nationalgrid

Boston Gas Company
d/b/a National Grid

Financial Statements

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

BOSTON GAS COMPANY

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INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of
Boston Gas Company

Opinion

We have audited the financial statements of Boston Gas 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

BOSTON GAS COMPANY
STATEMENTS OF OPERATIONS
(in thousands of dollars)

	Years Ended March 31,		
	2024	2023	2022
Operating revenues	**$ 1,980,586**	$ 2,183,684	$ 1,845,479
Operating expenses:			
Purchased gas	**556,149**	874,865	682,551
Operations and maintenance	**727,071**	672,061	584,513
Depreciation and amortization	**251,904**	229,353	217,946
Impairment loss	**-**	-	77,082
Amortization of acquisition premium	**8,200**	8,200	8,200
Other taxes	**97,964**	105,068	98,796
Total operating expenses	**1,641,288**	1,889,547	1,669,088
Operating income	**339,298**	294,137	176,391
Other income and (deductions):			
Interest on long-term debt	**(103,067)**	(86,069)	(71,738)
Other interest, including affiliate interest, net	**15,042**	13,665	16,058
Other income (deductions), net	**29,758**	19,483	(1,635)
Total other deductions, net	**(58,267)**	(52,921)	(57,315)
Income before income taxes	**281,031**	241,216	119,076
Income tax expense	**68,472**	57,191	25,972
Net income	**$ 212,559**	$ 184,025	$ 93,104

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

BOSTON GAS COMPANY
STATEMENTS OF CASH FLOWS
(in thousands of dollars)

	Years Ended March 31,		
	2024	2023	2022
Operating activities:			
Net income	**$ 212,559**	$ 184,025	$ 93,104
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**251,904**	229,353	217,946
Impairment loss	**-**	-	77,082
Accrued interest on tax reserves	**3,835**	898	(143)
Regulatory amortizations	**15,324**	8,200	8,200
Deferred income tax expense	**81,217**	144,519	52,428
Bad debt expense	**28,755**	40,073	26,923
Allowance for equity funds used during construction	**(9,869)**	(12,106)	(6,406)
Pension and postretirement (benefit) expenses	**(9,677)**	3,280	4,538
Other non-cash items	**1,481**	1,104	975
Pension and postretirement benefits contributions, net	**(8,722)**	(15,265)	(7,138)
Environmental remediation payments	**(4,612)**	(1,328)	(922)
Changes in operating assets and liabilities:			
Accounts receivable, net and unbilled revenues, net	**(46,283)**	(29,122)	(129,015)
Accounts receivable from/payable to affiliates, net	**(7,959)**	(18,207)	31,715
Inventory	**10,075**	(55,472)	(10,528)
Regulatory assets and liabilities - current, net	**(17,402)**	(87,011)	(13,689)
Regulatory assets and liabilities – noncurrent, net	**(33,850)**	(17,414)	350
Derivative instruments	**(19,547)**	98,568	(58,827)
Prepaid and accrued taxes, net	**100,749**	(97,705)	5,462
Accounts payable and other liabilities	**(11,053)**	53,193	30,255
Other, net	**11,913**	11,954	5,279
Net cash provided by operating activities	**548,838**	441,537	327,589
Investing activities:			
Capital expenditures	**(783,672)**	(811,124)	(677,122)
Cost of removal	**(34,672)**	(30,428)	(19,892)
Intercompany money pool	**32,128**	140,992	86,312
Net cash used in investing activities	**(786,216)**	(700,560)	(610,702)
Financing activities:			
Payments on long-term debt	**(216,000)**	(35,000)	(40,000)
Issuance from long-term debt	**400,000**	200,000	400,000
Payment of debt issuance costs	**(3,234)**	(449)	(1,825)
Intercompany money pool	**54,092**	-	(318,386)
Equity infusion from Parent	**-**	90,000	250,000
Net cash provided by financing activities	**234,858**	254,551	289,789
Net (decrease) increase in cash and cash equivalents	**(2,520)**	(4,472)	6,676
Cash and cash equivalents, beginning of year	**10,287**	14,759	8,083
Cash and cash equivalents, end of year	**$ 7,767**	$ 10,287	$ 14,759
Supplemental disclosures:			
Interest paid, net of amounts capitalized	**$ (93,891)**	$ (85,163)	$ (70,963)
Income taxes refunded	**111,578**	30,960	40,428
Significant non-cash items:			
Capital-related accruals included in accounts payable	**30,805**	13,960	38,647
ROU assets obtained in exchange for new operating lease liabilities	**9,977**	3,257	8,260

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

BOSTON GAS COMPANY
BALANCE SHEETS
(in thousands of dollars)

	March 31, 2024	March 31, 2023
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 7,767**	$ 10,287
Accounts receivable, net	**358,421**	346,275
Accounts receivable from affiliates	**21,477**	16,351
Intercompany moneypool asset	**-**	32,128
Unbilled revenues, net	**122,488**	114,428
Inventory	**117,447**	127,522
Regulatory assets	**233,105**	219,365
Accrued tax benefit	**15,851**	119,311
Other, net	**3,010**	1,889
Total current assets	**879,566**	987,556
Property, plant and equipment, net	**7,433,068**	6,759,517
Non-current assets:		
Regulatory assets	**272,842**	263,058
Goodwill	**450,395**	450,395
Postretirement benefits asset	**128,333**	100,989
Other	**880**	771
Total non-current assets	**852,450**	815,213
Total assets	**$ 9,165,084**	$ 8,562,286

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

BOSTON GAS COMPANY
BALANCE SHEETS
(in thousands of dollars)

	March 31, 2024	March 31, 2023
LIABILITIES AND CAPITALIZATION		
Current liabilities:		
Accounts payable	**$ 126,076**	$ 110,871
Accounts payable to affiliates	**106,010**	108,843
Intercompany moneypool liability	**54,092**	-
Current portion of long-term debt	**5,000**	16,000
Interest accrued	**17,877**	14,353
Regulatory liabilities	**47,026**	50,688
Derivative instruments	**25,520**	41,640
Payroll and benefits accruals	**26,370**	23,578
Other	**29,243**	43,861
Total current liabilities	**437,214**	409,834
Non-current liabilities:		
Regulatory liabilities	**1,448,516**	1,353,568
Deferred income tax liabilities, net	**922,718**	827,100
Postretirement benefits	**38,634**	69,766
Environmental remediation costs	**62,461**	54,610
Operating lease liabilities	**72,745**	64,739
Other	**121,531**	122,884
Total non-current liabilities	**2,666,605**	2,492,667
Commitments and contingencies (Note 14)		
Capitalization:		
Shareholders' equity	**3,521,308**	3,313,074
Long-term debt	**2,539,957**	2,346,711
Total capitalization	**6,061,265**	5,659,785
Total liabilities and capitalization	**$ 9,165,084**	$ 8,562,286

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

BOSTON GAS COMPANY
STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(in thousands of dollars)

	Common Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss): Pension and Other Postretirement Benefits	Accumulated Other Comprehensive Income (Loss): Total Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total
Balance as of March 31, 2021	**$ 51,418**	**$ 2,073,906**	**$ -**	**$ -**	**$ 571,183**	**$ 2,696,507**
Net income	-	-	-	-	93,104	93,104
Other comprehensive income:						
Change in pension and other postretirement obligations, net of $401 tax benefit	-	-	(1,066)	(1,066)	-	(1,066)
Total comprehensive income						92,038
Equity infusion from Parent	-	250,000	-	-	-	250,000
Balance as of March 31, 2022	**$ 51,418**	**$ 2,323,906**	**$ (1,066)**	**$ (1,066)**	**$ 664,287**	**$ 3,038,545**
Net income	-	-	-	-	184,025	184,025
Other comprehensive income:						
Change in pension and other postretirement obligations, net of $189 tax expense	-	-	504	504	-	504
Total comprehensive income						184,529
Equity infusion from Parent	-	90,000	-	-	-	90,000
Balance as of March 31, 2023	**$ 51,418**	**$ 2,413,906**	**$ (562)**	**$ (562)**	**$ 848,312**	**$ 3,313,074**
Net income	-	-	-	-	212,559	212,559
Other comprehensive income:						
Change in pension and other postretirement obligations, net of $213 tax expense	-	-	562	562	-	562
Total comprehensive income						213,121
Implementation of ASC 326, net of $1,837 tax benefit (1)	-	-	-	-	(4,887)	(4,887)
Balance as of March 31, 2024	**$ 51,418**	**$ 2,413,906**	**$ -**	**$ -**	**$ 1,055,984**	**$ 3,521,308**

The Company had 514,184 shares of common 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.

