of Structures		0
37	(530) Maintenance of Reactor Plant Equipment		0
38	(531) Maintenance of Electric Plant		0
38.1	(531.1) Maintenance of Computer Hardware		0
38.2	(531.2) Maintenance of Computer Software		0
38.3	(531.3) Maintenance of Communication Equipment		0
39	(532) Maintenance of Miscellaneous Nuclear Plant		0
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	0	0
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)	0	0

42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		0
45	(536) Water for Power		0
46	(537) Hydraulic Expenses		0
47	(538) Electric Expenses		0
48	(539) Miscellaneous Hydraulic Power Generation Expenses		0
49	(540) Rents		0
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	0	0
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering		0
54	(542) Maintenance of Structures		0
55	(543) Maintenance of Reservoirs, Dams, and Waterways		0
56	(544) Maintenance of Electric Plant		0
56.1	(544.1) Maintenance of Computer Hardware		0
56.2	(544.2) Maintenance of Computer Software		0
56.3	(544.3) Maintenance of Communication Equipment		0
57	(545) Maintenance of Miscellaneous Hydraulic Plant		0
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	0	0
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	0	0
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	0	0
63	(547) Fuel	0	0
64	(548) Generation Expenses	0	0
65	(549) Miscellaneous Other Power Generation Expenses	0	0
66	(550) Rents		0
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	0	0
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		0
70	(552) Maintenance of Structures		0
71	(553) Maintenance of Generating and Electric Plant		0
71.1	(553.1) Maintenance of Computer Hardware		
71.2	(553.2) Maintenance of Computer Software		
71.3	(553.3) Maintenance of Communication Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		0
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	0	0
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	0	0
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	1,754,026,787	1,847,611,246

76.1	(555.1) Power Purchased for Storage Operations		
76.2	(555.2) Bundled Environmental Credits	81,752,885	
76.3	(555.3) Unbundled Environmental Credits	(31,152,166)	
77	(556) System Control and Load Dispatching	879	1,079
78	(557) Other Expenses	425,904	430,772
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	1,805,054,289	1,848,043,097
79.1	F. Solar Generation		
79.2	Operation		
79.3	(558.1) Operation Supervision and Engineering		
79.4	(558.2) Solar Panel Generation and Other Plant Operating Expenses		
79.6	(558.4) Rents		
79.7	TOTAL Operation (Enter Total of lines 79.3 thru 79.6)		
79.8	Maintenance		
79.9	(558.6) Maintenance Supervision and Engineering		
79.10	(558.7) Maintenance of Solar Panels, Structures, and Equipment		
79.11	(558.8) Maintenance of Computer Hardware		
79.12	(558.9) Maintenance of Computer Software		
79.13	(558.10) Maintenance of Communication Equipment		
79.14	(558.11) Maintenance of Miscellaneous Solar Generation Plant		
79.15	TOTAL Maintenance (Enter Total of lines 79.9 thru 79.14)		
79.16	TOTAL Power Production Expenses-Solar (total of lines 79.7 & 79.15)		
79.17	G. Wind Generation		
79.18	Operation		
79.19	(558.13) Operation Supervision and Engineering		
79.20	(558.14) Wind Turbine Generation and Other Plant Operating Expenses		
79.21	(558.16) Rents		
79.22	TOTAL Operation (Enter Total of lines 79.19 thru 79.21)		
79.23	Maintenance		
79.24	(558.18) Maintenance Supervision and Engineering		
79.25	(558.19) Maintenance of Wind Turbines, Structures, and Equipment		
79.26	(558.20) Maintenance of Computer Hardware		
79.27	(558.21) Maintenance of Computer Software		
79.28	(558.22) Maintenance of Communication Equipment		
79.29	(558.23) Maintenance of Miscellaneous Wind Generation Plant		
79.30	TOTAL Maintenance (Enter Total of lines 79.24 thru 79.29)		
79.31	TOTAL Power Production Expenses-Wind (total of lines 79.22 & 79.30)		
79.32	H. Other Renewable Generation		
79.33	Operation		
79.34	(559.1) Operation Supervision and Engineering		
79.35	(559.2) Other Miscellaneous Generation and Other Plant Operating Expenses		
79.36	(559.3) Fuel		

79.37	(559.4) Rents		
79.38	TOTAL Operation (Enter Total of lines 79.34 thru 79.37)		
79.39	Maintenance		
79.40	(559.6) Maintenance Supervision and Engineering		
79.41	(559.7) Maintenance of Structures		
79.42	(559.9) Maintenance of Boilers		
79.43	(559.10) Maintenance of Generating and Electric Equipment		
79.44	(559.12) Maintenance of Computer Hardware		
79.45	(559.13) Maintenance of Computer Software		
79.46	(559.14) Maintenance of Communication Equipment		
79.47	(559.15) Maintenance of Miscellaneous Renewable Production Plant		
79.48	TOTAL Maintenance (Enter Total of lines 79.40 thru 79.47)		
79.49	TOTAL Power Production Expenses-Other Renewable (total of lines 79.38 & 79.48)		
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74, 79, 79.16, 79.31, & 79.49)	1,805,054,289	1,819,735,965
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	8,920,524	7,966,544
85	(561.1) Load Dispatch-Reliability	3,893,885	3,704,631
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	5,343,803	5,122,197
87	(561.3) Load Dispatch-Transmission Service and Scheduling	4,836,258	4,807,636
88	(561.4) Scheduling, System Control and Dispatch Services	12,041,904	10,685,991
89	(561.5) Reliability, Planning and Standards Development	2,303,074	2,035,253
90	(561.6) Transmission Service Studies	1,632,628	1,272,112
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	39,659	(22,077)
93	(562) Station Expenses	9,008,838	7,551,340
94	(563) Overhead Lines Expenses	315,988	576,887
95	(564) Underground Lines Expenses	3,171,361	2,386,609
96	(565) Transmission of Electricity by Others	(6,825,197)	2,051,520
97	(566) Miscellaneous Transmission Expenses	1,115,976	1,581,241
98	(567) Rents	814,804	751,022
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	46,613,505	50,470,906
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	1,379,419	1,231,512
102	(569) Maintenance of Structures	3,348,480	3,286,773
103	(569.1) Maintenance of Computer Hardware	3,876,655	
104	(569.2) Maintenance of Computer Software	12,018,171	0
105	(569.3) Maintenance of Communication Equipment	652,136	
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	6,846,617	1,437,021
108	(571) Maintenance of Overhead Lines	37,432,189	42,672,264

109	(572) Maintenance of Underground Lines	111,876	119,665
110	(573) Maintenance of Miscellaneous Transmission Plant	4,932	3,715
111	TOTAL Maintenance (Total of Lines 101 thru 110)	65,670,475	48,750,950
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	[a]112,283,980	[a]99,221,856
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		0
116	(575.2) Day-Ahead and Real-Time Market Facilitation		0
117	(575.3) Transmission Rights Market Facilitation		0
118	(575.4) Capacity Market Facilitation		0
119	(575.5) Ancillary Services Market Facilitation		0
120	(575.6) Market Monitoring and Compliance		0
121	(575.7) Market Facilitation, Monitoring and Compliance Services	5,121,678	4,140,197
122	(575.8) Rents		0
123	Total Operation (Lines 115 thru 122)	5,121,678	4,140,197
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		0
126	(576.2) Maintenance of Computer Hardware		0
127	(576.3) Maintenance of Computer Software		0
128	(576.4) Maintenance of Communication Equipment		0
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		0
130	Total Maintenance (Lines 125 thru 129)	0	0
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	5,121,678	4,140,197
131.1	4. ENERGY STORAGE EXPENSES		
131.2	Operation		
131.3	(577.1) Operation Supervision and Engineering		
131.4	(577.2) Operation of Energy Storage Equipment		
131.5	(577.3) Storage Fuel		
131.6	(577.4) Rents		
131.7	Total Operation (Lines 131.3 thru 131.6)		
131.8	Maintenance		
131.9	(578.1) Maintenance Supervision and Engineering		
131.10	(578.2) Maintenance of Energy Storage Equipment and Structures		
131.11	(578.3) Maintenance of Computer Hardware		
131.12	(578.4) Maintenance of Computer Software		
131.13	(578.5) Maintenance of Communication Equipment		
131.14	(578.6) Maintenance of Miscellaneous Other Energy Storage Plant		
131.15	Total Maintenance (Lines 131.9 thru 131.14)		
131.16	TOTAL Energy Storage Expenses (Total of 131.7 and 131.15)		
132	5. DISTRIBUTION EXPENSES		
133	Operation		

134	(580) Operation Supervision and Engineering	11,057,815	13,234,118
135	(581) Load Dispatching	2,998,841	4,278,960
136	(582) Station Expenses	1,466,527	1,472,592
137	(583) Overhead Line Expenses	20,251,143	18,247,024
138	(584) Underground Line Expenses	2,691,778	5,210,650
139	(585) Street Lighting and Signal System Expenses	0	0
140	(586) Meter Expenses	3,463,361	1,923,310
141	(587) Customer Installations Expenses	256,661	226,609
142	(588) Miscellaneous Expenses	11,459,113	6,134,959
143	(589) Rents	1,917,459	1,801,982
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	55,562,698	52,530,204
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	2,095,587	1,859,430
147	(591) Maintenance of Structures	27,635	337,304
148	(592) Maintenance of Station Equipment	8,925,684	7,601,453
148.1	(592.2) Maintenance of Computer Hardware	10,261,414	
148.2	(592.3) Maintenance of Computer Software	18,778,677	
148.3	(592.4) Maintenance of Communication Equipment	940,861	
149	(593) Maintenance of Overhead Lines	163,740,608	147,868,629
150	(594) Maintenance of Underground Lines	7,756,230	5,341,736
151	(595) Maintenance of Line Transformers	1,204,062	2,906,914
152	(596) Maintenance of Street Lighting and Signal Systems	4,178,820	4,152,102
153	(597) Maintenance of Meters	1,546,061	1,361,561
154	(598) Maintenance of Miscellaneous Distribution Plant	1,771	(20)
155	TOTAL Maintenance (Total of Lines 146 thru 154)	219,457,410	171,429,109
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	275,020,108	223,959,313
157	6. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	0	0
160	(902) Meter Reading Expenses	5,029,067	4,893,517
161	(903) Customer Records and Collection Expenses	48,706,033	49,057,208
162	(904) Uncollectible Accounts	48,815,894	80,265,477
163	(905) Miscellaneous Customer Accounts Expenses	29,099,575	83,227,566
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	131,650,569	217,443,768
165	7. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		0
168	(908) Customer Assistance Expenses	255,211,241	219,524,040
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses	486,737	338,927
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	255,697,978	219,862,967

172	8. SALES EXPENSES		
173	Operation		
174	(911) Supervision		0
175	(912) Demonstrating and Selling Expenses		0
176	(913) Advertising Expenses		0
177	(916) Miscellaneous Sales Expenses	238	1,008
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	238	1,008
179	9. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	99,507,104	111,199,775
182	(921) Office Supplies and Expenses	7,637,869	7,643,862
183	(Less) (922) Administrative Expenses Transferred-Credit	10,855,516	11,719,637
184	(923) Outside Services Employed	10,055,129	49,376,228
185	(924) Property Insurance	[a]2,054,077	[a]2,104,646
186	(925) Injuries and Damages	10,154,049	10,598,268
187	(926) Employee Pensions and Benefits	9,733,062	8,065,257
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	[a]27,765,946	[a]26,085,130
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	[a](27,172)	[a]102,791
192	(930.2) Miscellaneous General Expenses	24,812,460	23,813,817
193	(931) Rents	8,712,225	8,630,005
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	189,549,233	235,900,142
195	Maintenance		
196	(935) Maintenance of General Plant	166,980	257,204
196.1	(935.1) Maintenance of Computer Hardware		
196.2	(935.2) Maintenance of Computer Software		
196.3	(935.3) Maintenance of Communication Equipment		
196.4	TOTAL Maintenance (Enter Total of lines 196 thru 196.3)	166,980	257,204
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196.4)	[a]189,716,213	[a]236,157,346
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 131.16, 156, 164, 171, 178, and 197)	2,774,545,053	2,820,522,420

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: TransmissionExpenses

Information on Formula Rates:

Calculated per company records as stipulated per contract.

Reference Page 106 lines 4, 5, 6, 7, 8 and 13.

(b) Concept: PropertyInsurance

For the year ended December 31, 2025, for transmission related balance refer to footnote line 197, 2025 table.

(c) Concept: RegulatoryCommissionExpenses

For the year ended December 31, 2025, for transmission related balance refer to footnote line 197, 2025 table.

(d) Concept: GeneralAdvertisingExpenses

For the year ended December 31, 2025, for transmission related balance refer to footnote line 197, 2025 table.

(e) Concept: AdministrativeAndGeneralExpenses

For the year ended December 31, 2025, the total amount of Administrative and General Expenses in Accounts 920 through 935 includes a transmission related component of $56,136,778.

2025		
35,374,216	FERC Account	920
1,886,186	FERC Account	921
(3,920,100)	FERC Account	922
5,565,584	FERC Account	923
1,213,839	FERC Account	924
2,241,834	FERC Account	925
1,613,558	FERC Account	926
3,423,944	FERC Account	928
614	FERC Account	930.1
6,382,032	FERC Account	930.2
2,312,639	FERC Account	931
42,432	FERC Account	935
56,136,778	TOTAL 920-935	

For the year ended December 31 2025 there were no merger related costs included in the Administrative and General Expenses in Accounts 920 through 935.
For the year ended December 31, 2025 there were no transmission related merger amortization costs included in the Administrative and General Expenses in Accounts 920 through 935.

