nationalgrid

Massachusetts Electric Company

Financial Statements

For the years ended March 31, 2024, 2023, and 2022

MASSACHUSETTS ELECTRIC COMPANY

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Deloitte & Touche LLP
30 Rockefeller Plaza
New York, NY
USA

Tel: +1 212 492 4000
Fax: +1 212 489 1687
www.deloitte.com

INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of
Massachusetts Electric Company

Opinion

We have audited the financial statements of Massachusetts Electric Company (the "Company"), which comprise the balance sheets as of March 31, 2024 and 2023, and the related statements of operations, cash flows and changes in shareholders' equity for each of the three years in the period ended March 31, 2024, and the related notes to the financial statements (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as of March 31, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended March 31, 2024 in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinion

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

Responsibilities of Management for the Financial Statements

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

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for one year after the date that the financial statements are issued.

Auditor's Responsibilities for the Audit of the Financial Statements

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

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

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

Deloitte & Touche LLP

June 28, 2024

MASSACHUSETTS ELECTRIC COMPANY
STATEMENTS OF OPERATIONS
(in thousands of dollars)

	Years Ended March 31,		
	2024	2023	2022
Operating revenues	**$ 2,700,872**	$ 2,871,989	$ 2,490,683
Operating expenses:			
Purchased electricity	**559,832**	855,898	562,256
Operations and maintenance	**1,675,119**	1,591,333	1,454,260
Depreciation and amortization	**182,813**	168,929	165,778
Other taxes	**62,712**	96,080	92,659
Total operating expenses	**2,480,476**	2,712,240	2,274,953
Operating income	**220,396**	159,749	215,730
Other income and (deductions):			
Interest on long-term debt	**(78,937)**	(76,708)	(76,712)
Other interest, including affiliate interest, net	**(3,563)**	2,889	1,499
Other income, net	**57,149**	40,924	10,929
Total other deductions, net	**(25,351)**	(32,895)	(64,284)
Income before income taxes	**195,045**	126,854	151,446
Income tax expense	**47,078**	22,856	31,914
Net income	**$ 147,967**	$ 103,998	$ 119,532

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

MASSACHUSETTS ELECTRIC COMPANY
STATEMENTS OF CASH FLOWS
(in thousands of dollars)

	Years Ended March 31,		
	2024	2023	2022
Operating activities:			
Net income	**$ 147,967**	$ 103,998	$ 119,532
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**182,813**	168,929	165,778
Regulatory amortizations	**14,791**	(10,741)	147
Deferred income tax expense	**76,411**	94,490	27,405
Bad debt expense	**50,870**	40,262	34,116
Allowance for equity funds used during construction	**(1,837)**	(10,415)	(6,980)
Pension and postretirement (benefits) expenses	**(13,638)**	10,608	24,513
Other non-cash items	**616**	793	744
Pension and postretirement benefit contributions, net	**2,501**	(15,976)	(12,412)
Environmental remediation payments	**(7,323)**	(4,161)	(6,291)
Changes in operating assets and liabilities:			
Accounts receivable, net, and unbilled revenues, net	**(72,316)**	(198,571)	(51,527)
Accounts receivable from/payable to affiliates, net	**75,850**	(6,483)	(14,593)
Inventory	**(34,942)**	(11,341)	(574)
Regulatory assets and liabilities (current), net	**(26,103)**	(37,054)	10,820
Regulatory assets and liabilities (non-current), net	**(175,857)**	(79,130)	(50,016)
Prepaid and accrued taxes, net	**76,026**	(111,728)	(4,681)
Accounts payable and other liabilities	**(56,557)**	227,662	50,642
Renewable energy certificate obligations, net	**(31,195)**	27,273	(3,752)
Other, net	**(1,749)**	15,855	(1,160)
Net cash provided by operating activities	**206,328**	204,270	281,711
Investing activities:			
Capital expenditures	**(508,686)**	(388,863)	(326,344)
Cost of removal	**(32,547)**	(29,422)	(28,563)
Intercompany money pool	**(252,922)**	151,781	75,547
Financial investments	**-**	-	11,531
Other, net	**261**	4,548	(20)
Net cash used in investing activities	**(793,894)**	(261,956)	(267,849)
Financing activities:			
Preferred stock dividends	**(75)**	(100)	(100)
Issuance of long-term debt	**400,000**	-	-
Payment of debt issuance costs	**(3,000)**	-	-
Intercompany money pool	**(66,546)**	66,546	-
Equity infusion from Parent	**250,000**	-	-
Net cash provided by (used in) financing activities	**580,379**	66,446	(100)
Net (decrease) increase in cash, cash equivalents, restricted cash, and special deposits	**(7,187)**	8,760	13,762
Cash, cash equivalents, restricted cash, and special deposits, beginning of year	**38,034**	29,274	15,512
Cash, cash equivalents, restricted cash, and special deposits, end of year	**$ 30,847**	$ 38,034	$ 29,274
Supplemental disclosures:			
Interest paid, net of amounts capitalized	**$ (76,021)**	$ (75,865)	$ (75,865)
Income taxes refunded (paid)	**97,897**	(7,804)	(18,678)
Significant non-cash items:			
Capital-related accruals included in accounts payable	**14,130**	8,282	11,854
Parent tax loss allocation	**-**	2,509	5,796
ROU assets obtained in exchange for new operating lease liabilities	**21,559**	12,453	17,905

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

MASSACHUSETTS ELECTRIC COMPANY
BALANCE SHEETS
(in thousands of dollars)

	March 31,	
	2024	2023
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 9,513**	$ 16,700
Restricted cash and special deposits	**21,334**	21,334
Accounts Receivable, net	**601,521**	607,876
Accounts receivable from affiliates	**23,504**	34,093
Intercompany moneypool asset	**252,922**	-
Unbilled revenues, net	**135,956**	117,978
Inventory	**168,770**	140,235
Regulatory assets	**233,707**	239,288
Accrued tax benefit	**30,674**	105,360
Other, net	**5,917**	3,081
Total current assets	**1,483,818**	1,285,945
Property, plant, and equipment, net	**4,874,700**	4,470,932
Non-current assets:		
Regulatory assets	**1,061,559**	847,145
Goodwill	**1,008,244**	1,008,244
Postretirement benefits asset	**65,189**	28,923
Other	**12,359**	9,948
Total non-current assets	**2,147,351**	1,894,260
Total assets	**$ 8,505,869**	$ 7,651,137

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

MASSACHUSETTS ELECTRIC COMPANY
BALANCE SHEETS
(in thousands of dollars)

	March 31, 2024	March 31, 2023
LIABILITIES AND CAPITALIZATION		
Current liabilities:		
Accounts payable	**$ 554,256**	$ 605,677
Accounts payable to affiliates	**220,608**	155,347
Intercompany moneypool liability	**-**	66,546
Customer deposits	**12,188**	13,817
Interest accrued	**25,999**	23,695
Regulatory liabilities	**-**	31,684
Renewable energy certificate obligations	**166,728**	204,330
Payroll and benefits accruals	**27,951**	25,175
Environmental remediation costs	**5,851**	10,888
Distributed generation advances	**55,128**	56,928
Other	**31,175**	30,535
Total current liabilities	**1,099,884**	1,224,622
Non-current liabilities:		
Regulatory liabilities	**820,946**	731,175
Deferred income tax liabilities, net	**683,286**	599,518
Environmental remediation costs	**64,372**	59,956
Other	**106,098**	97,478
Total non-current liabilities	**1,674,702**	1,488,127
Commitments and contingencies (Note 12)		
Capitalization:		
Shareholders' equity	**3,543,929**	3,148,493
Long-term debt	**2,187,354**	1,789,895
Total capitalization	**5,731,283**	4,938,388
Total liabilities and capitalization	**$ 8,505,869**	$ 7,651,137

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

MASSACHUSETTS ELECTRIC COMPANY
STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(in thousands of dollars)

				Accumulated Other Comprehensive Income (Loss)				
	Common Stock	Cumulative Preferred Stock	Additional Paid-in Capital	Unrealized Gain (Loss) on Available-For-Sale Securities	Pension and Other Postretirement Benefits	Total Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total
Balance as of March 31, 2021	**$ 59,953**	**$ 2,259**	**$ 1,863,394**	**$ 266**	**$ (552)**	**$ (286)**	**$ 991,350**	**$ 2,916,670**
Net income	-	-	-	-	-	-	119,532	119,532
Other comprehensive income:								
Unrealized gains on securities, net of $5 tax benefit	-	-	-	(14)	-	(14)	-	(14)
Change in pension and other postretirement obligations, net of $4 tax expense	-	-	-	-	12	12	-	12
Total comprehensive income								119,530
Parent tax loss allocation	-	-	5,796	-	-	-	-	5,796
Preferred stock dividends	-	-	-	-	-	-	(100)	(100)
Balance as of March 31, 2022	**$ 59,953**	**$ 2,259**	**$ 1,869,190**	**$ 252**	**$ (540)**	**$ (288)**	**$ 1,110,782**	**$ 3,041,896**
Net income	-	-	-	-	-	-	103,998	103,998
Other comprehensive income (loss):								
Change in pension and other postretirement obligations, net of $71 tax expense	-	-	-	-	190	190	-	190
Total comprehensive income								104,188
Parent tax loss allocation	-	-	2,509	-	-	-	-	2,509
Preferred stock dividends	-	-	-	-	-	-	(100)	(100)
Balance as of March 31, 2023	**$ 59,953**	**$ 2,259**	**$ 1,871,699**	**$ 252**	**$ (350)**	**$ (98)**	**$ 1,214,680**	**$ 3,148,493**
Net income	-	-	-	-	-	-	147,967	147,967
Other comprehensive income:								
Change in pension and other postretirement obligations, net of $91 tax expense	-	-	-	-	240	240	-	240
Total comprehensive income								148,207
Equity infusion from Parent	-	-	250,000	-	-	-	-	250,000
Preferred stock dividends	-	-	-	-	-	-	(75)	(75)
Implementation of ASC 326, net of $1,014 tax benefit [1]	-	-	-	-	-	-	(2,696)	(2,696)
Balance as of March 31, 2024	**$ 59,953**	**$ 2,259**	**$ 2,121,699**	**$ 252**	**$ (110)**	**$ 142**	**$ 1,359,876**	**$ 3,543,929**

The Company had 2,398,111 shares of common stock authorized, issued, and outstanding, with a par value of $25 per share, and 22,585 shares of cumulative preferred stock authorized, issued, and outstanding, with a par value of $100 per share, as of March 31, 2024 and 2023.

(1) See Note 4, "Allowance for Doubtful Accounts" for additional information.

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

MASSACHUSETTS ELECTRIC COMPANY
NOTES TO THE FINANCIAL STATEMENTS

1. NATURE OF OPERATIONS AND BASIS OF PRESENTATION

Massachusetts Electric Company ("the Company") is an electric retail distribution company providing electric service to approximately 1.4 million customers in Massachusetts. The properties of the Company consist principally of substations and distribution lines interconnected with transmission and other facilities of New England Power Company ("NEP"), an affiliated entity.

The Company is a wholly owned subsidiary of National Grid USA ("NGUSA" or the "Parent"), a public utility holding company with regulated subsidiaries engaged in the generation of electricity and the transmission, distribution, and sale of both natural gas and electricity. NGUSA is a direct wholly owned subsidiary of National Grid North America Inc. ("NGNA") and an indirect wholly owned subsidiary of National Grid plc, a public limited company incorporated under the laws of England and Wales.

Pursuant to a settlement agreement associated with NGUSA's purchase of Nantucket Electric Company ("Nantucket Electric") in 1996, which was approved by the Massachusetts Department of Public Utilities ("DPU"), the Company and its affiliate, Nantucket Electric, are considered as one regulated entity for the purpose of recovering costs and establishing rates assessed to customers, with the exception of the recovery of Nantucket Electric's investment in two undersea electric cables. In the recovery of certain regulatory assets, funding of the recovery is from the customers of both companies. The mechanism by which recovery is ultimately achieved, however, is through a single regulatory asset recorded on the balance sheet of the Company. Nantucket Electric's share of these costs and recoveries is reflected through a return on equity ("ROE") mechanism between the Company and Nantucket Electric, as discussed in Note 14, "Related Party Transactions."

The accompanying financial statements are prepared in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP"), including the accounting principles for rate-regulated entities. The financial statements reflect the ratemaking practices of the applicable regulatory authorities.

The Company has evaluated subsequent events and transactions through June 28, 2024, the date of issuance of these financial statements, and concluded that there were no events or transactions that require adjustment to, or disclosure in, the financial statements as of and for the year ended March 31, 2024, with the exception of items otherwise disclosed in these financial statements.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

In preparing financial statements that conform to U.S. GAAP, the Company must make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, and expenses, and the disclosure of contingent assets and liabilities included in the financial statements. Such estimates and assumptions are reflected in the accompanying financial statements. Actual results could differ from those estimates.

Regulatory Accounting

The Federal Energy Regulatory Commission ("FERC") and the DPU regulate the rates the Company charges its customers. In certain cases, the rate actions of the FERC and the DPU can result in accounting that differs from non-regulated companies. In these cases, the Company defers costs (as regulatory assets) or recognizes obligations (as regulatory liabilities) if it is probable that such amounts will be recovered from, or refunded to, customers through future rates. In accordance with Accounting Standards Codification ("ASC") 980, "*Regulated Operations*," regulatory assets and liabilities are reflected on the balance sheet consistent with the treatment of the related costs in the ratemaking process.

Revenue Recognition

Revenues are recognized for electric distribution services billed on a monthly cycle basis, together with unbilled revenues for the estimated amount of services rendered from the time meters were last read to the end of the reporting period. See Note 3, "Revenue," for additional details.

Income Taxes

Federal and state income taxes have been computed utilizing the asset and liability approach that requires the recognition of deferred tax assets and liabilities for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. Deferred income taxes also reflect the tax effect of net operating losses, capital losses, and general business credit carryforwards. The Company assesses the available positive and negative evidence to estimate whether sufficient future taxable income of the appropriate tax character will be generated to realize the benefits of existing deferred tax assets. When the evaluation of the evidence indicates that the Company will not be able to realize the benefits of existing deferred tax assets, a valuation allowance is recorded to reduce existing deferred tax assets to the net realizable amount.

The effects of tax positions are recognized in the financial statements when it is more likely than not that the position taken, or expected to be taken, in a tax return will be sustained upon examination by taxing authorities based on the technical merits of the position. The financial effect of changes in tax laws or rates is accounted for in the period of enactment. Deferred investment tax credits are amortized over the useful life of the underlying property.