BOSTON GAS COMPANY
NOTES TO THE FINANCIAL STATEMENTS

1. NATURE OF OPERATIONS AND BASIS OF PRESENTATION

Boston Gas Company d/b/a National Grid ("the Company") is a gas distribution company engaged in the transportation and sale of natural gas to approximately 969,000 residential, commercial, and industrial customers in the City of Boston, Essex County, and other communities in eastern and central Massachusetts.

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.

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 other events or transactions that require adjustment to, or disclosure in, the financial statements 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 Massachusetts Department of Public Utilities ("DPU") regulates the rates the Company charges its customers. In certain cases, the rate actions of 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 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 gas distribution services provided on a monthly billing cycle basis. The Company records 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 gas. 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.

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 $33.0 million, $40.1 million, and $26.9 million for the years ended March 31, 2024, 2023, and 2022, respectively, within operations and maintenance expenses in the accompanying statements of operations.

Inventory

Inventory is comprised of materials and supplies, as well as gas in storage. Materials and supplies are stated at weighted average cost, which represents net realizable value, and are expensed or capitalized as used. There were no significant write-offs of obsolete inventory for the years ended March 31, 2024, 2023, or 2022.

Gas in storage is stated at weighted average cost, and the related cost is recognized when delivered to customers. Existing rate orders allow the Company to pass directly through to customers the cost of gas purchased, along with any applicable authorized delivery surcharge adjustments. Gas costs passed through to customers are subject to regulatory approvals and are reported periodically to the DPU.

The Company had materials and supplies of $19.7 million and $19.1 million and gas in storage of $97.7 million and $108.5 million as of March 31, 2024 and 2023, respectively.

Derivative Instruments

The Company uses derivative instruments to manage commodity price risk. All derivative instruments are recorded on the balance sheet at fair value. All commodity costs, including the impact of derivative instruments, are passed on to customers through the Company's gas cost adjustment mechanisms. Regulatory assets or regulatory liabilities are recorded to defer the recognition of unrealized losses or gains on derivative instruments, respectively. The gains or losses on the settlement of these contracts are recognized as purchased gas on the statements of operations and then refunded to, or collected from, customers consistent with regulatory requirements.

The Company's accounting policy is to not offset fair value amounts recognized for derivative instruments and related cash collateral receivable or payable with the same counterparty under a master netting agreement, but rather to record and present the fair value of the derivative instruments on a gross basis, with related cash collateral recorded within restricted cash and special deposits on the balance sheet. There was zero collateral posted as of March 31, 2024, and $0.9 million of cash collateral posted as of March 31, 2023.

Fair Value Measurements

The Company measures derivative instruments 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 certain 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 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. The capitalized cost of additions to property, plant, and equipment includes costs such as direct material, labor and benefits, and an allowance for funds used during construction ("AFUDC").

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 DPU. The average composite rates for the years ended March 31, 2024, 2023, and 2022 are as follows:

	2024	2023	2022
Composite rates	**3.1%**	3.0%	3.3%

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 noncash 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 rates. The Company recorded AFUDC related to equity of $9.9 million, $12.1 million, and $6.4 million, and AFUDC related to debt of $8.4 million, $6.1 million, and $2.4 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 6.3%, 6.2%, and 5.5%, 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 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 year ended March 31, 2024 and 2023, there were no impairment losses recognized for the long-lived assets. For the year ended March 31, 2022, there were impairment losses recognized for long-lived assets due to the mid-cape impairment (See Note 6, "Rate Matters" for additional details).

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 ended March 31, 2024, 2023 and 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 postretirement benefit other than pension ("PBOP") plans for its employees, administered by NGUSA. The Company recognizes its portion of the pension and PBOP plans' funded status on the consolidated 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 the 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 and land. 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 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.

Reference Rate

In January 2021, the FASB issued ASU No. 2021-01 *"Reference Rate Reform (Topic 848): Scope"* clarifying the application of the optional relief and practical expedients for certain transactions, including contract modifications and hedging relationships affected by reference rate reform, as well as those that do not directly reference London Interbank Offered Rate ("LIBOR"), or any other reference rate expected to be discontinued. The standard applies to all entities that elect to apply the optional guidance in Topic 848 and is effective immediately. The Company adopted ASU 2021-01 in January 2021 with no impact upon adoption. In December 2022, the FASB issued ASU No. 2022-06 "*Reference Rate Reform (Topic 848): Deferral of Sunset Date of Topic 848"* to extend the reference rate reform transition period to December 31, 2024, all applicable agreements that previously used LIBOR as a reference rate have been amended to Secured Overnight Financing Rate. The adoption did not materially affect the Company's financial position, results of operations, or cash flows.

Accounting Guidance Not Yet Adopted

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, statement 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:			
Gas distribution	**$ 1,936,975**	$ 1,996,743	$ 1,706,464
Off-system sales	**88,733**	187,977	155,774
Total revenue from contracts with customers	**2,025,708**	2,184,720	1,862,238
Revenues from alternative revenue programs	**(45,122)**	(1,036)	(16,759)
Total operating revenues	**$ 1,980,586**	$ 2,183,684	$ 1,845,479

Gas Distribution: The Company owns, maintains, and operates a natural gas distribution network serving areas in Massachusetts. Distribution revenues are primarily from the sale of gas 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. Gas distribution revenues are derived from the regulated sale and distribution of natural gas 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 distribution sales is to provide natural gas to the customers on demand. The natural gas 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 natural gas as the Company provides this service. The Company records revenues related to the distribution sales 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.

The distribution revenue also includes estimated unbilled amounts, which represent the estimated amounts due from retail customers for natural gas provided to customers by the Company but not yet billed. Unbilled revenues are determined based on 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 natural gas from other suppliers. In those circumstances, revenue is only recognized for providing delivery of the commodity to the customer.

Off-system sales: Represent direct sales of gas to participants in the wholesale natural gas marketplace, which occur after customers' demands are satisfied. The performance obligation related to these off system sales is to deliver a quantity of gas at the delivery point which represents a single performance obligation that is satisfied over time.

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 gas 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 and unbilled revenue. The Company also has other ARPs related to the achievement of certain objectives, demand-side management initiatives, and certain other rate making mechanisms. The Company recognizes revenue 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.

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 $96.0 million and $99.2 million, of which $90.3 million and $99.2 million relates to Accounts receivable, $5.7 million and zero relates to Unbilled revenues, 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)*		
	Customer Accounts Receivables	Other Accounts Receivables	Total Allowance
Beginning Balance	$ 96,003	$ 3,235	$ 99,238
Impact of adoption of ASC Topic 326 on April 1, 2023	6,147	2,586	8,733
Credit Loss Expense	26,841	(3,188)	23,653
Write-Offs	(39,351)	(844)	(40,195)
Recoveries	4,401	138	4,539
Ending balance	$ 94,041	$ 1,927	$ 95,968

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 sheet:

	March 31, 2024	March 31, 2023
	(in thousands of dollars)	
Regulatory assets		
Current:		
Derivative instruments	**$ 26,678**	$ 46,225
Gas costs adjustment	**95,201**	92,255
Local distribution adjustment clause	**23,366**	962
Revenue decoupling mechanism	**85,749**	79,923
Other	**2,111**	-
Total	**233,105**	219,365
Non-current:		
Asset retirement obligation	**17,133**	16,253
Capital tracker	**19,725**	15,804
Environmental response costs	**76,747**	65,944
Rate adjustment mechanisms	**16,652**	21,660
Recovery of acquisition premium	**126,417**	134,617
Other	**16,168**	8,780
Total	**272,842**	263,058
Regulatory liabilities		
Current:		
Profit sharing	**46,552**	50,532
Other	**474**	156
Total	**47,026**	50,688
Non-current:		
Cost of removal	**1,081,140**	1,017,538
Postretirement benefits	**76,501**	29,128
Regulatory tax liability, net	**290,875**	306,902
Total	**$ 1,448,516**	$ 1,353,568

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 $78.2 million ($76.7 million of Environmental response costs and $1.5 million of others costs) and $68.0 million ($65.9 million of Environmental response costs and $2.1 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 $51.3 million and $35.0 million, respectively.

Asset retirement obligation: Represents accretion expense deferred as part of the Company's asset retirement obligation and is recovered through rates as part of depreciation expense.