(f) Concept: TransmissionExpenses

Information on Formula Rates:

Calculated per company records as stipulated per contract.

Reference Page 106 lines 4, 5, 6, 7, 8 and 13.

(g) Concept: PropertyInsurance

For the year ended December 31, 2024, for transmission related balance refer to footnote line 197, 2024 table.

(h) Concept: RegulatoryCommissionExpenses

For the year ended December 31, 2024, for transmission related balance refer to footnote line 197, 2024 table.

(i) Concept: GeneralAdvertisingExpenses

For the year ended December 31, 2024, for transmission related balance refer to footnote line 197, 2024 table.

(j) Concept: AdministrativeAndGeneralExpenses

For the year ended December 31, 2024, the total amount of Administrative and General Expenses in Accounts 920 through 935 includes a transmission related component of $68,782,864.

2024		
39,154,893	FERC Account	920
2,027,057	FERC Account	921
(4,083,984)	FERC Account	922
18,220,155	FERC Account	923
1,239,936	FERC Account	924
2,245,968	FERC Account	925
(948,984)	FERC Account	926
2,950,700	FERC Account	928
(1,641)	FERC Account	930.1
5,667,013	FERC Account	930.2
2,277,758	FERC Account	931
33,993	FERC Account	935
68,782,864	TOTAL	

For the year ended December 31 2024 there were no merger related costs included in the Administrative and General Expenses in Accounts 920 through 935.
For the year ended December 31, 2024 there were no transmission related merger amortization costs included in the Administrative and General Expenses in Accounts 920 through 935.

Name of Respondent: The Connecticut Light and Power Company	(1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES		COST/SETTLEMENT OF POWER			
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total (k+l+m) of Settlement ($) (n)
1	Associated Utilities:													0
2	[a] NSTAR Electric Company	OS					33					5,267	6,124	11,391
3	Nonassociated Utilities/ Companies:													
4	[b] Boston Energy	OS					72,980					7,916,044		7,916,044
5	[c] Calpine Energy	OS					960,810					118,490,138		118,490,138
6	[d] CFD Contractual Obligations	LU											57,882,109	57,882,109
7	[e] Connecticut Green Bank	OS					0					9,875,618		9,875,618
8	[f] Competitive Suppliers	OS					10,042,091							
9	[g] Constellation Energy Corporation	OS					4,614,720					524,893,771		524,893,771
10	[h] DTE Energy Trading Inc	OS					59,491					8,207,764		8,207,764

11	[f] ISO New England	OS	[ae] ISO-NE				34,963					3,348,985	592,187	3,941,172
12	[f] New York State Electric & Gas	OS	NYSE&G 85				126					12,294	3,969	16,263
13	[k] J. Aron	OS					522,602					54,887,364		54,887,364
14	[l] NextEra Energy Power Marketing, LLC	OS					3,005,294					335,676,077		335,676,077
15	[m] New Brunswick Energy	OS					518,874					59,232,556		59,232,556
16	[n] Peaker Contractual Obligations	LU											19,569,266	19,569,266
17	[o] Project 150 Cost Sharing Contracts	LU					301,918					38,134,902	(1,125,070)	37,009,832
18	[p] Section 1(b) Contractual Obligations	LU					167,176					13,718,777	(5,221,033)	8,497,744
19	[q] Section 1(c) Contractual Obligations	LU					178,976					14,884,638		14,884,638
20	[r] Section 3 Contractual Obligations	LU					49,031					2,316,006		2,316,006
21	[s] Section 6 Contractual Obligations	LU					31,383					3,398,037		3,398,037
22	[t] Section 8 Contractual Obligations	LU					278,772					27,908,600		27,908,600
23	[u] Section 127 Contractual Obligations	LU					49,646					7,696,050		7,696,050
24	[v] Section 127 Cost Sharing Contracts	LU					13,607					2,669,984		2,669,984
25	[w] United Illuminating Company	OS					34					4,223	6,262	10,485
26	Vermont Yankee Nuclear Power Corp.	LU	[aa] VYNPC 12										14,072	14,072
27	[x] Zero Carbon Emissions Contracts	LU					8,558,891					409,188,349		409,188,349
28	[y] Macquarie Energy LLC	OS					518,874					54,501,311		54,501,311
29	Municipals:													
30	[z] South Norwalk 4th Taxing District	OS										4,177	4,648	8,825
31	[aa] Alternative Compliance Payments	OS										(27,659,405)		(27,659,405)
32	[ab] CLEAResult Consulting Inc.	OS										8,160,339		8,160,339
33	Energy Efficiency Incremental													
34	[ac] Bid Recovery	OS										7,094,044		7,094,044
35	[ad] Fuel Costs Deferred	OS											(125,634,636)	(125,634,636)
36	[ae] LREC/ZREC Program	OS										43,729,417		43,729,417
	[af]													

37	NRES Program	OS										2,938,991	(101,523)	2,837,468
38	[aa] Fuel Cell Program	OS										484,855		484,855
39	[ab] SCEF Program	OS										2,807,342	(16,500)	2,790,842
40	[ac] [ac] SRECTrade, Inc	OS											34,375	34,375
41	[ad] [ad] Other Sellers						97,801					6,113,580		6,113,580
42	[ae] [ae] Residential, Commercial, Industrial and Other Nonutility Generators	OS					120,144					149,204,109		149,204,109
43	[ag] [ag] Other Nonutility Generators	AD					(91)					357,047		357,047
44	[ag] RGGI Auction Proceeds	OS										(31,587,995)		(31,587,995)
15	TOTAL						30,198,146	0				1,858,613,256	(53,985,750)	1,804,627,506

FERC FORM NO. 1 (ED. 12-90)

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Borderline service.

(b) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Standard Offer Service.

(c) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Standard Offer Service.

(d) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Capacity Contracts for Differences implemented pursuant to Connecticut law as set forth in Connecticut Department of Public Utility Control Docket Nos. 05-07-14PH02 and 07-04-24 whereby CL&P's customers are financially responsible for 80% of the expenses and benefits under these contracts.

(e) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

SHREC (Solar Home Renewable Energy Certificates) created from qualified renewable energy projects as set forth in the Public Utilities Regulatory Authority's Docket No. 16-05-07.

(f) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Represents energy for those customers who have chosen third party suppliers. The Connecticut Light and Power Company delivers energy to these customers, but does not bear the supply costs.

(g) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Standard Offer Service.

(h) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Standard Offer Service.

(i) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Short-term energy and capacity purchases.

(j) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Borderline service.

(k) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Standard Offer Service.

(l) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Standard Offer Service.

(m) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Standard Offer Service.
(n) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Peaking Generation Contracts implemented pursuant to Connecticut law as set forth in Connecticut Department of Public Utility Control Docket No. 08-01-01 whereby CL&P's customers are financially responsible for 80% of the expense and benefits under these contracts.
(o) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Long-term renewable energy contracts implemented pursuant to Connecticut law as set forth in Connecticut Public Utilities Docket Nos.08-03-03 and 07-04-27 whereby CL&P's customers are financially responsible for approximately 80% of the expenses and benefits under these contracts.
(p) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Purchase Power and Renewable Energy Certificate Agreements with Class 1 renewable generators implemented pursuant to Connecticut law as set forth in Connecticut Public Utilities Regulatory Authority Docket No.17-01-11.
(q) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Purchase Power and Renewable Energy Certificate Agreements with Class 1 renewable generators implemented pursuant to Connecticut law as set forth in Connecticut Public Utilities Regulatory Authority Docket No. 17-01-10.
(r) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Purchase Power and Renewable Energy Certificate Agreements with Class 1 renewable generators implemented pursuant to Connecticut law as set forth in Connecticut Public Utilities Regulatory Authority Docket No. 18-07-02.
(s) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Purchase Power and Renewable Energy Certificate Agreements with Class 1 renewable generators implemented pursuant to Connecticut law as set forth in Connecticut Public Utilities Regulatory Authority Docket No. 13-09-19.
(t) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Renewable Energy Certificate Agreements with Class 1 renewable generators implemented pursuant to Connecticut law as set forth in Connecticut Public Utilities Regulatory Authority Docket No. 14-02-02RE01.
(u) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Purchase Power and Renewable Energy Certificate Agreements with Class 1 renewable generators implemented pursuant to Connecticut law as set forth in Connecticut Public Utilities Regulatory Authority Docket Nos. 13-01-32 and 13-06-27.
(v) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Purchase Power and Renewable Energy Certificate Agreements with Class 1 renewable generators implemented pursuant to Connecticut law as set forth in Connecticut Public Utilities Regulatory Authority Docket No. 12-05-13 whereby CL&P customers are financially responsible for approximately 80% of the expenses and benefits under these contracts.
(w) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Borderline service.
(x) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Purchase Power Agreements with zero carbon emissions generated implemented pursuant to Connecticut law as set forth in Connecticut Public Utilities Regulatory Authority Docket No. 18-05-04.
(y) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Standard Offer Service.
(z) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Street Lighting.
(aa) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Connecticut Electric Suppliers' and Electric Distribution Companies' compliance with Connecticut's Renewable Energy Portfolio Standards pursuant to Connecticut Law as set forth in CT. Docket No. 17-06-23.
(ab) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
CLEAResult provides comprehensive calculations and distributes payments to Eversource Customers as Eversource's Solar Incentive Servicer for SMART Solar Program
(ac) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Connecticut Energy Efficiency Passive Demand Response Bid PA-15-107.
(ad) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Cumulative deferral of energy and other Standard Market Design product purchases made in support of supplying Standard Offer Service.
(ae) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Renewable Energy Certificates created from qualified renewable energy projects as set forth in the Public Utilities Regulatory Authority's approved CL&P's LREC/ZREC program as defined in Public Act 11-80(Section 107 for zero emissions projects and Section 110 for low emissions projects).
(af) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
NRES (Non-Residential Renewable Energy Solutions) Program requires Eversource to purchase REC's and energy from contracted counterparties known as Tariff Agreement Customers and allows for the collection of bid fees of $300 per applicant to cover bid and tariff agreement processing as set forth in the Public Utilities Regulatory Authority's Docket No. 21-08-03.
(ag) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
The Fuel Cell Program requires Eversource to issue incentive payments for fuel cell project owners as set forth in the Public Utilities Regulatory Authority's Docket No. 21-08-08.
(ah) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
SCEF (Shared Clean Energy Facilities) Program requires Eversource to purchase REC's and energy from system owners known as Subscriber Organizations and allows for the collection of bid fees of $750 agreement processing as set forth in the Public Utilities Regulatory Authority's Docket No. 19-07-01 & 23-08-04.

(ai) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Non-firm purchases from nonutility generators.

(aj) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Platform Fees

(ak) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Line #	Name of Company or Public Authority	Statistical Classification	MegaWatt Hours Purchased	Energy Charges ($)	Other Charges ($)	Total Settlement ($)
1	Avon Convalescent Home	OS	20	617		617
2	Barrow Solar	OS	3,149	155,308		155,308
3	Bristol Solar One	OS	4,902	244,905		244,905
4	Brookview Corp	OS	6	676		676
5	Burlington Solar One	OS	5,761	286,376		286,376
6	Clinton Solar	OS	1,655	80,761		80,761
7	Dayville Pond Hydro	OS	190	9,645		9,645
8	East Windsor Solar One	OS	6,475	341,954		341,954
9	Foxwoods	OS	6,397	389,724		389,724
10	Hartford Steam	OS	20,557	1,544,510		1,544,510
11	McHenry Solar	OS	1,583	75,715		75,715
12	Plainville Electrical Products	OS	245	15,526		15,526
13	Power Lines Solar	OS	3,830	193,207		193,207
14	Pratt & Whitney	OS	1,921	108,168		108,168
15	Putnam Hydro Power	OS	2,429	150,201		150,201
16	Rand-Whitney Containerboard	OS	18,746	1,454,386		1,454,386
17	Sandy Hook Hydro	OS	188	10,378		10,378
18	Saywatt Hydroelectric	OS	653	31,171		31,171
19	Southington Solar One	OS	8,971	458,585		458,585
20	Southington Cheshire YMCA	OS	17	862		862
21	TEN Companies	OS	14	2,183		2,183
22	Torrington Solar One	OS	3,226	160,417		160,417
23	Watertown Solar One	OS	2,924	145,312		145,312
24	WM Renewable Energy	OS	3,918	251,922		251,922
25	Individual Solar Generators	OS	24	1,071		1,071
		Totals	97,801	6,113,580	—	6,113,580

(al) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Non-firm purchases from nonutility generators.

(am) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Non-firm purchases from nonutility generators.

(an) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

This represents Residential, Commercial, Industrial and Nonutility Generators who generate energy and is recorded as Non-firm purchase power.

(ao) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Non-firm purchases from nonutility generators.

(ap) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Prior period adjustments for Other Nonutility Generators who generate energy and is recorded as Non-firm purchase power.

(aq) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Proceeds from 2025 Regional Greenhouse Gas Initiative Auction.

(ar) Concept: RateScheduleTariffNumber

ISO-New England, Inc. Transmission, Markets and Services Tariff.

(as) Concept: RateScheduleTariffNumber

Vermont Yankee Nuclear Power Corporation rate schedule number.