NGNA files consolidated federal tax returns including all of the activities of its subsidiaries. Each subsidiary determines its tax provision based on the separate return method, modified by a benefits-for-loss allocation pursuant to a tax sharing agreement between NGNA and its subsidiaries. The benefits of consolidated tax losses and credits are allocated to the NGNA subsidiaries giving rise to such benefits in determining each subsidiary's tax expense in the year that the loss or credit arises. In a year that a consolidated loss or credit carryforward is utilized, the tax benefit utilized in consolidation is paid proportionately to the subsidiaries that gave rise to the benefit regardless of whether those subsidiaries would have utilized the benefit. The tax sharing agreement also requires NGNA to allocate its parent tax losses, excluding deductions from acquisition indebtedness, to each subsidiary in the consolidated federal tax return with taxable income. The allocation of NGNA's parent tax losses to its subsidiaries is accounted for as a capital contribution and is performed in conjunction with the annual intercompany cash settlement process following the filing of the federal tax return. The Corporate Alternative Minimum Tax ("CAMT") is allocated based on the ratio of separate company CAMT to total consolidated NGNA CAMT.

Other Taxes

The Company collects taxes and fees from customers, such as sales taxes, other taxes, surcharges, and fees that are levied by state or local governments on the sale or distribution of electricity. The Company accounts for taxes that are imposed on customers (such as sales taxes) on a net basis (excluded from revenues).

The Company's policy is to accrue for property taxes on a calendar year basis.

Cash and Cash Equivalents

Cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less. Cash and cash equivalents are carried at cost, which approximates fair value.

Restricted Cash and Special Deposits

Restricted cash and special deposits consist of collateral paid to the Independent System Operator – New England ("ISO-NE") in connection with the ISO-NE's market participant financial assurance requirement.

Accounts Receivable and Allowance for Doubtful Accounts

The Company recognizes an allowance for doubtful account to reflect certain financial assets (including accounts receivable, unbilled accrued revenues, and other current assets) net of expected credit losses, at estimated net realizable value. Effective April 1, 2023, the current expected credit loss model was applied for purposes of calculating the allowance for doubtful accounts.

The allowance for doubtful accounts is determined based on a variety of factors, including, for each type of receivable, applying an estimated reserve percentage to each aging category, which takes into account historical collections, write-off experience, and management's assessment of collectability from customers, as appropriate. Management continuously assesses the collectability of receivables and adjusts estimates accordingly if circumstances change and such adjustments are reasonable and supportable based on actual experience, current conditions, and forward-looking information as well as future expectations. Receivable balances are written-off against the allowance for doubtful accounts when the accounts are disconnected and/or terminated, and when such balances are deemed to be uncollectible. The Company recorded bad debt expense of $61.2 million, $40.3 million, and $34.1 million for the years ended March 31, 2024, 2023, and 2022, respectively, within operations and maintenance expense in the accompanying statements of operations.

Inventory

Inventory is composed of materials and supplies as well as purchased renewable energy certificates (“RECs”). Materials and supplies are stated at weighted average cost, which represents net realizable value, and are expensed or capitalized into property, plant, and equipment as used. Purchased RECs are stated at cost. There were no significant write-offs of obsolete inventory for the years ended March 31, 2024, 2023, and 2022.

The Company had materials and supplies of $76.2 million and $41.3 million and purchased RECs of $92.6 million and $99.0 million as of March 31, 2024 and 2023, respectively.

Renewable Energy Certificate Obligations

RECs are stated at cost and are used to measure compliance with state renewable energy standards. The Company is required to comply with the Renewable Energy Portfolio Standard, which requires retail sellers of electricity to obtain a certain minimum percentage or amount of their power supply from renewable energy sources. RECs support new renewable generation resources and are held primarily to be utilized in fulfillment of the Company’s compliance obligations under the Renewable Energy Portfolio Standard. As of March 31, 2024 and 2023, the Company recorded renewable energy certificate obligations of $166.7 million and $204.3 million, respectively.

Power Purchase Agreements

The Company enters into power purchase agreements (“PPAs”) to procure electricity to serve its electric service customers. The Company first evaluates whether such agreements contain a lease. In performing this evaluation, the Company considers whether the terms of the PPA provide the Company with the right to direct use of the generating facility and if the Company has the right to obtain substantially all of the economic benefits derived from use of the facility. In determining whether the Company has the right to direct use of the facility, the Company will consider which rights have the most significant impact on the economic benefits to be derived from the asset; for example, dispatch rights or the right to be involved in the facility’s design. If the PPA is determined to contain a lease, the Company assesses whether it should be classified as a finance lease or an operating lease.

If the PPA does not contain a lease, the Company assesses whether the contract is a derivative or includes one or more embedded derivatives. In making this determination, the Company assesses whether the PPA includes a notional amount or payment provision through the contract’s delivery requirements or terms of default. If the PPA is a derivative or contains one or more embedded derivatives, the Company will assess whether the requirements for election of the normal purchases and normal sales scope exception are met. If the requirements for the election are not met or the election is not made, the Company reports the derivative at fair value on the consolidated balance sheet. If the election is made, the Company accounts for the PPA as an executory contract whereby costs are recognized as electricity is purchased. If the contract does not contain a lease and is not a derivative, the Company accounts for the PPA as an executory contract.

The Company also assesses whether the PPA is a variable interest in a variable interest entity (“VIE”). In determining whether the PPA is a variable interest, the Company assesses whether the contract absorbs certain risks, such as commodity price risk, that the VIE was designed to pass on to its interest holders. If the PPA is determined to be a variable interest in a VIE, the Company determines whether it is the primary beneficiary.

Distributed Generation Advances

Distributed generation refers to electricity that is generated from sources located near the point of use instead of centralized generation sources. Customers wishing to connect a power-generating facility to the Company’s electric power system are responsible for all review and study costs, interconnection equipment costs, and system modification costs reasonably incurred by the Company that are attributable to the proposed interconnection project. The Company bills customers for the costs that it expects to incur, and customers must pay these costs before the Company performs any work. The Company records such customer contributions that have not yet been spent within the distributed generation liability on the balance sheet. As of March 31, 2024 and 2023, the Company’s distributed generation liability was $55.1 million and $56.9 million, respectively.

Fair Value Measurements

The Company measures securities and pension and postretirement benefit other than pension (“PBOP”) plan assets at fair value. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The following is the fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value:

- Level 1: quoted prices (unadjusted) in active markets for identical assets or liabilities that a company has the ability to access as of the reporting date;
- Level 2: inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data;
- Level 3: unobservable inputs, such as internally developed forward curves and pricing models for the asset or liability due to little or no market activity for the asset or liability with low correlation to observable market inputs; and
- Not categorized: Investments in funds that meet certain conditions of ASC 820 are not required to be categorized within the fair value hierarchy. These investments are typically in commingled funds or limited partnerships that are not publicly traded and have ongoing subscription and redemption activity. As a practical expedient, the fair value of these investments is the Net Asset Value (“NAV”) per fund share.

The asset or liability’s fair value measurement level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. The Company uses valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost. The capitalized cost of additions to property, plant, and equipment includes costs such as direct materials, labor and benefits, and an allowance for funds used during construction (“AFUDC”). The cost of repairs and maintenance is charged to expense, and the cost of renewals and betterments that extend the useful life of property, plant, and equipment is capitalized.

Depreciation is computed over the estimated useful life of the asset using the composite straight-line method. Depreciation studies are conducted periodically to update the composite rates and are approved by the FERC and the DPU. The average composite rates for the years ended March 31, 2024, 2023, and 2022 were 3.1%.

Depreciation expense includes a component for the estimated cost of removal ("COR"), which is recovered through rates charged to customers. Any difference in cumulative costs recovered and costs incurred is recognized as a regulatory liability. When property, plant, and equipment is retired, the original cost, less salvage, is charged to accumulated depreciation, and the related COR is removed from the associated regulatory liability.

Allowance for Funds Used During Construction

The Company records AFUDC, which represents the debt and equity costs of financing the construction of new property, plant, and equipment. The equity component of AFUDC is reported in the accompanying statements of operations as non-cash income in other income (deductions), net. The debt component of AFUDC is reported as a non-cash offset to other interest, including affiliate interest, net. After construction is completed, the Company is permitted to recover these costs through their inclusion in rate base. The Company recorded AFUDC related to equity of $1.8 million, $10.4 million, and $7.0 million, and AFUDC related to debt of $9.2 million, $4.4 million, and $3.4 million, for the years ended March 31, 2024, 2023, and 2022, respectively. The average AFUDC rates for the years ended March 31, 2024, 2023, and 2022 were 5.7%, 7.2%, and 7.3%, respectively.

Impairment of Long-Lived Assets

The Company tests the impairment of long-lived assets when events or changes in circumstances indicate that the carrying amount of the asset (or asset group) may not be recoverable. If such an event or change in circumstances is identified, the recoverability of an asset is determined by comparing its carrying value to the estimated undiscounted cash flows that the asset is expected to generate. If the comparison indicates that the carrying value is not recoverable, an impairment loss is recognized for the excess of the carrying value over the estimated fair value. For the years ended March 31, 2024, 2023 and 2022, there were no impairment losses recognized for long-lived assets.

Goodwill

The Company tests goodwill for impairment annually on October 1, or more frequently if events occur or circumstances exist that indicate it is more likely than not that the fair value of the Company is below its carrying amount. The goodwill impairment test requires a recoverability test based on the comparison of the Company's estimated fair value with its carrying value, including goodwill. If the estimated fair value exceeds the carrying value, goodwill is not considered impaired. If the carrying value exceeds the estimated fair value, the Company is required to recognize an impairment charge for such excess, limited to the carrying amount of goodwill.

The Company applies two valuation methodologies to estimate its fair value, principally discounted projected future net cash flows and market-based multiples, commonly referred to as the income approach and market approach. Key assumptions include, but are not limited to, estimated future cash flows, multiples of earnings, and an appropriate discount rate. In estimating future cash flows, the Company incorporates current market information and historical factors. The determination of fair value incorporates significant unobservable inputs, requiring the Company to make significant judgments, whereby actual results may differ from assumed and estimated amounts. For the year ended March 31, 2024, the Company applied a 50/50 weighting for each valuation methodology, as it believes that each approach provides equally valuable and reliable information regarding the Company's estimated fair value.

The Company performed its latest annual goodwill impairment test as of October 1, 2023, at which time the Company's estimated fair value significantly exceeded the carrying value. The Company did not recognize any goodwill impairment during the years ending March 31, 2024, 2023 or 2022.

Asset Retirement Obligations

Asset retirement obligations are recognized for legal obligations associated with the retirement of property, plant and equipment primarily associated with the Company's distribution facilities. Asset retirement obligations are recorded at fair value in the period in which the obligation is incurred, if the fair value can be reasonably estimated. In the period in which new asset retirement obligations, or changes to the timing or amount of existing retirement obligations are recorded, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. In each subsequent period the asset retirement obligation is accreted to its present value.

The Company applies regulatory accounting guidance and both the depreciation and accretion costs associated with asset retirement obligation are recorded as increases to regulatory assets on the balance sheet. These regulatory assets represent timing differences between the recognition of costs in accordance with U.S. GAAP and costs recovered through the ratemaking process.

The Company does not recognize liabilities for asset retirement obligations for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain distribution and other assets cannot currently be estimated, and no amounts are recognized on the financial statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices.

Employee Benefits

The Company participates with other NGUSA subsidiaries in defined benefit pension plans and PBOP plans for its employees, administered by NGUSA. The Company recognizes its portion of the pension and PBOP plans' funded status on the balance sheet as a net liability or asset. The cost of providing these plans is recovered through rates; therefore, the net funded status is offset by a regulatory asset or liability. The pension and PBOP plans' assets are commingled and allocated to measure and record pension and PBOP funded status at each year-end date. Pension and PBOP plan assets are measured at fair value, using the year-end market value of those assets.

Leases

The Company has various operating leases, primarily related to buildings, land, and fleet vehicles. Right-of-use ("ROU") assets consist of the lease liability together with any payments made to the lessor prior to commencement of the lease (less any lease incentives) and any initial direct costs. ROU assets are amortized over the lease term. Lease liabilities are recognized based on the present value of the lease payments over the lease term at the commencement date. For any leases that do not provide an implicit rate, the Company uses an estimate of its collateralized incremental borrowing rate, based on the information available at the commencement date, to determine the present value of future payments. In measuring lease liabilities, the Company excludes variable lease payments, other than those that depend on an index or a rate, or those that are, in substance, fixed payments, and includes lease payments made at or before the commencement date. Variable lease payments were not material for the years ended March 31, 2024, 2023, and 2022.

The Company recognizes lease expense based on a pattern that conforms to the regulatory ratemaking treatment.

New and Recent Accounting Guidance

Accounting Guidance Recently Adopted

Financial Instruments – Credit Losses

In June 2016, the FASB issued ASU No. 2016-13 "*Financial Instruments–Credit Losses (Topic 326): Measurement of Credit Losses on Financial Statements*" which requires a financial asset (or a group of financial assets) measured at amortized cost basis to be presented at the net amount expected to be collected. The accounting standard provides a new model for recognizing credit losses on financial instruments based on an estimate of current expected credit losses that replaces existing incurred loss impairment methodology requiring delayed recognition of credit losses. A broader range of reasonable and supportable information must be considered in developing estimates of credit losses. The allowance for credit losses is a valuation account that is deducted from the amortized cost basis of the financial asset(s) to present the net carrying value at the amount expected to be collected on the financial asset. Credit losses relating to available-for-sale debt securities should be recorded through an allowance for credit losses.

In May 2019, the FASB issued ASU 2019-05, "*Financial Instruments—Credit Losses (Topic 326): Targeted Transition Relief*", permitting entities to irrevocably elect the fair value option for financial instruments that were previously recorded at amortized cost basis within the scope of Topic 326, except for held-to-maturity debt securities. In March 2022, the FASB issued ASU 2022-02, "F*inancial Instruments—Credit Losses (Topic 326): Troubled Debt Restructurings and Vintage Disclosures.*" The update eliminates the accounting guidance for troubled debt restructurings by creditors and enhances the disclosure requirements for loan refinancing and restructurings made with borrowers experiencing financial difficulty.

The Company adopted this new guidance on April 1, 2023. See Note 4, "Allowance for Doubtful Accounts" for further information.

Accounting Guidance Not Yet Adopted

Leases (Topic 842): Common Control Arrangements

In March 2023, the FASB issued ASU 2023-01, "Leases (Topic 842): Common Control Arrangements" which addresses two issues; under Issue 1, the ASU offers a practical expedient that gives an option of using the written terms and conditions of a common-control arrangement (instead of enforceable terms rights and obligations) when determining whether a lease exists and the subsequent accounting for the lease, including the lease's classification. Further, under Issue *2, the ASU* requires leasehold improvements in common control leases be amortized by the lessee over the useful life of the improvements with no consideration of the lease term as long as the lessee controls the use of the underlying asset. In addition, a lessee that no longer controls the use of the underlying asset will account for the transfer of the underlying asset as an adjustment to equity.

The Company will adopt this standard for annual periods effective April 1, 2024, including interim periods, with early adoption permitted. The Company is currently assessing the application of the new guidance but does not expect the adoption to have a material impact on the presentation, results of operations, cash flows, and financial position of the Company.