Capital tracker: The Company has in place a Gas System Enhancement Plan ("GSEP"), which was approved by the DPU on April 30, 2015 and is designed to provide concurrent recovery of the revenue requirement associated with the Company's capital costs for the replacement of eligible leak-prone pipe and ancillary equipment pursuant to the 2014 Gas Leaks Act passed in Massachusetts.

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

Derivative instruments: The Company evaluates open derivative instruments for regulatory deferral by determining if they are probable of recovery from, or refund to, customers through future rates. Derivative instruments that qualify for recovery are recorded at fair value, with changes in fair value recorded as regulatory assets or regulatory liabilities in the period in which the change occurs.

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 former manufactured gas plant ("MGP") sites and related facilities. The regulatory liability represents the excess of amounts received in rates over the Company's actual site investigation and remediation ("SIR") costs.

Gas costs adjustment: The Company is subject to rate adjustment mechanisms for commodity costs, whereby an asset or liability is recognized resulting from differences between billed revenues and the underlying cost being recovered, as approved by the DPU. These amounts will be refunded to, or recovered from, customers over the next year.

Local distribution adjustment clause ("LDAC"): A mechanism by which the Company is required to adjust its rates annually to recover or refund sundry costs, including the capital tracker, energy efficiency expenditures, Gas Business Enablement Refund, pension and PBOP costs, residential assistance costs, service quality penalties, and miscellaneous other amounts due to or from customers through rates.

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.

Profit sharing: Represents a portion of deferred margins from off-system sale transactions. Under current rate orders, the Company is required to return 90% of margins earned from such optimization transactions to firm customers. The amounts deferred on the balance sheet will be refunded to customers over the next year.

Rate adjustment mechanisms: Active Hardship-Protected Accounts Receivable is a mechanism which, through rates, allows the Company to recover account balances related to customers that are protected from service cutoff for non-payment with balances over 360 days past-due. The balance in this account represents the deferral of the Company's hardship balance.

Recovery of acquisition premium: Represents the unrecovered amount (plus related taxes) by which the purchase price paid exceeded net book value in the 1998 acquisition of Colonial Gas Company by Eastern Enterprises, Inc. Eastern Enterprises, Inc. was owned by KeySpan Corporation ("KeySpan") at the time of NGUSA's acquisition of KeySpan in 2007. In exchange for certain rate concessions and the achievement of certain merger savings targets, the DPU has allowed Boston Gas (as the sole surviving entity from the legal consolidation of Boston Gas and Colonial Gas Company during the year-ended March 31, 2020) to recover the acquisition premium in rates through August 2039.

Regulatory tax liability, net: Represents over-recovered federal 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”).

Revenue decoupling mechanism (“RDM”)*:* As approved by the DPU, the Company has a gas RDM, which allows for seasonal (peak/off-peak) adjustments to the Company’s delivery rates as a result of the reconciliation between allowed and actual billed and unbilled revenues. Any difference is recorded as a regulatory asset or regulatory liability.

6. RATE MATTERS

General Rate Case

On November 13, 2020, the Company filed a rate case with the DPU, including a request for approval of a performance-based ratemaking plan (“PBR Plan”), and related proposals. The Company requested that the DPU approve new distribution rates to increase distribution revenues by $220.7 million, including the transfer of $81.9 million of recovery of the Company’s Gas System Enhancement Program (“GSEP”) investments completed through March 31, 2020, from the GSEP factors to base distribution rates, with new rates to be effective October 1, 2021. The actual net revenue deficiency calculated by the Company for distribution rates is $138.8 million, or an incremental increase in distribution revenue of 18.1 percent.

On September 30, 2021, the DPU issued an Order in the Company’s rate case. The Order allowed an increase in base revenues of $144.9 million. On October 20, 2021, the Attorney General filed a motion for recalculation. On October 22, 2021, the Company filed a motion for recalculation and reconsideration. On November 17, 2021, the DPU issued its Order on those motions which reduced annual base distribution revenues to $142.0 million effective December 1, 2021. DPU authorized an ROE of 9.70%, raised from the previous ROE of 9.50%. The Order also authorized a capital structure of 53.44% equity and 46.56% debt. The DPU approved a five-year PBR Plan for the Company which is applicable to both core capital expenditures and operational expenditures, and which allows the Company to adjust revenues each year for inflation, adjusted by a productivity factor and consumer dividend. As part of the PBR Plan, the DPU approved cost recovery for certain exogenous events where an individual event’s cost change is over $2.0 million annually, and also approved an Earnings Sharing Mechanism, pursuant to which the Company will share 75% of excess earnings with customers set to begin at 200 basis points over the allowed ROE of 9.70%. The DPU allowed for recovery of the costs of 133 new employees hired after the end of the test year in the case and approves an adjustment to base distribution rates to reflect the recovery of capital additions after the test year through December 31, 2020. The Order also permits the Company to make a request for a one-time adjustment to its allowance in rates for the recovery of LNG investments, at a point in the 5-year PBR term chosen by the Company. On June 14, 2024, the Company made the one-time initial filing to recover the costs of its LNG investments from April 1, 2020, through March 31, 2024. The total investment for which recovery is being sought is $132.1 million. The revenue requirement for these investments is $19.1 million.

As per this rate order, the Company is not allowed to earn a return on investment on the Mid-Cape Main Replacement Project. This event qualifies as an indirect disallowance under ASC 980-360, the impairment loss in the amount of $77.0 million resulting from this indirect disallowance that has been recorded in the statements of operations for the year ended March 31, 2022 and balance sheet as of March 31, 2022. On June 17, 2022, the Company filed a late Motion for Clarification regarding the Mid-Cape disallowance: (1) whether the Department’s decision in D.P.U. 20-120 applies to Project costs that were not presented for recovery in the case, but that relate to the Project; and (2) whether the disallowed return on Project costs that were reviewed by the Department carries beyond the term of the PBR Plan and would preclude the presentation of new evidence in the Company’s next base distribution rate proceeding following the conclusion of the PBR Plan. On August 17, 2022, the DPU denied the Company’s Motion for Clarification. The Department held that the denial of a return applies to all costs of the Mid-Cape Main Replacement Project, including post-test year costs, and that the Company can make arguments in its next rate case regarding costs beyond the term of the PBR Plan, but there is no guarantee that the DPU will consider those arguments.

PBR Plan Filing

On June 17, 2022, Boston Gas Company filed the first annual PBR Plan filing for rates effective October 1, 2022. The Company requested approval of a base distribution rate adjustment effective October 1, 2022 of approximately $64.0 million based on a PBR percentage of 4.80 percent and a one-time adjustment for certain investment during the period April 2020 through December 2020. The PBR Percentage is the result of implementing the Company's proposed one-time Customer Impact Mitigation Plan, which the Company proposed due to the extreme economic circumstances currently impacting customers at this time. In the absence of the Customer Impact Mitigation Plan, the Company would be proposing a base distribution rate adjustment of $76.7 million based on a PBR Percentage of 6.35 percent and the capital investment adjustment noted above, in accordance with the PBR Tariff. On September 26, 2022, the DPU approved the Company's proposed base distribution rate adjustment and Customer Impact Mitigation Plan.

The Company made its annual PBR filing on June 15, 2023. The filing requests a PBR Adjustment for effect October 1, 2023 of approximately $57.4 million. It includes a voluntary Customer Impact Mitigation Plan by the Company in light of continuing high inflation; the mitigation plan reduces what the Company would have otherwise requested under its PBR formula by $14.0 million, from $71.4 million to $57.4 million. The filing also includes 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 ($4.2 million for the year ended March 31, 2021 and 2022; and $0.2 million for the year ended March 31, 2023). On September 28, 2023, the DPU approved the Company's proposed base distribution rate adjustment and Customer Impact Mitigation Plan. The DPU also approved recovery of incremental property taxes for fiscal years 2021 and 2022 as proposed. Incremental property taxes for fiscal year 2023 were disallowed as the annual impact of $0.2 million did not meet the significance threshold for exogenous recovery under the Company's current PBR provision.

The Company made its third annual PBR filing on June 14, 2024. The filing requests a PBR Adjustment for effect October 1, 2024, of approximately $41.4 million based on a PBR percentage of 4.38 percent. The Company also seeks approval to update the volumetric billing determinants for its residential heating rate classes from calendar year 2020 billing determinants to calendar year 2023 billing determinants to reflect in its rate design the lower weather-normalized usage the Company has experienced over the past several years. In addition, the Company provides a progress report on its PBR scorecard metrics, which includes an update to its methane emission metrics for calendar year 2022 and a baseline for its Grade 3 leak backlog metric.

