nationalgrid

National Grid USA and Subsidiaries

Consolidated Financial Statements

For the years ended March 31, 2023 and 2022

NATIONAL GRID USA AND SUBSIDIARIES

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INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of
National Grid USA

Opinion

We have audited the consolidated financial statements of National Grid USA and Subsidiaries (the "Company"), which comprise the consolidated balance sheets as of March 31, 2023 and 2022, and the related consolidated statements of operations and comprehensive income, cash flows and changes in equity for the years then ended, and the related notes to the consolidated 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, 2023 and 2022, and the results of its operations and its cash flows for the years then ended 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.

Emphasis of Matter

As discussed in Note 1 and Note 17 to the financial statements, the Company signed an agreement to sell its 100% indirect ownership in The Narragansett Electric Company which closed on May 25, 2022. Our opinion is not modified with respect to this matter.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with 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 30, 2023

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(in millions of dollars)

	Years Ended March 31,	
	2023	2022
Operating revenues	**$ 14,304**	$ 14,065
Operating expenses:		
Purchased electricity	**2,102**	1,951
Purchased gas	**2,891**	2,456
Operations and maintenance	**4,623**	4,983
Depreciation and amortization	**1,505**	1,509
Other taxes	**1,335**	1,422
Total operating expenses	**12,456**	12,321
Operating income	**1,848**	1,744
Other income (deductions):		
Interest on long-term debt, net	**(609)**	(578)
Other interest, including affiliate interest, net	**(8)**	41
Gain on disposal of Narragansett	**847**	-
Other income, net	**363**	240
Total other income (deductions)	**593**	(297)
Income before income taxes	**2,441**	1,447
Income tax expense	**662**	271
Net income	**1,779**	1,176
Net income attributed to non-controlling interests	**(1)**	(2)
Dividends on preferred stock	**(593)**	(592)
Net income attributed to common shareholders	**$ 1,185**	$ 582
Other comprehensive income, net of taxes:		
Unrealized losses on securities, net of tax benefit of ($2) and ($4) in 2023 and 2022, respectively	**(5)**	(10)
Change in pension and other postretirement obligations, net of tax expense of $8 and $9 in 2023 and 2022, respectively	**21**	23
Unrealized gains on hedges, net of tax expense of $1 and zero in 2023 and 2022, respectively	**3**	-
Total other comprehensive income	**19**	13
Comprehensive income	**$ 1,798**	$ 1,189
Less: Comprehensive income attributed to non-controlling interest	**(1)**	(2)
Comprehensive income attributed to common shareholders	**$ 1,797**	$ 1,187

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

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions of dollars)

	Years Ended March 31,	
	2023	2022
Operating activities:		
Net income	**$ 1,779**	$ 1.176
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**1,505**	1,509
Impairment loss	**-**	97
Deferred income tax expense and amortization of investment tax credits	**427**	281
Bad debt expense	**74**	192
Gain on disposal of Narragansett	**(847)**	-
Allowance for equity funds used during construction	**(102)**	(100)
Pension and postretirement benefit expense, net	**41**	(18)
Other, net	**8**	11
Pension and postretirement benefits contributions	**(70)**	(148)
Environmental remediation payments	**(112)**	(119)
Changes in operating assets and liabilities:		
Accounts receivable and unbilled revenues, net	**(407)**	(668)
Inventory	**(258)**	(31)
Regulatory assets and liabilities (current), net	**(376)**	586
Regulatory assets and liabilities (non-current), net	**(558)**	(225)
Derivative instruments, net	**483**	(508)
Accounts payable and other liabilities	**800**	569
Other assets and liabilities, net	**161**	42
Net cash provided by operating activities	**2,548**	2,646
Investing activities:		
Capital expenditures	**(4,529)**	(4,257)
Cost of removal	**(192)**	(178)
Proceeds from disposal of Narragansett	**3,877**	-
Intercompany Money Pool	**(716)**	(252)
Purchases of financial investments	**(57)**	(143)
Proceeds from sales of financial investments	**66**	312
Other, net	**24**	31
Net cash used in investing activities	**(1,527)**	(4,487)
Financing activities:		
Preferred stock dividends	**(593)**	(592)
Payments on long-term debt	**(859)**	(59)
Proceeds from long-term debt	**2,300**	1,600
Intercompany Money Pool	**578**	52
Changes in advances from affiliates, net	**(2,119)**	761
Other, net	**(11)**	(7)
Net cash provided by financing activities	**(704)**	1,755
Net increase in cash, cash equivalents, restricted cash and special deposits, including cash classified within assets held for sale	**317**	(86)
Less: Net decrease in cash classified within assets held for sale	**-**	(1)
Net increase in cash, cash equivalents, restricted cash and special deposits	**317**	(87)
Cash, cash equivalents, restricted cash and special deposits, beginning of year	**1,110**	1,197
Cash, cash equivalents, restricted cash and special deposits, end of year	**$ 1,427**	$ 1,110
Supplemental disclosures:		
Interest paid, net of amounts capitalized	**$ (516)**	$ (549)
Income taxes paid	**64**	(29)
Significant non-cash items:		
Capital-related accruals included in accounts payable	**298**	422
Parent tax loss allocation	**20**	17
ROU assets obtained/(released) in exchange for operating lease liabilities	**309**	(49)

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

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in millions of dollars)

	March 31, 2023	March 31, 2022
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 1,309**	$ 1,044
Restricted cash and special deposits	**118**	66
Accounts receivable	**2,909**	3,044
Allowance for doubtful accounts	**(631)**	(858)
Accounts receivable from affiliates	**337**	249
Intercompany Money Pool	**1,703**	987
Unbilled revenues	**559**	498
Inventory	**754**	472
Regulatory assets	**632**	441
Derivative instruments	**69**	321
Prepaid taxes	**274**	292
Other	**210**	278
Assets held for sale	**-**	5,839
Total current assets	**8,243**	12,673
Property, plant and equipment, net	**43,388**	39,850
Non-current assets:		
Regulatory assets	**5,265**	4,308
Goodwill	**6,349**	6,349
Derivative instruments	**9**	45
Postretirement benefits	**1,263**	1,544
Financial investments	**528**	580
Other	**215**	175
Total non-current assets	**13,629**	13,001
Total assets	**$ 65,260**	$ 65,524

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

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in millions of dollars)

	March 31,			
	2023		2022	
LIABILITIES AND EQUITY				
Current liabilities:				
Accounts payable	**$**	**2,329**	$	2,110
Accounts payable to affiliates		**311**		238
Intercompany Money Pool		**808**		230
Advances from affiliates		**6,709**		8,828
Current portion of long-term debt		**104**		859
Taxes accrued		**101**		142
Interest accrued		**160**		147
Regulatory liabilities		**969**		1,154
Derivative instruments		**165**		8
Renewable energy certificate obligations		**266**		268
Payroll and benefits accruals		**413**		379
Environmental remediation obligations		**168**		172
Other		**944**		827
Liabilities held for sale		**-**		2,850
Total current liabilities		**13,447**		18,212
Non-current liabilities:				
Regulatory liabilities		**6,568**		6,710
Asset retirement obligations		**149**		102
Deferred income tax liabilities, net		**5,172**		4,547
Postretirement benefits		**683**		770
Environmental remediation obligations		**2,309**		2,182
Derivative instruments		**51**		13
Operating lease liabilities		**655**		469
Other		**870**		594
Total non-current liabilities		**16,457**		15,387
Commitments and contingencies (Note 13)				
Long-term debt		**15,797**		13,609
Equity:				
Common stock and additional paid-in capital		**14,165**		14,120
Retained earnings		**5,275**		4,090
Accumulated other comprehensive income		**57**		38
Common shareholders' equity		**19,497**		18,248
Non-controlling interests		**62**		68
Total equity		**19,559**		18,316
Total liabilities and equity	**$**	**65,260**	$	65,524