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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		REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS			
									Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
1	NEPOOL/ISO													
2	OATT - Regional Network Service	Not Applicable	Not Applicable	OS	ISO-NE OATT	Not Applicable	Not Applicable	0	0	0			244,170,704	244,170,704
3	OATT - Scheduling & Dispatch	Not Applicable	Not Applicable	OS	ISO-NE OATT	Not Applicable	Not Applicable	0	0	0			6,355,166	6,355,166
4	OATT - Through or Out Service	Not Applicable	Not Applicable	OS	ISO-NE OATT	Not Applicable	Not Applicable	0	0	0			4,817,571	4,817,571
5	TRANSMISSION SUPPORT													
6	Millstone 3 Support	Not Applicable	Not Applicable	OS	ISO-NE OATT	Not Applicable	Not Applicable	0	0	0			6,679,125	6,679,125
7	NETWORK SERVICE													
8	The Connecticut Light & Power Company	Associated Utility	The Connecticut Light & Power Co.	FNS	ISO-NE OATT	Various	CL&P System	0	20,492,217	20,492,217			0	0
9	CT Transmission Municipal Electric Energy Coop	Various New England Utilities	CT Transmission Municipal Elec	FNO	ISO-NE OATT	Various	CTMEEC System	0	1,167,070	1,167,070			3,165,832	3,165,832
10	GenConn Energy, LLC	Various	GenConn Energy, LLC	FNO	ISO-NE OATT	Various	GenConn System	0	2,392	2,392			9,208	9,208
11	Reserved for Future													
12	Reserved for Future>													
13	OTHER SERVICE													
14	Shared Microwave Transmission Revenue	Not Applicable	Not Applicable	OS	ISO-NE OATT	Not Applicable	Not Applicable	0	0	0			246,168	246,168
15	CPV Towantic, LLC	Not Applicable	Not Applicable	OS	ISO-NE OATT	Not Applicable	Not Applicable	0	2,847	2,847			1,299	1,299
16	AcrLight/Generation Bridge CT Holdings, LLC	Not Applicable	Not Applicable	OS	ISO-NE OATT	Not Applicable	Not Applicable	0	0	0			18,718	18,718
17	CT Transmission Municipal Electric Energy	Not Applicable	Not Applicable	OS	ISO-NE OATT	Not Applicable	Not Applicable	0	0	0			1,224,798	1,224,798
18	Dominion Energy Marketing, Inc.	Not Applicable	Not Applicable	OS	ISO-NE OATT	Not Applicable	Not Applicable	0	18,051	18,051			32,725	32,725
19	GB II Connecticut LLC- New Haven Harbor	Not Applicable	Not Applicable	OS	ISO-NE OATT	Not Applicable	Not Applicable	0	0	0			21,362	21,362
20	GB II Connecticut LLC- New Haven Peak	Not Applicable	Not Applicable	OS	ISO-NE OATT	Not Applicable	Not Applicable	0	0	0			3,729	3,729
21	GenConn Devon, LLC	Not Applicable	Not Applicable	OS	ISO-NE OATT	Not Applicable	Not Applicable	0	4,611	4,611			4,463	4,463
					ISO-NE	Not	Not							

22	GenConn Energy, LLC	Not Applicable	Not Applicable	OS	OATT	Applicable	Applicable	0	884	884			3,657	3,657
23	Kleen Energy Systems, LLC	Not Applicable	Not Applicable	OS	ISO-NE OATT	Not Applicable	Not Applicable	0	5,359	5,359			6,673	6,673
24	Milford Power Company, LLC	Not Applicable	Not Applicable	OS	ISO-NE OATT	Not Applicable	Not Applicable	0	4,565	4,565			2,724	2,724
25	NRG Energy, Inc.	Not Applicable	Not Applicable	OS	ISO-NE OATT	Not Applicable	Not Applicable	0	22,694	22,694			0	0
26	Quinebaug Solar	Not Applicable	Not Applicable	OS	ISO-NE OATT	Not Applicable	Not Applicable	0	0	0			761	761
27	Revere Power	Not Applicable	Not Applicable	OS	ISO-NE OATT	Not Applicable	Not Applicable	0	0	0			2,873	2,873
28	The United Illuminating Company	Not Applicable	Not Applicable	OS	ISO-NE OATT	Not Applicable	Not Applicable	0	0	0			7,364,076	7,364,076
29	Nutmeg Solar, LLC	Not Applicable	Not Applicable	OS	ISO-NE OATT	Not Applicable	Not Applicable	0	263	263			368	368
30	Wallingford Electric Department	Not Applicable	Not Applicable	OS	ISO-NE OATT	Not Applicable	Not Applicable	0	0	0			801,885	801,885
31	Waterbury Generation, LLC	Not Applicable	Not Applicable	OS	ISO-NE OATT	Not Applicable	Not Applicable	0	1,982	1,982			1,451	1,451
32	Reserved for Future>>													
33	Reserved for Future>>>													
34	NON FIRM WHEELING SERVICE													
35	Ahlstrom Nonwovens, LLC	Ahlstrom Nonwovens, LLC	NEPOOL PTF	NF	ISO-NE OATT	Windsor Locks Sub	NEPOOL PTF	0	61,923	61,923			262,859	262,859
36	Covanta Energy Marketing, LLC	Covanta Energy Marketing, LLC	NEPOOL PTF	NF	ISO-NE OATT	Hallville SS	NEPOOL PTF	0	0	0			371,503	371,503
37	FirstLight Power Resources, Inc	FirstLight Power Resources, Inc	NEPOOL PTF	NF	ISO-NE OATT	Various	NEPOOL PTF	0	145,086	145,086			637,314	637,314
38	Generate Colchester Fuel Cells, LLC	Generate Colchester Fuel Cells, LLC	NEPOOL PTF	NF	ISO-NE OATT	Judd Brooke Sub	NEPOOL PTF	0	14,342	14,342			61,021	61,021
39	Generate New Britain Fuel Cell, LLC	Generate New Britain Fuel Cell, LLC	NEPOOL PTF	NF	ISO-NE OATT	Various	NEPOOL PTF	0	163,566	163,566			699,449	699,449
40	Sterling Light Department	Sterling Light Department	NEPOOL PTF	NF	ISO-NE OATT	Tracy Substation	NEPOOL PTF	0	828	828			3,463	3,463
41	Sterling Municipal Light Department	Sterling Municipal Light Depart	NEPOOL PTF	NF	ISO-NE OATT	Tracy Substation	NEPOOL PTF	0	450	450			1,846	1,846
42	Woods Hill Solar, LLC	Woods Hill Solar, LLC	NEPOOL PTF	NF	ISO-NE OATT	Tracy Substation	NEPOOL PTF	0	8,898	8,898			42,634	42,634
43	Reserved for Future>>>>													
44	Reserved for Future>>>>>													
45	FIRM WHEELING SERVICE													
46	HQ Energy Services, U.S.	Hydro-Quebec	HQ Phase I or II	OLF	ISO-NE OATT	NE HVDC Border	HQ Phase I or II	0	648,123	648,123			18,860,155	18,860,155
47	MAG Energy Solutions Inc.	Hydro-Quebec	HQ Phase I or II	OLF	ISO-NE OATT	NE HVDC Border	HQ Phase I or II	0	278	278			2,459,126	2,459,126
48	NRG Energy, Inc.	NRG Energy, Inc.	NEPOOL PTF	LFP	ISO-NE OATT	Middletown 345 KV	NEPOOL PTF	0	68,484	68,484			866,664	866,664
35	TOTAL							0	22,834,913	22,834,913	0	0	299,201,370	299,201,370

FOOTNOTE DATA

(a) Concept: RevenuesFromTransmissionOfElectricityForOthers

Intracompany revenues are not reported on the FERC Form.

(b) Concept: RevenuesFromTransmissionOfElectricityForOthers

Schedule Page: 328 Line No.: 35 Column: n

This page represents customer S&D amounts reflected in the total $299,201,370

Ahlstrom Nonwovens, LLC	12,809
Covanta Energy Marketing, LLC	19,333
FirstLight Power Resources, Inc	30,301
Generate Colchester Fuel Cells, LLC	2,893
Generate New Britain Fuel Cell, LLC	32,990
Sterling Municipal Light Department	248
Woods Hill Solar, LLC	2,246
CT Transmission Municipal Electric Energy Coop - Network	159,466
GenConn Energy, LLC - Network	442
Total	260,728

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:
   FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter ""TOTAL"" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	CTMEEC	OS					158,923	158,923

2	ISO-NE	OS					11,954,367	11,954,367
3	National Grid	OS					6,446,596	[a]6,446,596
4	NSTAR Electric Company	OS					52,515	[b]52,515
5	NSTAR Electric Company(West)						582,516	[c]582,516
6	United Illuminating Co.	OS					5,841,075	5,841,075
7	Vermont Electric Transmission Company	OS					362,681	[d]362,681
8	Deferred Transm. Exp.	OS					(70,305,318)	(70,305,318)
9	Retail Transm. Deferral	OS					38,081,448	38,081,448
	TOTAL		0	0	0	0	(6,825,197)	(6,825,197)

FERC FORM NO. 1 (REV. 02-04)

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FOOTNOTE DATA

(a) Concept: ChargesForTransmissionOfElectricityByOthers

Hydro Quebec DC Phase II Support (New England Hydro Transmission Corp)	2,277,084
Hydro Quebec Phase II Support Chester SVC (New England Hydro Transmission Corp.)	115,423
Hydro Quebec DC Phase II Support (New England Hydro Transmission Electric Co.)	2,948,805
Hydro Quebec AC Phase II Support (New England Power Co.)	956,723
Hydro Quebec DC Phase I Support (New England Electric Transmission Corp.)	148,561
Total	6,446,596

(b) Concept: ChargesForTransmissionOfElectricityByOthers

Associated Company
Hydro Quebec AC Phase II Support (NSTAR) 52,515

(c) Concept: ChargesForTransmissionOfElectricityByOthers

Associated Company
NSTAR West 582,516

(d) Concept: ChargesForTransmissionOfElectricityByOthers

Associated Company
Hydro Quebec DC Phase I Support (Vermont Electric Transmission Co) 362,681

FERC FORM NO. 1 (REV. 02-04)

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	671,150
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	17,172
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Employee Compensation and Shareholder Expenses	960,932
7	Service Company Billing	21,368,050
8	Trustee Fees and Expense	675,990
9	Bank/Debt Fees and Other	1,119,166
46	TOTAL	24,812,460

FERC FORM NO. 1 (ED. 12-94)

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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			0	0	0
2	Steam Production Plant					0
3	Nuclear Production Plant					0
4	Hydraulic Production Plant-Conventional					0
5	Hydraulic Production Plant-Pumped Storage					0
5.1	Solar Production Plant					
5.2	Wind Production Plant					
5.3	Other Renewable Production Plant					
6	Other Production Plant					0
7	Transmission Plant	190,129,140				190,129,140
8	Distribution Plant	229,926,992				229,926,992
9	Regional Transmission and Market Operation					0
9.1	Energy Storage Plant					
10	General Plant	41,555,192		0		41,555,192
11	Common Plant-Electric					0
12	TOTAL	461,611,324	0	0	0	461,611,324

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)
12	Transmission - Non-Pro						
13	350	69,564			1.54%		
14	351.1	4,979			6.67%		
15	351.11	4,052			20%		
16	351.2	1,137			10%		
17	351.21	6,807			20%		

18	351.22	1,776			33.33%		
19	351.3	196,928			2.29%		
20	351.31	12,316			5%		
21	351.32	32			20%		
22	352	215,328			2.86%		
23	353	1,984,961			2.23%		
24	354	34,038			2.21%		
25	355	2,441,753			3.77%		
26	356	725,352			3.01%		
27	357	489,261			1.91%		
28	357.1	2,019			1.51%		
29	357.2	32			1.85%		
30	357.3	6			2.02%		
31	357.4	1,450			2.1%		
32	357.5	228			2.12%		
33	358	499,260			1.35%		
34	358.1	5,716			1.95%		
35	358.2	5,157			2.04%		
36	358.3	3,601			2.1%		
37	358.4	4,905			2.17%		
38	358.5	77,792			2.2%		
39	358.6	5,359			2.65%		
40	359	254,468			1.54%		
41	Subtotal Transmission	7,048,275					
42	Distribution						
43	360	5,297			1.17%		
44	361	99,931			2.19%		
45	362	1,109,109			2.38%		
46	363.1	7,921			6.67%		
47	363.11	6,709			20%		
48	363.2	7,584			10%		
49	363.21	31,564			20%		
50	[au] 363.22	15,241					
51	363.3	21,103			2.29%		
52	363.31	77,361			5%		
53	363.32	6			20%		
54	364	880,666			3.58%		
55	365	2,319,238			2.86%		
56	366	525,718			1.49%		
57	367	1,380,308			2.44%		
58	368	912,907			2.48%		
59	369	441,090			2.91%		

60	370	234,267			4.92%		
61	370.1	577			20%		
62	371	43,149			7.37%		
63	373	63,684			5.71%		
64	Subtotal Distribution	8,183,427					
65	General Plant						
66	390	278,881			1.98%		
67	390.1	1,119			10.28%		
68	391	4,915			6.67%		
69	391.1	1,470			20%		
70	393	10,875			5%		
71	394	92,508			4%		
72	394.1	2			33.33%		
73	(j) 394.2	279					
74	395	9,032			4%		
75	397	2,451			2.29%		
76	397.1	346			5%		
77	398	1,582			6.67%		
78	Subtotal General Plant	403,458					
79	Total	15,635,161					

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: AmortizationOfLimitedTermPlantOrProperty

Schedule Page: 336 Line No.: 1 Column: d

For transmission related component recorded to FERC Account 404, refer to footnote in column (f)

(b) Concept: AmortizationOfOtherElectricPlant

Schedule Page: 336 Line No.: 1 Column: e

For transmission related component recorded to FERC Account 405, refer to footnote in column (f)

(c) Concept: DepreciationAndAmortization

Schedule Page: 336 Line No.: 1 Column: f

Account	Transmission
404	$—
405	$—

Estimated depreciation accrual on AFUDC equity for the twelve months ending December 2025:
Transmission related component $0

(d) Concept: DepreciationAndAmortization

Schedule Page: 336 Line No.: 7 Column: f

Estimated depreciation accrual on AFUDC equity is for twelve months ended December 2025:
Transmission component $8,237,300

(e) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments

Schedule Page: 336 Line No.: 10 Column: b

For transmission related component recorded to FERC Account 403, refer to footnote in column (f)

(f) Concept: AmortizationOfLimitedTermPlantOrProperty

Schedule Page: 336 Line No.: 10 Column: d

For transmission related component recorded to FERC Account 404, refer to footnote in column (f)

(g) Concept: DepreciationAndAmortization

Schedule Page: 336 Line No.: 10 Column: f

Account	Transmission
403	$6,356,950
404	$—

Estimated depreciation accrual on AFUDC equity for the twelve months ending December 2025:
Transmission related component $30,675

(h) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

Schedule Page : 337 Line No.: 50 Column: e

An "End of Life" depreciation method is utilized for account 363.22. The depreciation rate is calculated monthly based off an end of life date of 12/2030.