Everett Marine Terminal LNG Contract

On February 9, 2024, the Company filed for the DPU's approval of a six-year agreement with Constellation LNG, LLC for liquified natural gas (LNG) service from Everett Marine Terminal, requesting an Order by May 1, 2024. Constellation requested that the DPU complete its review of contracts for supply from the Everett Marine Terminal by May 1, 2024, to assure ongoing commercial operation of the facility after expiration of the Mystic Cost of Service Agreement with ISO-New England on May 31, 2024. The briefing period concluded on April 23, 2024. On April 24, 2024, Constellation submitted a letter to the DPU informing parties that it did not anticipate executing agreements for the required maximum seasonal quantity that Constellation deemed necessary to keep the Everett Marine Terminal open and, as a result, it would need to change to a certain price term to avoid having to exercise its termination right. On April 25, 2024, the Company responded that given the important reliability benefits provided by the agreement, the Company continues to request the DPU's approval, and that Constellation's proposed price change resulted in a minimal bill increase compared to the original agreement's pricing. Comments in response to Constellation's letter and the Company's response were submitted by Conservation Law Foundation on May 2, 2024. On May 15, 2024, the Company and the other local gas distribution companies ("LDCs") filed amendments extending certain dates in the agreement. On May 17, 2024, the DPU issued an order approving the Constellation agreement; the order requires certain periodic reporting requirements.

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.

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.

Gas System Enhancement Plan (GSEP)

On April 28, 2023, the DPU approved the Company's CY2023 GSEP, including recovery of approximately $126.7 million in revenue requirements, related to anticipated investments in 2023 under an accelerated pipe replacement program, through GSEP. The rates are effective from May 2023 to April 2024. The DPU approved the Company's plan for replacing of leak-prone infrastructure in 2023, finding that the Company's GSEP accomplishes the continued accelerated replacement of leak-prone infrastructure consistent with the requirements of state law. Specifically, the DPU approved the proposal to replace or abandon 116 miles of leak-prone pipe (LPP) in the legacy Boston Gas service territory, and 14 miles of LPP in the former Colonial Gas service territory; and to line 4 miles of cast iron pipe and repair 870 cast iron joints with CISBOT technology, as well as to spend $2.0 million to repair Grade 3 Significant Environmental Impact leaks.

On May 1, 2023, the Company filed with the DPU its reconciliation of its GSEP costs from calendar year 2022, and its documentation of the GSEP work completed in calendar year 2022. On October 31, 2023, the DPU issued an order approving the Company's calendar year 2022 GSEP investments. The DPU approved the Company's proposed reconciliation factors to address recovery of the reconciliation balances from the Company's calendar year 2022 investments in its former Colonial Gas Company service territory. The DPU denied the Company's request to waive the 3% incremental recovery cap for its Boston Gas Company GSEP investments, meaning that $18.7 million of Boston Gas's GSEP investments for calendar year 2022 that are above the cap will not be recovered through this year's GSEP reconciliation factors and will instead be recovered through a future GSEP reconciliation filing or through the Company's next rate case. The DPU directed the Company to implement revised reconciliation factors for Boston Gas, that allow for recovery of Boston Gas's GSEP reconciliation balances below the recovery cap.

On October 31, 2023, the Company filed with the DPU its proposed GSEP plan for calendar year 2024. The proposed plan includes replacing or retiring 134 miles of leak-prone pipe and repairing an estimated 230 Grade 3 Significant Environmental Impact leaks. The plan also proposes that the costs of its second anticipated geothermal pilot be recovered through GSEP. The plan also identifies a targeted electrification non-pipe alternatives pilot project using integrated energy planning, which the Company anticipates filing for the Department's approval during calendar year 2024. The DPU approved the Company's calendar year 2024 GSEP on April 30, 2024.

On May 1, 2024, the Company filed with the DPU its reconciliation of its GSEP costs from calendar year 2023, and its documentation of the GSEP work completed in calendar year 2023. The proposed rate increase exceeds the 3 percent incremental recovery cap for the Company GSEP investments, meaning that $24.6 million of revenue on the Company's GSEP investments for calendar year 2023 that is above the cap will not be recovered through this year's GSEP reconciliation factors and will instead be recovered through a future GSEP reconciliation filing or through the Company's next rate case. If approved and combined with the amount of calendar year 2022 GSEP investment recovery that exceeded the cap as discussed above, a cumulative $43.3 million plus interest would be deferred for future recovery of Boston Gas – related GSEP investment.

Gas Business Enablement (GBE) Recovery Mechanism

On October 13, 2023, the DPU issued an order denying the Company's CY2021 GBE costs and suspended the Company's cost recovery mechanism that recovers annual GBE Program implementation costs. In addition to the suspending the cost recovery mechanism the DPU ordered the Company to refund approximately $24.4 million in total GBE program costs with interest to be calculated at the prime rate as set forth in the Company's LDAC tariff to customers. The DPU did so due to the continued delays of implementation in Massachusetts for gas customers and not the prudency of the documentation submitted. The DPU further stated that the Company may seek recovery of GBE costs through traditional rate making, such as the next gas rate case. On October 30, 2023, the Company filed a Motion for Clarification and Stay of Compliance Filing with the DPU. The Company was seeking clarification from the DPU that the costs refunded are not denied and can be deferred until the next rate case where we can seek recovery of all GBE implementation costs if the full program is in service and used and useful for Massachusetts gas customers. On November 16, 2023, the DPU issued an order denying the Company's Motion for Clarification filed on October 30, 2023, and directed the Company to refund its ratepayers beginning December 1, 2023. Following that ruling, on December 1, 2023, the Company filed a Motion for Reconsideration of the DPU's order along with a Request for Deferral of $69.9 million, and Motion to Extend Judicial Appeal period.

On March 19, 2024, the DPU issued an Order denying the Company's motion for reconsideration and petition for deferral. The DPU found that the Company should have treated the DPU's October 2023 order suspending the GBE tracker and ordering a refund of amounts previously collected $24.4 million plus interest as a final order, such that the Company's subsequent motion for reconsideration and petition for deferral was not timely filed. The Company has been directed to make the compliance filing to implement refunds of the $24.4 million plus interest no later than April 1, 2024. On March 26, 2024, the Company submitted its compliance filing in accordance with the DPU directive to implement refunds of the GBE program costs of $24.4 million plus interest no later than April 1, 2024. The Department approved the compliance filing of the refund on March 28, 2024. On April 8, 2024, the Company filed a petition for appeal of the DPU's final decision in this docket with the MA Supreme Judicial Court asking the court to vacate the order with instructions to the DPU to conduct appropriate proceedings to review the prudence of GBE program costs in accordance with due process, MA law, and DPU precedent.

Revenue Decoupling Adjustment (RDA)

The Company makes semi-annual filings with the DPU to reconcile revenues according to the revenue decoupling provision. In the Company's filing for effect November 1, 2023 through April 30, 2024, the Company requested a waiver of the Three Percent Revenue Decoupling Cap to recover the full Revenue Decoupling Adjustment of approximately $109.1 million, thereby eliminating the need to carry a deferral into future periods and eliminating the interest charges on the deferral, estimated at $5.0 million per year based on the currently effective prime rate. The Department approved the Company's waiver request in its Order issued on October 30, 2023.

Massachusetts Petition for Waiver of Jurisdiction regarding the RI Sale

On May 3, 2021, PPL Energy Holdings, LLC assigned its right to acquire The Narragansett Electric Company ("NECO") to its wholly owned subsidiary, PPL Rhode Island Holdings, LLC ("PPL Rhode Island"), such that, upon closing, PPL Rhode Island owned 100 percent 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 Attorney General ("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 Massachusetts Electric Company and Nantucket Electric Company rate filing on November 16, 2023.