Income Taxes (Topic 740): Income Tax Disclosures

In December 2023, the FASB issued ASU 2023-09*, "Income Taxes (Topic 740): Improvements to Income Tax Disclosures"* which improves the income tax disclosures by requiring disaggregated information about a reporting entity's effective tax rate reconciliation as well as information on income taxes paid.

The Company will early adopt this standard for annual periods effective April 1, 2025. The Company is currently assessing the application of the new guidance but does not expect the adoption to have a material impact.

Reclassifications

Certain reclassifications have been made to the financial statements to conform the prior period's balances to the current period's presentation. These reclassifications had no effect on reported income, statements of cash flows, total assets, or stockholders' equity as previously reported.

3. REVENUE

The following table presents, for the years ended March 31, 2024, 2023, and 2022, revenue from contracts with customers, as well as additional revenue from sources other than contracts with customers, disaggregated by major source:

	Years Ended March 31,		
	2024	2023	2022
		(in thousands of dollars)	
Revenue from contracts with customers:			
Electric services	**$ 2,720,894**	$ 2,804,165	$ 2,484,650
Total revenue from contracts with customers	**2,720,894**	2,804,165	2,484,650
Revenue from alternative revenue programs	**(50,452)**	34,685	(20,957)
Other revenue	**30,430**	33,139	26,990
Total operating revenues	**$ 2,700,872**	$ 2,871,989	$ 2,490,683

Electric services: The Company owns, maintains, and operates an electric distribution network in upstate Massachusetts. Distribution revenues are primarily from the sale of electricity and related services to retail customers. Distribution sales are regulated by the DPU, which is responsible for determining the prices and other terms of services as part of the ratemaking process. The arrangement where a utility provides a service to a customer in exchange for a price approved by a regulator is referred to as a tariff sales contract. Electric services revenues are derived from the regulated sale and distribution of electricity to residential, commercial, and industrial customers within the Company's service territory under the tariff rates. The tariff rates approved by the regulator are designed to recover the costs incurred by the Company for the products and services provided, along with a return on investment.

The performance obligation related to these sales is to provide electricity to the customers on demand. The electricity supplied under the tariff represents a single performance obligation, as it is a series of distinct goods or services that are substantially the same. The performance obligation is satisfied over time because the customer simultaneously receives and consumes the electricity as the Company provides these services. The Company records revenues based upon the approved tariff rate and the volume delivered to the customers, which corresponds with the amount the Company has the right to invoice.

This revenue also includes estimated unbilled amounts, which represent the estimated amounts due from retail customers for electricity provided to customers by the Company but not yet billed. Unbilled revenues are determined by taking estimated unbilled sales volumes for the respective customer classes and then applying the applicable tariff rate to those volumes. Actual amounts billed to customers when the meter readings occur may be different from the estimated amounts. Certain customers have the option to obtain electricity from other suppliers. In those circumstances, revenue is only recognized for providing delivery of the commodity to the customer.

Additionally, the Company owns an electric transmission system in Massachusetts. Transmission systems generally include overhead lines, underground cables, and substations connecting generation and interconnectors to the distribution system. The Company's transmission services are regulated by both the ISO-NE and the FERC. Additionally, the Company makes available its transmission facilities to NEP for operation and control pursuant to an integrated facilities agreement, Service Agreement No. 23. See Note 14, "Related Party Transactions," for additional details. Transmission revenues arise under tariff/rate agreements and are collected primarily from the Company's Massachusetts distribution customers.

Revenue from alternative revenue programs: The Company records revenues in accordance with accounting principles for rate-regulated operations for arrangements between the Company and the regulator, which are not accounted for as contracts with customers. These primarily include programs that qualify as Alternative Revenue Programs ("ARPs"). ARPs enable the Company to adjust rates in the future, in response to past activities or completed events. The Company's electric distribution rates have a revenue decoupling mechanism ("RDM") which allows for annual adjustments to the Company's delivery rates as a result of the reconciliation between allowed revenue and billed revenue. In addition, the Company has demand side management incentives. The Company recognizes revenues from ARPs with a corresponding offset to a regulatory asset or liability account when the regulatory specified events or conditions have been met, when the amounts are determinable, and are probable of recovery (or payment) through future rate adjustments within 24-months from the end of the annual reporting period.

Other revenue: Includes lease income and other transactions that are not considered contracts with customers.

4. ALLOWANCE FOR DOUBTFUL ACCOUNTS

Receivables are recorded at amortized cost, net of a credit loss allowance for doubtful accounts. The allowance primarily relates to trade receivables from utility customers (both billed and unbilled), as well as amounts receivable from various other counterparties such as governmental agencies, municipalities, and other utilities. The Company had a total allowance for doubtful accounts of $220.4 million and $208.9 million, of which $208.5 million and $208.9 million relates to accounts receivable, $11.1 million and zero relates to unbilled revenues, and $0.8 million and zero relates to certain other current assets as of the years ended March 31, 2024 and 2023, respectively. The activity in the allowance for doubtful accounts for the year ended March 31, 2024 is as follows:

	Year Ended March 31, 2024 (in thousands of dollars)		
	Customers Accounts Receivables	**Other Accounts Receivables**	**Total Allowance**
Beginning balance	$ 205,123	$ 3,802	$ 208,925
Impact of adoption of ASC Topic 326 on April 1, 2023	4,033	453	4,486
Credit loss expense	92,453	875	93,328
Write-offs	(102,091)	(3,226)	(105,317)
Recoveries	16,182	2,787	18,969
Ending balance	$ 215,700	$ 4,691	$ 220,391

5. REGULATORY ASSETS AND LIABILITIES

The Company records regulatory assets and liabilities that result from the ratemaking process. The following table presents the regulatory assets and regulatory liabilities recorded on the balance sheets:

	March 31,	
	2024	2023
	(in thousands of dollars)	
Regulatory assets		
Current:		
Rate adjustment mechanisms	**$ 127,199**	$ 76,742
Renewable energy certificates	**74,174**	105,369
Residential assistance adjustment factor	**5,137**	42,061
Revenue decoupling mechanism	**16,544**	15,116
Transmission service	**5,190**	-
Other	**5,463**	-
Total	**233,707**	239,288
Non-current:		
COVID-19 delivery bad debt	**27,340**	27,340
Environmental response costs	**68,427**	68,026
Exogenous events	**90,003**	-
Net metering deferral	**340,488**	233,721
Postretirement benefits	**79,902**	97,649
Rate adjustment mechanisms	**31,144**	43,485
Storm costs	**340,818**	317,490
Other	**83,437**	59,434
Total	**1,061,559**	847,145
Regulatory liabilities		
Current:		
Rate adjustment mechanisms	**-**	27,870
Transmission service	**-**	3,814
Total	**-**	31,684
Non-current:		
Cost of removal	**362,692**	344,727
Energy efficiency	**68,810**	7,033
Environmental response costs	**15,696**	16,879
Postretirement benefits	**73,429**	58,937
Regulatory tax liability, net	**284,098**	292,379
Other	**16,221**	11,220
Total	**$ 820,946**	$ 731,175

Regulatory assets associated with future financial obligations that were deferred in accordance with Orders issued by the DPU do not earn a return until such time a cash outlay has been made. As of March 31, 2024 and 2023, regulatory assets of $104.3 million ($100.9 million of postretirement benefits and $3.4 million of other costs) and $117.7 million ($115.9 million of postretirement benefits and $1.8 million of other costs), respectively, did not earn a return. The recovery period of these regulatory assets is to be determined in future rate plans or other Orders issued by the DPU.

The Company recovers carrying charges related to regulatory assets where there has been a cash outlay. These carrying charges include an interest component, recognized as a component of regulatory assets, associated with the portion of the regulatory assets deemed to be financed with debt. These carrying charges also include an equity return component, which is an allowance for earnings on shareholders' investment. This equity return component will be recovered through future rates, but is not recognized for financial reporting purposes. The equity return component not recognized in the financial statements as of March 31, 2024 and 2023 was $4.5 million and $2.9 million, respectively.

Cost of removal: Represents cumulative removal amounts collected, but not yet spent, to dispose of property, plant, and equipment. This liability is discharged as removal costs are incurred.

COVID-19 delivery bad debt: Represents the delivery-related uncollectible expense deferral, per D.P.U. 20-58 and 20-91, to defer the delivery bad debt expense as a result of COVID-19.

Energy efficiency: Represents the difference between revenue billed to customers through the Company's energy efficiency charge and the costs of the Company's energy efficiency programs, as approved by the state authorities.

Environmental response costs: The regulatory asset represents deferred costs associated with the Company's share of the estimated costs to investigate and perform certain remediation activities at sites with which it may be associated. The Company's rate plans provide for specific rate allowances for these costs, with variances deferred for future recovery from, or return to, customers. The regulatory liability represents the excess of amounts received in rates over the Company's actual site investigation and remediation costs.

Exogenous events: The Property Tax Exogenous Event Long Term qualifies for the exogenous cost recovery under the Company's Performance-based Ratemaking Plan "PBR" plan. This mechanism defers the Accumulated Exogenous Impact for Property Taxes, as approved per DPU 23-55, resulting from the Department of Revenue change in property tax valuation methodology. In addition, the exogenous events represent the deferred costs associated with major storm threshold. In accordance with the PBR tariff, the recovery of incremental storm costs for those weather events that cause the Company to incur incremental costs exceeding $30 million per event shall always be through a separate factor that will recover each amount requested for recovery over a five-year period. In order for incremental costs exceeding $30 million per event be eligible for recovery pursuant to the provisions of this section, the total of (1) the balance of the Company's Storm Contingency Fund; and (2) the total incremental costs for all weather events where each event's incremental cost exceed $30 million, must exceed $75 million.

Net metering deferral: Net metering deferral reflects the recovery mechanism for costs associated with customer-installed on-site generation facilities, including the costs of renewable generation credits. This surcharge provides the Company with a mechanism to recover such amounts.

Postretirement benefits: The regulatory asset represents the Company's unamortized non-cash accrual of net pension actuarial gains and losses, which is partially offset by the excess amounts received in rates over actual costs of the Company's pension plans. The regulatory asset will be recovered from customers in future periods. The regulatory liability represents the Company's unamortized non-cash accrual of net PBOP actuarial gains and losses, which will be passed back to customers in future periods.

Rate adjustment mechanisms: In addition to commodity costs, the Company is subject to a number of additional rate adjustment mechanisms, whereby an asset or liability is recognized resulting from differences between billed revenues and the underlying cost being recovered or differences between billed revenues and targeted amounts, as approved by the DPU.

Regulatory tax liability, net: Represents over-recovered federal and state deferred taxes of the Company, primarily as a result of regulatory flow-through accounting treatment, state income tax rate changes, and excess federal deferred taxes as a result of the Tax Cuts and Jobs Act of 2017 ("Tax Act").

Renewable energy certificates: Represents deferred costs associated with the Company's compliance with Massachusetts' Renewable Portfolio Standards ("RPS"). The RPS legislation was established to foster the development of new renewable energy sources. The regulatory asset will be recovered over the next year.

Residential assistance adjustment factor: The Company is allowed to recover the incremental costs associated with the operation of the Company's Arrearage Management Programs ("AMPs") offered to qualifying customers, along with the discount provided to customers receiving retail delivery service under Residential Low-Income Rate R-2. Discounts provided to eligible customers amount to 32% of the customers' total bill for service.

Revenue decoupling mechanism ("RDM"): As approved by the DPU, the Company has an electric RDM, which allows for an annual adjustment to the Company's delivery rates as a result of the reconciliation between allowed revenue and billed and unbilled revenues. Any difference is recorded as a regulatory asset or regulatory liability.

Storm costs: The Company is allowed to recover qualifying storm costs from all retail delivery service customers. This balance reflects costs incurred and yet to be recovered. See Note 6, "Rate Matters," for additional information regarding the recovery of storm costs.

Transmission service: The Company arranges transmission service on behalf of its customers and bills the costs of those services to customers pursuant to the Company's Transmission Service Cost Adjustment Provision. Any over or under recoveries of these costs are passed on to customers receiving transmission service over the subsequent year.

6. RATE MATTERS

Rate Case Filing

On November 16, 2023, the Company and its affiliate, Nantucket Electric, filed an application for new base distribution rates to become effective October 1, 2024. The Company and Nantucket Electric's petition requests an overall net increase in base distribution revenue of approximately $131 million based upon a 10.5% return on equity, and a capital structure of 53.48% equity, 46.47 % long-term debt, and 0.05% preferred stock. The proposed increase includes an increase in annual funding of the storm fund from $16 million to $53 million per year and $7 million per year related to exogenous property tax expenses previously approved and deferred for future recovery. The net increase in base distribution revenue was updated to $123 million in the revised revenue requirements and bill impacts filed on May 3, 2024.

Also included in the petition is the Company's five-year Comprehensive Performance and Investment Plan or "CPI Plan", which encompasses the Company's core investment plan, investments to deliver the clean energy transition, and performance metrics to hold the Company accountable to its CPI Plan. The CPI Plan includes two methods of cost recovery: (1) five-year performance-based ratemaking for operating costs only ("PBR-O") plan, which adjusts non-capital related components of base distribution revenue annually based on a pre-determined formula, plus recovery of incremental capital-related operating expense, and exogenous event costs if applicable; and (2) an Infrastructure, Safety, Reliability and Electrification or "ISRE" mechanism for the annual recovery outside of base rates related to both core capital investment post-test year and any incremental costs associated with the Company's "Future Grid" plan to be reviewed by the Department in the separate Electric Sector Modernization Plan ("ESMP") proceeding. Both the PBR-O and ISRE recovery mechanisms include the potential to earn incentive revenues and/or penalties as determined annually by the Company's actual performance against a suite of symmetrical performance metrics. The PBR-O mechanism also includes recovery of exogenous events which meet a significance threshold of $3.6 million, including separate recovery factors related to exogenous storm costs for single storm events greater than $30 million as well as a new proposed exogenous debt cost recovery factor which would refund or collect from customers the difference between actual debt costs incurred and the level of debt cost recovery embedded in base distribution rates annually. The PBR-O proposal includes an earnings sharing mechanism, under which the Company would share 75% of its earnings that exceed 11.5% return on equity with customers. If approved, the Company would agree not to file for an effective change in base distribution rates outside of the annual PBR-O and ISRE mechanisms for a period of five years from the effective date of new rates.

In addition to the base request of $123 million and CPI plan, the Company has petitioned for three additional proposals outside of its base distribution rates. The first is an extension of the storm fund replenishment factor through September 2029 as well as an increase of approximately $13 million to the annual funding level. The Company has also petitioned to extend the term of its Vegetation Management Pilot through September 2029. Finally, the Company has proposed revisions to its current low-income discount rate structure for customers earning 60% of the state median income or less, from the current flat discount rate of 32% to a tiered structure with discounts ranging from 32% to 55%, depending on income and energy burden. The low-income proposal also includes a dedicated team to engage eligible customers through in-person events and a targeted outreach to increase program participation. Recovery of the increased discounts along with costs of increased education and outreach activities would occur through the Company's existing Residential Assistance Adjustment Factors once the program is implemented.