(i) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

Schedule Page : 337 Line No.: 73 Column: e

An "End of Life" depreciation method is utilized for account 394.2. The depreciation rate is calculated monthly based off an end of life date of 11/2026.

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.
3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in columns (f), (g), and (h), expenses incurred during the year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

						EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR		
						CURRENTLY CHARGED TO						
Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)	Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
1	Connecticut Light and Power Company Assessments charged by State of Connecticut Department of Public Utilities	15,214,984		15,214,984		Electrical	928	15,214,984				
2	Rate Cases and various other regulatory proceedings before the State of Connecticut		6,245,212	6,245,212		Electrical	928	6,245,212				
3	Proportionate share of expenses of the State of Connecticut in connection with Consultant Fees for PURA, OCC, and AG	1,201,806		1,201,806		Electrical	928	1,201,806				
4	Proportionate share of expenses of the Connecticut Legislation in connection with Operation Fuel	1,680,000		1,680,000		Electrical	928	1,680,000				
5	Proportionate share of expenses of the Federal Energy Regualtory Commission (FERC) Assessment Order No. 472	2,654,159		2,654,159		Electrical	928	2,654,159				
	Rate cases and various other regulatory proceedings before the											

6	FERC Energy Regulatory Commission (FERC)		769,785	769,785		Electrical	928	769,785				
46	TOTAL	20,750,949	7,014,997	27,765,946				27,765,946				

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D and D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D and D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:
   Classifications:

   A. Electric R, D and D Performed Internally:

      1. Generation

         a. hydroelectric

            i. Recreation fish and wildlife
            ii. Other hydroelectric

         b. Fossil-fuel steam
         c. Internal combustion or gas turbine
         d. Nuclear
         e. Solar
         f. Wind
         g. Other renewable
         h. Unconventional generation
         i. Siting and heat rejection

      2. Transmission

         a. Overhead
         b. Underground

      3. Distribution
      4. Regional Transmission and Market Operation
      5. Energy Storage
      6. Environment (other than equipment)
      7. Other (Classify and include items in excess of $50,000.)
      8. Total Cost Incurred

   B. Electric, R, D and D Performed Externally:

      1. Research Support to the electrical Research Council or the Electric Power Research Institute
      2. Research Support to Edison Electric Institute
      3. Research Support to Nuclear Power Groups
      4. Research Support to Others (Classify)
      5. Total Cost Incurred

3. Include in column (c) all R, D and D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D and D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D and D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e).
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D and D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by ""Est.""
7. Report separately research and related testing facilities operated by the respondent.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)
					Amounts Charged In Current Year: Account (e)	Amounts Charged In Current Year: Amount (f)	
1	Electricity Utility RD&D Performed Internally			0		0	
2	Electricity Utility RD&D Performed Externally			0		0	
3	B. (1)	EPRI		208,142		208,142	
4	B. (4)	University of Connecticut - Energy Center		577,280	Various	577,280	
5	TOTAL			785,422		785,422	

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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	0		
4	Transmission	20,050,962		
5	Regional Market	0		
5.1	Energy Storage			
6	Distribution	38,998,394		
7	Customer Accounts	18,416,165		
8	Customer Service and Informational	9,777,736		
9	Sales	0		
10	Administrative and General	73,361,388		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	160,604,645		
12	Maintenance			
13	Production	0		
14	Transmission	11,570,448		
15	Regional Market	0		
15.1	Energy Storage			
16	Distribution	60,332,430		
17	Administrative and General	0		
18	TOTAL Maintenance (Total of lines 13 thru 17)	71,902,878		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	0		
21	Transmission (Enter Total of lines 4 and 14)	31,621,410		
22	Regional Market (Enter Total of Lines 5 and 15)	0		
22.1	Energy Storage (Enter Total of Lines 5.1 and 15.1)			
23	Distribution (Enter Total of lines 6 and 16)	99,330,824		
24	Customer Accounts (Transcribe from line 7)	18,416,165		
25	Customer Service and Informational (Transcribe from line 8)	9,777,736		
26	Sales (Transcribe from line 9)	0		
27	Administrative and General (Enter Total of lines 10 and 17)	73,361,388		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	232,507,523	(3,934,541)	228,572,982
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	0		
38	Customer Service and Informational	0		
39	Sales	0		
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)	0		
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)	0		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	0		
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,	0		
54	Other Gas Supply (Enter Total of lines 33 and 45)	0		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	0		
56	Transmission (Lines 35 and 47)	0		
57	Distribution (Lines 36 and 48)	0		
58	Customer Accounts (Line 37)	0		
59	Customer Service and Informational (Line 38)	0		
60	Sales (Line 39)	0		
61	Administrative and General (Lines 40 and 49)	0		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	0		
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	232,507,523	(3,934,541)	228,572,982
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	175,016,290	10,543,832	185,560,122
69	Gas Plant			

70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	175,016,290	10,543,832	185,560,122
72	Plant Removal (By Utility Departments)			
73	Electric Plant	12,829,187	16,712,171	29,541,358
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	12,829,187	16,712,171	29,541,358
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	146 Accounts Receivable from Associated Companies	23,450,438	0	23,450,438
80	163 Stores Expense Clearing	13,029,154	(15,180,014)	(2,150,860)
81	182 Deferred Storm Costs	20,188,223	0	20,188,223
82	183 Preliminary Survey & Investigation	100,096	0	100,096
83	184 Clearing Accounts	8,176,658	(8,176,658)	0
84	185 Temporary Services	19,549	4,695	24,244
85	186 Miscellaneous Deferred Debits	1,366,880	30,111	1,396,991
86	228 Injuries & Damages	107,616	39	107,655
87	252 Dist Gen Advance Cust Pmts	589	0	589
88	426 Miscellaneous Income Deductions	12,779,315	365	12,779,680
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	79,218,518	(23,321,462)	55,897,056
96	TOTAL SALARIES AND WAGES	499,571,518	0	499,571,518

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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.

Not applicable, no details for this page.

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

	(2) A Resubmission		

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, Purchase 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)	1,154,653	1,346,227	1,814,769	3,348,985
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(248,050,146)	(330,323,743)	(454,362,965)	(640,491,118)
4	Transmission Rights	(30,519)	(30,519)	(30,519)	(30,519)
5	Ancillary Services	18,435	(5,729,980)	(13,362,537)	(25,893,476)
6	Other Items (list separately)				
7	Auction Revenue Rights		3	14,234	7,149
8	NCPC Day Ahead				
9	Forward Capacity Market	(2,003,436)	(3,984,202)	(5,252,669)	(7,315,564)
10	Mystic Cost of Service	28,009	28,009	28,009	28,009
11	Inventoried Energy Program	20	(15)	(5)	(5)
46	TOTAL	(248,882,984)	(338,694,220)	(471,151,683)	(670,346,539)

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.
In columns for usage, report usage-related billing determinant and the unit of measure.

1. On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	[a]0	$/mw	19,704,410	[a]0	$/mw	14,017,672
2	Reactive Supply and Voltage	[a]0	$/mw	2,940,405	[a]0	$/mvar	157,909
3	Regulation and Frequency Response	[a]0	$/mwh	2,347	[a][a]0	$/mwh	2,882
4	Energy Imbalance	34,963	$/mwh	3,348,985	359,638	$/mwh	17,566,574
5	Operating Reserve - Spinning	0		[a]0	0		[a]0
6	Operating Reserve - Supplement	[a]0	$/mwh&$/mw	[a]142,064	[a]0	$/mwh&$/mw	[a]118,712
7	Other	[a][a]0	$/mw	9,013,961	0		0
8	Total (Lines 1 thru 7)	34,963		35,152,172	359,638		31,863,749

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedNumberOfUnits

Data is not readily available

(b) Concept: AncillaryServicesSoldNumberOfUnits

Data is not readily available

(c) Concept: AncillaryServicesPurchasedNumberOfUnits

Data is not readily available

(d) Concept: AncillaryServicesSoldNumberOfUnits

Data is not readily available

(e) Concept: AncillaryServicesPurchasedNumberOfUnits

Data is not readily available

(f) Concept: AncillaryServicesSoldNumberOfUnits

Data is not readily available

(g) Concept: AncillaryServicesSoldNumberOfUnits

Data is not readily available.

(h) Concept: AncillaryServicesPurchasedAmount

Allocation of Operating Reserves is not readily available.

(i) Concept: AncillaryServicesSoldAmount

Allocation of Operating Reserves is not readily available.

(j) Concept: AncillaryServicesPurchasedNumberOfUnits

Data is not readily available

(k) Concept: AncillaryServicesPurchasedAmount

Allocation of Operating Reserves is not readily available.

(l) Concept: AncillaryServicesSoldNumberOfUnits

Data is not readily available

(m) Concept: AncillaryServicesSoldAmount

Allocation of Operating Reserves is not readily available.

(n) Concept: AncillaryServicesPurchasedNumberOfUnits

Data is not readily available.

(o) Concept: AncillaryServicesPurchasedNumberOfUnits

Data is not readily available

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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	4,461	21	18	3,586	405		470		
2	February	4,279	18	19	3,421	373		485		
3	March	3,816	3	19	3,066	346		404		
4	Total for Quarter 1				10,073	1,124	0	1,359	0	0
5	April	3,025	8	20	2,734	291		0		
6	May	2,864	16	19	2,523	341		0		
7	June	5,956	24	18	4,952	600		404		
8	Total for Quarter 2				10,209	1,232	0	404	0	0
9	July	5,614	29	19	4,733	585		296		
10	August	5,006	13	16	4,093	509		404		
11	September	3,830	6	16	3,166	439		225		
12	Total for Quarter 3				11,992	1,533	0	925	0	0
13	October	3,105	7	19	2,766	339		0		
14	November	3,359	11	18	2,913	325		121		
15	December	3,965	15	18	3,540	391		34		
16	Total for Quarter 4				9,219	1,055	0	155	0	0
17	Total				41,493	4,944	0	2,843	0	0
	NAME OF SYSTEM: Not applicable									
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total									

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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: Not applicable									
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: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 2026-04-17	Year/Period of Report End of: 2025/ Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	(a)20,350,866
3	Steam		23	Requirements Sales for Resale (See instruction 4, page 311.)	46
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	9,632,733
5	Hydro-Conventional		25	Energy Furnished Without Charge	

6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
6.1	Solar		27	Total Energy Losses	214,501
6.2	Wind		27.1	Total Energy Stored	
6.3	Other Renewable		28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	30,198,146
7	Other				
8	Less Energy for Pumping				
9	Net Generation (Enter Total of lines 3 through 8)	0			
10	Purchases (other than for Energy Storage)	30,198,146			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)	0			
15	Transmission For Other (Wheeling)				
16	Received	22,834,913			
17	Delivered	22,834,913			
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)	30,198,146			

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 2026-04-17	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: MegawattHoursSoldSalesToUltimateConsumers

Instructions 9 - Unmetered Sales:

Residential	1,713
Commercial/Industrial	55,808
Streetlights	48,547
Total	106,068

The total "Megawatt Hours Sold" to CL&P retail customers represents the delivery of energy to all distribution customers including energy for customers who have chosen third party suppliers. In addition, it includes 80,840 MWHs related to unbilled revenues for the year 2025.