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

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(in millions of dollars)

	Common Stock [1]	Cumulative Preferred Stock [2]	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss): Unrealized Gain (Loss) on Securities	Accumulated Other Comprehensive Income (Loss): Pension and Other Postretirement Benefits	Accumulated Other Comprehensive Income (Loss): Hedging Activity	Accumulated Other Comprehensive Income (Loss): Total Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-controlling Interest [3]	Total
Balance as of March 31, 2021	**$ -**	**$ -**	**$ 14,076**	**$ 8**	**$ 20**	**$ (3)**	**$ 25**	**$ 3,508**	**$ 66**	**$ 17,675**
Net income	-	-	-	-	-	-	-	1,174	2	1,176
Other comprehensive income (loss):										
Unrealized gains (losses) on securities, net of ($4) tax expense (benefit)	-	-	-	(10)	-	-	(10)	-	-	(10)
Change in pension and other postretirement obligations, net of $9 tax expense (benefit)	-	-	-	-	23	-	23	-	-	23
Total comprehensive income										1,189
Parent tax loss allocation	-	-	17	-	-	-	-	-	-	17
Stock-based compensation	-	-	27	-	-	-	-	-	-	27
Preferred stock dividends	-	-	-	-	-		-	(592)	-	(592)
Balance as of March 31, 2022	**$ -**	**$ -**	**$ 14,120**	**$ (2)**	**$ 43**	**$ (3)**	**$ 38**	**$ 4,090**	**$ 68**	**$ 18,316**
Net income	-	-	-	-	-	-	-	1,778	1	1,779
Other comprehensive income (loss):										
Unrealized gains (losses) on securities, net of ($2) tax expense (benefit)	-	-	-	(5)	-	-	(5)	-	-	(5)
Change in pension and other postretirement obligations, net of $8 tax expense (benefit)	-	-	-	-	21	-	21	-	-	21
Unrealized gains (losses) on hedges, net of $1 tax expense (benefit)	-	-	-	-	-	3	3	-	-	3
Total comprehensive income										1,798
Parent tax loss allocation	-	-	20	-	-	-	-	-	-	20
Stock-based compensation	-	-	25	-	-	-	-	-	-	25
Disposal of Narragansett – Preferred Stock release	-	-	-	-	-	-	-	-	(3)	(3)
Preferred stock dividends	-	-	-	-	-	-	-	(593)	-	(593)
Other	-	-	-	-	-	-	-	-	(4)	(4)
Balance as of March 31, 2023	$ -	$ -	$ 14,165	$ (7)	$ 64	$ -	$ 57	$ 5,275	$ 62	$ 19,559

(1) National Grid USA ("NGUSA") had 641 shares of common stock authorized, issued and outstanding, with a par value of $0.10 per share.

(2) NGUSA had 915 shares of cumulative preferred stock authorized, issued and outstanding, with a par value of $0.10 per share. See Note 16, "Preferred Stock".

(3) NGUSA subsidiaries had 323,552 and 372,641 shares of cumulative preferred stock authorized, issued and outstanding, with par values of either $100 or $50 per share at March 31, 2023 and 2022, respectively. See Note 16, "Preferred Stock".

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

NATIONAL GRID USA AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. NATURE OF OPERATIONS AND BASIS OF PRESENTATION

National Grid USA ("NGUSA" or "the Company") is 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 (the "Parent"), a public limited company incorporated under the laws of England and Wales.

NGUSA has two major lines of business, "Gas Distribution" and "Electric Services," and operates various energy services and investment companies. The Company's Gas Distribution business consists of four gas distribution subsidiaries which provide gas distribution services to customers in the areas of central, northern, and eastern New York, the New York City boroughs of Brooklyn, Queens, and Staten Island, and the Long Island Counties of Nassau and Suffolk, as well as the state of Massachusetts. The Company's Electric Services business primarily consists of four electric distribution subsidiaries which provide electric services to customers in the areas of eastern, central, northern, and western New York, as well as the state of Massachusetts. The Company also operates electric transmission facilities in Massachusetts, New Hampshire, Maine, and Vermont, and provides energy services, supplies capacity, and produces energy for the use of customers of the Long Island Power Authority ("LIPA") on Long Island, New York. The services provided to LIPA through a power supply agreement provide LIPA with electric generating capacity, energy conversion, and ancillary services from the Company's Long Island generating units.

The Company's wholly-owned New England subsidiaries include: New England Power Company ("NEP"), Massachusetts Electric Company ("Massachusetts Electric"), Nantucket Electric Company ("Nantucket"), and Boston Gas Company ("Boston Gas"). The Company's wholly-owned New York subsidiaries include: Niagara Mohawk Power Corporation ("Niagara Mohawk"), National Grid Generation, LLC ("Genco"), The Brooklyn Union Gas Company ("Brooklyn Union"), and KeySpan Gas East Corporation ("KeySpan Gas East"). Certain of the Company's subsidiaries are subject to regulation by state and federal regulatory authorities (see Note 2, "Summary of Significant Accounting Policies" for additional details).

On March 17, 2021, NGUSA announced the sale of its Rhode Island business (Narragansett) to PPL Energy Holdings, LLC. for $3.9 billion (excluding long-term debt). The associated assets and liabilities that form part of the sale have been presented as Held for sale in the consolidated balance sheets as of March 31, 2022. The sale closed on May 25, 2022, with all regulatory approvals obtained. See Note 19, "Sale of Narragansett" for additional details. As of January 1, 2023, PPL operates the electric transmission facilities in Rhode Island on behalf of Narragansett.

The Company also has a wholly-owned subsidiary, National Grid LNG LLC, which is engaged in the business of receiving, storing, and redelivering liquefied natural gas ("LNG") in liquid and gaseous states, through facilities located in Providence, Rhode Island, as well as a 53.7% interest in two hydro-transmission electric companies which are consolidated into these financial statements. The investments in LNG and the hydro-transmission electric companies collectively make up less than 1.0% of consolidated Total Assets, Revenue, Operating Income, and Net Income and approximately 1.2% of consolidated net Utility Plant.

The Company's unregulated energy investments business consists of development investments such as natural gas pipelines, as well as certain other domestic energy-related investments.

The accompanying consolidated 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 as applicable. The consolidated financial statements reflect the ratemaking practices of the applicable regulatory authorities.

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries. Non-controlling interests of the Company's majority-owned subsidiaries are calculated based upon the respective non-controlling interest ownership percentages. All intercompany transactions with consolidated subsidiaries have been eliminated in consolidation.