The new base distribution rates would be reflected on customers' bills starting November 1, 2024. To ensure the Company invests, operates, and maintains its distribution system wisely, the proposal will undergo a prudency review by the Department over a statutory 10-month period and will provide for public input and comment. Public hearings were held in March, April and May 2024 across the service territory. Evidentiary hearings were concluded in May 2024 and an order is expected in September 2024.

PBR Plan Filing

On June 15, 2021, the Company and Nantucket Electric filed the second annual PBR plan filing for rates effective October 1, 2021. The PBR plan filing adjusts base distribution rates pursuant to a revenue cap formula, provides a credit to customers for any customer share of excess earnings pursuant to the earnings sharing mechanism, and recovers from or credits customers for the impact of costs in excess of a threshold associated with exogenous events, including storms having incremental costs in excess of $30 million. On September 8, 2021, the Department allowed the Company's proposed PBR Adjustment and Capital Expenditure Adjustment for effect October 1, 2021, subject to further investigation and reconciliation. On February 23, 2022, the Department gave final approval to the Company's second annual PBR plan filing for rates that went into effect October 1, 2021, a total increase to base distribution revenue of 2.709%, or $22.8 million.

On June 17, 2022, the Company and Nantucket Electric filed the third annual PBR plan filing for rates effective October 1, 2022. The Company and Nantucket Electric requested approval of a PBR adjustment of $43.9 million, based on a PBR percentage of 4.92%. This adjustment reflects the implementation of the Company and Nantucket Electric's proposed voluntary one-time customer impact mitigation plan, which the Company proposed due to the extreme economic circumstances and high inflation rates currently impacting customers. On September 26, 2022, the DPU approved the Company and Nantucket Electric's proposed PBR adjustment and customer impact mitigation plan, effective October 1, 2022. The DPU also stated that it will conduct its review of the Company and Nantucket Electric's proposed amortization of the exogenous storm event with incremental costs in excess of $30 million as part of the Company and Nantucket Electric's next PBR plan filing.

The Company made its fourth annual PBR filing on June 15, 2023. The filing requested a PBR Adjustment for effect October 1, 2023 of $66.7 million, plus recovery of $13.5 million annually over five years associated with an exogenous storm event in which the Company incurred incremental costs in excess of $30 million, resulting in a total of $80.2 million. The filing included a voluntary Customer Impact Mitigation Plan, that reduced what the Company would have otherwise requested under its PBR formula by $14.7 million, from $81.4 million to $66.7 million (not inclusive of the storm event costs). The filing also included a request to approve the recovery method for increased local property taxes due to a change in the assessment methodology, which the DPU previously determined was an "exogenous event" under the PBR tariff, and to recover the ongoing yearly impacts of this change ($5.9 million for the year ended March 31, 2021; $7.4 million for the year ended March 31, 2022; and $0.6 million for the year ended March 31, 2023).

On September 28, 2023, the DPU approved the Company and Nantucket Electric's proposed PBR Adjustment and Customer Impact Mitigation Plan, as well as the proposed exogenous storm cost recovery factors, effective October 1, 2023. The DPU also approved recovery of the ongoing incremental property tax as requested pertaining to the years ended March 31, 2021 and March 31, 2022.

On June 14, 2024, the Company filed its fifth annual PBR filing, proposing to recover two exogenous storms with incremental costs in excess of $30 million in the storm factor effective October 1, 2024 as allowed by the PBR Provision, equating to recovery of approximately $16.3 million annually over 5 years.

Recovery of Transmission Costs

The Company’s transmission facilities are currently operated in combination with the transmission facilities of its New England affiliate, NEP, as a single integrated system, with NEP designated as the combined operator. In accordance with the provisions in the Integrated Facilities Agreement “IFA” between NEP and the Company, the Company is compensated for its actual monthly transmission costs, with its authorized maximum ROE of 11.74% on its transmission assets. The amounts remitted by NEP to the Company is included in NEP’s Local and Regional Network Service rates for recovery from wholesale transmission customers. The amounts remitted by NEP to the Company for the years ended March 31, 2024, 2023 and 2022 were $22.3 million, $21.6 million and $24.2 million, respectively, which are reflected as credits within operating expenses in the accompanying statements of operations.

The ROE for transmission rates under the ISO-NE OATT is the subject of four complaints pending before the FERC. Under orders on the first complaint issued in 2014 and 2015, the FERC reset the base ROE applicable to transmission assets under the ISO-NE OATT to 10.57% effective as of October 16, 2014, and for a 15-month refund period beginning October 1, 2011, and established a maximum ROE of 11.74%. These orders were appealed by NEP and multiple other parties. On April 14, 2017, the U.S. Court of Appeals for the D.C. Circuit (“Court of Appeals”) vacated and remanded the FERC's 2014 and 2015 orders lowering the base ROE and total ROE of NEP and other New England transmission owners (“NETOs”).

On October 16, 2018, the FERC initiated a paper hearing process on the ROE issues that were remanded by the Court of Appeals. NEP, along with other NETOs, filed a brief supporting a new ROE methodology and recommending a 10.41% base ROE. The FERC has not issued a final order on NEP’s brief, and the base ROE in New England remains at 10.57% subject to adjustments back to the first complaint refund period and other prior periods when the FERC acts on the briefs submitted by NEP and other parties in this paper hearing.

In November 2019, the FERC issued an order in the Midcontinent Independent System Operator (“MISO”) transmission owner ROE complaint dockets, changing the way it arrives at a just and reasonable ROE. Base ROEs were reduced from 10.32% to 9.88% when the FERC applied this revised methodology in two MISO ROE complaints. In the MISO order, the FERC made statements that it is setting new ROE policy nationwide. In December 2019, the NETOs filed a supplemental brief in the New England ROE complaint dockets, showing the FERC the detrimental effects on New England if the 2019 MISO order was applied to New England. In that brief, the NETOs asked the FERC to reopen the record in New England so that the NETOs could submit more testimony. Other stakeholders had an opportunity to reply to the NETOs’ supplemental brief by January 21, 2020 and did so, arguing that the NETOs’ request should be denied, and that the record in New England should not be reopened.

On May 21, 2020, the FERC, on rehearing, revised the methodology to determine MISO transmission owner ROEs. The FERC’s November 2019 order proposed to create “zones of reasonableness” based on averages of two (rather than four) models to judge whether ROEs are just and reasonable in complaint cases. The May 2020 order relies on three models to estimate ROEs. The application of this new methodology increased base ROEs in the MISO complaints from 9.88% to 10.02%. On November 19, 2020, the FERC issued a further order on rehearing in the MISO complaint dockets, upholding the 10.02% base ROE. The FERC’s MISO ROE orders are currently on appeal before the Court of Appeals. On August 9, 2022, the D.C. Court of Appeals issued its decision, which vacated the MISO transmission owner ROE complaint orders and remanded the matter to the FERC for further proceedings. As grounds for its decision, the D.C. Court of Appeals found that the FERC failed to offer a reasoned explanation for its decision to reintroduce the risk premium model to help calculate ROEs after initially rejecting it. The matter was returned to the FERC on September 30, 2022, but the FERC will not be under any particular deadline to act on the remand. It is likely that this development will also further delay any additional orders in the NETO ROE complaint cases.

On March 17, 2022, the FERC issued an order in a case addressing the base ROE for Pacific Gas and Electric Company (“PG&E”). The FERC applied the ROE methodology from the 2020 MISO ROE orders and found that 9.26% was the just and reasonable base ROE for PG&E in that proceeding. The FERC did not act on requests for a rehearing regarding its March 2022 PG&E order, so these requests for a rehearing were deemed to be denied by operation of law in May 2022. The FERC’s orders on PG&E’s base ROE are currently on appeal before a federal Court of Appeals but the appellate cases currently are being held in abeyance to allow for FERC to issue a substantive order addressing rehearing requests in the PG&E rate case.

On July 28, 2023, FERC issued Order No. 2023 to reform its proforma generator interconnection procedures and agreements. FERC adopted these reforms to reduce interconnection queue backlogs, improve certainty in the interconnection processes managed by ISOs, Regional Transmission Organizations ("RTO") and transmission providers, and ensure access to the transmission system for new technologies. On March 8, 2024 ISO-NE presented to the Participating Transmission Owner Administrative Committee ("PTO-AC"), of which NEP is a member, proposed ISO-NE Tariff revisions to the Large Generator, Small Generator and Elective Transmission Upgrade Interconnection Procedures to comply with Order 2023. The PTO-AC voted to approve the tariff changes. From a transmission perspective, Order 2023 makes numerous significant changes to the interconnection process that will impact the Company including moving to a First-Ready, FirstServed Cluster study process and establishing Study Deadlines and Delay Penalties, Order 2023 will take effect on November 6, 2023, however, the ISO-NE tariff changes to implement Order 2023 are proposed to become effective May 31, 2024. On March 21, 2024, the FERC issued an order requiring the ISO-NE to make its Order 2023/2023-A compliance filing within 30 days. ISO-NE made its compliance filing on May 14, 2024 to comply with Order 2023. The filings set a June 13, 2024 Eligibility Date after which no new Interconnection Requests will be accepted until the first standard Cluster Study opens. The Company has collaborated with ISO-NE in crafting its compliance filing and, therefore, does not anticipate filing comments in opposition.

The Company does not believe the outcomes of these complaints will have a material impact on the Company's financial condition, results of operations, or cash flows.

Tax Cuts and Jobs Act

On November 21, 2019, the FERC issued Order 864 to address ratemaking and regulatory reporting of excess or deficient accumulated deferred income taxes ("ADIT") related to the Tax Act. On June 29, 2020, NEP, on behalf of the Company, submitted a compliance filing to address the application of Order 864 in NEP's Tariff No. 1. The filing proposed changes to various revenue requirement calculations in the tariff for the inclusion of the rate adjustment and income tax allowance mechanisms. The filing also included the populated permanent ADIT worksheet, which will be provided with the issuance of final bills pursuant to the provisions of the tariff. NEP has proposed for the Company to amortize transmission-related, protected property-related excess or deficient ADIT associated with the 2017 Tax Act using the average rate assumption method, and a 21-year amortization period for unprotected property-related excess or deficient balances. Other unprotected excess or deficient ADIT is proposed to be amortized over five years, consistent with the time period approved in the DPU docket addressing the Tax Act. Following discussions with FERC staff, NEP made a supplemental compliance filing on the Company's behalf on July 19, 2022, in which it proposed adjustments to the initial filing to add greater clarity and transparency. NEP, on behalf of the Company, submitted a supplement to the amended compliance filing on October 3, 2022, based on further discussions with FERC staff. On October 25, 2022, FERC issued an order accepting the Company's compliance filings related to application of Order 864 in Tariff No. 1.

Grid Modernization Plan

On August 19, 2015, the Company, together with Nantucket Electric, filed its first proposed grid modernization plan ("GMP") with the DPU. On May 10, 2018, the DPU issued an order approving $82 million in grid-facing investments over three years (and subsequently, the DPU extended the GMP to a fourth year) in (1) conservation voltage reduction and volt/volt-amps reactive optimization; (2) advanced distribution automation; (3) feeder monitors; (4) communications and information/operational technologies; and (5) advanced distribution management/distribution supervisory control and data acquisition. The DPU allowed recovery of both operation and maintenance ("O&M") expenses and capital costs through a reconciling mechanism. The DPU did not approve any advanced metering infrastructure, or "AMI" investments; the DPU said it would address these in a further investigation (which it did in the Company's GMP for calendar years 2022-2025, see below). The Company has filed annual reports and cost recovery filings with the DPU for its GMP in 2019, 2020, 2021, 2022 and 2023.

The Company filed its proposed four-year GMP (for calendar years 2022–2025) on July 1, 2021, which included proposals to continue the previously-approved investments (designated as "Track 1" in the proceeding), invest in a distributed energy resource management system ("DERMS"), conduct two demonstration projects, and deploy AMI (all designated as "Track 2" in the proceeding). On October 7, 2022, the DPU issued its final order on Track 1, preauthorizing a $300.8 million budget in (1) monitoring and control ($4.1 million); (2) volt/volt-amps reactive optimization ($76.4 million); (3) advanced distribution automation ($37.7 million); (4) an advanced distribution management system ($61.0 million); (5) information/operational technology ($18.8 million); and (6) communications ($102.8 million) for the 2022-2025 GMP. On November 30, 2022, the DPU issued its Track 2 Order, preauthorizing $35.4 million in new grid-facing investments for the years 2022-2025 grid modernization plan. Accelerated cost recovery for these investments will continue through the separate grid modernization factor. The DPU also has preauthorized $391.1 million in spending for our AMI "core" investments for the years 2023-2027, and created a new AMI factor for accelerated cost recovery for these costs. The DPU separated some of the AMI investments into a new category of "supporting" AMI investments and provided preliminary approval for a budget of $96.1 million for these investments. On March 15, 2024, the Company made its first annual AMI cost recovery filing for calendar year 2023, which seeks recovery of $3.9 million in O&M costs for calendar year 2023. The filing also provides an update on calendar year 2023 program implementation. The Company plans to complete its AMI implementation by the end of 2027.

On April 1, 2022, the Company filed with the DPU its four-year Grid Modernization Term Report, which reports on the Company's implementation of its Grid Modernization Program for calendar years 2018-2021. The DPU also consolidated into this proceeding the Company's annual grid modernization cost recovery filings for calendar years 2018-2021, and is conducting a final review of the costs in this proceeding.

On January 12, 2024, the DPU changed the Grid Modernization annual report filing deadline from April 1st to July 1st, in order to allow the companies time to present "final, audited" cost information in the annual reports. On March 15, 2024, the Company made its GMP cost recovery filing for calendar year 2023, seeking recovery of a $20.4 million revenue requirement, with total costs for CY2023 of $100.5 million. The filing provides a brief update on program implementation for calendar year 2023. Overall the program remains on track, a full update will be provided in the calendar year 2023 Grid Modernization annual report which is due to the DPU on July 1, 2024.

COVID-19 Moratorium on Utility Shut Offs

Between March 24, 2020 and February 26, 2021, the Chairman of the DPU declared a moratorium prohibiting all residential utility collection activities due to the COVID-19 pandemic until July 1, 2021. Effective July 1, 2021, the Company recommenced normal collections activities, which includes issuing notices of amounts in arrears and alerting customers that their service is subject to disconnection for non-payment. Transitional extended deferred payment arrangements were, however, in place through May 2022, and more flexible terms for the arrearage management program (e.g., an increase in arrearages forgiven from $4,000 to $12,000) are still in effect. The commercial and industrial moratorium was lifted effective September 1, 2020.