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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	2,866,707	861,354	3,607	22	19
30	February	2,524,039	781,325	3,428	18	19
31	March	2,487,788	885,874	3,082	4	19
32	April	1,997,657	603,941	2,749	8	21
33	May	2,093,904	650,168	2,573	16	19
34	June	2,686,385	860,805	4,967	24	19
35	July	3,119,923	883,862	4,735	29	19
36	August	2,626,668	823,410	4,208	14	18
37	September	2,365,638	846,322	3,171	6	16
38	October	2,177,291	726,206	2,784	6	19
39	November	2,416,006	846,410	2,941	20	18
40	December	2,836,140	863,055	3,546	15	18
41	Total	30,198,146	9,632,733			

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

Steam Electric Generating Plant Statistics

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.
9. Items under Cost of Plant are based on USofA accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Line No.	Item (a)	Plant Name: 0
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)	
6	Net Peak Demand on Plant - MW (60 minutes)	
7	Plant Hours Connected to Load	
8	Net Continuous Plant Capability (Megawatts)	
9	When Not Limited by Condenser Water	
10	When Limited by Condenser Water	
11	Average Number of Employees	
12	Net Generation, Exclusive of Plant Use - kWh	
13	Cost of Plant: Land and Land Rights	

14	Structures and Improvements	
15	Equipment Costs	
16	Asset Retirement Costs	
17	Total Cost (10-23)	
18	Cost per KW of Installed Capacity (line 17/5) Including	
19	Production Expenses: Oper, Supv, & Engr	
20	Fuel	
21	Coolants and Water (Nuclear Plants Only)	
22	Steam Expenses	
23	Steam From Other Sources	
24	Steam Transferred (Cr)	
25	Electric Expenses	
26	Misc Steam (or Nuclear) Power Expenses	
27	Rents	
28	Allowances	
29	Maintenance Supervision and Engineering	
30	Maintenance of Structures	
31	Maintenance of Boiler (or reactor) Plant	
32	Maintenance of Electric Plant	
33	Maintenance of Misc Steam (or Nuclear) Plant	
34	Total Production Expenses	0
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

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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)	
6	Net Peak Demand on Plant-Megawatts (60 minutes)	
7	Plant Hours Connect to Load	
8	**Net Plant Capability (in megawatts)**	
9	(a) Under Most Favorable Oper Conditions	
10	(b) Under the Most Adverse Oper Conditions	
11	Average Number of Employees	
12	Net Generation, Exclusive of Plant Use - kWh	
13	**Cost of Plant**	
14	Land and Land Rights	
15	Structures and Improvements	
16	Reservoirs, Dams, and Waterways	
17	Equipment Costs	
18	Roads, Railroads, and Bridges	
19	Asset Retirement Costs	
20	Total Cost (10-23)	
21	Cost per KW of Installed Capacity (line 20 / 5)	
22	**Production Expenses**	
23	Operation Supervision and Engineering	
24	Water for Power	
25	Hydraulic Expenses	
26	Electric Expenses	
27	Misc Hydraulic Power Generation Expenses	
28	Rents	
29	Maintenance Supervision and Engineering	
30	Maintenance of Structures	
31	Maintenance of Reservoirs, Dams, and Waterways	
32	Maintenance of Electric Plant	
33	Maintenance of Misc Hydraulic Plant	
34	Total Production Expenses (total 23 thru 33)	
35	Expenses per net kWh	

The Connecticut Light and Power Company	(1) An Original (2) A Resubmission	04/17/2026	End of: 2025/ 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)	0
6	Plant Hours Connect to Load While Generating	0
7	Net Plant Capability (in megawatts)	0
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - kWh	0
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	0
15	Reservoirs, Dams, and Waterways	0
16	Water Wheels, Turbines, and Generators	0
17	Accessory Electric Equipment	0
18	Miscellaneous Powerplant Equipment	0
19	Roads, Railroads, and Bridges	0
20	Asset Retirement Costs	0
21	Total Cost (10-23)	
22	Cost per KW of installed cap (line 21 / 4)	
23	**Production Expenses**	
24	Operation Supervision and Engineering	0
25	Water for Power	0
26	Pumped Storage Expenses	0
27	Electric Expenses	0
28	Misc Pumped Storage Power generation Expenses	0
29	Rents	0
30	Maintenance Supervision and Engineering	0

31	Maintenance of Structures	0
32	Maintenance of Reservoirs, Dams, and Waterways	0
33	Maintenance of Electric Plant	0
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

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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, pumped storage plants, and renewable 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, renewable, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 402.
4. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
									Fuel Production Expenses (i)	Maintenance Production Expenses (j)			
1													
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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

ENERGY STORAGE OPERATIONS (Large Plants)

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) and (b) report the name of the energy storage project and location.
3. In column (c), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In column (d) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (c) should include MWHs delivered/provided to a generator's own load requirements or used for the provision of ancillary services.
5. In column (e) report MWHs lost during conversion, storage and discharge of energy.
6. In column (f) report the MWHs sold.
7. In column (g), 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 (h), 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 (i) and (j), report fuel costs for storage operations associated with self-generated power and other costs associated with self-generated power.
9. In column (l) 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)	Location of the Project (b)	MWHs (c)	MWHs delivered to the grid (d)	MWHs Lost During Conversion, Storage and Discharge of Energy (e)	MWHs Sold (f)	Revenues from Energy Storage Operations (g)	Power Purchased for Storage Operations (555.1) (Dollars) (h)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (i)	Other Costs Associated with Self-Generated Power (Dollars) (j)	Account for Project Costs (k)	Total Project Plant Costs (l)
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31												
32												
33												
34												
35	TOTAL		0	0	0	0	0	0	0	0		0

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

ENERGY STORAGE OPERATIONS (Small Plants)

1. Small Plants are plants less than 10,000 Kw.
2. In columns (a) and (b) report the name of the energy storage project, and location.
3. In column (c), report project plant cost including but not exclusive of land and land rights, structures and improvements, energy storage equipment and any other costs associated with the energy storage project.
4. In column (d), report operation expenses excluding fuel, (e), maintenance expenses, (f) fuel costs for storage operations and (g) cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined.
5. If any other expenses, report in column (h) and footnote the nature of the item(s).

Line No.	Name of the Energy Storage Project (a)	Location of the Project (b)	Project Cost (c)	Plant Operating Expenses				
				Operations (Excluding Fuel used in Storage Operations) (d)	Maintenance (e)	Cost of fuel used in storage operations (f)	Account No. 555.1, Power Purchased for Storage Operations (g)	Other Expenses (h)
1								
2								
3								
4								
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35								
36	TOTAL							

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
4. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
5. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.
6. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).
7. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
8. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
9. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs	Operation Expenses	Maintenance Expenses	Rents	Total Expenses
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	Millstone Station	Manchester S/S	345	345	SCSP	4.41		1	2-1272 ACSR	134,876	125,668,898	125,803,774				
2	Millstone Station	Manchester S/S	345	345	SCHF	40.92		0	2-1272 ACSR	0	0	0				
3	Millstone Station	Manchester S/S	345	345	SCLT	1.61		0	2-1272 ACSR	0	0	0				
4	Long Mountain S/S	Plumtree S/S	345	345	SCHF	2.92		1	2-954 ACSR	4,544,038	21,817,862	26,361,900				
5	Long Mountain S/S	Plumtree S/S	345	345	SCLT	2.93		0	2-954 ACSR	0	0	0				
6	Long Mountain S/S	Plumtree S/S	345	345	SCSPHF	0.14		0	2-954 ACSR	0	0	0				
7	Long Mountain S/S	Plumtree S/S	345	345	DCSP		0.32	0	2-954 ACSR	0	0	0				
8	Long Mountain S/S	Plumtree S/S	345	345	SCSP	0.55		0	2-1272 ACSR	0	0	0				
	Long Mountain								2-1272							

9	S/S	Plumtree S/S	345	345	DCSP		10.90	0	ACSR	0	0	0				
10	Long Mountain S/S	Plumtree S/S	345	345	DCLT		0.08	0	2-1272 ACSR	0	0	0				
11	Frost Bridge S/S	Southington S/S	345	345	SCHF	12.72		1	2156 ACSR	744,279	29,185,158	29,929,437				
12	Card S/S	Lake Road S/S	345	345	SCHF	27.75		1	2-954 ACSR	1,273,834	49,367,575	50,641,409				
13	Card S/S	Lake Road S/S	345	345	SCSPHF	0.20		0	2-954 ACSR	0	0	0				
14	Card S/S	Lake Road S/S	345	345	SCSP	1.07		0	2-954 ACSR	0	0	0				
15	Card S/S	Lake Road S/S	345	345	SCSP	0.17		0	2-1272 ASCR	0	0	0				
16	Card S/S	Lake Road S/S	345	345	SCSP	0.03		0	2- 1590 ACSR	0	0	0				
17	Killingly S/S	CT/RI State Line (Sherman Rd. S/S)	345	345	SCHF	7.40		1	2-954 ACSR	583,659	13,762,544	14,346,203				
18	Killingly S/S	CT/RI State Line (Sherman Rd. S/S)	345	345				0		0	0	0				
19	Millstone Station	Haddam S/S (Beseck S/Sj)	345	345	SCSP	0.14		1	2-954 ACSR	3,297,783	68,060,940	71,358,723				
20	Millstone Station	Haddam S/S (Beseck S/Sj)	345	345	SCSP	3.95		0	2-1272 ACSR	0	0	0				
21	Millstone Station	Haddam S/S (Beseck S/Sj)	345	345	SCHF	21.30		0	2-954 ACSR	0	0	0				
22	Millstone Station	Haddam S/S (Beseck S/Sj)	345	345	DCLT	0.65		0	2-1192 ACSR	0	0	0				
23	Millstone Station	Haddam S/S (Beseck S/Sj)	345	345	DCLT	0.23		0	2-954 ACSR	0	0	0				
24	Frost Bridge S/S	Long Mountain S/S	345	345	SCHF	20.71		1	2156 ACSR	628,766	41,349,648	41,978,414				
25	Manchester S/S	Kleen S/S	345	345	SCHF	0.10		1	2-954 ACSR	569,209	32,940,689	33,509,898				
26	Manchester S/S	Kleen S/S	345	345	SCLT	1.21		0	2156 ACSR	0	0	0				
27	Manchester S/S	Kleen S/S	345	345	SCHF	15.05		0	2156 ACSR	0	0	0				
28	Manchester S/S	Kleen S/S	345	345	SCLT	0.03		0	2-1590 ACSR	0	0	0				
29	Manchester S/S	Kleen S/S	345	345	SCSPHF	0.21		0	2-1590 ACSR	0	0	0				
30	Kleen S/S	Scovill Rock S/S	345	345	SCSP	0.12		1	2-1590 ACSR	0	8,406,423	8,406,423				
31	Kleen S/S	Scovill Rock S/S	345	345	SCSPHF	0.88		0	2-1590 ACSR	0	0	0				
32	Kleen S/S	Scovill Rock S/S	345	345	SCHF	2.79		0	2-954 ACSR	0	0	0				
33	Haddam Neck S/S	Beseck Station	345	345	SCLT	4.63		1	2-954 ACSR	3,653,832	46,855,083	50,508,915				
34	Haddam Neck S/S	Beseck Station	345	345	SCSP	1.92		0	2-954 ACSR	0	0	0				
35	Haddam Neck S/S	Beseck Station	345	345	SCHF	7.21		0	2-954 ACSR	0	0	0				
36	Haddam Neck S/S	Beseck Station	345	345	SCSHF	0.04		0	2-954 ACSR	0	0	0				

37	Haddam Neck S/S	Beseck Station	345	345	SCLT	0.20		0	2-1192 ASCR	0	0	0				
38	Haddam Neck S/S	Beseck Station	345	345	TCSHF	0.43		0	2-1192 ACSR	0	0	0				
39	Haddam Neck S/S	Beseck Station	345	345	SCSP	2.68		0	2-1590 ACSR	0	0	0				
40	Haddam Neck S/S	Beseck Station	345	345	DCSP	1.13		0	2-1590 ACSR	0	0	0				
41	Haddam Neck S/S	Montville Station	345	345	SCHF	22.05		1	2-954 ACSR	775,111	49,051,782	49,826,893				
42	Haddam Neck S/S	Montville Station	345	345	SCSPHF	0.15		0	2-954 ACSR	0	0	0				
43	Haddam Neck S/S	Montville Station	345	345	SCLT	0.20		0	2-954 ACSR	0	0	0				
44	Haddam Neck S/S	Montville Station	345	345	TCLT	0.24		0	2-954 ACSR	0	0	0				
45	Manchester S/S	Card S/S	345	345	SCHF	0.09		1	2-1590 ACSR	694,560	42,958,337	43,652,897				
46	Manchester S/S	Card S/S	345	345	SCSP	0.61		0	2-1590 ACSR	0	0	0				
47	Manchester S/S	Card S/S	345	345	SCLT	0.12		0	2-1590 ACSR	0	0	0				
48	Manchester S/S	Card S/S	345	345	DCSP	0.99		0	2-1590 ACSR	0	0	0				
49	Manchester S/S	Card S/S	345	345	SCHF	17.97		0	2156 ACSR	0	0	0				
50	Manchester S/S	Card S/S	345	345	SCSP	0.13		0	2156 ACSR	0	0	0				
51	Millstone Station	Montville Station	345	345	SCSP	1.67		1	2-954 ACSR	1,408,808	30,111,531	31,520,339				
52	Millstone Station	Montville Station	345	345	SCHF	9.93		0	2-954 ACSR	0	0	0				
53	Millstone Station	Montville Station	345	345	SCSPHF	0.15		0	2-954 ACSR	0	0	0				
54	Millstone Station	Montville Station	345	345	TCLT	0.43		0	2-954 ACSR	0	0	0				
55	Haddam Neck S/S	Scovill Rock S/S	345	345	SCLT	4.60		1	2-954 ACSR	0	14,815,027	14,815,027				
56	Haddam Neck S/S	Scovill Rock S/S	345	345	SCLT	0.13		0	2-1192 ACSR	0	0	0				
57	Haddam Neck S/S	Scovill Rock S/S	345	345	TCSPHF	0.43		0	2-1192 ACSR	0	0	0				
58	Haddam Neck S/S	Scovill Rock S/S	345	345	SCHF	0.05		0	2-954 ACSR	0	0	0				
59	Millstone Station	Card S/S	345	345	SCSP	1.70		1	2-954 ACSR	1,143,134	59,234,809	60,377,943				
60	Millstone Station	Card S/S	345	345	SCHF	27.03		0	2-954 ACSR	0	0	0				
61	Middletown Station	Scovill Rock S/S	345	345	SCHF	0.57		1	2-954 ACSR	0	6,014,864	6,014,864				
62	Middletown Station	Scovill Rock S/S	345	345	SCHF	2.68		0	2156 ACSR	0	0	0				
63	Scovill Rock S/S	ES Border (East Shore S/S)	345	345	SCHF	13.81		1	2-954 ACSR	3,010,198	57,802,591	60,812,789				
64	Scovill Rock S/S	ES Border (East Shore S/S)	345	345	SCLT	0.37		0	2-954 ACSR	0	0	0				
		ES Border (East							2-954							