Geothermal District Energy Demonstration Program

On December 15, 2021, the DPU approved the Company's petition for a five-year, $15.6 million geothermal district energy demonstration program. The costs for the demonstration program are recovered through a factor in the Local Distribution Adjustment Factor (LDAF). The program allows the Company to install, own, and operate up to four geothermal shared-loops sites that evaluate one or more of the following: (1) assessing the thermal performance and economics of shared loops serving a larger number of customers with more diverse load profiles than the project completed by the Company's affiliate KeySpan Gas East Corporation on Long Island, New York; (2) switching gas customers to geothermal energy as an alternative to leak-prone pipe replacements; (3) installing shared loops to manage local gas system constraints and peaks; and (4) installing shared loops to lower operating costs and greenhouse gas ("GHG") emissions for low-income customers and environmental justice communities. On May 16, 2022, the Company filed its geothermal energy demonstration program implementation plan for DPU review and approval. On September 13, 2022, the DPU approved the Company's implementation plan. The Company selected the first site project in Lowell, Massachusetts and has been conducting outreach to enroll gas customers in the program. On June 30, 2023, the Company filed its first annual report and associated costs with the DPU. Due to minimal costs incurred during the prior calendar year, the Company proposed to delay review and collection of the 2022 costs until next annual filing to be made by July 1, 2024 in the interest of administrative efficiency. The DPU approved the Company's proposal on August 24, 2023. On January 25, 2024, the Company announced that its second geothermal site will be located in Franklin Fields, Boston working with the Boston Housing Authority.

Investigation into the Future of Natural Gas

On October 29, 2020, the DPU opened an investigation into the role of LDCs in achieving the Commonwealth's 2050 climate goals. The investigation explored strategies to meet the Commonwealth's greenhouse gas emissions reductions targets while ensuring safe, reliable, and cost-effective natural gas service, and potentially recasting the role of gas companies in the Commonwealth. On March 18, 2022, each LDC submitted a proposal to the DPU that included recommendations and plans for helping Massachusetts achieve its 2050 climate goals, supported by an independent consultants' report, that had incorporated feedback and advice obtained through a stakeholder process. Supported by the consultants' analysis, the Company's proposal envisioned meeting the state's 2050 climate goals by utilizing a decarbonized and integrated gas and electric system that: (1) increases investment and adoption of energy efficiency measures, including the prioritization of building envelope; (2) eliminates fossil fuels from our gas supply by pursuing delivery of fossil-free gas such as renewable natural gas and renewable hydrogen through our network to all our customers; (3) enables customer use of hybrid heating by supporting customer adoption of heating technologies best suited to their needs; and (4) utilizes targeted electrification, including new solutions such as networked geothermal where safe and cost-effective. Initial comments by stakeholders on the consultants' report, LDC plans, and any alternative proposals were submitted to the DPU by May 6, 2022, and the discovery period ended June 7, 2022. At the direction of the DPU, the LDCs submitted joint comments responding to stakeholder comments on the consultants' report and LDC proposals on July 29, 2022. Several stakeholders submitted additional comments by the October 14, 2022, deadline.

On December 6, 2023, the DPU issued an order on regulatory principles and a framework to meet the state's climate goals without choosing a preferred decarbonization pathway or technology. While setting forth regulatory principles and future proceedings, the order recognizes the state and federal safety requirement-related investments that the

LDCs must make, confirms the GSEP remains unchanged at this time, and does not jeopardize cost recovery of existing, prudent gas system investments. Going forward, LDCs will need to provide evidence as to the prudency of future investments including an analysis of non-pipeline alternatives ("NPA"). The order provides for potential future networked geothermal programs, requires targeted electrification pilots, and allows hydrogen and renewable natural gas pilots for targeted end uses under certain circumstances. The order requires LDCs to change the revenue decoupling mechanism from a revenue per customer to revenue cap approach in its next rate case, and also requires each LDC to file a periodic five-year Climate Compliance Plan, the first of which is due by April 1, 2025, outlining the company's approach to the decarbonization transition. On December 29, 2023, the gas companies filed joint motions for clarification and extension of the judicial appeal period. The motion for clarification includes the timing and application of the non-pipeline alternative analysis to investment types, how new performance-based ratemaking metrics tied to climate plan objectives are to be incorporated in future rate plans, and certain emissions reduction calculations. Several stakeholders submitted responses to the motion for clarification by the January 22, 2024, deadline.

On April 2, 2024, the DPU issued an order on the motion, which clarifies that the requirement to evaluate NPAs applies to all new gas investments, including safety, reliability, and GSEP, at the project level from the date of the original order on December 6, 2023. The Company must also engage with stakeholders to develop a full NPA framework, including any feasibility or category screens, prior to filing for DPU review. The order also confirms that climate compliance plan metrics must be filed in the Company's next base rate case, regardless of whether the Company propose a PBR plan, and that the Company must report Scope 1 and 3 GHG emissions in the climate compliance plan.

Municipal Fiscal Year 2022 Property Tax Exogenous Event Request

During the year ended March 31, 2021, the Massachusetts Department of Revenue ("DOR") changed the way in which municipalities 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 PBR plan, along with Massachusetts Electric Company and Nantucket Electric 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 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 to recover this 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 and 2023 incremental costs incurred to date in its PBR filing made June 15, 2023, and, if approved, will include these costs in base distribution rates on a going-forward basis beginning with its 2024 PBR filing with rates effective October 1, 2024. The DPU approved recovery of the fiscal year 2021 and fiscal year 2022 property tax increases as proposed, on September 28, 2023. Recovery of the fiscal year 2023 property tax expense was disallowed as the annual impact did not meet the significance threshold for exogenous recovery under the Company's current PBR provision.

7. PROPERTY, PLANT, AND EQUIPMENT

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

	March 31,	
	2024	2023
	(in thousands of dollars)	
Plant and machinery	**$ 8,315,636**	$ 7,553,979
Land and buildings	**324,416**	277,440
Assets in construction	**399,145**	427,648
Software and other intangibles	**85,977**	85,977
Operating leases ROU assets	**84,390**	74,413
Total property, plant, and equipment	**9,209,564**	8,419,457
Accumulated depreciation and amortization	**(1,767,038)**	(1,652,484)
Accumulated amortization - Operating lease ROU assets	**(9,458)**	(7,456)
Property, plant, and equipment, net	**$ 7,433,068**	$ 6,759,517

8. DERIVATIVE INSTRUMENTS

The Company utilizes derivative instruments to manage commodity price risk associated with its natural gas purchases. The Company's commodity risk management strategy is to reduce fluctuations in firm gas sales prices to its customers.

The Company's financial exposures are monitored and managed as an integral part of the Company's overall financial risk management policy. The Company engages in risk management activities only in commodities and financial markets where it has an exposure, and only in terms and volumes consistent with its core business.

The volume of outstanding gas derivative instruments at March 31, 2024 and March 31, 2023 was 34.5 million dekatherms and 37.4 million dekatherms, respectively.

The following tables reflect the gross and net amounts of the Company's derivative assets and liabilities at March 31, 2024 and March 31, 2023:

March 31, 2024
(in thousands of dollars)

	Gross amounts of recognized assets (liabilities)	Gross amounts offset in the Balance Sheets	Net amounts of assets (liabilities) presented in the Balance Sheets	Gross amounts not offset in the Balance Sheets	Net amount
ASSETS:	*A*	*B*	*C=A+B*	*D*	*E=C-D*
Other current assets					
Gas contracts	$ 1,459	$ -	$ 1,459	$ 1,170	$ 289
Other non-current assets					
Gas contracts	64	-	64	40	24
Total	$ 1,523	$ -	$ 1,523	$ 1,210	$ 313
LIABILITIES:					
Current liabilities					
Gas contracts	$ 25,520	$ -	$ 25,520	$ 1,170	$ 24,350
Other non-current liabilities					
Gas contracts	2,681	-	2,681	40	2,641
Total	$ 28,201	$ -	$ 28,201	$ 1,210	$ 26,991
Net liabilities	$ 26,678	$ -	$ 26,678	$ -	$ 26,678

March 31, 2023
(in thousands of dollars)

	Gross amounts of recognized assets (liabilities)	Gross amounts offset in the Balance Sheets	Net amounts of assets (liabilities) presented in the Balance Sheets	Gross amounts not offset in the Balance Sheets	Net amount
ASSETS:	*A*	*B*	*C=A+B*	*D*	*E=C-D*
Other current assets					
Gas contracts	$ 1,078	$ -	$ 1,078	$ 83	$ 995
Other non-current assets					
Gas contracts	-	-	-	-	-
Total	$ 1,078	$ -	$ 1,078	$ 83	$ 995
LIABILITIES:					
Current liabilities					
Gas contracts	$ 41,640	$ -	$ 41,640	$ 83	$ 41,557
Other non-current liabilities					
Gas contracts	5,663	-	5,663	-	5,663
Total	$ 47,303	$ -	$ 47,303	$ 83	$ 47,220
Net liabilities	$ 46,225	$ -	$ 46,225	$ -	$ 46,225

The Company enters into enabling agreements that allow for payment netting with its counterparties, which reduce its exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty.