On December 31, 2020, the DPU approved the following implementation items related to the ratemaking treatment of the COVID-19 customer assistance programs on which the Massachusetts local distribution companies and the Massachusetts Attorney General's ("AG") office had reached consensus: (1) the distribution companies should be allowed to record, defer, and track their bad debt and other COVID-related expenses; (2) cost recovery should be limited to the incremental costs incurred; and (3) certain costs must be extraordinary to qualify for recovery. As of March 31, 2023 and March 31, 2024, the Company has deferred $27.3 million of delivery bad debt (for both the Company and Nantucket Electric) and $0.8 million of other COVID-related costs, as the Company believes that these amounts are probable of recovery.

The DPU decided that the contested issues, including the extent to which the distribution companies will be allowed to recover their COVID-19 costs, should be fully adjudicated in a new docket, D.P.U. 20-91. The AG opposes recovery by distribution companies with PBR plans (including the Company) of incremental COVID-related O&M expenses. The AG also opposes using the pre-tax overall weighted cost of capital for the calculation of carrying charges on bad debt, arguing that the short-term debt rate, or, in the alternative, an interest rate contemporaneous to two-year U.S. Treasury notes, is the correct rate. The AG also takes the position that the DPU should consider the significance of the distribution companies' net incremental O&M costs due to COVID-19 to determine whether they resulted in substantial harm to the distribution companies' financial position. The briefing phase has concluded, and the DPU's order is pending. The Order will likely be issued after August 2024 when the Distribution Companies submit their final report on bad debt levels through June 30, 2024. The Distribution Companies were required to track delivery-related bad-debt write-offs for two years, from July 1, 2020 through June 30, 2022, and filed a report on August 1, 2022, reporting incremental delivery-related net charge offs. The Companies are required to continue to track bad-debt write-offs for the two-year period of July 1, 2022 through June 30, 2024, with a report to be filed on August 1, 2024, depending on each utility's timing of base distribution rate case filings, and to submit filings to the DPU after that point to commence recovery of the demonstrated incremental amount.

Massachusetts Petition for Waiver of Jurisdiction Regarding the Rhode Island Sale

On May 3, 2021, PPL Energy Holdings, LLC assigned its right to acquire NECO to its wholly owned subsidiary, PPL Rhode Island, such that, upon closing, PPL Rhode Island owned 100% of the outstanding shares of common stock in NECO. The Department approved NGUSA's request for a waiver of G.L. c. 164, § 96(c), regarding the sale of NECO in July 2021. Following that approval there was an appeal process which concluded in May 2022 with a settlement agreement with the Attorney General and on May 25, 2022, NECO was sold to PPL Rhode Island.

On June 24, 2022, the Company submitted its compliance filing per directives in the Department's July 16, 2021, order as well as commitments in the AGO Settlement to issue a one-time bill credit to customers. On July 26, 2022, the Department approved the Company's bill credit proposal and compliance filing. The one-time bill credit was refunded to customers through their bills over six months period from November 2022 to April 2023. On June 30, 2023, the Company made a filing on the annual report with the AG and DPU in accordance with Section 2.13 of the Settlement. The Company also provided information related to the annual report requirements as part of the Cost Mitigation Report submitted with the rate filing on November 16, 2023. Review of the cost mitigation report by the Department and AG will occur in the context of the rate case.

Storm Threshold Deferral Requests

On June 17, 2022, the Company and Nantucket Electric petitioned the DPU for authorization to defer for future recovery $6.2 million in storm cost threshold amounts associated with four qualifying major storm events that occurred in calendar year 2021. On January 19, 2023, the Department issued an order allowing the Company to apply deferral accounting treatment to threshold amounts associated with three major storm events, totaling $4.65 million. The Department disallowed $1.55 million of threshold costs associated with the October 26, 2021 Wind/Rain Event because it would be considered as an exogenous event. The Department will determine the appropriate level of recovery for the excess storm fund threshold amount (if any) in the Company's next base distribution rate case. On June 15, 2023, the Company and Nantucket Electric petitioned the DPU for authorization to defer for future recovery $6.2 million in storm cost threshold amounts associated with four qualifying major storm events that occurred in calendar year 2022. Briefing concluded on October 24, 2023. On November 13, 2023, the DPU issued an order allowing the Company and Nantucket Electric to apply deferral accounting treatment to the four storm thresholds. The Company has sought recovery of deferred amounts in its current rate case petition. The DPU will determine what if any recovery is appropriate in its rate case order. On June 14, 2024, the Company requested deferral accounting treatment of 8 storm thresholds for events in calendar year 2023 for a total of $12.4 million until the storm cost recovery filing to be made in 2025.

Storm Cost Recovery

On September 26, 2019, Massachusetts Electric Company and Nantucket Electric submitted a cost recovery filing to the DPU for three storms from in 2017 and 2018 totaling $102.5 million in incremental O&M costs pursuant to the storm fund. On November 27, 2023, the DPU issued an order approving $99.7 million in requested costs, disallowing $2.8 million due to insufficient documentation and unrelated storm costs. On January 11, 2024, the Company made an original compliance filing to recalculate costs for storm fund recovery based on the revised capitalization methodology approved in D.P.U. 18-94-A and calculated consistent with D.P.U. 18-94 and D.P.U. 18-153. The total net incremental O&M deferred storm costs was decreased by $18.7 million, comprised of $2.8 million of disallowances, $16.1 million increase in capital exclusions, and a decrease of $0.2 million in materials exclusions. Due to the calculation revisions, the originally sought amount $102.5 million was reduced to $83.8 million, which will result in $2.8 million of disallowances; the net increase to capital and materials exclusions was recorded as a reclassification from the deferral account to property plant and equipment and will be recovered through rate base in a future base rate filing. The compliance filing was approved on February 12, 2024 without revision. The Company filed a revised compliance filing on May 3, 2024. The storm cost deficit was reduced by $0.3 million as of December 31, 2023.

Municipal Fiscal Year 2022 Property Tax Exogenous Event Request

The Massachusetts Department of Revenue (DOR) has required municipalities to change the way they calculate property taxes, resulting in property tax increases to the Company. On October 18, 2022, the Company filed to be able to recover the costs of this change as an "exogenous event" under its performance-based ratemaking (PBR) plan, along with Nantucket Electric and Boston Gas Company. On May 17, 2023, the DPU approved the Company's request to recover incremental fiscal year 2022 property tax expenses due to certain municipalities changing their assessment methodology after DOR changed its certification standards. The approved amount was $7.4 million for the Company and Nantucket Electric. The Company was directed to propose a recovery method for the approved amounts in the next PBR filing due on June 15, 2023. After a favorable ruling in a separate case allowing Eversource Energy to recover these type of incremental property taxes, the Company added a request to recover fiscal year 2021 incremental property taxes in the proceeding, but the DPU did not allow this request because it was not part of the initial filing and notice in the proceeding. The Company requested recovery of these fiscal year 2021 amounts and fiscal year 2023 incremental costs in its PBR filing made June 15, 2023. On September 28, 2023, the DPU approved the Company's recovery proposal pertaining to fiscal years 2021 and 2022 incremental property tax expense. Recovery of fiscal year 2023 incremental property tax expense was disallowed, as the annual incremental expense incurred of $0.6 million did not meet the significance threshold for exogenous recovery under the current PBR provision. The Company sought approval to defer the recovery of $40.0 million associated with the cumulative annual increase to its property taxes for fiscal years 2021 through 2023 and to recover $8.0 million each year over a five-year period beginning on October 1, 2024. The DPU approved the Company's proposal, and consistent with the disallowance of the fiscal year 2023 incremental property tax costs above, reduced the amount of recovery to $38.7 million or $7.7 million each year. As of March 31, 2024, $39.1 million was deferred to regulatory assets which resulted in the reduction of property tax expense in current year.

Electric Sector Modernization Plan

G.L. c. 164, Sections 92B and 92C, requires each electric distribution company to develop ESMP to proactively upgrade the distribution system to help the Commonwealth realize its statewide greenhouse gas ("GHG") emissions limits and sublimits under Chapter 21N. On January 29, 2024, the Company filed its ESMP with the DPU. Per the Department's February 20, 2024 Interlocutory Order on Scope of Proceedings, the DPU will investigate these first ESMP filings as strategic plans and in that context will investigate compliance with the statute, the electric distribution companies' ("EDCs") forecast methods and net benefits proposals, the appropriate cost recovery framework (base rates or a reconciling mechanism), and the standard of review, and will defer performance metrics to a subsequent phase of the proceedings. The Department will not adjudicate budget pre-approval requests (including for new CIPs) or cost allocation or rate design proposals. The statute requires the DPU to issue an order by August 29, 2024.

7. PROPERTY, PLANT, AND EQUIPMENT

The following table summarizes property, plant, and equipment at cost and operating leases ROU assets, along with accumulated depreciation and amortization:

	March 31,	
	2024	2023
	(in thousands of dollars)	
Plant and machinery	**$ 6,009,386**	$ 5,634,047
Land and buildings	**284,408**	249,295
Assets in construction	**381,064**	316,699
Operating leases ROU assets	**119,438**	101,813
Total property, plant, and equipment	**6,794,296**	6,301,854
Accumulated depreciation and amortization	**(1,863,002)**	(1,784,333)
Accumulated amortization – Operating lease ROU assets	**(56,594)**	(46,589)
Property, plant, and equipment, net	**$ 4,874,700**	$ 4,470,932

8. EMPLOYEE BENEFITS

The Company participates with other NGUSA subsidiaries in qualified and non-qualified non-contributory defined benefit pension plans (the "Pension Plans") and PBOP plans (the "PBOP Plans," together with the Pension Plans, the "Plans"), covering substantially all employees. As of April 1, 2021, NGUSA became the sponsoring company of the nonqualified pension arrangements the Company participated in and all assets and liabilities associated with those nonqualified arrangements were transferred to NGUSA.

Plan assets are maintained for all of NGUSA and its subsidiaries in commingled trusts. In respect of cost determination, plan assets are allocated to the Company based on its proportionate share of the projected benefit obligations. The Plans' costs are first directly charged to the Company based on the Company's employees that participate in the Plans. Costs associated with affiliated service companies' employees are then allocated as part of the labor burden for work performed on the Company's behalf. The Company applies deferral accounting for pension and PBOP expenses associated with its regulated electric operations. Any differences between actual costs and amounts used to establish rates are deferred and collected from, or refunded to, customers in subsequent periods. Pension and PBOP service costs are included within operations and maintenance expense, and non-service costs are included within other income (deductions), net in the accompanying statements of operations. Non-service costs contain components for interest cost, expected return on assets, amortization of actuarial gain/loss and settlement charges. Portions of the net periodic benefit costs disclosed below have been capitalized as a component of property, plant, and equipment, net.

Pension Plans

The Qualified Pension Plans are defined benefit plans which provide most union employees, as well as non-union employees hired before January 1, 2011, with a retirement benefit. Supplemental non-qualified, non-contributory executive retirement programs provide additional defined pension benefits for certain executives. During the years ended March 31, 2024, 2023, and 2022, the Company made contributions of approximately zero, $18.6 million, and $14.8 million, respectively, to the Qualified Pension Plans. The Company does not expect to contribute to the Qualified Pension Plans during the year ending March 31, 2025.

Benefit payments to Pension Plan participants for the years ended March 31, 2024, 2023, and 2022 were approximately $61.4 million, $35.8 million, and $32.0 million, respectively. Benefit payments for the year ended March 31, 2024 included payments for an annuity contract purchase.

PBOP Plans

The PBOP Plans provide health care and life insurance coverage to eligible retired employees. Eligibility is based on age and length of service requirements, and, in most cases, retirees must contribute to the cost of their coverage. During the years ended March 31, 2024, 2023, and 2022, the Company made contributions of zero, $0.2 million and zero to the PBOP Plans. The Company does not expect to contribute to the PBOP Plans during the year ending March 31, 2025.

Gross benefit payments to PBOP Plan participants for the years ended March 31, 2024, 2023, and 2022 were approximately $14.1 million, $18.8 million, and $10.1 million, respectively.

Net Periodic Benefit Costs

The Company's total pension costs (benefits) for the years ended March 31, 2024, 2023, and 2022 were ($4.3) million, $3.7 million, and $20.6 million, respectively. This included non-service pension costs (benefits) for the year ended March 31, 2024 of ($14.6) million.

The Company's total PBOP costs (benefits) for the years ended March 31, 2024, 2023, and 2022 were ($5.0) million, $(1.9) million, and $0.7 million, respectively. This included non-service PBOP costs (benefits) for the year ended March 31, 2024 of ($8.0) million.

Amounts Recognized in Regulatory Assets/Liabilities and Accumulated Other Comprehensive Income

The following tables summarize the Company's changes in actuarial gains/losses and prior service costs recognized in regulatory assets/liabilities and accumulated other comprehensive income ("AOCI") as of March 31, 2024, 2023, and 2022:

	Pension Plans		
	March 31,		
	2024	2023	2022
		(in thousands of dollars)	
Net actuarial (gain) loss	**$ (15,294)**	$ 15,622	$ (54,426)
Amortization of net actuarial loss	**(40)**	(3,326)	(17,834)
Amortization of prior service cost, net	**(3)**	(4)	(4)
Total	**$ (15,337)**	$ 12,292	$ (72,264)
Change in regulatory assets or liabilities	**$ (15,006)**	$ 12,553	$ (72,248)
Change in AOCI	**(331)**	(261)	(16)
Total	**$ (15,337)**	$ 12,292	$ (72,264)

	PBOP Plans		
	March 31,		
	2024	2023	2022
		(in thousands of dollars)	
Net actuarial (gain) loss	**$ (17,584)**	$ 2,003	$ (45,233)
Amortization of net actuarial gain	**3,092**	1,876	-
Total	**$ (14,492)**	$ 3,879	$ (45,233)
Change in regulatory assets or liabilities	**$ (14,492)**	$ 3,879	$ (45,233)
Total	**$ (14,492)**	$ 3,879	$ (45,233)

Amounts Recognized in Regulatory Assets/Liabilities and AOCI – not yet recognized as components of net actuarial gain/loss

The following tables summarize the Company's amounts recognized in regulatory assets/liabilities and AOCI on the balance sheet that have not yet been recognized as components of net actuarial gain/loss as of March 31, 2024, 2023, and 2022:

	Pension Plans		
	March 31,		
	2024	2023	2022
		(in thousands of dollars)	
Net actuarial loss	**$ 101,093**	$ 116,427	$ 104,131
Prior service cost	**-**	3	7
Total	**$ 101,093**	$ 116,430	$ 104,138
Included in regulatory assets	**$ 100,942**	$ 115,948	$ 103,395
Recognized in AOCI	**151**	482	743
Total	**$ 101,093**	$ 116,430	$ 104,138

	PBOP Plans		
	March 31,		
	2024	2023	2022
		(in thousands of dollars)	
Net actuarial gain	**$ (73,429)**	$ (58,937)	$ (62,816)
Total	**$ (73,429)**	$ (58,937)	$ (62,816)
Included in regulatory liabilities	**$ (73,429)**	$ (58,937)	$ (62,816)
Total	**$ (73,429)**	$ (58,937)	$ (62,816)

Reconciliation of Funded Status to Amounts Recognized on the Balance Sheet

	Pension Plans		PBOP Plans	
	March 31,		March 31,	
	2024	2023	**2024**	2023
		(in thousands of dollars)		
Projected benefit obligation	**$ (629,539)**	$ (701,608)	**$ (238,596)**	$ (247,700)
Allocated fair value of assets	**672,734**	725,187	**260,242**	252,466
Funded status	**$ 43,195**	$ 23,579	**$ 21,646**	$ 4,766
Non-current assets	**$ 43,465**	$ 24,093	**$ 21,724**	$ 4,830
Other current liabilities	**-**	-	**(78)**	(64)
Non-current liabilities	**(270)**	(514)	**-**	-
Total	**$ 43,195**	$ 23,579	**$ 21,646**	$ 4,766

For the year ended March 31, 2024, the net actuarial gain for Pension was primarily driven by an increase in discount rate and slight changes in the retirement assumption tables resulting from a recent experience study, partially offset by asset losses due to returns that were less than expected. The net actuarial gains for the PBOP Plans were driven by an increase in discount rate, savings recognized from a Pharmacy Benefit Manager market check completed for the Company's contract, as well as the updated Medicare Advantage contract to reflect actual enrollment. For the year ended March 31, 2023, the net actuarial losses for the Pension and PBOP plans were primarily driven by asset losses due to returns that were less than expected. These losses were partially offset by the increase in the discount rate, slight changes to the withdrawal assumption resulting from the recent experience study, and savings resulting from a new Medicare Advantage contract for PBOP. For the year ended March 31, 2022, the net actuarial gains for the Pension and PBOP Plans were largely driven by an increase in the discount rate and a change in the mortality assumption resulting from the recent experience study, which were partially offset by small asset losses due to returns that were less than expected.