65	Scovill Rock S/S	Shore S/S)	345	345	SCSP	1.93		0	ACSR	0	0	0				
66	Scovill Rock S/S	ES Border (East Shore S/S)	345	345	SCSPHF	0.17		0	2-954 ACSR	0	0	0				
67	Scovill Rock S/S	ES Border (East Shore S/S)	345	345	DCSP	1.16		0	2-954 ACSR	0	0	0				
68	Scovill Rock S/S	ES Border (East Shore S/S)	345	345	SCHF	9.42		0	2156 ACSR	0	0	0				
69	Manchester S/S	North Bloomfield S/S	345	345	SCSP	1.70		1	2-1590 ACSR	1,411,209	43,175,830	44,587,039				
70	Manchester S/S	North Bloomfield S/S	345	345	SCHF	7.74		0	2-954 ACSR	0	0	0				
71	Manchester S/S	North Bloomfield S/S	345	345	DCLT	0.31		0	2-1192 ACSR	0	0	0				
72	Manchester S/S	North Bloomfield S/S	345	345	SCSP	1.22		0	2-954 ACSR	0	0	0				
73	Manchester S/S	North Bloomfield S/S	345	345	DCSP	3.81		0	2-954 ACSR	0	0	0				
74	Manchester S/S	Barbour Hill S/S	345.00	345.00	SCLT	0.16		1	2156 ACSR	281,274	15,130,005	15,411,279				
75	Manchester S/S	Barbour Hill S/S	345.00	345.00	DCLT	1.99		0	2156 ACSR	0	0	0				
76	Manchester S/S	Barbour Hill S/S	345.00	345.00	DCLT	0.62		0	2-2156 ACSR	0	0	0				
77	Manchester S/S	Barbour Hill S/S	345.00	345.00	SCHF	4.79		0	2156 ACSR	0	0	0				
78	Long Mountain S/S	CT/NY State Line (Pleasant Valley S/S)	345.00	345.00	SCHF	0.11		1	2-1590 ACSR	395,426	14,556,963	14,952,389				
79	Long Mountain S/S	CT/NY State Line (Pleasant Valley S/S)	345.00	345.00	SCHF	5.25		0	2156 ACSS	0	0	0				
80	Long Mountain S/S	CT/NY State Line (Pleasant Valley S/S)	345.00	345.00	SCSP	0.19		0	2156 ACSS	0	0	0				
81	Scovill Rock S/S	Southington S/S	345.00	345.00	SCHF	7.21		1	2-1272 ACSR	58,140	56,677,522	56,735,662				
82	Scovill Rock S/S	Southington S/S	345.00	345.00	SCSPD	0.13		0	2-954 ACSR	0	0	0				
83	Scovill Rock S/S	Southington S/S	345.00	345.00	SCHF	10.19		0	2-954 ACSR	0	0	0				
84	Scovill Rock S/S	Southington S/S	345.00	345.00	SCSPHF	0.18		0	2-954 ACSR	0	0	0				
85	Scovill Rock S/S	Southington S/S	345.00	345.00	SCLT	1.04		0	2-954 ACSR	0	0	0				
86	Scovill Rock S/S	Southington S/S	345.00	345.00	SCLWHF	0.56		0	2-954 ACSR	0	0	0				
87	Lake Road S/S	Killingly S/S	345.00	345.00	SCSP	0.20		1	2-1272 ACSR	0	1,313,563	1,313,563				
88	Lake Road S/S	Killingly S/S	345.00	345.00	SCHF	0.36		0	2-954 ACSR	0	0	0				
89	Plumtree S/S	Norwalk S/S	345.00	345.00	SCHF	3.16		1	2-1590 ACR	5,604,052	32,391,899	37,995,951				
90	Plumtree S/S	Norwalk S/S	345.00	345.00	SCSP	4.25		0	2-1590 ACR	0	0	0				
91	Plumtree S/S	Norwalk S/S	345.00	345.00	DCSP	1.22		0	2-1590 ACR	0	0	0				
92	Plumtree S/S	Norwalk S/S	345.00	345.00	SCUG	2.18		0	2-1750 Cpr XLPE	0	126,162,933	126,162,933				

93	Plumtree S/S	Norwalk S/S	345.00	345.00	SCUG	9.66		0	2-2500 Cpr HPFF	0	0	0				
94	Barbour Hill S/S	CT/MA State Line (Ludlow S/S)	345.00	345.00	SCHF	10.29		1	2156 ACSR	755,967	27,061,763	27,817,730				
95	Barbour Hill S/S	CT/MA State Line (Ludlow S/S)	345.00	345.00	SCLT	3.66		0	2156 ACSR	0	0	0				
96	Beseck Station	Southington S/S	345.00	345.00	SCSF	0.11		1	2-1590 ACSR	324,385	37,394,771	37,719,156				
97	Beseck Station	Southington S/S	345.00	345.00	SCSP	1.66		0	2-1590 ACSR	0	0	0				
98	Beseck Station	Southington S/S	345.00	345.00	DCSP	1.14		0	2-1590 ACSR	0	0	0				
99	Beseck Station	Southington S/S	345.00	345.00	SCHF	7.37		0	2-954 ACSR	0	0	0				
100	Beseck Station	Southington S/S	345.00	345.00	SCLT	0.51		0	2-954 ACSR	0	0	0				
101	Beseck Station	Southington S/S	345.00	345.00	SCLWHF	1.09		0	2-954 ACSR	0	0	0				
102	East Devon Station	Beseck Station	345.00	345.00	DCSP	11.09		1	4-1590 ACSR	669,898	107,531,779	108,201,677				
103	East Devon Station	Beseck Station	345.00	345.00	2-SCSP	0.95		0	4-1590 ACSR	0	0	0				
104	East Devon Station	Beseck Station	345.00	345.00	SCSP	18.94		0	2-1590 ACSR	0	0	0				
105	East Devon Station	Beseck Station	345.00	345.00	DCSP	1.90		0	2-1590 ACSR	0	0	0				
106	East Devon Station	Beseck Station	345.00	345.00	SCSPHF	0.20			2-1590 ACSR	0	0	0				
107	North Bloomfield S/S	ES Border (Agawam S/S)	345.00	345.00	SCSF	9.10		1	2-1590 ACSR	1,540,615	62,229,743	63,770,358				
108	North Bloomfield S/S	ES Border (Agawam S/S)	345.00	345.00	DCSP	0.79			2-1590 ACSR	0	0	0				
109	Lake Road	RI Border (West Farnum)	345.00	345.00	SCSP	0.26		1	2-1590 ACSS	0	38,040,596	38,040,596				
110	Lake Road	RI Border (West Farnum)	345.00	345.00	SCSPHF	7.13			2-1590 ACSS	0	0	0				
111	Lake Road	RI Border (West Farnum)	345.00	345.00	SCDSP	0.10			2-1590 ACSS	0	0	0				
112	Card St	Lake Road	345.00	345.00	SCDSP	0.51		1	2-1590 ACSS	775,817	128,960,578	129,736,395				
113	Card St	Lake Road	345.00	345.00	SCSP	2.46			2-1590 ACSS	0	0	0				
114	Card St	Lake Road	345.00	345.00	SCSPHF	22.30			2-1590 ACSS	0	0	0				
115	Singer S/S	Norwalk S/S	345.00	345.00	SCUG	15.40		1	3000 Cpr XLPE	10,000,237	374,550,324	384,550,561				
116	East Devon Station	ES Border	345.00	345.00	SCUG	2.35		1	3000 Cpr XLPE	219,958	55,555,202	55,775,160				
117	Singer S/S B	Norwalk S/S	345.00	345.00	SCUG	15.40		1	3000 Cpr XLPE	0	0	0				
118	Haddam S/S	Beseck S/S	345.00	345.00	SCHF	0.04		1	1590 ACSS	0	12,036,719	12,036,719				
119	Haddam S/S	Beseck S/S	345.00	345.00	SCHF	7.90			2-954 ACSR	0	0	0				
120	Haddam S/S	Beseck S/S	345.00	345.00	SCSP	1.78			2-1590 ACSR	0	0	0				

121	Haddam S/S	Beseck S/S	345.00	345.00	DCSP	5.68			2-1590 ACSR	0	0	0				
122	Norwalk Harbor Station	Northport Station	138.00	138.00	SCSU	16.80		3	3-1374 XLPE	376,016	72,441,117	72,817,133				
123	115 KV Overhead Lines	115 KV Overhead Lines	115.00	115.00		779.21	309.28	158		30,821,470	2,236,708,791	2,267,530,261				
124	69 KV Overhead Lines	69 KV Overhead Lines	69.00	69.00		65.99	31.42	11		1,212,793	146,561,615	147,774,408				
125	115 KV Underground Lines	115 KV Underground Lines	115.00	115.00		76.23		32		9,840,611	456,607,676	466,448,287				
126	69 KV Underground Lines	69 KV Underground Lines	69.00	69.00		2.84		1		0	246,339	246,339				
127	Oper. & Maint. Transm. Line												3,487,349	44,232,209	814,804	48,534,362
36	TOTAL					1,466.62	352.00	238		86,749,955	4,742,739,489	4,829,489,444	3,487,349	44,232,209	814,804	48,534,362

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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	Falls Village	Torrington	0.05	underground				5000XLPE			69					0	Underground
2	Archers Lane	Norwalk	9.70	underground				2500 kCMill			345					0	Overground
3																0	
44	TOTAL		9.75		0	0	0					0	0	0	0	0	

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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.

		Character of Substation	VOLTAGE (In MVa)				Conversion Apparatus and

Line No.	Name and Location of Substation (a)	Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Special Equipment		
										Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
1	TRANSMISSION SUBSTATIONS (NO DISTRIBUTION)											
2	Archers Lane 35P,Redding	Transmission	Unattended	[a]345.0								
3	Beseck Station 9F, Wallingford	Transmission	Unattended	345.0						Shunt Reactor	1	165
4	Canterbury 36F, Canterbury	Transmission	Unattended	115.0								
5	Devon 7R, Milford	Transmission	Unattended	115.0								
6	East Devon 8G,Milford	Transmission	Unattended	345.0	115.0		600	3				
7	Ely Avenue Terminal, Norwalk	Transmission	Unattended	115.0								
8	Frost Bridge 8R, Watertown	Transmission	Unattended	345.0	115.0		600	3		Capacitors	5	252
9	Haddam Neck 14B, Haddam	Transmission	Unattended	345.0						Shunt Reactor	1	150
10	Gravel Pit 35E East Windsor	Transmission	Unattended	115.0								
11	Hoyt's Hill 33J, Bethel	Transmission	Unattended	345.0								
12	Killingly 2G, Killingly	Transmission	Unattended	345.0	115.0		600	1		Capacitor	1	25
13	Kleen Energy 44G,Middletown	Transmission	Unattended	345.0								
14	Lake Road 27E, Killingly	Transmission	Unattended	345.0								
15	Laurel Energy 10F, Middletown	Transmission	Unattended	345.0								
16	Long Mountain 13J, New Milford	Transmission	Unattended	345.0								
17	Middletown Station 5A, Middletown	Transmission	Unattended	115.0								
18	Millstone 15G, Waterford	Transmission	Unattended	345.0								
19	Montville 4J, Montville	Transmission	Unattended	345.0	115.0		800	2		Capacitors	2	101
20	Montville 4J, Montville 1	Transmission	Unattended	115.0	69.0		134	2				
21	Norwalk Harbor 6J, Norwalk	Transmission	Unattended	138.0	115.0		450	1	3			
22	Norwalk Junction Station 32M,Wilton	Transmission	Unattended	345.0						Shunt Reactor	2	300
23	Scovill Rock 22P,Middletown	Transmission	Unattended	345.0								
24	Towantic 3P, Oxford	Transmission	Unattended	115.0								
25	DISTRIBUTION SUBSTATIONS WITH TRANSMISSION LINES											
26	Baldwin 13F, Waterbury	Distribution	Unattended	115.0	13.8		93	2				
27	Baldwin 13F, Waterbury 1	Distribution	Unattended	13.8	4.8		6	1				
28	Barbour Hill 23J, South Windsor	Distribution	Unattended	345.0	115.0		1200	6	1			
29	Barbour Hill 23J, South Windsor 1	Distribution	Unattended	115.0	23.0		93	2				
30	Barbour Hill 23J, South Windsor 2	Distribution	Unattended	23.0	13.8		42	2				
31	Bates Rock 21K, Southbury	Distribution	Unattended	115.0	13.8		93	2		DVAR	4	8
32	Beacon Falls 11N, Beacon Falls	Distribution	Unattended	115.0	13.8		93	2				
33	Berlin 6A, Berlin	Distribution	Unattended	115.0	13.8		93	2		Capacitor	3	126
34	Berlin 6A, Berlin 1	Distribution	Unattended	115.0	23.0		25	1				
35	Black Rock 11H, New Britain	Distribution	Unattended	115.0	69.0		67	1		Capacitor	2	12