The changes in fair value of the Company's rate-recoverable contracts are offset by changes in regulatory assets and liabilities. As a result, the changes in fair value of those contracts had no impact in the accompanying statements of operations. All of the Company's derivative instruments are subject to rate recovery as of March 31, 2024, and March 31, 2023.

Credit and Collateral

The Company is exposed to credit risk related to transactions entered into for commodity price risk management. Credit risk represents the risk of loss due to counterparty non-performance. Credit risk is managed by assessing each counterparty's credit profile and negotiating appropriate levels of collateral and credit support.

The credit policy for commodity transactions is managed and monitored by the Finance Committee to National Grid plc's Board of Directors ("Finance Committee"), which is responsible for approving risk management policies and objectives for risk assessment, control and valuation, and the monitoring and reporting of risk exposures. NGUSA's Energy Procurement Risk Management Committee ("EPRMC") is responsible for approving transaction strategies, annual supply plans, and counterparty credit approval, as well as all valuation and control procedures. The EPRMC is chaired by the Vice President of U.S. Treasury and reports to both the NGUSA Board of Directors and the Finance Committee.

The EPRMC monitors counterparty credit exposure, and appropriate measures are taken to bring such exposures below the limits, including, without limitation, netting agreements, and limitations on the type and tenor of trades. In instances where a counterparty's credit quality has declined, or credit exposure exceeds certain levels, the Company may limit its credit exposure by restricting new transactions with the counterparty, requiring additional collateral or credit support, and negotiating the early termination of certain agreements. Similarly, the Company may be required to post collateral to its counterparties.

The Company's credit exposure for all commodity derivative instruments and applicable payables and receivables, net of collateral, and instruments that are subject to master netting agreements, was a net liability of $26.7 million and a net liabilities of $46.2 million as of March 31, 2024 and March 31, 2023, respectively.

The aggregate fair value of the Company's commodity derivative instruments with credit-risk-related contingent features that were in a liability position at March 31, 2024 and March 31, 2023 was $11.2 million and $31.2 million, respectively. The Company had zero collateral posted for these instruments as of March 31, 2024 and $0.9 million posted as of March 31, 2023.

If the Company's credit rating were to be downgraded by three levels, it would be required to post $11.7 million and $30.4 million additional collateral to its counterparties at March 31, 2024 and March 31, 2023, respectively. If the Company credit rating were to be downgraded two levels, it would be required to post $4.0 million and $14.7 million additional collateral and if the Company's credit rating were to be downgraded by one level it would be required to post zero collateral at March 31, 2024 and March 31, 2023, respectively. The counterparties had $3.7 million posted to the Company as of March 31, 2024.

9. FAIR VALUE MEASUREMENTS

The following tables present assets and liabilities measured and recorded at fair value on the balance sheet on a recurring basis and their level within the fair value hierarchy as of March 31, 2024 and March 31, 2023:

	March 31, 2024			
	Level 1	Level 2	Level 3	Total
		(in thousands of dollars)		
Assets:				
Derivative instruments				
Gas contracts	$ -	$ 1,523	$ -	$ 1,523
Total	-	1,523	-	1,523
Liabilities:				
Derivative instruments				
Gas contracts	-	26,821	1,380	28,201
Total	-	26,821	1,380	28,201
Net liabilities	$ -	$ 25,298	$ 1,380	$ 26,678

	March 31, 2023			
	Level 1	Level 2	Level 3	Total
		(in thousands of dollars)		
Assets:				
Derivative instruments				
Gas contracts	$ -	$ 1,078	$ -	$ 1,078
Total	-	1,078	-	1,078
Liabilities:				
Derivative instruments				
Gas contracts	-	45,358	1,945	47,303
Total	-	45,358	1,945	47,303
Net liabilities	$ -	$ 44,280	$ 1,945	$ 46,225

Derivative instruments: The Company's Level 2 fair value derivative instruments primarily consist of over-the-counter ("OTC") gas swap contracts and gas purchase contracts with pricing inputs obtained from the New York Mercantile Exchange and the Intercontinental Exchange ("ICE"), except in cases where the ICE publishes seasonal averages or where there were no transactions within the last seven days. The Company may utilize discounting based on quoted interest rate curves, including consideration of non-performance risk, and may include a liquidity reserve calculated based on bid/ask spreads for the Company's Level 2 derivative instruments. Substantially all of these price curves are observable in the marketplace throughout at least 95% of the remaining contractual quantity, or they could be constructed from market-observable curves with correlation coefficients of 95% or higher.

The Company's Level 3 fair value derivative instruments consist of OTC gas option purchase contracts, which are valued based on internally developed models. Industry-standard valuation techniques, such as the Black-Scholes pricing model, Monte Carlo simulation, and Financial Engineering Associates libraries, are used for valuing such instruments. For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivative instruments valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks, such as liquidity, volatility, and contract duration. Such instruments are categorized in Level 3, as the model inputs generally are not observable. The Company considers non-performance risk and liquidity risk in the valuation of derivative instruments categorized in Level 2 and Level 3.

The significant unobservable inputs used in the fair value measurement of the Company's gas purchase derivative instruments are forward curves and unobservable basis points. A relative change in commodity price at various locations underlying the open positions can result in significantly different fair value estimates.

10. 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.

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 the Company's proportionate share of the Plans' 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 gas operations. Any differences between actual pension 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 provides 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 zero contributions, $11.4 million, and $7.0 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 $56.0 million, $36.8 million, and $21.5 million, respectively. Benefit payments for the years ended March 31, 2024, and 2023, included payments for an annuity contract purchase.

PBOP Plans

The Company's 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 health coverage. During the years ended March 31, 2024, 2023, and 2022, the Company made contributions of $9.5 million, $4.1 million, and $0.5 million, respectively, to the PBOP Plans. The Company expects to contribute $1.5 million 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 $9.2 million, $8.2 million, and $10.0 million, respectively.

Net Periodic Benefit Costs

The Company's total pension costs for the years ended March 31, 2024, 2023, and 2022 were $2.5 million, $6.3 million, and $8.0 million, respectively. This included non-service pension benefits for the year ended March 31, 2024, of $7.5 million.

The Company's total PBOP costs for the years ended March 31, 2024, 2023, and 2022 were $2.3 million, $3.3 million, and $3.1 million, respectively.

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

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

	Pension Plans		
	Years Ended March 31,		
	2024	2023	2022
		(in thousands of dollars)	
Net actuarial (gain) loss	**$ (26,469)**	$ 32,037	$ (36,425)
Amortization of net actuarial loss	**(730)**	(1,091)	(5,640)
Amortization of prior service cost, net	**(3,163)**	(2,647)	(2,526)
Total	**$ (30,362)**	$ 28,299	$ (44,591)
Change in regulatory assets or liabilities	**$ (29,587)**	$ 28,992	$ (46,057)
Change in AOCI	**(775)**	(693)	1,466
Total	**$ (30,362)**	$ 28,299	$ (44,591)

	PBOP Plans		
	Years Ended March 31,		
	2024	2023	2022
		(in thousands of dollars)	
Net actuarial gain	**$ (13,297)**	$ (1,700)	$ (16,215)
Amortization of net actuarial gain	**968**	237	244
Amortization of prior service cost, net	**2**	1	1
Total	**$ (12,327)**	$ (1,462)	$ (15,970)
Change in regulatory assets or liabilities	**$ (12,327)**	$ (1,462)	$ (15,970)
Total	**$ (12,327)**	$ (1,462)	$ (15,970)

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

The following tables summarize the Company's amounts recognized in AOCI and regulatory assets/liabilities 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 (gain) loss	**$ (21,560)**	$ 5,639	$ (25,307)
Prior service cost	**(5,274)**	(2,111)	536
Total	**$ (26,834)**	$ 3,528	$ (24,771)
Included in regulatory assets (liabilities)	**$ (26,832)**	$ 2,755	$ (26,237)
Included in AOCI	**(2)**	773	1,466
Total	**$ (26,834)**	$ 3,528	$ (24,771)