Expected Benefit Payments

Based on current assumptions, the Company expects to make the following benefit payments subsequent to March 31, 2024 (amounts for PBOP Plans are shown net of employer group waiver plan subsidies expected):

(in thousands of dollars) Years Ending March 31,	Pension Plans	PBOP Plans
2025	$ 38,418	$ 13,600
2026	37,649	14,203
2027	39,376	14,737
2028	40,711	15,307
2029	41,697	15,810
2030-2034	219,366	82,036
Total	$ 417,217	$ 155,693

Assumptions Used for Employee Benefits Accounting

	Pension Plans		
	Years Ended March 31,		
	2024	2023	2022
Benefit obligations:			
Discount rate	**5.15%**	4.85%	3.65%
Rate of compensation increase (non-union)	**4.30%**	4.30%	4.30%
Rate of compensation increase (union)	**4.25%**	4.25%	4.25%
Weighted average cash balance interest crediting rate	**4.47%**	4.40%	2.75%
Net periodic benefit costs:			
Discount rate	**4.85%**	3.65%-4.30%	3.25%
Rate of compensation increase (non-union)	**4.30%**	4.30%	4.10%
Rate of compensation increase (union)	**4.25%**	4.25%	4.05%
Expected return on plan assets	**6.50%**	5.25%-5.75%	5.50%
Weighted average cash balance interest crediting rate	**4.40%**	2.75%	2.75%

	PBOP Plans		
	Years Ended March 31,		
	2024	2023	2022
Benefit obligations:			
Discount rate	**5.15%**	4.85%	3.65%
Net periodic benefit costs:			
Discount rate	**4.85%**	3.65%-4.30%	3.25%
Expected return on plan assets	**6.25%-6.75%**	5.00%-6.00%	5.00%-5.50%

Discount rate and expected return on plan asset assumptions reflect remeasurements during the year ended March 31, 2024. The Company selects its discount rate assumption based upon rates of return on highly rated corporate bond yields in the marketplace as of each measurement date. Specifically, the Company uses the Aon AA-Only Bond Universe Curve along with the expected future cash flows from the Company retirement plans to determine the weighted average discount rate assumption.

The expected rate of return for various passive asset classes is based on both analysis of historical rates of return and forward-looking analysis of risk premiums and yields. Current market conditions, such as inflation and interest rates, are evaluated in connection with the setting of the long-term assumptions. A premium is added for active management of both equity and fixed income securities. The long-term rates of return for each asset class are then weighted in accordance with the actual asset allocation, resulting in an expected return on plan assets for each plan.

Assumed Health Cost Trend Rate

	Years Ended March 31,	
	2024	2023
Health care cost trend rate assumed for next year		
Pre-65	**6.20%**	6.40%
Post-65	**5.10%**	5.20%
Prescription	**8.00%**	7.10%
Rate to which the cost trend is assumed to decline (ultimate)	**4.50%**	4.50%
Year that rate reaches ultimate trend		
Pre-65	**2031**	2031+
Post-65	**2031**	2031+
Prescription	**2033**	2031+

Plan Assets

The Pension Plan is a trusteed non-contributory defined benefit plan covering all eligible represented employees of the Company and eligible non-represented employees of the participating National Grid companies. The PBOP Plans are both a contributory and non-contributory, trusteed, employee life insurance and medical benefit plan sponsored by NGUSA. Life insurance and medical benefits are provided for eligible retirees, dependents, and surviving spouses of NGUSA.

NGUSA, as the Plans' sponsor, manages the benefit plan investments for the exclusive purpose of providing retirement benefits to participants and beneficiaries and paying plan expenses. The benefit plans' named fiduciary is the Retirement Plans Committee ("RPC"). The RPC seeks to minimize the long-term cost of operating the Plans, with a reasonable level of risk. The investment objectives of the Plans are to maintain a level and form of assets adequate to meet benefit obligations to participants, achieve the expected long-term total return on the Plans' assets within a prudent level of risk, and maintain a level of volatility that is not expected to have a material impact on the Company's expected contributions and expenses or the Company's ability to meet plan obligations.

The RPC has established and reviews at least annually the Investment Policy Statement ("IPS"), which sets forth the guidelines for how plan assets are to be invested. The IPS contains a strategic asset allocation for each plan, which is intended to meet the objectives of the Plans by diversifying their funds across asset classes, investment styles, and fund managers. An asset/liability study is conducted periodically to determine whether the current strategic asset allocation continues to represent the appropriate balance of expected risk and reward for the plan to meet expected liabilities. Each study considers the investment risk of the asset allocation and determines the optimal mix of assets for the plan. The target asset allocation for fiscal year-end 2024 reflects the results of such a pension study conducted and implemented in fiscal year 2024. As a result of that asset liability analysis, the asset mix for the Pension Plans were changed to further reduce investment risk given the increased funded status of the plans and to better hedge the respective plan liabilities. The Non-Union PBOP Plan asset liability study was conducted in fiscal year 2024. The study did not result in a change to the National Grid Non-Union PBOP asset allocation. The last Union PBOP study was conducted in fiscal year 2023. As a result of that asset liability analysis, the asset mix was changed to further reduce investment risk given the increased funded status of the plans and to better hedge the respective plan liabilities. Those change took effect during fiscal year 2023.

Individual fund managers operate under written guidelines provided by the RPC, which cover such areas as investment objectives, performance measurement, permissible investments, investment restrictions, trading and execution, and communication and reporting requirements. National Grid management, in conjunction with a third-party investment advisor, regularly monitors and reviews asset class performance, total fund performance, and compliance with asset allocation guidelines. This information is reported to the RPC at quarterly meetings. The RPC changes fund managers and rebalances the portfolio as appropriate.

Equity investments are broadly diversified across U.S. and non-U.S. stocks, as well as across growth, value, and small and large capitalization stocks. Likewise, the fixed income portfolio is broadly diversified across market segments and is mainly invested in investment-grade securities. Where investments are made in non-investment grade assets, the higher volatility is carefully judged and balanced against the expected higher returns. While the majority of plan assets are invested in equities and fixed income securities, other asset classes are utilized to further diversify the investments. These asset classes include private equity, real estate, and diversified alternatives. The objective of these other investments is enhancing long-term returns while improving portfolio diversification. For the PBOP Plans, since the earnings on a portion of the assets are taxable, those investments are managed to maximize after-tax returns consistent with the broad asset class parameters established by the asset/liability study. Investment risk and return are reviewed by the plan investment advisors, National Grid management, and the RPC on a regular basis. The assets of the Plans have no significant concentration of risk in one country (other than the United States), industry, or entity.

The target asset allocations for the benefit plans as of March 31, 2024 and 2023 are as follows:

	Pension Plan		**Union PBOP Plans**		**Non-Union PBOP Plans**	
	March 31,		**March 31,**		**March 31,**	
	2024	2023	**2024**	2023	**2024**	2023
Equity	**13%**	24%	**15%**	15%	**70%**	70%
Diversified alternatives	**4%**	7%	**5%**	5%	**0%**	0%
Fixed income securities	**60%**	60%	**80%**	80%	**30%**	30%
Private equity	**12%**	4%	**0%**	0%	**0%**	0%
Real estate	**5%**	3%	**0%**	0%	**0%**	0%
Infrastructure	**6%**	2%	**0%**	0%	**0%**	0%
	100%	100%	**100%**	100%	**100%**	100%

Fair Value Measurements

The following tables provide the fair value measurement amounts for the pension and PBOP assets at the trust level (includes all trusts applicable to Plans the Company participates in):

	March 31, 2024			
	Level 1	**Level 2**	**Not Categorized**	**Total**
		(in thousands of dollars)		
Pension assets:				
Equity	$ 33,748	$ -	$ 211,424	$ 245,172
Diversified alternatives	18,614	-	64,033	82,647
Corporate bonds	-	615,887	138,114	754,001
Government securities	2,056	166,919	179,406	348,381
Private equity	-	-	222,159	222,159
Real estate	-	-	91,543	91,543
Infrastructure	-	-	110,291	110,291
Total assets	**$ 54,418**	**$ 782,806**	**$ 1,016,970**	**$ 1,854,194**
Pending transactions				(44,661)
Total net assets				**$ 1,809,533**
PBOP assets:				
Equity	$ 45,180	$ -	$ 128,400	$ 173,580
Diversified alternatives	17,870	-	1,628	19,498
Corporate bonds	-	229,188	-	229,188
Government securities	10,416	92,491	631	103,538
Insurance contracts	-	-	41,699	41,699
Total assets	**$ 73,466**	**$ 321,679**	**$ 172,358**	**$ 567,503**
Pending transactions				5,152
Total net assets				**$ 572,655**

March 31, 2023	Level 1	Level 2	Not Categorized	Total
			(in thousands of dollars)	
Pension assets:				
Equity	$ 59,894	$ -	$ 235,930	$ 295,824
Diversified alternatives	34,092	-	112,876	146,968
Corporate bonds	-	577,597	160,085	737,682
Government securities	2,701	150,827	184,534	338,062
Private equity	-	-	213,372	213,372
Real estate	-	-	113,168	113,168
Infrastructure	-	-	96,438	96,438
Total assets	**$ 96,687**	**$ 728,424**	**$ 1,116,403**	**$ 1,941,514**
Pending transactions				(22,711)
Total net assets				**$ 1,918,803**
PBOP assets:				
Equity	$ 59,685	$ -	$ 106,977	$ 166,662
Diversified alternatives	19,661	-	2,057	21,718
Corporate bonds	-	214,895	-	214,895
Government securities	13,309	90,634	781	104,724
Insurance contracts	-	-	38,731	38,731
Total assets	**$ 92,655**	**$ 305,529**	**$ 148,546**	**$ 546,730**
Pending transactions				4,079
Total net assets				**$ 550,809**

The methods used to fair value pension and PBOP assets are described below:

Equity: Equity includes both actively and passively managed assets, with investments in domestic equity index funds as well as international equities.

Diversified alternatives: Diversified alternatives consist of holdings of global tactical asset allocation funds that seek to invest opportunistically in a range of asset classes and sectors globally.

Corporate bonds: Corporate bonds consist of debt issued by various corporations and corporate money market funds. Corporate bonds also include small investments in preferred securities, as these are used in the fixed income portfolios as yield-producing investments. In addition, certain fixed income derivatives are included in this category, such as credit default swaps, to assist in managing credit risk.

Government securities: Government securities include individual U.S. agency securities, U.S. Treasury securities, state and local municipal bonds, as well as a U.S. Treasury exchange-traded fund. The Plans hold a small amount of non-U.S. government debt, which is also captured here. U.S. government money market funds are also included. In addition, interest rate futures and swaps are included in this category as a tool to manage interest rate risk.

Private equity: Private equity consists of limited partnership investments where all the underlying investments are privately held. This primarily consists of buy-out investments, with smaller allocations to venture capital.

Real estate: Real estate consists of limited partnership investments, primarily in U.S. core open-end real estate funds as well as some core-plus closed-end real estate funds.

Infrastructure: Infrastructure consists of limited partnership investments that seek to invest in physical assets that are considered essential for a society to facilitate the orderly operation of its economy. Investments in infrastructure typically include transportation assets (such as airports and toll roads) and utility-type assets. Investments in infrastructure funds are utilized as a diversifier to other asset classes within the pension portfolio. Infrastructure investments are also typically income-producing assets.

Insurance contracts: Insurance contracts consist of trust-owned life insurance.

Not categorized: For investments in commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the NAV per fund share, derived from the underlying securities' quoted prices in active markets, and they are excluded from the fair value hierarchy. Investments in commingled funds with redemption restrictions and that use NAV are excluded from the fair value hierarchy.

Pending transactions: These are short-term cash transactions that are expected to settle within a few days of the measurement date.

Defined Contribution Plans

NGUSA has defined contribution retirement plans that cover substantially all employees. For the years ended March 31, 2024, 2023, and 2022, the Company recognized an expense in the accompanying statements of operations of $4.9 million, $4.5 million, and $4.3 million, respectively, for matching contributions.

9. CAPITALIZATION

Total capitalization for the Company at March 31, 2024 and 2023 is as follows:

			March 31,	
			2024	2023
			(in thousands of dollars)	
Total shareholders' equity			**$ 3,543,929**	$ 3,148,493
Long-term debt:	Interest Rate	Maturity Date		
Senior note	1.73%	November 24, 2030	**500,000**	500,000
Senior note	5.90%	November 15, 2039	**800,000**	800,000
Senior note	4.00%	August 15, 2046	**500,000**	500,000
Senior note	5.87%	February 26, 2054	**400,000**	-
Total debt			**2,200,000**	1,800,000
Unamortized debt discount			**(1,940)**	(1,494)
Unamortized debt issuance costs			**(10,706)**	(8,611)
Total long-term debt			**2,187,354**	1,789,895
Total capitalization			**$ 5,731,283**	$ 4,938,388

The aggregate maturities of long-term debt for the years subsequent to March 31, 2024 are as follows:

(in thousands of dollars) **March 31,**	**Maturities of Long-Term Debt**
2025	$ -
2026	-
2027	-
2028	-
2029	-
Thereafter	2,200,000
Total	$ 2,200,000

The Company's debt agreements and banking facilities contain general covenants, including those relating to the periodic and timely provision of financial information by the issuing entity, and financial covenants, such as restrictions on the level of indebtedness. Failure to comply with these covenants, or to obtain waivers of those requirements, could in some cases trigger a right, at the lender's discretion, to require repayment of some of the Company's debt, and may restrict the Company's ability to draw upon its facilities or access the capital markets. As of March 31, 2024 and 2023, the Company was in compliance with all such covenants.