36	Black Rock 11H, New Britain 1	Distribution	Unattended	115.0	13.8	4.8	100	2				
37	Black Rock 11H, New Britain 2	Distribution	Unattended	115.0	13.8		47	1				
38	Bloomfield 3B, Bloomfield	Distribution	Unattended	115.0	23.0		170	3		Capacitor	3	28.8
39	Bokum 15L, Old Saybrook	Distribution	Unattended	115.0	23.0		113	2		Capacitor		
40	Bokum 15L, Old Saybrook 1	Distribution	Unattended	27.6	23.0		29	1				
41	Branford 11J, Branford	Distribution	Unattended	115.0	23.0		100	2		Capacitor	1	50
42	Bristol 11K, Bristol	Distribution	Unattended	115.0	13.8	4.8	100	2				
43	Brooklyn 30Y, Danielson	Distribution	Unattended	115.0	23.0		47	1		Capacitor	0	0
44	Bulls Bridge 11M, New Milford	Distribution	Unattended	115.0	27.6	4.80	47	1				
45	Bulls Bridge 11M, New Milford 1	Distribution	Unattended	27.6	23.0		13	1				
46	Bunker Hill 12B, Waterbury	Distribution	Unattended	115.0	13.8		93	2		Capacitor		
47	Campville 14R, Harwinton	Distribution	Unattended	115.0	27.6		97	2		Capacitor	1	5
48	Canal 15Q, Southington	Distribution	Unattended	115.0	23.0		110	2				
49	Canton 5R, Canton	Distribution	Unattended	115.0	23.0		156	3		Capacitor	2	50
50	Canton 5R, Canton 1	Distribution	Unattended	23.0	27.6		29	1		Capacitor	0	0
51	Card 11F, Lebanon	Distribution	Unattended	345.0	115.0		800	2				
52	Card 11F, Lebanon 1	Distribution	Unattended	115.0	69.0		133	2				
53	Card 11F, Lebanon 2	Distribution	Unattended	115.0	23.0		93	2		Capacitor	0	0
54	Carmel Hill 11S, Woodbury	Distribution	Unattended	115.0	23.0		88	1				
55	Cedar Heights 4R, Stamford	Distribution	Unattended	115.0	13.2		140	3				
56	Chippen Hill 15U, Bristol	Distribution	Unattended	115.0	13.8		100	2				
57	Compo 23K, Westport	Distribution	Unattended	115.0	13.8		93	2				
58	Cos Cob 11R, Greenwich	Distribution	Unattended	115.0	27.6		144	3		Capacitor	2	12
59	Cos Cob 11R, Greenwich 1	Distribution	Unattended	115.0	13.2		55	2				
60	Darien 13S, Darien	Distribution	Unattended	115.0	13.2		93	2		Capacitor	1	38
61	Dooley 30K, Middletown	Distribution	Unattended	115.0	13.2		93	2				
62	East Hartford 32G, East Hartford	Distribution	Unattended	115.0	23.0		160	2		Capacitor	3	9
63	East Meriden 21P, Meriden	Distribution	Unattended	115.0	13.8		109	2				
64	East New Britain 7L, New Britain	Distribution	Unattended	115.0	13.8		120	2				
65	Enfield 12C, Enfield	Distribution	Unattended	115.0	27.6	4.80	100	2		Capacitor	2	7
66	Enfield 12C, Enfield 1	Distribution	Unattended	115.0	23.0		93	2				
67	Falls Village 9A, Canaan	Distribution	Unattended	69.0	13.2		40	1				
68	Farmington 1C, Farmington	Distribution	Unattended	115.0	23.0		151	3		Capacitor	1	10
69	Flanders 11Y, East Lyme	Distribution	Unattended	115.0	23.0		93	2				
70	Flax Hill 24A, Norwalk 1	Distribution	Unattended	115.0	13.8		93	2				
71	Flax Hill 24A, Norwalk	Distribution	Unattended	115.0	27.6	4.80	30	1				
72	Forestville 12A, Bristol	Distribution	Unattended	115.0	13.8		140	3				
73	Franklin Drive 1B, Torrington	Distribution	Unattended	115.0	13.2	4.16	50	2		Capacitor	2	11
74	Franklin Drive 1B, Torrington 1	Distribution	Unattended	115.0						Capacitor	1	38
75	Freight 11W, Waterbury	Distribution	Unattended	115.0	13.8		84	3		Capacitor	3	15
76	Fry Brook 13B, Plainfield	Distribution	Unattended	115.0	23.0		93	2				
77	Gales Ferry 11B, Ledyard	Distribution	Unattended	69.0	13.8		131	2				

78	Glenbrook 1K, Stamford	Distribution	Unattended	115.0	13.2		153	3		Capacitor	8	333
79	Glenbrook 1K, Stamford 1	Distribution	Unattended	115.0	14.6					Statcom	2	300
80	Green Hill 30R, Madison	Distribution	Unattended	115.0	23.0		140	3				
81	Greenwich 28F	Distribution	Unattended	115.0	13.2		125	2				
82	Haddam 11C, Haddam	Distribution	Unattended	345.0	115.0		1200	6				
83	Haddam 11C, Haddam 1	Distribution	Unattended	115.0	23.0		93	2		Capacitor	1	38
84	Hanover 12F, Meriden	Distribution	Unattended	115.0	23.0		100	2				
85	Hanover 12F, Meriden 1	Distribution	Unattended	115.0	13.8		93	2		Capacitor	1	6
86	Hanover 12F, Meriden 2	Distribution	Unattended	13.8	4.8		6	1				
87	Hopewell 22R, Glastonbury	Distribution	Unattended	115.0	23.0		93	2				
88	Manchester 3A,Manchester	Distribution	Unattended	345.0	115.0		1200	3	3	Capacitor	6	302
89	Manchester 3A,Manchester 1	Distribution	Unattended	115.0	23.0		180	3		Capacitor	4	32
90	Mansfield 12J, Mansfield	Distribution	Unattended	69.0	27.6		30	1				
91	Mansfield 12J, Mansfield 1	Distribution	Unattended	69.0	13.8		63	1				
92	Middle River 28M, Danbury	Distribution	Unattended	115.0	13.8		140	3				
93	Mystic 13K, Stonington	Distribution	Unattended	115.0	34.5	13.80	33	1		Capacitor	2	50
94	Mystic 13K, Stonington 1	Distribution	Unattended	115.0	34.5		37	1		Capacitor	2	12
95	Mystic 13K, Stonington 2	Distribution	Unattended	115.0	13.8		93	2				
96	Newington 4A, Newington	Distribution	Unattended	115.0	23.0		175	3		Capacitor	3	29
97	Newtown 12M, Newtown	Distribution	Unattended	115.0	13.8		83	3				
98	Noera 13H, Waterbury	Distribution	Unattended	115.0	13.8	4.80	100	2				
99	Noera 13H, Waterbury 1	Distribution	Unattended	13.8	4.8		13	2				
100	North Bloomfield 2A, Bloomfield	Distribution	Unattended	345.0	115.0		600	3	1	Capacitor	3	151
101	North Bloomfield 2A, Bloomfield 1	Distribution	Unattended	345.0	115.0		450	1				
102	North Bloomfield 2A, Bloomfield 2	Distribution	Unattended	115.0	23.0		109	2				
103	North Canann 5L, North Canann	Distribution	Unattended	69.0	13.2		25	1				
104	Northeast Simsbury 43F, Simsbury	Distribution	Unattended	115.0	23.0		113	2				
105	Northwest Hartford 2N, Hartford	Distribution	Unattended	115.0	23.0		180	3		Capacitor	2	19
106	Norwalk 9S, Norwalk	Distribution	Unattended	345.0	115.0		1200	6	1			
107	Norwalk 9S, Norwalk 1	Distribution	Unattended	115.0	27.6	4.80	150	3				
108	Norwalk 9S, Norwalk 2	Distribution	Unattended	115.0	13.8		153	3				
109	Oxford 26N, Oxford	Distribution	Unattended	115.0	13.8		93	2				
110	Peaceable 12N, Redding	Distribution	Unattended	115.0	13.8		55	2				
111	Plumtree 30G, Bethel	Distribution	Unattended	345.0	115.0		900	2		Capacitor	2	88
112	Plumtree 30G, Bethel 1	Distribution	Unattended	115.0	13.8		47	1				
113	Portland 21H, Portland	Distribution	Unattended	115.0	23.0		107	2				
114	Portland 21H, Portland 1	Distribution	Unattended	23.0	13.2		62	3				
115	Ridgefield 22N, Ridgefield	Distribution	Unattended	115.0	13.8		131	2				
116	Riverside Drive 2R, East Hartford	Distribution	Unattended	115.0	23.0		180	3		Capacitor	3	29
117	Rockville 14W, Vernon	Distribution	Unattended	115.0	23.0		27	1				
118	Rockville 14W, Vernon 1	Distribution	Unattended	115.0	13.8		93	2				
119	Rocky Hill 3R, Rocky Hill	Distribution	Unattended	115.0	23.0		151	3		Capacitor	7	28

120	Rocky River 12Y, New Milford 1	Distribution	Unattended	115.0	13.8		93	2		Capacitor	1	25
121	Rocky River 12Y, New Milford	Distribution	Unattended	13.8	6.9	4.80	8	1				
122	Rood Avenue 24J, Windsor	Distribution	Unattended	115.0	23.0		123	2				
123	Salisbury 21J, Salisbury	Distribution	Unattended	69.0	13.2		13	1				
124	Sandy Hook 37F, Newtown	Distribution	Unattended	115.0	23.0		88	2				
125	Scitico 27H, Enfield	Distribution	Unattended	115.0	23.0		169	3				
126	Shaws Hill 24H, Watertown	Distribution	Unattended	115.0	13.8		93	2				
127	Shepaug 13A, Southbury	Distribution	Unattended	115.0	69.0		67	1				
128	Shepaug 13A, Southbury 1	Distribution	Unattended	69.0	13.8		4	1				
129	Sherwood 18P	Distribution	Unattended	115.0	13.8		120	2				
130	Shunock 32P, North Stonington	Distribution	Unattended	115.0	13.8		143	3		Synchronous Conde	1	50
131	Skungamaug 49S, Coventry	Distribution	Unattended	69.0	13.8	4.80	18	1				
132	SONO 24P, South Norwalk	Distribution	Unattended	115.0	13.8		80	2				
133	South End 1G, Stamford	Distribution	Unattended	115.0	13.2		208	4		Capacitor	6	38
134	South Meadow Station 1A,Hartford	Distribution	Unattended	115.0	23.0		240	3	3	Capacitor	3	29
135	South Meadow Station 1A,Hartford 1	Distribution	Unattended	23.0	11.0		44	3				
136	South Naugatuck 21L, Naugatuck	Distribution	Unattended	115.0	13.8		67	2		Capacitor	1	6
137	Southwest Hartford 47N, Hartford	Distribution	Unattended	115.0	23.0		160	2				
138	South Windsor 14L, South Windsor	Distribution	Unattended	115.0	13.8		93	2				
139	Southington 4C, Southington	Distribution	Unattended	345.0	115.0		1600	4	3	Capacitor	6	302
140	Southington 4C, Southington 1	Distribution	Unattended	115.0	13.8		93	2				
141	Stepstone 35L, Guilford	Distribution	Unattended	115.0	23.0		123	2				
142	Stepstone 35L, Guilford 1	Distribution	Unattended	23.0	13.8		42	2				
143	Stevenson 14A, Monroe	Distribution	Unattended	115.0	27.6		30	1				
144	Stevenson 14A, Monroe 1	Distribution	Unattended	27.6	8.3		4	1				
145	Stony Hill 48C, Brookfield	Distribution	Unattended	115.0	13.8		93	2		Capacitor	3	101
146	Stony Hill 48C, Brookfield 1	Distribution	Unattended	13.8	0.5					DVAR	2	16
147	Thomaston 2B, Thomaston	Distribution	Unattended	115.0	13.2		50	2				
148	Todd 30L, Wolcott	Distribution	Unattended	115.0	13.8		93	2				
149	Tomac 12H, Greenwich	Distribution	Unattended	115.0	27.6		47	1				
150	Tomac 12H, Greenwich 1	Distribution	Unattended	27.6	13.2		15	1				
151	Tomac 12H, Greenwich 2	Distribution	Unattended	27.6	4.8		9	1				
152	Torrington Terminal 8A, Torrington	Distribution	Unattended	115.0	69.0		33	1	3			
153	Torrington Terminal 8A, Torrington 1	Distribution	Unattended	115.0	13.2		27	1				
154	Tracy 14M, Putnam	Distribution	Unattended	115.0	23.0		140	3		Capacitor	2	8
155	Triangle 11A, Danbury	Distribution	Unattended	115.0	13.8		141	3				
156	Tunnel 12S, Preston	Distribution	Unattended	115.0	69.0		90	1				
157	Tunnel 12S, Preston 1	Distribution	Unattended	115.0	23.0		93	2				
158	Uncasville 1Q, Montville	Distribution	Unattended	115.0	27.6		27	1				
159	Uncasville 1Q, Montville 1	Distribution	Unattended	115.0	13.2		50	2				
160	Waterford 36F, Waterford	Distribution	Unattended	115.0	23.0		120	2				