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

Under its holding company structure, the Company does not have significant independent operations or sources of income of its own and conducts most of its operations through its subsidiaries. As a result, the Company depends on the earnings and cash flow of, and dividends or distributions from, its subsidiaries to provide the funds necessary to meet its debt and contractual obligations. Furthermore, a substantial portion of the Company's consolidated assets, earnings, and cash flow is derived from the operations of its regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to the Company is subject to regulation by state regulatory authorities.

The Company has evaluated subsequent events and transactions through June 30, 2023, the date of issuance of these consolidated financial statements, and concluded that there were no events or transactions that require adjustment to, or disclosure in, the consolidated financial statements as of and for the year ended March 31, 2023, except as otherwise disclosed in Note 5, "Rate Matters", and Note 10, "Capitalization".

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

In preparing consolidated 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 consolidated financial statements. Such estimates and assumptions are reflected in the accompanying financial statements. Actual results could differ from those estimates.

Regulatory Accounting

The Federal Energy Regulatory Commission ("FERC"), the New York Public Service Commission ("NYPSC") and the Massachusetts Department of Public Utilities ("DPU") regulate the rates the Company's regulated subsidiaries charge their customers in the applicable states. In certain cases, the rate actions of the FERC, NYPSC and DPU can result in accounting that differs from non-regulated companies. In these cases, the subsidiaries defer costs (as regulatory assets) or recognize obligations (as regulatory liabilities) if it is probable that such amounts will be recovered from, or refunded to, customers through future rates. In accordance with Accounting Standards Codification ("ASC") 980, "Regulated Operations," regulatory assets and liabilities are reflected on the consolidated balance sheets consistent with the treatment of the related costs in the ratemaking process.

Revenue Recognition

Revenues are recognized by regulated subsidiaries for energy services billed on a monthly cycle basis, together with unbilled revenues for the estimated amount of services rendered from the time meters were last read to the end of the accounting period (see Note 3, "Revenue" for additional details). The Company recognizes lease income from the sale of capacity and energy to LIPA under terms of the amended and restated Power Supply Agreement ("A&R PSA"), with rates approved by the FERC. The A&R PSA is accounted for as an operating lease (see Note 14, "Leases" 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 consolidated 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, including NGUSA, 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 benefit 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 that subsidiary 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.

Other Taxes

The Company’s subsidiaries collect 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 and electricity. The Company accounts for taxes that are imposed on customers (such as sales taxes) on a net basis (excluded from revenues), while taxes imposed on the Company, such as excise taxes, are recognized on a gross basis. Excise taxes collected and expected to be paid for the years ended March 31, 2023 and 2022, were $147 million and $191 million, respectively.

Cash and Cash Equivalents

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

Restricted Cash and Special Deposits

Restricted cash consists of margin calls to the New York Mercantile Exchange (“NYMEX”), collateral paid to the Company’s counterparties for outstanding commodity and financial derivative instruments. There is also restricted cash held by an environmental remediation trust. This cash can only be used by the trust to pay for environmental remediation expenses. Special deposits primarily consist of health care deposits, collateral paid to the Independent System Operator – New England (“ISO-NE”) in connection with the ISO-NE's market participant financial assurance requirement. The Company had restricted cash of $52 million and $4 million and special deposits of $66 million and $62 million as of March 31, 2023 and 2022, respectively.

Accounts Receivable and Allowance for Doubtful Accounts

The Company recognizes an allowance for doubtful accounts to record accounts receivable at estimated net realizable value. The allowance is determined based on a variety of factors including, for each type of receivable, applying an estimated reserve percentage to each aging category, taking into account historical collection and write-off experience, and management's assessment of collectability from individual customers, as appropriate. The collectability of receivables is continuously assessed and, if circumstances change, the allowance is adjusted accordingly. Receivable balances are written off against the allowance for doubtful accounts when the accounts are disconnected and/or terminated, and the balances are deemed to be uncollectible. The Company recorded bad debt expense of $74 million and $192 million for the years ended March 31, 2023 and 2022, respectively, within operations and maintenance in the accompanying consolidated statements of operations and comprehensive income.

Inventory

Inventory is composed of materials and supplies, gas in storage, purchased Renewable energy certificates ("RECs"), and emission credits.

Materials and supplies are stated at weighted average cost, which represents net realizable value, and are expensed or capitalized into property, plant and equipment as used. There were no significant write-offs of obsolete inventory for the years ended March 31, 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 purchased gas, 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 applicable state regulators.

RECs are stated at cost and used to measure compliance with renewable energy standards. RECs support new renewable generation resources and are held primarily to be utilized in fulfillment of the Company's compliance obligations. Emission credits are comprised of nitrogen oxide ("NOx") and carbon dioxide credits. Emission credits are valued at the lower of weighted average cost or net realizable value and are held primarily for consumption or may be sold to third-party purchasers.

The following table summarizes inventory recorded on the consolidated balance sheets:

	March 31,	
	2023	2022
	(in millions of dollars)	
Materials and supplies	**$ 251**	$ 199
Gas in storage	**343**	126
Purchased RECs	**99**	111
Emission credits	**61**	36
Total inventory	**$ 754**	$ 472

Renewable Energy Standard Obligation

RECs and Zero-Emissions Credits ("ZECs") are stated at cost and used to measure compliance with renewable energy standards. RECs support new renewable generation resources whereas ZECs support generation by in-state nuclear power plants and are purchased from third parties. RECs and ZECs are held primarily to be utilized in fulfillment of the Company's compliance obligations. As of March 31, 2023 and 2022, the Company recorded renewable energy certificate obligations of $266 million and $268 million, respectively.

Derivative Instruments

The Company uses derivative instruments to manage commodity price and foreign currency rate risk. All derivative instruments, except commodity contracts that qualify for the normal purchase normal sale exception, are reported at fair value on the consolidated balance sheets.

All commodity costs, including the impact of derivative instruments, are passed on to customers through the Company's commodity rate adjustment mechanisms. Regulatory assets or regulatory liabilities are recorded to defer the recognition of unrealized losses or gains on derivative instruments, respectively.

The Company has certain non-trading instruments for the physical purchase of electricity that qualify for the normal purchase normal sale exception and are accounted for upon settlement. If the Company was to determine that a contract no longer qualifies for the normal purchase normal sale exception, the Company would recognize the fair value of the contract and, if applicable, account for the gains and losses using the regulatory accounting described above. This has not occurred during the years ended March 31, 2023 or 2022.

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 instrument on a gross basis, with related cash collateral receivable and payable recorded within restricted cash and special deposits, and in other current liabilities, respectively on the consolidated balance sheets.

Power Purchase Agreements

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

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

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

Fair Value Measurements

The Company measures derivative instruments, securities, pension and postretirement benefits other than pension plan ("PBOP") assets, and financial investments for which it has elected the fair value option, 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 an entity 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 cost. The capitalized cost of additions to property, plant and equipment includes costs such as direct materials, labor and benefits, and an allowance for funds used during construction ("AFUDC"). The cost of repairs and maintenance is charged to expense and the cost of renewals and betterments that extend the useful life of property, plant and equipment is capitalized.