Debt Authorizations

The Company has regulatory approval from the FERC to issue up to $750 million of short-term debt internally or externally that expires on October 14, 2024. The Company had no external short-term debt as of March 31, 2024 and 2023. Refer to the Intercompany Money Pool section in Note 14, "Related Party Transactions," for short-term debt outstanding with affiliated companies.

On August 31, 2020, the Company received approval from the DPU to issue up to $1.1 billion of long-term debt in one or more transactions through August 31, 2023. On July 17, 2023, the Company received approval from the DPU to extend the issue up to $1.1 billion of long-term debt in one or more transactions through August 31, 2024. In November 2020, the Company issued $500 million of unsecured long-term debt at 1.73% with a maturity date of November 24, 2030. On February 26, 2024, the Company issued $400 million of unsecured long-term debt at 5.87% with a maturity date of February 26, 2054, resulting in $200 million of remaining authorization.

Equity Infusion

In March 2024, the Company received an equity infusion of $250.0 million from NGUSA.

Dividend Restrictions

Pursuant to the Company's preferred stock arrangement, as long as any preferred stock is outstanding, certain restrictions on the payment of common stock dividends would come into effect if the common stock equity was, or by reason of the payment of such dividends became, less than 25% of total capitalization. The Company was in compliance with this covenant, and, accordingly, the Company was not restricted as to the payment of common stock dividends under the foregoing provisions as of March 31, 2024 or 2023.

Cumulative Preferred Stock

The Company has certain issues of non-participating cumulative preferred stock outstanding, which can be redeemed at the option of the Company. There are no mandatory redemption provisions on the Company's cumulative preferred stock. A summary of cumulative preferred stock is as follows:

	Shares Outstanding		Amount		
	March 31,		March 31,		Call
Series	**2024**	2023	**2024**	2023	Price
	(in thousands of dollars, except per share and number of shares data)				
$100 par value -					
4.44% Series	**22,585**	22,585	**$ 2,259**	$ 2,259	$ 104.068

The Company did not redeem any preferred stock as of March 31, 2024, 2023, or 2022. The annual dividend requirement for cumulative preferred stock was $0.1 million as of March 31, 2024, 2023, or 2022.

10. INCOME TAXES

Components of Income Tax Expense

	Years Ended March 31,		
	2024	2023	2022
		(in thousands of dollars)	
Current tax expense (benefit):			
Federal	**$ (24,094)**	$ (56,354)	$ 1,027
State	**(5,239)**	(15,280)	3,482
Total current tax expense (benefit)	**(29,333)**	(71,634)	4,509
Deferred tax expense:			
Federal	**56,283**	71,455	18,837
State	**22,724**	25,282	8,902
Total deferred tax expense	**79,007**	96,737	27,739
Amortized investment tax credits [1]	**(2,596)**	(2,247)	(334)
Total deferred tax expense	**76,411**	94,490	27,405
Total income tax expense	**$ 47,078**	$ 22,856	$ 31,914

[1] Investment tax credits ("ITC") are accounted for using the deferral and gross-up method of accounting, and are amortized over the depreciable life of the property giving rise to the credits.

Statutory Rate Reconciliation

The Company's effective tax rates for the years ended March 31, 2024, 2023, or 2022 are 24.1%, 18.0%, and 21.1%, respectively. The following table presents a reconciliation of income tax expense at the federal statutory tax rate of 21.0% to the actual tax expense:

	Years Ended March 31,		
	2024	2023	2022
	(in thousands of dollars)		
Computed tax	**$ 40,960**	$ 26,639	$ 31,803
Change in computed taxes resulting from:			
State income tax, net of federal benefit	**13,813**	7,902	9,783
Amortization of regulatory tax liability-net	**(6,872)**	(9,531)	(9,059)
Investment tax credits	**(2,596)**	(2,247)	(334)
Other	**1,773**	93	(279)
Total changes	**6,118**	(3,783)	111
Total income tax expense	**$ 47,078**	$ 22,856	$ 31,914

The Company is included in the NGNA and subsidiaries consolidated federal income tax return and Massachusetts unitary state income tax return. The Company has joint and several liability for any potential assessments against the consolidated group.

Inflation Reduction Act

On August 16, 2022, President Biden signed into law the Inflation Reduction Act ("IRA"), which may impact how the U.S. taxes certain large corporations. The IRA imposes a 15% CAMT on the "adjusted financial statement income" of certain large corporations for tax years beginning after December 31, 2022. National Grid is subject to the new CAMT on its federal income tax return for the tax year ending March 31, 2024. Any CAMT amount paid will generate a CAMT credit carryforward that has no expiration period and can be claimed against regular income tax in the future.

Deferred Tax Components

	March 31,	
	2024	2023
	(in thousands of dollars)	
Deferred tax assets:		
Allowance for doubtful accounts	**$ 60,211**	$ 57,078
Environmental remediation costs	**19,342**	19,511
Regulatory liabilities	**134,729**	124,277
Renewable energy certificate obligations	**45,550**	55,823
Reserves not currently deducted	**19,907**	17,956
Corporate alternative minimum tax credit	**12,727**	-
Other items	**18,301**	49,121
Total deferred tax assets	**310,767**	323,766
Deferred tax liabilities:		
Property related differences	**593,822**	585,045
Regulatory assets	**353,867**	296,813
Other items	**15,968**	9,248
Total deferred tax liabilities	**963,657**	891,106
Net deferred income tax liabilities	**652,890**	567,340
Deferred investment tax credits	**30,396**	32,178
Deferred income tax liabilities, net	**$ 683,286**	$ 599,518

Net Operating Losses

The amounts and expiration dates of the Company's net operating losses carryforward as of March 31, 2024 are as follows:

	Carryforward Amount	Expiration Period
	(in thousands of dollars)	
Federal	$ 38,647	Indefinite
Massachusetts	56,897	2044

As a result of the accounting for uncertain tax positions, the amount of deferred tax assets reflected in the financial statements is less than the amount of the tax effect of the federal and state net operating losses carryforward reflected on the income tax returns.

Status of Income Tax Examinations

The following table indicates the earliest tax year subject to examination for each major jurisdiction:

Jurisdiction	Tax Year
Federal	March 31, 2021
Massachusetts	March 31, 2013

Uncertain Tax Positions

The Company recognizes interest related to unrecognized tax benefits in other interest, including affiliate interest and related penalties, if applicable, in other income, net, in the accompanying statements of operations. As of March 31, 2024 and 2023, the Company has accrued for interest related to unrecognized tax benefits of $0.1 million and $0.2 million, respectively. During the years ended March 31, 2024, 2023, and 2022, the Company recorded interest income of $0.1 million, and interest expense of $0.1 million and $0.1 million, respectively. No tax penalties were recognized during the years ended March 31, 2024 and 2023.

It is reasonably possible that other events will occur during the next twelve months that would cause the total amount of unrecognized tax benefits to increase or decrease. However, the Company does not believe any such increases or decreases would be material to its results of operations, financial position, or cash flows.

11. ENVIRONMENTAL MATTERS

The normal ongoing operations and historic activities of the Company are subject to various federal, state, and local environmental laws and regulations. Under federal and state Superfund laws, potential liability for the historic contamination of property may be imposed on responsible parties jointly and severally, without regard to fault, even if the activities were lawful when they occurred.

The United States Environmental Protection Agency ("EPA") and the Massachusetts Department of Environmental Protection ("DEP"), as well as private entities, have alleged that the Company is a potentially responsible party under state or federal law for the remediation of numerous sites. The Company's most significant liabilities relate to former Manufactured Gas Plant ("MGP") facilities, which were formerly owned or operated by the Company. The Company is currently investigating and remediating, as necessary, those MGP sites and certain other properties under agreements with the EPA and DEP. Expenditures incurred for the years ended March 31, 2024, 2023, and 2022 were $7.5 million, $3.8 million, and $6.6 million, respectively.

The Company estimated the remaining costs of environmental remediation activities were $70.2 million and $70.8 million as of March 31, 2024 and 2023, respectively. These costs are expected to be incurred over approximately 31 years, and these undiscounted amounts have been recorded as estimated liabilities on the balance sheet. However, remediation costs for each site may be materially higher than estimated, depending on changing technologies and regulatory standards, selected end use for each site, and actual environmental conditions encountered. The Company has recovered amounts from certain insurers and potentially responsible parties, and, where appropriate, the Company may seek additional recovery from other insurers and from other potentially responsible parties, but it is uncertain whether, and to what extent, such efforts will be successful.

The DPU has approved a settlement agreement that provides for rate recovery of remediation costs of former MGP sites and certain other hazardous waste sites located in Massachusetts. Under that agreement, qualified costs related to these sites are paid out of a special fund established as a regulatory liability on the balance sheet. Rate-recoverable contributions of approximately $5.1 million were made to the fund during the year ended March 31, 2024, along with interest, lease payments, and any recoveries from insurance carriers and other third parties. Accordingly, as of March 31, 2024 and 2023, the Company has recorded environmental regulatory assets of $68.4 million and $68.0 million, respectively, and environmental regulatory liabilities of $15.7 million and $16.9 million, respectively. See Note 6, "Regulatory Assets and Liabilities," for additional details.

The Company believes that its ongoing operations, and its approach to addressing conditions at historic sites, are in compliance with all applicable environmental laws. Where the Company has regulatory recovery, it believes that the obligations imposed on it because of environmental laws will not have a material impact on its results of operations or financial position.

12. COMMITMENTS AND CONTINGENCIES

Purchase Commitments

The Company has several contracts for the purchase of electric power. Substantially all of these contracts require power to be delivered before the Company is obligated to make payment. In addition, the Company has various capital commitments related to the construction of property, plant, and equipment.

The Company's commitments under these contracts for the years subsequent to March 31, 2024 are summarized in the table below:

(in thousands of dollars) **March 31,**	**Energy Purchases**	**Capital Expenditures**
2025	$ 322,383	$ 36,326
2026	124,100	3,477
2027	431,425	3,226
2028	441,123	979
2029	450,965	-
Thereafter	8,777,299	-
Total	$ 10,547,295	$ 44,008

Power Purchase Agreements for Renewable Energy Projects

Section 83A

On February 26, 2014, the DPU approved three long-term (20-year) contracts for the purchase of the electricity and renewable energy credits from three separate wind-powered generating facilities. The approval by the DPU allows the Company, along with Nantucket Electric (collectively "the Massachusetts Electric Companies"), to recover the costs incurred under the agreements, including 2.75% remuneration on the annual payments made under the contracts. One of these facilities, Wild Meadows Wind, terminated prior to achieving commercial operation. The remaining facilities, Oakfield Wind and Bingham Wind, consist of a combined total of approximately 332 megawatts ("MWs") of total nameplate capacity. These remaining projects achieved commercial operation in 2015 and 2016, respectively. The Massachusetts Electric Companies have since purchased 45.9% of the output generated by the individual facilities, which in aggregate represents approximately 152.5 MWs of nameplate capacity.

Three-State Procurement: Section 83A

On June 15, 2018, the DPU approved ten long-term (20-year) contracts for the purchase of the electricity and renewable energy credits from ten separate generating facilities. The Massachusetts Electric Companies will purchase the actual output generated by the individual facilities, which in aggregate represents approximately 91 MWs of nameplate capacity. The Massachusetts Electric Companies entered into agreements after a three-state solicitation for renewable energy generation, pursuant to Section 83A of the Green Communities Act. The approval by the DPU allows the Massachusetts Electric Companies to recover the costs incurred under the agreements, including 2.75% remuneration on the annual payments made under the contracts. As of December 31, 2021, all projects have either become operational or terminated. Of the contracted 91 MWs, approximately 73 MWs are currently operational, and approximately 18 MWs have been terminated.

Clean Energy Procurement: Section 83D

On June 13, 2018, the Massachusetts Electric Companies entered into two separate agreements for the transportation and purchase of electricity and the related environmental attributes from hydroelectric facilities located in the Canadian province of Québec. The two agreements were entered into pursuant to Section 83D of the Green Communities Act. The first agreement is a 20-year power purchase agreement ("PPA") with H.Q. Energy Services Inc. ("H.Q. Energy") for the purchase of approximately 498 megawatt-hours of electricity and the related environmental attributes from a portfolio of hydroelectric facilities owned and operated by affiliates of H.Q. Energy. The second agreement is a 20-year transmission service agreement ("TSA") with NECEC Transmission LLC ("NECEC"). This agreement was assigned to NECEC by Central Maine Power Company, with the consent of the Massachusetts Electric Companies. The TSA provides for the transmission of the electricity supplied by H.Q. Energy on a proposed new transmission line that will run from the United States border to Lewiston, Maine, where it will interconnect with the ISO-NE system. Both the TSA with NECEC and the PPA with H.Q. Energy are contingent on the successful development and construction of the underlying transmission line by NECEC. The anticipated commercial operations date of the transmission line is in August 2024, based on the contractual terms. The DPU approved the Section 83D contracts on June 25, 2019, and the Massachusetts Electric Companies will be able to recover the costs incurred under the agreements, including 2.75% remuneration on the annual payments made. NextEra Energy Resources, LLC filed an appeal of the DPU's approval of the PPA with H.Q. Energy on July 12, 2019. On September 3, 2020, the Massachusetts Supreme Judicial Court upheld the DPU's approval. On November 2, 2021, the citizens of Maine passed a referendum which rejected the construction of the NECEC transmission line. NECEC has halted construction at the request of Maine's Governor while appeals are ongoing. In August 2022, the Maine Supreme Judicial Court ruled that the 2021 ballot initiative is unconstitutional, if NECEC can prove they have completed enough of the project to have earned "vested rights" in continuing with the project. This case was remanded to the Business and Consumer Court; on April 20, 2023, a jury unanimously ruled in favor of Central Maine Power. While this ruling is still subject to appeal, CMP is legally permitted to resume work on the project as of this ruling.