	PBOP Plans		
	March 31,		
	2024	2023	2022
	(in thousands of dollars)		
Net actuarial gain	**$ (29,478)**	$ (17,149)	$ (15,686)
Prior service credit	**(3)**	(5)	(6)
Total	**$ (29,481)**	$ (17,154)	$ (15,692)
Included in regulatory liabilities	**$ (29,481)**	$ (17,154)	$ (15,692)
Total	**$ (29,481)**	$ (17,154)	$ (15,692)

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	**$ (378,942)**	$ (463,929)	**$ (97,513)**	$ (109,361)
Allocated fair value of assets	**507,275**	552,168	**58,879**	52,345
Funded status	**$ 128,333**	$ 88,239	**$ (38,634)**	$ (57,016)
Non-current assets	**$ 128,333**	$ 100,989	**$ -**	$ -
Non-current liabilities	**-**	(12,750)	**(38,634)**	(57,016)
Total	**$ 128,333**	$ 88,239	**$ (38,634)**	$ (57,016)

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 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 loss for Pension was largely driven by asset losses due to returns that were less than expected as well as the increase in the cash balance interest crediting rate, offset by the increase in discount rate and slight changes to the withdrawal assumption resulting from the recent experience study. The net actuarial gains for the PBOP Plans were driven by the increase in discount rate and savings resulting from a new Medicare Advantage contract for PBOP, offset by asset losses and the slight withdrawal assumption changes. The net actuarial gain was offset by asset losses due to returns that were less than expected. For the year ended March 31, 2022, the net actuarial gain for pension and PBOP was largely driven by the increase in discount rate and change in the mortality assumption resulting from the recent experience study, 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 Ended March 31,**	**Pension Plans**	**PBOP Plans**
2025	$ 19,583	$ 7,424
2026	19,550	7,824
2027	20,353	8,076
2028	21,078	8,288
2029	21,583	8,493
2030-2034	113,294	44,179
Total	$ 215,441	$ 84,284

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 (nonunion)	**4.30%**	4.30%	4.30%
Rate of compensation increase (union)	**5.20%**	5.20%	5.20%
Weighted average cash balance interest crediting rate	**4.28%**	4.40%	3.75%
Net Periodic Benefit Costs:			
Discount rate	**4.85%**	3.65%	3.25%
Rate of compensation increase (nonunion)	**4.30%**	4.30%	4.10%
Rate of compensation increase (union)	**5.20%**	5.20%	5.00%
Expected return on plan assets	**6.50%**	5.00%	5.50%
Weighted average cash balance interest crediting rate	**4.40%**	3.75%	3.75%

	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%	3.25%
Expected return on plan assets	**6.25%-6.75%**	5.00%-5.50%	5.00%-5.50%

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 both on 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 the 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-ended 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. As a result of that study, the RPC approved changes to the Non-Union PBOP asset allocation effective in fiscal year 2024. 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 Plans		**Union PBOP Plans**		**Non-Union PBOP Plans**	
	March 31,		**March 31,**		**March 31,**	
	2024	2023	**2024**	2023	**2024**	2023
Equity	13%	24%	15%	15%	65%	70%
Diversified alternatives	4%	7%	5%	5%	0%	0%
Fixed income securities	60%	60%	80%	80%	35%	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

During the year ended March 31, 2024, certain PBOP plans and trusts were consolidated. The following tables provide the fair value measurement amounts for the pension and PBOP assets at the trust level (includes all trust applicable to Plans the Company participates in):

	March 31, 2024			
	Level 1	Level 2	Not categorized	Total
		(in thousands of dollars)		
Pension assets:				
Equity	$ 93,283	$ -	$ 484,506	$ 577,789
Diversified alternatives	48,954	-	163,329	212,283
Corporate bonds	-	1,355,457	278,499	1,633,956
Government securities	2,213	359,537	379,594	741,344
Infrastructure	-	-	213,884	213,884
Private equity	-	-	431,469	431,469
Real estate	-	-	172,697	172,697
Total assets	**$ 144,450**	**$ 1,714,994**	**$ 2,123,978**	**$ 3,983,422**
Pending transactions				(99,945)
Total net assets				**$ 3,883,477**
PBOP assets:				
Equity	$ -	$ -	$ 282,235	$ 282,235
Diversified alternatives	46,313	-	4,591	50,904
Corporate bonds	-	709,777	52,088	761,865
Government securities	31,051	211,808	-	242,859
Private equity	-	-	121	121
Insurance contracts	-	-	160,400	160,400
Total assets	**$ 77,364**	**$ 921,585**	**$ 499,435**	**$ 1,498,384**
Pending transactions				13,054
Total net assets				**$ 1,511,438**

	March 31, 2023			
	Level 1	Level 2	Not categorized	Total
	(in thousands of dollars)			
Pension assets:				
Equity	$ 131,388	$ -	$ 594,806	$ 726,194
Diversified alternatives	71,059	-	206,311	277,370
Corporate bonds	-	1,598,998	368,071	1,967,069
Government securities	5,098	390,055	439,850	835,003
Infrastructure	-	-	187,713	187,713
Private equity	-	-	420,274	420,274
Real estate	-	-	213,449	213,449
Total assets	**$ 207,545**	**$ 1,989,053**	**$ 2,430,474**	**$ 4,627,072**
Pending transactions				(82,364)
Total net assets				**$ 4,544,708**
PBOP assets:				
Equity	$ 5,905	$ -	$ 185,250	$ 191,155
Diversified alternatives	49,138	-	4,711	53,849
Corporate bonds	-	690,632	-	690,632
Government securities	33,578	127,733	-	161,311
Private equity	-	-	279	279
Insurance contracts	-	-	142,459	142,459
Total assets	**$ 88,621**	**$ 818,365**	**$ 332,699**	**$ 1,239,685**
Pending transactions				11,112
Total net assets				**$ 1,250,797**

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 U.S. agency and treasury securities, as well as state and local municipal bonds. 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 $3.6 million, $3.4 million, and $3.1 million, respectively, for matching contributions.

11. CAPITALIZATION

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

			March 31,	
			2024	2023
			(in thousands of dollars)	
Total shareholder's equity			**$ 3,521,308**	$ 3,313,074
Long-term debt:	Interest Rate	Maturity Date		
Unsecured notes:				
Senior Note	3.15%	August 1, 2027	**500,000**	500,000
Senior Note	3.13%	October 5, 2027	**150,000**	150,000
Senior Note	3.00%	August 1, 2029	**500,000**	500,000
Senior Note	3.76%	March 16, 2032	**400,000**	400,000
Senior Note	4.49%	February 15, 2042	**500,000**	500,000
Senior Note	4.63%	March 15, 2042	**25,000**	25,000
Senior Note	6.12%	July 20, 2053	**400,000**	-
			2,475,000	2,075,000
Term Loans:				
Bank Term Loan	Variable	December 31, 2024	**-**	200,000
Medium-Term Notes ("MTNs"):				
MTN Series 1995 C	6.95%	December 1, 2023	**-**	10,000
MTN Series 1994 B	6.98%	January 15, 2024	**-**	6,000
MTN Series 1995 C	6.95%	December 1, 2024	**5,000**	5,000
MTN Series 1995 C	7.25%	October 1, 2025	**20,000**	20,000
MTN Series 1995 C	7.25%	October 1, 2025	**5,000**	5,000
			30,000	46,000
First Mortgage Bonds ("FMBs"):				
FMB Series A-1	7.38%	October 14, 2025	**10,000**	10,000
FMB Series A-2	6.90%	December 15, 2025	**10,000**	10,000
FMB Series A-3	6.94%	February 5, 2026	**10,000**	10,000
FMB Series B-1	7.12%	April 7, 2028	**20,000**	20,000
			50,000	50,000
Total debt			**2,555,000**	2,371,000
Unamortized debt discount			**(155)**	(204)
Unamortized debt issuance costs			**(9,888)**	(8,085)
Total debt less unamortized costs			**2,544,957**	2,362,711
Current portion of long-term debt			**5,000**	16,000
Total long-term debt			**2,539,957**	2,346,711
Total capitalization			**$ 6,061,265**	$ 5,659,785

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	$ 5,000
2026	55,000
2027	-
2028	650,000
2029	20,000
Thereafter	1,825,000
Total	$ 2,555,000

The Company's debt agreements and banking facilities contain 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, 2023, and 2022, the Company was in compliance with all such covenants.