Depreciation is computed over the estimated useful life of the asset using the composite straight-line method. Depreciation studies are conducted periodically to update the composite rates and are approved by the state authorities. The average composite rates for the years ended March 31, 2023 and 2022 are as follows:

	Composite Rates	
	Years Ended March 31,	
	2023	2022
Electric	**2.8%**	2.7%
Gas	**2.4%**	2.5%
Common	**12.7%**	12.5%

Depreciation expense for regulated subsidiaries includes a component for the estimated cost of removal, which is recovered through rates charged to customers. Any difference in cumulative costs recovered and costs incurred is recognized as a regulatory asset or regulatory liability. When property, plant and equipment is retired, the original cost, less salvage, is charged to accumulated depreciation, and the related cost of removal is removed from the associated regulatory asset or regulatory liability. The Company recognized a regulatory liability for the amount that was in excess of costs incurred of $1.7 billion and $1.6 billion at March 31, 2023 and 2022, respectively, and a regulatory asset for the excess of costs incurred over amounts collected in rates of $58 million and $70 million at March 31, 2023 and 2022, respectively.

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 other income, net within the accompanying consolidated statements of operations and comprehensive income. The debt component of AFUDC is reported as an offset to other interest, including affiliate interest, net. After construction is completed, the Company is permitted to recover these costs through their inclusion in rate base. The Company recorded AFUDC related to equity of $102 million and $100 million and AFUDC related to debt of $50 million and $36 million for the years ended March 31, 2023 and 2022, respectively. The average AFUDC rates for the years ended March 31, 2023 and 2022 were 6.6% and 6.5%, respectively.

Impairment of Long-Lived Assets

The Company tests long-lived assets for impairment when events or changes in circumstances indicate that the carrying amount of the asset (or asset group) may not be recoverable. If such an event is identified, the recoverability of an asset group is determined by comparing its carrying value to the estimated undiscounted cash flows the asset group is expected to generate. If the comparison indicates that the carrying value is not recoverable, an impairment loss is recognized for the excess of carrying value over the estimated fair value. For its regulated subsidiaries, the Company also considers whether there have been any abandonments or disallowances of recently completed plant, such that guidance provided by ASC 980 on regulated property, plant and equipment may apply.

For the year ended March 31, 2022, the Company recorded a disallowance of $77 million at Boston Gas against costs capitalized in relation to the Mid Cape pipeline project in Massachusetts. The disallowance arose due to the DPU's decision to not provide Boston Gas with any return on the project, which represents recently completed plant. The DPU did not disallow the recovery of depreciation expense on the project. The Company also recorded $10 million of disallowances for recently completed plant at Narragansett. The Company recorded a total of $10 million of other impairments during the year ended March 31, 2022.

Goodwill

The Company tests goodwill for impairment annually, or more frequently if events occur or circumstances exist that indicate it is more likely than not that the fair value of a reporting unit is below its carrying amount. During the year ended March 31, 2023, the Company tested goodwill residing at NGUSA based upon two identified reporting units, New York, and New England. Previously, the Company had identified three reporting units at NGUSA: New York, New England, and the NECO Held for Sale group. The sale of NECO occurred in May 2022.

At March 31, 2023 and 2022, the carrying value of goodwill primarily includes amounts assigned to the New England and New York reporting units. amounted to approximately $2,364 million and $3,981 million, respectively. There are no historical accumulated impairment losses included in the carrying values of goodwill.

The goodwill impairment test requires a recoverability test based on the comparison of the Company's estimated fair value for each reporting unit with the reporting unit's 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 allocated carrying amount of goodwill.

Prior to the latest annual goodwill impairment test, the Company utilized an annual impairment test date of January 1. During the year ended March 31, 2023, the Company changed the date of the annual impairment test from January 1 to October 1. Management has determined that the use of October 1 as its annual goodwill impairment test date is preferable compared to January 1 given it aligns better with the long-range planning and forecasting process, and it also facilitates a timelier evaluation in advance of the Company's reporting period. The movement of the date has not resulted in any change in the timing of recording any potential impairment, nor does it represent a material change to a method of applying accounting principle, and thus, prospective treatment is appropriate.

For goodwill at the New York and New England reporting units, the Company applies two valuation methodologies to estimate the fair value of its reporting units, 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, 2023, the Company applied a balanced 50/50 weighting for each valuation methodology, as it believes that each approach provides equally valuable and reliable information regarding the New York and New England reporting units' estimated fair value.

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

Financial Investments

The Company holds a range of financial investments, including equity securities and available-for-sale debt securities.

Corporate owned life insurance policies (“COLI”) and Trust owned life insurance policies (“TOLI”) are measured at cash surrender value with increases and decreases in the value of these assets recorded in earnings.

Available-for-sale debt securities are measured at fair value with changes in fair value recorded in other comprehensive income. Investments in available-for-sale debt securities are monitored for other than temporary impairment by comparing fair value against amortized cost.

Equity securities consist of shares held as part of a portfolio of financial instruments, such as corporate stocks and mutual funds, and are measured at fair value with changes in fair value recorded in earnings.

The Company has mutual funds and money market funds representing funds designated for Supplemental Executive Retirement Plans (“SERPs”). These investments are measured at fair value with changes in fair value recorded in earnings.

The following table presents the financial investments recorded on the consolidated balance sheets:

	March 31,	
	2023	2022
	(in millions of dollars)	
COLI/TOLI	**$ 286**	$ 308
Debt securities[(1)]	**217**	235
SERPs	**25**	37
Total financial investments	**$ 528**	$ 580

(1) See Note 8, “Fair Value Measurements” for additional details.

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 gas distribution and electric generation facilities. Asset retirement obligations are recorded at fair value in the period in which the obligation is incurred, provided 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, whereby accretion costs associated with asset retirement obligations are recorded as increases to regulatory assets on the consolidated balance sheets. These regulatory assets represent timing differences between the recognition of costs in accordance with U.S. GAAP and costs recovered through the ratemaking process.

Employee Benefits

The Company has defined benefit pension plans and postretirement benefit other than pension plans for its employees. The Company recognizes all pension and PBOP plans’ funded status on the consolidated balance sheets as a net liability or asset with an offsetting adjustment to accumulated other comprehensive income (“AOCI”) in shareholders’ equity. If the cost of providing these plans is recovered in rates through the Company’s regulated subsidiaries, the net funded status is offset by a regulatory asset or liability. The Company measures and records its pension and PBOP funded status at each year-end. Pension and PBOP plan assets are measured at fair value.

Reference Rate

The benchmark interest rates hedged are currently based on US London Interbank Offered Rate ("LIBOR"). LIBOR is being replaced as an interest rate benchmark by alternative reference rates ("ARRs") in certain currencies including USD, and foreign currencies in which the Company operates. This impacts contracts including financial liabilities that pay LIBOR-based cash flows, and derivatives that receive or pay LIBOR-based cash flows. The Company is managing the risk by planning to replace US LIBOR cash flows with Secured Overnight Financing Rate (SOFR) on our affected contracts. The Company has not amended any of its current agreements that have LIBOR as a reference rate during the years ended March 31, 2023 and 2022.

Leases

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

The Company's regulated subsidiaries recognize lease expense based on a pattern that conforms to the regulatory ratemaking treatment.

New and Recent Accounting Guidance

Accounting Guidance Recently Adopted

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 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. The Company plans to apply the accounting relief as relevant contract modifications are made during the course of the reference rate reform transition period.