161	Waterside 22M, Stamford	Distribution	Unattended	115.0	13.2		153	3		Capacitor	2	49
162	West Brookfield 14H, Brookfield	Distribution	Unattended	115.0	13.8		50	2				
163	Weston 21M, Weston	Distribution	Unattended	115.0	27.6		106	2		Capacitor	1	5
164	Weston 21M, Weston 1	Distribution	Unattended	27.6	13.8		50	3				
165	West Side 7A, Middletown	Distribution	Unattended	115.0	13.2		88	2		Capacitor	1	25
166	Williams Street 9L, New London	Distribution	Unattended	115.0	13.2		93	2		Capacitor	4	17
167	Willimantic 14S, Windham	Distribution	Unattended	115.0	27.6	4.8	100	2		Capacitor	1	6
168	Wilton 35A, Wilton	Distribution	Unattended	115.0	13.8		120	2				
169	Windsor Locks 14K,Windsor Locks	Distribution	Unattended	115.0	27.6		67	2		Capacitor	1	5
170	Windsor Locks 14K,Windsor Locks 1	Distribution	Unattended	115.0	23.0		93	2				
171	DISTRIBUTION WITH NO TRANSMISSION (=> 10 MVA)											
172	Albany Avenue 36, West Hartford	Distribution	Unattended	23.0	4.8		15	2				
173	Blair 15M, Stafford	Distribution	Unattended	27.6	23.0		38	3				
174	Burrville 29J, Burrville	Distribution	Unattended	27.6	23.0		25	2		Capacitor	2	6
175	Byram 13C, Greenwich	Distribution	Unattended	27.6	13.2		25	2				
176	Center 24F, Meriden	Distribution	Unattended	13.8	4.8		13	2		Capacitor	1	1.2
177	Christian 31C, Washington	Distribution	Unattended	27.6	23.0		13	1				
178	East Bantam19U, Litchfield	Distribution	Unattended	27.6	23.0		13	1				
179	East Bantam19U, Litchfield 1	Distribution	Unattended	27.6	8.3		6	1				
180	East Rocks 17R, Norwalk	Distribution	Unattended	27.6	13.8		15	2				
181	Frederick Road 34, West Hartford	Distribution	Unattended	23.0	4.8		15	2				
182	Granby Street 29, Hartford	Distribution	Unattended	23.0	4.8		10	2				
183	Hartford Avenue 23, Wethersfield	Distribution	Unattended	23.0	4.8		13	2				
184	Harwinton 13Y, Harwinton	Distribution	Unattended	27.6	23.0		15	1				
185	Judd Brook 32R, Colchester	Distribution	Unattended	27.6	23.0		50	2				
186	Lakeview 31A, New Canaan	Distribution	Unattended	27.6	13.8		75	3				
187	Mianus 16Q, Greenwich	Distribution	Unattended	27.6	13.2		26	2				
188	Monroe 15Y, Monroe_1	Distribution	Unattended	27.6	23.0		25	2				
189	North Greenwich, Greenwich 27K	Distribution	Unattended	27.6	13.2		75	3				
190	Pepperidge 28A, Norwalk	Distribution	Unattended	27.6	13.8		25	2				
191	Prospect Street 22E, Greenwich	Distribution	Unattended	27.6	13.2		55	4				
192	Riverton 14N, Winchester	Distribution	Unattended	27.6	23.0		13	1				
193	Riverton 14N, Winchester 1	Distribution	Unattended	27.6	4.8		4	1				
194	Saybrook 22D, Old Saybrook	Distribution	Unattended	27.6	13.8		50	2				
195	Simsbury Road 44, Bloomfield	Distribution	Unattended	23.0	4.8		10	2				
196	South Leonard 23N, Waterbury	Distribution	Unattended	13.8	4.8		13	2				
197	Suffield 36M, Suffield	Distribution	Unattended	27.6	23.0		25	2				
198	Van Dyke Avenue 12, Hartford	Distribution	Unattended	23.00	11.00		68	4		Capacitor	3	18
199	Westport 27F, Westport	Distribution	Unattended	27.60	13.80		25	2				
200	DISTRIBUTION WITH NO TRANSMISSION LINES (< 10 MVA)											
201	Boulevard 45, West Hartford	Distribution	Unattended	23.0	4.8		5	1		Capacitor	3	18

202	Brook Street 17F, Bristol	Distribution	Unattended	13.8	4.8		6	1				
203	Buckingham 31K, Glastonbury	Distribution	Unattended	23.0	8.3		4	1				
204	Carver 19R, New Britain	Distribution	Unattended	13.8	4.8		6	1				
205	Clayton Court 21W, New Britain	Distribution	Unattended	13.8	4.8		4	1				
206	Columbia 20Y, Columbia	Distribution	Unattended	27.6	13.8		9	1				
207	Cornwall 37J, Cornwall	Distribution	Unattended	27.6	8.3		4	1				
208	Dayville 24K, Killingly	Distribution	Unattended	23.0	4.8		6	1				
209	Deep River 13Q, Deep River	Distribution	Unattended	23.0	4.8		6	1				
210	East Hampton 23A, East Hampton	Distribution	Unattended	23.0	4.8		6	1				
211	Eggleston 42, Bloomfield	Distribution	Unattended	23.0	4.8		5	1				
212	Essex 16M, Essex	Distribution	Unattended	23.0	4.8		7	1				
213	Farmington 23L, Farmington	Distribution	Unattended	13.8	4.8		10	2				
214	Jefferson Hill 26F, Litchfield	Distribution	Unattended	27.6	8.3		6	1				
215	Lounsbury 39M, Willimantic	Distribution	Unattended	27.6	4.8		5	1				
216	Madison 27G, Madison	Distribution	Unattended	23.0	4.8		7	1				
217	Middlebury 18J, Middlebury	Distribution	Unattended	13.8	4.8		4	1				
218	New 2H, Manchester	Distribution	Unattended	23.0	4.8		9	2				
219	North Square 25G, Waterbury	Distribution	Unattended	13.8	4.8		6	1				
220	Oak Street 5S, Middletown	Distribution	Unattended	13.2	4.2		4	1				
221	Robert Street 8F, Middletown	Distribution	Unattended	13.2	4.2		2	1				
222	Schoolhouse Road 16S, Prospect	Distribution	Unattended	13.8	4.8		6	1				
223	South Cheshire 20H, Cheshire	Distribution	Unattended	23.0	4.8		6	1				
224	Terryville 21Q, Plymouth	Distribution	Unattended	13.8	4.8		6	1				
225	Thompson 23Q, Thompson	Distribution	Unattended	23.0	23.0							
226	Watertown 25R, Watertown	Distribution	Unattended	13.8	4.8		6	1				
227	Wells 38, Wethersfield	Distribution	Unattended	23.0	4.8		5	1				
228	Westbrook 20S, Westbrook	Distribution	Unattended	27.6	4.8		6	1				
229	Winchester 29W, Winchester	Distribution	Unattended	23.0	4.8		6	1				
230	Wolcott 24R, Wolcott	Distribution	Unattended	13.8	4.8		6	1				
231	Yale 25L, Middlebury	Distribution	Unattended	13.8	4.8		4	1				
233	TotalTransmissionSubstationMember			27.6	13.8		25	1				

Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: PrimaryVoltageLevel

Summary of Substations

	MVa	Number of Substations
Transmission (No Distribution)	3,184	22
Distribution with Transmission Lines	21,047	100
Distribution with No Transmission Lines (=> 10 MVA)	755	26
Distribution with No Transmission Lines (< 10 MVA)	172	31
Total	25,158	179

FERC FORM NO. 1 (ED. 12-96)

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ 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	Storm Outage Support	Public Service Company of New Hampshire	402	334,619
3	Storm Outage Support	NSTAR Electric Company	402	440
4	Storm Outage Support	Yankee Gas Services Company	402	786
5	General Services in a Holding Compan System	Eversource Energy Service Company	Various (see note)	[a]480,728,745
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Non-power Goods or Services Provided for Affiliate			
22	Transfer of Meters	NSTAR Electric Company	107	335,455
23	Transmission System Modifications	NSTAR Electric Company	107	7,336,142
24	Transformer Replacement	NSTAR Electric Company	107	369,555
42				

FERC FORM NO. 1 ((NEW))

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Name of Respondent: The Connecticut Light and Power Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/17/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Service Department - Function	Account	Amount
Benefits	401	94,332,984
	402	0
	107	4,959,313
	228	19,626
	232	15,550
	237	0
	408	14,970,776
	421	1,743,638
	426	103,395
Benefits Total		**116,145,282**
Benefits Loader	401	(21,450,221)
	402	5,773,852
	107	29,877,433
	108	10,265
	163	1,959,297
	182	—
	183	—
	184	302,684
	186	1,265
	228	502
	403	(40,395,624)

	408	(14,742,886)
	417	—
	426	454,785
Benefits Loader Total		**(38,208,648)**
Building Rent and Maintenance	401	6,762,934
	402	19,141
	403	484,244
	431	47,873
Building Rent and Maintenance Total		**7,314,192**
Corporate Relations	401	8,210,419
	402	749,605
	107	556,153
	183	—
	184	552
	228	183,145
	426	2,075,374
Corporate Relations Total		**11,775,248**
Customer Group	401	49,013,200
	402	845,155
	107	1,471,602
	108	(180)
	143	1,278
	182	—
	183	—
	186	—
	426	14,386
Customer Group Total		**51,345,441**
Depreciation	184	451,449
	403	73,677,434
Depreciation Total		**74,128,883**
Electric Distribution	401	14,852,747
	402	5,057,936
	107	13,504,127
	108	190,415
	163	—
	183	—
	184	507
	186	2,736
	228	—
	426	364
Electric Distribution Total		**33,608,832**
Energy Supply	401	1,950,022
	402	3,174
Energy Supply Total		**1,953,196**
Engineering	401	14,741,886
	402	798,975
	107	18,471,219
	108	151,355
	154	81
	183	—
	184	627
	186	418,045
	426	3,279
Engineering Total		**34,585,467**
Enterprise Energy Strat + Bus Dev	401	—
Enterprise Energy Strat + Bus Dev Total		**—**
Enterprise Risk Management	401	1,072,721
	402	947
	107	53,715
	184	163,806
	228	436,258
	408	6,831
Enterprise Risk Management Total		**1,734,278**
Finance and Accounting	401	12,728,330
	402	39,262
	107	3,937,237
	108	2,688
	154	31
	163	52,495
	165	9,600
	184	37,534
	228	515
	426	16,313

Finance and Accounting Total		**16,824,005**
General Administration	401	595,281
General Administration Total		**595,281**
Human Resources	401	4,727,370
	402	2,022
	184	—
Human Resources Total		**4,729,392**
Information Technology	401	49,796,704
	402	28,573
	107	936,470
	108	—
	426	46
Information Technology Total		**50,761,793**
Internal Audit + Security	401	2,084,853
	402	5,270
	108	(244)
	163	272
	184	167
Internal Audit + Security Total		**2,090,318**
Investor Relations	401	702,361
Investor Relations Total		**702,361**
Legal	401	6,985,105
	402	11,382
	107	102,631
	108	11,852
	183	—
	228	27,404
	426	45,205
Legal Total		**7,183,579**
Miscellaneous	401	(517,881)
	402	16,029
	106	—
	107	209,029
	108	4,515
	154	10,065
	163	14,595
	165	283,183
	182	—
	183	—
	184	70,561
	186	1,382
	232	—
	237	352,564
	242	1,838,692
	408	(19,681)
	419	(268,079)
	421	(166)
	426	894
	432	(574,758)
Miscellaneous Total		**1,420,944**
New Business Improvement	401	6,785
	426	(99)
New Business Improvement Total		**6,686**
Operations Administration	401	424,085
	402	651
	107	70
	163	1,010
	184	95
Operations Administration Total		**425,911**
Operations Services	401	1,541,930
	402	631
	107	190,277
	108	—
	184	366,675
	186	—
Operations Services Total		**2,099,513**
Rate of Return	401	39,261,019
Rate of Return Total		**39,261,019**
Safety	401	1,170,887
	402	286
	107	1,034,735
	426	6,364
Safety Total		**2,212,272**

Supply Chain+Real Estate+Materials	401	8,041,065
	402	43,224
	107	2,205,585
	108	50,262
	163	2,099,481
	183	—
	184	96,474
	185	—
	186	8,022
	417	—
	426	1,359
Supply Chain+Real Estate+Materials Total		**12,545,472**
Taxes	401	4,602,489
	408	926,810
Taxes Total		**5,529,299**
Transmission	401	9,225,794
	402	409,776
	107	29,457,906
	108	43,509
	183	171,651
	184	361
	186	511,294
	253	8,573
	426	129,865
Transmission Total		**39,958,729**
Grand Total		**480,728,745**

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