Offshore Wind Energy Procurement: Section 83C Round 1

On July 31, 2018, the Massachusetts Electric Companies entered into two separate 20-year PPAs with Vineyard Wind LLC ("Vineyard Wind") for the purchase of 46.16% of the electricity and renewable energy credits generated by two offshore wind farms proposed by Vineyard Wind, with each individual wind farm having a capacity of up to 400 MWs. The contracts with Vineyard Wind were entered into pursuant to Section 83C of the Green Communities Act. On April 12, 2019, the DPU approved the contracts, and the Massachusetts Electric Companies will be able to recover the costs incurred under the agreements, including 2.75% remuneration on the annual payments made. Based on the terms of the contracts, the commercial operations date for the first wind farm was initially expected to be in January 2022, with the second wind farm anticipated in May 2022. On October 21, 2021, the DPU approved two amendments to the PPAs for both wind farms, which extend the critical milestone dates by twenty-four months, including the commercial operations dates. On November 7, 2023, Vineyard Wind notified the MA EDCs of their intent to utilize three (3) of the available six month critical milestone extensions in the Facility 1 PPA, and two (2) of the available six month critical milestone extensions in the Facility 2 PPA. As such, the new guaranteed commercial operations dates are July 15, 2025 for the first wind farm and May 31, 2025 for the second wind farm.

Offshore Wind Energy Procurement: Section 83C Round 2

On January 10, 2020, the Massachusetts Electric Companies entered into two separate 20-year PPAs with Mayflower Wind Energy LLC ("Mayflower Wind") for the purchase of 45.41% of the electricity and renewable energy credits generated by two offshore wind farms proposed by Mayflower Wind, with the first wind farm having a capacity of up to 408 MWs and the second having a capacity of up to 396 MWs. The contracts with Mayflower Wind were entered into pursuant to Section 83C of the Green Communities Act. Based on the terms of the contracts, the commercial operations date for the first wind farm was initially expected to be in September 2025, with the second wind farm anticipated in December 2025. These contracts were filed with the DPU on February 10, 2020. On November 5, 2020, the DPU approved the contracts, and the Massachusetts Electric Companies will be able to recover the costs incurred under the agreements, including 2.75% remuneration on the annual payments made. The AG filed a motion for reconsideration on November 25, 2020, in which the AG asked the DPU for additional information regarding the DPU's approval of 2.75% remuneration on the annual payments made. The AG's motion was denied on June 23, 2021. On July 9, 2021, the decision became final and unappealable, and regulatory approval was achieved. On May 25, 2022, the Massachusetts Electric Companies filed an amendment to the PPAs for the DPU's review and approval. The amendment extends the critical milestone dates by approximately eighteen months, including the commercial operations dates. On December 30, 2022, the DPU issued a stamp approval, approving the proposed amended contract.

Offshore Wind Energy Procurement: Section 83C Round 3

On April 8, 2022, the Massachusetts Electric Companies entered into a 20-year PPA with Commonwealth Wind LLC ("Commonwealth Wind") for the purchase of 43.87% of the electricity and renewable energy credits generated by a proposed offshore wind farm with a nameplate capacity of 1,232 MWs. On April 15, 2022, the Massachusetts Electric Companies entered into a 20-year PPA with Mayflower Wind for the purchase of 38.003% of the electricity and renewable energy credits generated by a proposed offshore wind farm with a nameplate capacity of 480 MWs. Both PPAs were filed with the DPU for its review and approval on May 25, 2022. These contracts were entered into pursuant to Section 83C of the Green

Communities Act. The Commonwealth Wind project has a commercial operations date of November 2027, and the Mayflower Wind project has a commercial operations date of March 2028.

On October 20, 2022, Avangrid, the developer of the Commonwealth Wind project, requested a one-month delay in the DPU's review of the Commonwealth Wind contract to allow time for Avangrid to renegotiate the contracted electricity price. Avangrid cited the war in Ukraine, inflation, supply chain issues, and rising interest rates as factors in its decision to request what it describes as a modest increase in price. Mayflower Wind supported Avangrid's motion for a delay and indicated that it wanted to renegotiate its own contracted electricity price. On November 4, 2022, the DPU issued an order rejecting Avangrid's request for a delay. On November 7, 2022, Mayflower Wind filed a response to the DPU it which it withdrew its support for Avangrid's motion to delay the proceedings and stated that it intends to move forward with the existing PPAs. On November 14, 2022, Avangrid filed its response to the DPU order, stating that "absent the relief that Commonwealth Wind has previously requested, the Department should not dismiss the [contract review] proceedings." On December 30, 2022, the DPU issued an order approving both proposed contracts. On January 19, 2023, Commonwealth Wind filed a Petition to Appeal. Also on January 19, 2023, Mayflower Wind filed a motion petitioning for full participant status in the proceeding, and a request for an extension of the appeal period. On March 14, 2023, the DPU issued an order denying both requests.

Offshore Wind Energy Procurement: Termination of Section 83C Round 2 and 3

As noted above, both Commonwealth Wind and SouthCoast Wind (formerly Mayflower Wind) indicated that they were unable to build their projects under their awarded contract prices. After negotiations with the MA EDCs, both counterparties elected to request amendments to their contracts allowing for Termination and Release.

On July 13, 2023, the Massachusetts Electric Companies filed a First Amendment to the Commonwealth Wind Power Purchase Agreement which allows for Termination and Release of the Agreement. The primary terms of the amendment include a termination payment, payable to each distribution company, which will be returned to their customers; Commonwealth Wind is additionally required to file any necessary motions in order to withdraw their appeal of the DPU's approval of the PPA with the MA Supreme Judicial Court. On August 23, 2023, the DPU issued its Stamp Approval of the Commonwealth Amendment. The contract was terminated as per the Effective Date of October 2, 2023.

On August 29, 2023, the Massachusetts Electric Companies filed Second Amendments to both phases of the SouthCoast Wind Round 2 and 3 Power Purchase Agreements, which allow for Termination and Release of the Agreements. The primary terms of the amendments include termination payments, payable to each distribution company, which will be returned to their customers. On September 29, 2023, the DPU issued its Stamp Approval of the SouthCoast Amendments. The contract was terminated as per the Effective Date of October 23, 2023.

As of November 1, 2023, the Company has received all termination payments, totaling approximately $49 million. These funds are currently being returned to customers through distribution rates, effective March 1, 2024.

Legal Matters

The Company is subject to various legal proceedings arising out of the ordinary course of its business. The Company does not consider any of such proceedings to be material, individually or in the aggregate, to its business or likely to result in a material adverse effect on its results of operations, financial position, or cash flows.

Federal and Regulatory Investigations into Allegations of Fraud and Bribery

On June 17, 2021, five former employees of National Grid USA Service Company, Inc. in the downstate New York facilities department were arrested on federal charges alleging fraud and bribery. The five former employees subsequently pleaded guilty to the charges, pursuant to plea agreements. NGUSA was deemed a victim of the crimes. The DPU, the New York Public Service Commission ("NY PSC"), and the Rhode Island Public Utilities Commission have issued requests for information related to the alleged criminal conduct. The DPU has indicated that it will open an investigation into this matter after the conclusion of the NY PSC's investigation. The Company does not expect this matter will have a material adverse effect on its results of operations, financial position, or cash flows.

Energy Efficiency Programs Investigations

National Grid is participating in regulatory proceedings regarding certain conduct associated with the energy efficiency programs operated by its affiliates. At this time, it is not possible to predict the outcomes or the amount, if any, of any liabilities that may be incurred in connection with it by National Grid and its affiliates. However, the Company does not expect this matter will have a material adverse effect on its results of operations, financial position or cash flows.

Financial Guarantees

The Company unconditionally guarantees the full and prompt payment of the principal, premium, if any, and interest on certain tax-exempt bonds issued by the Massachusetts Development Finance Agency in connection with Nantucket Electric's financing of its first and second underground and submarine cable projects. The Company would be required to make any principal, interest, and premium payments if Nantucket Electric failed to pay. The carrying value of the debt guaranteed is approximately $51.3 million as of March 31, 2024, and the debt has maturities extending through 2042. This guarantee is absolute and unconditional. As of the date of this report, the Company has not had a claim made against it for this guarantee and has no reason to believe that Nantucket Electric will default on its obligations.

13. LEASES

The Company has various operating leases, primarily related to buildings, land, and fleet vehicles used to support its electric operations, with real estate lease terms ranging between 1 and 31 years.

Operating lease ROU assets are included in property, plant, and equipment, net, and operating lease liabilities are included in other current liabilities and other noncurrent liabilities on the balance sheet. As of March 31, 2024, the Company does not have any financing leases.

The expense related to operating leases was $15.6 million, $15.0 million, and $14.1 million for the years ended March 31, 2024, 2023, and 2022, respectively.

As of March 31, 2024, the Company does not have material rights or obligations under operating leases that have not yet commenced.

The following table presents the components of cash flows arising from lease transactions and other operating lease-related information:

	Years Ended March 31,		
	2024	2023	2022
		(in thousands of dollars)	
Cash paid for amounts included in lease liabilities			
Operating cash flows from operating leases	**$ 15,650**	$ 15,041	$ 14,132
ROU assets obtained in exchange for new operating lease liabilities	**21,559**	12,453	17,905
Weighted average remaining lease term – operating leases	**8 years**	8 years	5 years
Weighted average discount rate – operating leases	**3.9%**	2.9%	2.7%

The following table contains the Company's maturity analysis of its operating lease liabilities as of March 31, 2024, showing the undiscounted cash flows on an annual basis reconciled to the discounted operating lease liabilities recognized in the comparative balance sheet:

	Operating Leases
Year Ending March 31,	*(in thousands of dollars)*
2025	$ 13,922
2026	12,195
2027	10,798
2028	9,698
2029	7,440
Thereafter	18,893
Total future minimum lease payments	72,946
Less: imputed interest	10,102
Total	$ 62,844
Reported as of March 31, 2024:	
Current lease liability	$ 11,763
Non-current lease liability	51,081
Total	$ 62,844

There are certain leases in which the Company is the lessor. Revenue under such leases was immaterial for the years ended March 31, 2024, 2023, and 2022.

14. RELATED PARTY TRANSACTIONS

Accounts Receivable from and Accounts Payable to Affiliates

NGUSA and its affiliates provide various services to the Company, including executive and administrative, customer services, financial (including accounting, auditing, risk management, tax, and treasury/finance), human resources, information technology, legal, and strategic planning, that are charged between the companies and charged to each company.

The Company records short-term receivables for any deposits held by affiliates that are due to the Company, and payables for any deposits held by the Company that are due to affiliates, in the ordinary course of business. The amounts receivable from, and payable to, its affiliates do not bear interest and are settled through the intercompany Money Pool. A summary of outstanding accounts receivable from affiliates and accounts payable to affiliates is as follows:

	Accounts Receivable from Affiliates		Accounts Payable to Affiliates	
	March 31,		March 31,	
	2024	2023	**2024**	2023
	(in thousands of dollars)			
Boston Gas Company	**$ -**	$ -	**$ 8,587**	$ 1,513
Nantucket Electric Company	**350**	233	**1,178**	803
New England Power Company	**7,072**	7,012	**86,816**	66,391
NGUSA	**-**	3,128	**7,689**	8,220
NGUSA Service Company	**16,063**	23,634	**116,236**	77,079
Niagara Mohawk Power Corporation	**-**	-	**87**	697
Other Affiliates	**19**	86	**15**	644
Total	**$ 23,504**	$ 34,093	**$ 220,608**	$ 155,347

As discussed in Note 6, “Rate Matters,” NEP operates the pooled transmission facilities of the Company and NEP as a single integrated system (“NEPOOL”) under NEP’s Tariff No. 1. These transmission services are regulated by both the ISO-NE and the FERC. NEP charges the ISO-NE for these transmission services. As NEP is the sole operator of the NEPOOL assets, ISO-NE revenues are remitted from NEP to the Company, representing the substantial portion of the accounts receivable due from NEP.

In turn, the ISO-NE charges the Company for RNS, with some of those charges being associated with the Company-owned transmission assets in the NEPOOL. $44.1 million and $35.5 million of the unpaid charges from the ISO-NE to the Company have been presented as a payable to NEP related to these Company-owned transmission assets as of March 31, 2024 and 2023, respectively. Additionally, NEP charges the Company for LNS. The amounts paid to NEP for RNS and LNS for the years ended March 31, 2024, 2023, and 2022 were $476.8 million, $415.4 million, and $374.3 million, respectively. These amounts are presented within operations and maintenance expense in the accompanying statements of operations.

Advances from Affiliates

The Company has an agreement with NGUSA whereby the Company can borrow up to $200 million from time to time for working capital needs. The advance is non-interest bearing. As of March 31, 2024 and 2023, the Company had no outstanding advances from affiliates.

Intercompany Money Pool

The settlement of the Company’s various transactions with NGUSA and certain affiliates generally occurs via the intercompany money pool in which it participates. The Company is a participant in the Regulated Money Pool and can both borrow and invest funds. Borrowings from the Regulated Money Pool bear interest in accordance with the terms of the Regulated Money Pool Agreement. As the Company fully participates in the Regulated Money Pool rather than settling intercompany charges with cash, all changes in the intercompany money pool balance are reflected as investing or financing activities in the accompanying statements of cash flows. For the purpose of presentation in the statements of cash flows, it is assumed all amounts settled through the intercompany money pool are constructive cash receipts and payments, and therefore are presented as such.

The Regulated Money Pool is funded by operating funds from participants. NGUSA has the ability to borrow up to $3.0 billion from National Grid plc for working capital needs, including funding of the Regulated Money Pool, if necessary. The Company had short-term intercompany money pool investment of $252.9 million and borrowings of $66.5 million as of March 31, 2024 and 2023, respectively. The average interest rates for the intercompany money pool were 5.2%, 2.9%, and 0.4% for the years ended March 31, 2024, 2023, and 2022, respectively. Additionally, NGUSA had committed revolving credit facilities of approximately $6.7 billion, all of which have expiry dates beyond March 31, 2026, with two one-year extensions. As of March 31, 2024 these facilities have not been drawn against and can be used to fund the money pool.

Related Party Reimbursement

In accordance with the Credit and Operating Support Agreement dated March 26, 1996, the Company will reimburse Nantucket Electric an amount equal to the difference between Nantucket Electric's actual net income for the year and the net income necessary for Nantucket Electric to earn its DPU-approved ROE for the year, which is currently 9.6%. This reimbursement represents additional revenue to Nantucket Electric and expense to the Company. If Nantucket Electric's actual ROE for the year exceeds its allowed ROE, there is no reimbursement. For the years ended March 31, 2024, 2023, and 2022, the Company reimbursed Nantucket Electric $8.7 million, $7.4 million, and $6.3 million, respectively.

Service Company Charges

The affiliated service companies of NGUSA provide certain services to the Company at cost, without a mark-up. The service company costs are generally allocated to associated companies through a tiered approach. First and foremost, costs are directly charged to the benefited company whenever practicable. Secondly, in cases where direct charging cannot be readily determined, costs are allocated using cost/causation principles linked to the relationship of that type of service, such as number of employees, number of customers/meters, capital expenditures, value of property owned, and total transmission and distribution expenditures. Lastly, all other costs are allocated based on a general allocator determined using a 3-point formula based on net margin, net property, plant, and equipment, and operations and maintenance expense.

Charges from the service companies of NGUSA to the Company are mostly related to traditional administrative support functions. For the years ended March 31, 2024, 2023, and 2022, costs allocated to the Company were $527.3 million, $457.7 million, and $431.8 million, respectively.