In December 2022, the FASB issued ASU No 2022-06 "*Reference Rate Reform (Topic 848): Deferral of Sunset Date of Topic 848*", extending the transition period, or deferring the sunset date from December 31, 2022, to December 31, 2024, after which entities will no longer be permitted to apply the relief in Topic 848. The Company continues to assess the potential impact related to replacing LIBOR.

Leases – Certain Leases with Variable Lease Payments

In July 2021, the FASB issued ASU No. 2021-05, "*Leases (Topic 842): Lessors – Certain Leases with Variable Lease Payments*" which eliminates the lessor's day-one loss issue on sales-type (or direct financing) leases with variable lease payments that do not depend on a reference index or a rate by requiring the lessors to classify and account for such leases as operating leases. The Company adopted this new guidance prospectively on April 1, 2022. The adoption did not materially affect the Company's financial position, results of operations, or cash flows.

Disclosures by Business Entities About Government Assistance

In November 2021, the FASB issued ASU No. 2021-10, "*Government Assistance (Topic 832): Disclosures by Business Entities about Government Assistance*". The update requires disclosures about the transactions with a government that are accounted for by applying a grant or contribution accounting model by analogy, including the types of transactions, the accounting for those transactions, and the effect of those transactions on an entity's financial statements.

The Company adopted this standard prospectively on April 1, 2022. The adoption of the standard did not impact the Company's disclosures for March 31, 2023.

Accounting Guidance Not Yet 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, "*Financial 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 will adopt this new guidance on April 1, 2023. The adoption of this new guidance will not have a material impact on the Company's financial position, results of operations, or cash flows as of April 1, 2023.

Leases (Topic 842): Common Control Arrangements

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

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

3. REVENUE

The following table presents, for the years ended March 31, 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	
	2023	2022
	(in millions of dollars)	
Revenue from contracts with customers:		
Electric services	**$ 6,577**	$ 6,919
Gas distribution	**6,614**	6,202
Off system sales	**560**	397
Total revenue from contracts with customers	**13,751**	13,518
Revenue from regulatory mechanisms	**(169)**	(60)
Other revenue	**722**	607
Total operating revenues	**$ 14,304**	$ 14,065

Electric Services and Gas Distribution: Revenue from contracts with customers, includes electric services and gas distribution. Electric services are comprised of electric distribution and transmission services.

The Company's subsidiaries own and maintain electric and natural gas distribution networks. Distribution revenues are primarily from the sale of electricity, gas, and related services to retail customers. Distribution sales are regulated by the applicable state agencies, which are 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 and electric distribution revenues are derived from the regulated sale and distribution of electricity and 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 products and services provided along with a return on investment.

The performance obligation related to these sales is to provide electricity or natural gas to the customers on demand. The electricity or 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 electricity or natural gas as the Company provides these services. The Company records revenues related to 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.

Distribution revenue also includes estimated unbilled amounts, which represent the estimated amounts due from retail customers for electricity and 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 electricity or natural gas from other suppliers. In those circumstances revenue is only recognized for providing delivery of the commodity to the customer.

Transmission services are provided as demanded by the customers and represents a single performance obligation. The price for the services provided are based on the underlying tariff rates established by FERC related to both Niagara Mohawk and New York Independent System Operator ("NYISO"). The performance obligation is satisfied over time as the transmission services are provided by Niagara Mohawk. Niagara Mohawk records revenue related to transmission services based on the volumes delivered and the approved tariff rates, which corresponds with the amount Niagara Mohawk has the right to invoice, as it is entitled to compensation for the performance completed to date.

Off system sales: Represents direct sales of gas to participants in the wholesale natural gas marketplace, which occur after customers' demands are satisfied.

Revenue from regulatory mechanisms: The Company's regulated subsidiaries record revenues in accordance with accounting principles for rate-regulated operations for arrangements between the regulated subsidiaries and their respective regulators, which are not accounted for as contracts with customers. These primarily include deferral mechanisms and programs that qualify as Alternative Revenue Programs ("ARPs"). ARPs enable the regulated subsidiaries to adjust rates in the future, in response to past activities or completed events. The regulated subsidiaries' electric and gas distribution rates have revenue decoupling mechanisms ("RDM") which allow for periodic adjustments to delivery rates as a result of the reconciliation between allowed revenue and billed revenue. The regulated subsidiaries also have other ARPs related to the achievement of certain objectives, demand- side management initiatives, and certain other ratemaking mechanisms. Revenues from ARPs are recognized, with a corresponding offset to a regulatory asset or liability account, when the regulatory-specified events or conditions have been met, the amounts are determinable and probable of recovery (or payment) through future rate adjustments within 24-months from the end of the annual reporting period.

Other Revenue: Includes lease income and other transactions that are not considered contracts with customers. Lease income primarily includes electric generation revenue, which is derived from billings to LIPA for electric generation capacity and, to the extent requested, energy from the Company's existing oil and gas-fired generating plants. The arrangement is treated as an operating lease within the scope of the leasing standard, where Genco acts as lessor with rental income being recorded as other income, which forms part of total revenue. Lease payments (capacity payments) are recognized on a straight-line basis and variable lease payments are recognized as the energy is generated.

4. REGULATORY ASSETS AND LIABILITIES

The Company records regulatory assets and liabilities that result from the ratemaking process. Regulatory deferrals are recorded by each legal entity as right of offset does not exist across the Company's regulated subsidiaries. The following table presents the regulatory assets and regulatory liabilities recorded on the consolidated balance sheets:

	March 31,	
	2023	2022
	(in millions of dollars)	
Regulatory assets		
Current:		
Derivative instruments	**$ 138**	$ -
Gas cost adjustment mechanism	**95**	144
Rate adjustment mechanisms	**110**	107
Renewable energy certificates	**105**	97
Revenue decoupling mechanism	**104**	39
Other	**80**	54
Total	**632**	441
Non-current:		
Cost of removal	**58**	70
Environmental response costs	**2,647**	2,534
Net metering deferral	**234**	170
Postretirement benefits	**564**	390
Storm costs	**694**	409
Arrears Reduction	**235**	-
Other	**833**	735
Total	**5,265**	4,308
Regulatory liabilities		
Current:		
Energy efficiency	**337**	354
Derivative instruments	**-**	345
Gas cost adjustment mechanism	**144**	152
Rate adjustment mechanisms	**316**	93
Revenue decoupling mechanism	**90**	142
Other	**82**	68
Total	**969**	1,154
Non-current:		
Cost of removal	**1,723**	1,611
Environmental response costs	**193**	197
Postretirement benefits	**1,232**	1,259
Regulatory tax liability	**2,150**	2,341
Other	**1,270**	1,302
Total	**6,568**	6,710

As of March 31, 2023 and 2022, other than $323 million ($199 million of Postretirement benefits, $66 million of Environmental response costs, and $58 million of Other costs) and $276 million ($205 million of Postretirement benefits, $52 million of Environmental response costs, and $19 million of Other costs), respectively, of the regulatory assets summarized above, all regulatory assets earn a rate of return.

As of March 31, 2023, and 2022, $187 million and $265 million, respectively, of allowances for earnings on shareholders' investment were capitalized for rate-making purposes but not for US GAAP.