At the time of the merger of the Company and Colonial Gas, an affiliated gas distribution company, Colonial Gas had issued and outstanding first mortgage bonds ("the FMBs") under a mortgage indenture dated June 15, 1992, as amended (the "Indenture"). As such, Colonial Gas's assets were pledged as collateral under the terms of the Indenture to secure the repayment of the FMBs. The pledged assets remain subject to a blanket lien created under the Indenture. After the merger the Colonial Gas assets that were transferred and vested in Boston by operation of law remain subject to the blanket lien of the indenture until such time as all the FMBs are fully repaid. Prior to the merger, Colonial Gas successfully completed a consent solicitation with its FMBs holders that amended its Indenture to limit the assets covered by the blanket lien of the Indenture to the legacy assets of Colonial Gas only and any repairs renewals or replacements to such assets.

Debt Authorizations

In December 2022, the Company entered into a $200.0 million Term loan at a variable interest rate with a maturity date of December 1, 2023, with an extension option of up to additional 13 months. On July 27, 2023, the Term Loan was fully repaid.

On July 20, 2023, the Company issued $400.0 million of unsecured senior long-term debt at a fixed rate of 6.12% with a maturity date of July 20, 2053.

The Company has authority to issue long-term debt securities through November 2024 of up to $1.5 billion and has issued $1.0 billion so far. On April 3, 2024, the Company filed a motion to extend the financing authority for one year until November 2025 so that it may use the remaining $500.0 million and requested an increase in the maximum interest rate from 7 percent to 8 percent. The DPU issued a procedural schedule with discovery concluding by May 3, 2024, and a request for an evidentiary hearing and/or briefing by May 7, 2024, which would allow for an order by June 30, 2024, as requested by the Company. Initial briefs were filed on May 29, 2024, by the Company and Attorney General. The Attorney General does not object to the Company's request for extension of the financing term but does not support increasing the interest rate to 8 percent. The Company filed its reply brief on June 4, 2024, stating that the increase of the max interest rate to 8 percent is appropriate given the recent market trends, along with a motion to strike a statement the Attorney General made for the first time on brief unsupported by the record. Comments on the Company's motion are due June 10, 2024. The Attorney General did not file a substantive reply brief.

12. INCOME TAXES

Components of Income Tax Expense (Benefit)

	Years Ended March 31,		
	2024	2023	2022
	(in thousands of dollars)		
Current tax expense (benefit):			
Federal	**$ (1,182)**	$ (70,921)	$ (9,130)
State	**(11,563)**	(16,407)	(17,326)
Total current tax expense (benefit)	**(12,745)**	(87,328)	(26,456)
Deferred tax expense (benefit):			
Federal	**45,851**	107,693	24,149
State	**35,366**	36,826	28,279
Total deferred tax expense (benefit)	**81,217**	144,519	52,428
Total income tax expense (benefit)	**$ 68,472**	$ 57,191	$ 25,972

Statutory Rate Reconciliation

The Company's effective tax rates for the years ended March 31, 2024, 2023, and 2022 are 24.4%, 23.7%, and 21.8%, 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	**$ 59,016**	$ 50,656	$ 25,006
Change in computed taxes resulting from:			
State income tax, net of federal benefit	**18,804**	16,131	8,654
Amortization of regulatory tax liability, net	**(12,019)**	(12,518)	(9,751)
Penalties and fines	**2,371**	2,790	3,249
Other items, net	**300**	132	(1,186)
Total changes	**9,456**	6,535	966
Total income tax expense	**$ 68,472**	$ 57,191	$ 25,972

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 15.0% corporate alternative minimum tax ("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 ended 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.

In April 2023, the IRS released Revenue Procedure 2023-15, which provides a safe harbor method of accounting that taxpayers may use to determine whether certain expenditures to maintain, repair, replace, or improve natural gas transmission and distribution property must be capitalized as improvements by the taxpayer or currently deducted for federal income tax purposes. The Company does not expect the impact to be material to its results of operations, financial position, or cash flows.

Deferred Tax Components

	March 31,	
	2024	2023
	(in thousands of dollars)	
Deferred tax assets:		
Allowance for doubtful accounts	**$ 26,218**	$ 27,112
Environmental remediation costs	**18,823**	16,631
Net operating losses	**30,383**	-
Postretirement benefits	**10,602**	19,107
Regulatory liabilities	**113,769**	106,206
Reserves not currently deducted	**26,584**	24,233
Corporate alternative minimum tax credit	**18,324**	-
Other items	**17,607**	25,391
Total deferred tax assets	**262,310**	218,680
Deferred tax liabilities:		
Property-related differences	**1,010,888**	885,486
Regulatory assets	**138,225**	131,798
Other items	**35,915**	28,496
Total deferred tax liabilities	**1,185,028**	1,045,780
Deferred income tax liabilities, net	**$ 922,718**	$ 827,100

Net Operating Losses

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

Jurisdiction	Carryforward Amount	Expiration Period
	(in thousands of dollars)	
Federal	$ 140,120	Indefinite
Massachusetts	132,705	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 $6.6 million and $2.8 million, respectively. During the years ended March 31, 2024, 2023 and 2022, the Company recorded interest expense of $3.8 million and $0.9 million, and interest income of $0.1 million, respectively. No tax penalties were recognized during the years ended March 31, 2024, 2023 and 2022.

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.

13. 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.

Within the Commonwealth of Massachusetts, the Company is aware of numerous former MGP sites and related facilities within the existing or former service territories of the Company. Investigation and remediation expenditures incurred for the years ended March 31, 2024, 2023, and 2022 were $5.1 million, $1.3 million, and $0.9 million, respectively.

The Company estimated the remaining costs of environmental remediation activities were $68.9 million and $60.9 million as of March 31, 2024 and March 31, 2023, respectively. These costs are expected to be incurred over approximately 46 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.

By rate orders, the DPU has provided for the recovery of site investigation and remediation costs. Accordingly, as of March 31, 2024 and March 31, 2023, the Company has recorded environmental regulatory assets of $77.5 million (including $0.8 million related to LDAC) and $66.2 million (including $0.3 million related to LDAC), respectively.

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.

14. COMMITMENTS AND CONTINGENCIES

Purchase Commitments

The Company has entered into various contracts for gas delivery, storage, and supply services. Certain of these contracts require payment of annual demand charges, which are recoverable from customers. The Company is liable for these payments regardless of the level of service required from third parties. In addition, the Company has various capital commitments related to the construction of property, plant, and equipment.

The Company's commitments under these long-term 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	$ 390,759	$ 15,711
2026	356,849	342
2027	303,919	-
2028	288,194	-
2029	260,369	-
Thereafter	1,722,909	-
Total	$ 3,322,999	$ 16,053

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

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.

15. LEASES

The Company has various operating leases, primarily related to buildings and land used to support its gas operations, with lease terms ranging between 5 and 70 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 finance leases.

Expense related to operating leases was $4.9 million, $4.3 million and $3.9 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:

	Year ended March 31,		
	2024	**2023**	**2022**
	(in thousands of dollars)		
Cash paid for amounts included in lease liabilities			
Operating cash flows from operating leases	**$ 4,887**	$ 4,403	$ 4,275
ROU assets obtained in exchange for new operating lease liabilities	**9,977**	3,257	8,260
Weighted-average remaining lease term – operating leases	**18 years**	18 years	19 years
Weighted-average discount rate – operating leases	**3.9%**	3.3%	3.2%

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	**$ 4,662**
2026	**5,282**
2027	**5,743**
2028	**5,909**
2029	**6,020**
Thereafter	**78,150**
Total future minimum lease payments	**105,766**
Less: imputed interest	**31,322**
Total	**$ 74,444**
Reported as of March 31, 2024:	
Current lease liability	**$ 1,699**
Non-current lease liability	**72,745**
Total	**$ 74,444**

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

16. 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, purchase gas, 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, 2024	March 31, 2023	**March 31, 2024**	March 31, 2023
	(in thousands of dollars)			
NGUSA	**$ 94**	$ 784	**$ 68,979**	$ 81,900
NGUSA Service Company	**11,913**	8,913	**35,945**	21,367
The Brooklyn Union Gas Company	**901**	5,249	**962**	4,997
Massachusetts Electric Company	**8,405**	1,264	**56**	311
Other Affiliates	**164**	141	**68**	268
Total	**$ 21,477**	$ 16,351	**$ 106,010**	$ 108,843

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 borrowings of $54.1 million and short-term investments of $32.1 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.

Service Company Charges

The affiliated service companies of NGUSA provide certain services to the Company at their cost. 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, which for the years ended March 31, 2024, 2023, and 2022 were $371.2 million, $325.6 million, and $297.6 million respectively.