Arrears Reduction: The arrears reduction program was implemented in compliance with the proceeding to address Energy Affordability for Low Income Utility Customers and the proceeding regarding the Effects of Covid-19 on Utility Service. The program addresses arrears held by low-income customers and is funded by a combination of state funds, shareholder contributions, existing energy affordability program liabilities as well as surcharge to other customers.

Cost of removal: The regulatory asset represents cumulative removal amounts spent, but not yet collected, to dispose of property, plant and equipment, while the regulatory liability represents cumulative removal amounts collected but not yet spent. The asset is reduced as the allowance for cost of removal is recovered in rates. The liability is discharged as removal costs are incurred.

Derivative instruments: The Company evaluates open commodity 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.

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

Environmental response costs: The regulatory asset represents deferred costs associated with the Company's share of the estimated costs to investigate and perform certain remediation activities at former manufactured gas plant ("MGP") sites and related facilities. The Company believes future costs, beyond the expiration of current rate plans, will continue to be recovered through rates. 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 of supply. These amounts will be refunded to, or recovered from, customers over the next year.

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

Postretirement benefits: The regulatory asset balance represents the Company's, unamortized, non-cash accrual of net pension actuarial gains and losses in addition to actual costs associated with the Company's pension plans in excess of amounts received in rates that are to be collected in future periods. The regulatory liability represents the Company's, unamortized, non-cash accrual of net PBOP actuarial gains and losses in addition to excess amounts received in rates over actual costs of the Company's PBOP plans that are to be recovered from or passed back to customers in future periods.

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

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

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

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

Storm costs: The Company is allowed to recover qualifying storm costs from retail delivery service customers. This balance reflects costs yet to be recovered. See Note 5, "Rate Matters," for additional information regarding the recovery of storm costs.

5. RATE MATTERS

Niagara Mohawk

Electric and Gas Filing

On September 27, 2021, Niagara Mohawk, the Department of Public Service ("DPS") Staff and other settlement parties filed a Joint Proposal ("NIMO-JP") for a three-year rate plan for Niagara Mohawk's electric and gas businesses beginning July 1, 2021 and ending June 30, 2024. The highlights of the rate plan include: enhanced energy affordability programs ("EAP") and services for low and moderate income customers; initiatives to reduce methane emissions and deploy clean energy solutions, including electric vehicles ("EV"), battery storage and energy efficiency and demand response programs, in support of the Climate Leadership and Community Protection Act ("CLCPA"); support for deploying Advanced Metering Infrastructure ("AMI"); and funding for $3.3 billion in capital projects to improve safety, resiliency and reliability of our energy networks. The proposed revenue increases are 1.4% for electric operations and 1.8% for gas operations in Rate Year 1 and 1.9% for both electric and gas operations in Rate Year 2 and Rate Year 3. In addition, the NIMO-JP also includes mechanisms that would allow Niagara Mohawk to extend the rate plan by nine months ("Stayout Period"), such that new rates would become effective April 1, 2025. To mitigate the potential bill impacts on customers, the settlement applies existing deferral credits of $146 million and $54 million for electric and gas customers, respectively, over the term of the rate plan and Stayout Period. The settlement is based upon a 9% return on equity and a ratemaking capital structure reflecting a common equity component of 48%. The NIMO-JP includes an earning sharing mechanism by which customers will share in earnings in excess of a 9.5% calculated return on equity for each rate year under the rate plan.

On January 20, 2022, the NYPSC approved and adopted the three-year settlement through June 30, 2024 and supporting schedules for Niagara Mohawk's electric and gas businesses with limited additional requirements. Pursuant to the NIMO-JP, Niagara Mohawk recorded the Make Whole provision with new rates effective February 1, 2022. The Make Whole provision covering the period July 2021 through January 2022 was recorded in February 2022 to ensure Niagara Mohawk is restored to the same financial position it would have been in had new rates gone into effect July 1, 2021. The NYPSC stated in its approval that the agreed upon electric and gas rate plans will result in sufficient mitigation of rate impacts on customers while preserving Niagara Mohawk's operational and financial stability; are consistent with the environmental, social and economic policies of the Commission and the State of New York, including the CLCPA; and fall within the range of potential litigated outcomes or otherwise provide benefits to ratepayers that could not have been achieved in a fully litigated proceeding.

Advanced Metering Infrastructure

On November 20, 2020, the NYPSC approved Niagara Mohawk's proposal for the deployment of AMI, also referred to as smart meters. The upstate New York Smart Meter program will provide our customers with real-time energy consumption data and tools to make clean energy choices and reduce costs. The approval assumes a six-year project deployment schedule (two years of back-office systems followed by four years of electric meter and gas module deployment) with bulk meter/module deployment anticipated to begin in the third quarter of calendar year 2023. Niagara Mohawk intends to install approximately 1.7 million electric AMI meters and 640,000 gas modules across its service territory. In the approved rate case, Niagara Mohawk will be authorized to recover $119 million of AMI-related operations and maintenance ("O&M") expense incurred during the six-year AMI deployment period beginning fiscal year 2022 subject to a downward-only reconciliation at the end of the six-year AMI deployment period. Likewise, the November 2020 AMI Order established a capital expenditure cap for the program of approximately $475 million over the six-year AMI deployment period.

Proceeding on Energy Affordability Programs and Effects of COVID-19 on Utility Service

On June 11, 2020, the NYPSC opened a proceeding to investigate the impacts of COVID-19 on utilities' customers, operations, finances and ability to provide safe and reliable service at just and reasonable rates. Niagara Mohawk along with the other New York State utilities worked closely with our regulators to develop approaches that support residential and commercial customers, utilities, clean energy developers, and other stakeholders, all of whom contribute to the State's economic health. On January 19, 2023, the NYPSC closed the proceeding on the effects of COVID-19 on utility service, when it issued its order authorizing the Phase 2 Arrears Reduction Program.

COVID-19 Recovery

On January 20, 2021, the DPS Staff issued a guidance letter regarding deferral treatment of incremental COVID-19 costs. The letter articulated two scenarios under which utilities could seek deferral of such costs – through change in law provisions contained in utilities' existing rate plans or through a separate deferral petition.

On December 16, 2021, Niagara Mohawk notified the NYPSC that under its previous and current rate plan provisions Niagara Mohawk has met the requirements during Rate Year 3 and the Stayout Period to defer, for ratemaking purposes, the unbilled fees (late payment charges and other waived fees, net of related savings) of approximately $17 million and $3 million, for the electric and gas businesses, respectively, resulting from New York State's COVID-related orders and legislation. On February 7, 2022, the New York Companies petitioned for approval of an alternative recovery mechanism for the COVID-19 related unbilled fees that are deferred during the term of the rate plans. On June 16, 2022, the NYPSC approved Niagara Mohawk's petition for an alternative recovery mechanism of COVID-19 unbilled fees, whereby Niagara Mohawk will collect its deferral for the last fifteen months of its prior rate plan (April 1, 2020 – June 30, 2021) of $17 million for the electric business and $3 million for the gas business through a surcharge effective July 1, 2022, through June 30, 2023. In addition, the NYPSC authorizes Niagara Mohawk to surcharge or credit the deferred COVID-19 unbilled fees, net of related savings, for Rate Years 1 and 2 under its current rate plan during the periods from July 1, 2023, through June 30, 2024, and July 1, 2024, through June 30, 2025, respectively. The order also approved Niagara Mohawk's proposal to commit $2 million of the deferred unbilled fee toward customer arrearages, discussed below. In June 2022, Niagara Mohawk met the requirements under U.S. GAAP to recognize the revenues for the COVID-19 unbilled fees for the amounts deferred through June 30, 2022. Accordingly, Niagara Mohawk recorded the revenue related to the COVID-19 unbilled fees deferral, in fiscal year 2023, of $28 million to revenue from regulatory mechanisms and the associated interest income of $2 million on the deferral to other income, net.

Energy Affordability Programs

On February 4, 2021, the DPS issued a Whitepaper providing recommendations in both the proceeding for Energy Affordability for Low Income utility customers and the proceeding on the effects of COVID-19 on utility service. On August 12, 2021, the NYPSC issued an order to adopt recommendations that aim to provide uniformity of energy affordability programs statewide via standardized practices and facilitate the ease of enrollment and customer participation. The Commission also adopted modifications to the bill discount calculation methodology to move further toward achieving the Commission's six percent energy burden goal. In the order, the NYPSC directs the joint utilities to update their respective EAP bill discounts and file tariff modifications to become effective on a temporary basis, on September 1, 2021, to quickly provide relief to low-income customers and to establish an Energy Affordability Policy working group ("EAP Working Group"), in which Niagara Mohawk is a member.

Phase 1 Arrears Reduction Program

Several initiatives have been developed since the issuance of the August 2021 order, most notably, the Utility Arrears Relief Program ("UARP"), which was included in the fiscal year 2022-2023 New York State budget ("NYS budget") and which is aimed at reducing the arrears held by ratepayers from March 7, 2020, until March 1, 2022. Pursuant to the requirements of the UARP, the NYS budget enacted in April 2022, directed the DPS to establish a residential arrears reduction program for electric and gas customers, in consultation with the EAP Working Group, to first prioritize the $250 million allocation of State funds, of which Niagara Mohawk's portion is approximately $40 million, to eligible low-income customers no later than August 1, 2022.

In May 2022, the EAP Working Group issued an Arrears Report recommending, among other matters, to implement an arrears reduction program in two phases. The first phase ("Phase 1") would target low-income customers to provide much needed COVID-19 related relief through a one-time bill credit that eliminates accrued arrears through May 1, 2022, with portions above the $250 million state appropriation being funded from a combination of sources including ratepayers. The second phase ("Phase 2") would allow the EAP Working Group to develop a program designed to reduce arrears for customers who were not eligible for arrears relief under the Phase 1 program.

On June 16, 2022, the NYPSC approved the recommendations made in the Phase 1 Arrears Report discussed above. The order authorized the implementation of the Phase 1 Arrears Reduction Program, whereby, Niagara Mohawk's total EAP arrears reduction one-time bill credits are to be funded by approximately $40 million from the NYS budget allocation, a shareholder contribution of $2 million under Niagara Mohawk's approved petition for alternative recovery mechanism of COVID-19 unbilled fees, utilization of $25 million from existing deferred EAP liabilities, with the remaining balance to be recovered from customers through a surcharge over a three year recovery period effective on August 1, 2022. This order denied a petition filed on September 29, 2020 which requested the approval for a COVID-19 Customer Assistance Program and instead directed Niagara Mohawk to use the deferred low-income balances to reduce the cost of Niagara Mohawk's arrears reduction program. Niagara Mohawk issued a total of approximately $106 million of Phase 1 EAP one-time bill credits to its electric and gas customers through March 31, 2023.

Phase 2 Arrears Reduction Program

On December 23, 2022, the EAP Working Group filed the Phase 2 Arrears Report recommending that the NYPSC adopt a second phase of relief for COVID-19 related arrears through May 1, 2022 for residential non-EAP customers who did not receive relief under Phase 1 and for small commercial customers.

On January 19, 2023, the NYPSC approved the EAP Working Group's Phase 2 proposal ("Phase 2 Order"). The Phase 2 relief will include a one-time bill credit to resolve arrears through May 1, 2022 for approximately 75 percent of residential non-EAP and small business customers, and partially resolve arrears for approximately 25 percent of remaining customers. In total, the Phase 2 program provided approximately $73 million of one-time bill credits, to eligible customers who did not receive relief under the Phase 1 program. The cost of the Phase 2 program bill credits and carrying costs will be funded by a combination of approximately $3 million in economic development program deferrals, with the remaining balance to be recovered from customers through a surcharge over a six-year period. On February 21, 2023, in accordance with the Phase 2 Order, National Grid submitted a compliance filing and also requested a proposed uncollectible expense reconciliation mechanism in exchange for a future adjustment of the Phase 2 program customer surcharge, which Niagara Mohawk does not expect will have a material impact to the financial statements. It is uncertain as to when the NYPSC will respond to this proposal.

New York Transmission Projects

CLCPA Phase 1

On November 8, 2021, Niagara Mohawk filed a petition, which was subsequently updated on April 8, 2022, requesting authorization to develop 27 local transmission projects (“Phase 1”) and approval of cost recovery mechanisms for those projects. Niagara Mohawk estimates the Phase 1 projects will cost approximately $738 million to develop and expects to place 19 of the projects into service during the term of its current rate plan. On July 14, 2022, the NYPSC issued an order determining that 26 of the proposed local transmission projects qualify for treatment as Phase 1 investments and authorized Niagara Mohawk to use its existing net regulatory liabilities to offset the estimated $9 million in revenue requirement associated with the initial Phase 1 Projects that enter service prior to March 31, 2025. The NYPSC also authorized Niagara Mohawk to defer, for future recovery from ratepayers, the operations expenses up to $1 million associated with the development of subsequent Phase 1 projects through fiscal year 2025, with the expectation that cost recovery will transition into base rates in Niagara Mohawk's next rate filing.

CLCPA Phase 2

On August 19, 2022, FERC accepted the New York Transmission Owners’ (a group of New York electric utilities including Niagara Mohawk) Phase 2 Cost Sharing and Recovery Agreement (“CSRA”), which was developed to recover the costs of local transmission upgrades determined by the NYPSC to be necessary to meet New York’s climate and renewable energy goals as required by the CLCPA. CSRA provides that the costs of NYPSC-approved local transmission upgrades will be shared statewide among the CLCPA’s customers and recovered on a volumetric load-ratio basis. On February 16, 2023 the NYPSC issued an order authorizing Central Hudson Gas & Electric Corporation, New York State Electric & Gas Corporation, Rochester Gas & Electric Corporation and Niagara Mohawk Power Corporation (the “Sponsoring Utilities”) (i) to proceed with more than $4 billion of proposed transmission upgrades (with some modifications) and (ii) to seek recovery of associated costs through the previously approved CSRA. The Order approved 100% of the approximately $2 billion in transmission upgrades proposed by Niagara Mohawk in the Northern New York and the Capital regions, finding the projects were well supported under the criteria established by the NYPSC that considered, among other factors, incremental transmission capacity, curtailment risk, and costs.

Smart Path Connect

On August 12, 2022, the NYPSC approved National Grid and the New York Power Authority’s (“NYPA”) filing seeking permission to construct and operate the Smart Path Connect (“SPC”) project. SPC is a bulk transmission project jointly developed with NYPA in Northern New York. Niagara Mohawk's portion of the project is estimated at approximately $535 million plus financing costs and will upgrade approximately 55 miles of an existing double circuit North-South transmission corridor from the Canadian border to central New York. The NYPSC found the project will improve the reliability and economy of the electric system and provide increased transmission capability for renewable resources required to meet the State’s obligations under the CLCPA.

In July 2022, FERC rejected National Grid’s Section 205 tariff filing for cost recovery of its investment in SPC. Niagara Mohawk made a revised Section 205 filing in January 2023 that addresses the issues raised by FERC in its July 2022 order. In late March 2023, FERC issued a deficiency letter for the revised Section 205 filing and posed a series of questions about the proposed accounting treatment of certain aspects of the project. On May 30, 2023, Niagara Mohawk submitted its response to the deficiency letter, in which Niagara Mohawk is modifying its SPC Project Filing to remove its request at this time, for specific accounting treatment for the cost of removal of certain transmission assets that will be removed to construct and place the SPC project into service. This modification will not impact the balance of the requests in the SPC Project Filing and will not result in any rate impacts.

On October 24, 2022, FERC found Niagara Mohawk's Compliance Filing on August 23, 2022, as supplemented on October 11, 2022, satisfied the conditions of the FERC Order issued in March 2022 with respect to the Abandoned Plant Incentive for the SPC project, which will allow for recovery of 100% of prudently incurred costs expended on or after the date of FERC’s March 2022 Order if the SPC project is abandoned for reasons beyond Niagara Mohawk's control.

Community Investment

In October 2022, National Grid announced its commitment to help customers and communities navigate increasing winter energy prices. To help customers who need financial assistance, as winter energy prices are expected to rise significantly due to the global energy crisis and inflation, National Grid committed $17 million in philanthropic shareholder funding. These funds are in addition to annual local community and philanthropic support. The funds will be distributed through National Grid and the National Grid Foundation to existing networks and community partners across Massachusetts and New York that are set up to help individuals, families and communities who need it most. The assistance allocated to New York is approximately $7 million of which $4 million was spent in fiscal year 2023.

The New York Gas Companies

Rate Case Filing

On April 28, 2023, The Brooklyn Union Gas Company and KeySpan Gas East Corporation (the "New York Gas Companies") filed to increase revenues by $414 million and $228 million for the twelve months ending March 31, 2025 ("Rate Year 1"), respectively. While the New York Gas Companies' filings propose new rates for Rate Year 1 only, cost data for three additional years have been included to facilitate a potential multi-year settlement. The New York Gas Companies believe that a multi-year settlement would allow for a phase in of the revenue increases and the ability to better manage customer bill impacts and affordability. If approved, the new charges would take effect from April 1, 2024.

These rate filings demonstrate the New York Gas Companies commitment to continuing its broad support of New York's energy goals and meeting the challenges of climate change, while also ensuring the overall reliability, resiliency, and affordability of the energy system. The New York Gas Companies are proposing numerous programs that will reduce emissions and advance the clean energy goals of the CLCPA. Among the specific programs are targeted main replacement, a new leak repair program, extending an unprecedented ramp-up in energy efficiency, and promotion of weatherization programs.

General Rate Case

On April 30, 2019, the New York Gas Companies filed to increase revenues for the twelve months ending March 31, 2021 ("Rate Year 1"). The New York Gas Companies were granted an extension of the suspension period, such that new rates would now become effective September 1, 2021 and included a Make Whole provision in order to keep the New York Gas Companies and their customers in the same financial position they would have been had the New York Gas Companies files for new rates by April 30, 2020.

On May 14, 2021, the DPS Staff and the New York Gas Companies filed a Joint Proposal ("DSNY-JP") for a three-year rate plan beginning April 1, 2020 and ending March 31, 2023. The total revenue increases are 0% in Rate Year 1 for the New York Gas Companies and 2% and 1.8% in Rate Year 2 and Rate Year 3 for The Brooklyn Union Gas Company and KeySpan Gas East Corporation, respectively. To mitigate the potential bill impacts on customers, the settlement applies nearly $100 million of credits over the three years of the rate plan. In addition, the revenue requirements include amounts from the amortization of excess federal Accumulated Deferred Income Taxes ("ADIT"), which was also used to benefit customers by mitigating rates.

The DSNY-JP addresses the goals of the CLCPA and includes provisions that promote energy efficiency, demand response, geothermal, and electrification options to meet customers' energy needs while minimizing the need for additional gas infrastructure. The settlement is based upon an 8.8% return on equity ("ROE") and 48% common equity ratio and includes an earning sharing mechanism with customers when the New York Gas Companies' ROE is in excess of 9.3%. In addition, the DSNY-JP also includes a mechanism that would allow the New York Gas Companies to extend the rate plan by twelve months ("Stayout Period"), such that new rates would become effective April 1, 2024. Beginning April 1, 2023, the New York Gas Companies began the Stayout Period which continued the provisions of the current rate plan with some modifications, including the deferral of incremental revenue requirement over the allowance in base rates for the net utility plant and depreciation expense reconciliation mechanism (capped at forecast levels) and Commission-approved energy efficiency costs not recovered in base rates to achieve energy efficiency targets (not to exceed the authorized budget) for the twelve months ended March 31, 2024.

The DSNY-JP authorized KeySpan Gas East Corporation to reduce the pension and postretirement regulatory liability deferral amount of $47 million due to customers for pension and postretirement benefit other than pension related amounts. This resulted because KeySpan Gas East Corporation's customers previously received the benefit of historical gains which were properly allocated based on the accounting treatment for a curtailment event, but ultimately should not have been economically shared with this customer group.

On August 12, 2021, the NYPSC approved and adopted the DSNY-JP and supporting schedules with limited additional requirements. Pursuant to the DSNY-JP, the New York Gas Companies recorded the Make Whole provision during the fiscal year ended March 31, 2022, the impact of this provision for Rate Year 1 did not result in a material impact on the New York Gas Companies' financial position, results of operations or cash flows.

Downstate Gas Moratorium

The downstate gas moratorium settlement agreement (the "Settlement Agreement") entered in November 2019, and subsequently approved by the NYPSC, required the New York Gas Companies to lift the moratorium for approximately two years and implemented $35 million in customer assistance, demand response, energy efficiency and other shareholder funded programs. On February 25, 2021, the DPS Staff and the New York Gas Companies entered into the Second Amendment to the Settlement Agreement, approved by the NYPSC on April 15, 2021, which repurposed the $20 million of shareholder funding designated to support clean energy projects under the original Settlement Agreement. On August 12, 2021, the NYPSC approved the New York Gas Companies rate case which authorized to use the $20 million settlement amount to offset the revenue requirement of The Brooklyn Union Gas Company in the current rate plan.

Downstate Order to Show Cause

On February 25, 2021, the DPS Staff and the New York Gas Companies entered into a settlement agreement resolving all issues arising out of the "Orders Instituting Proceeding and to Show Cause" dated July 2019 and November 2018 for alleged gas safety violations. The settlement agreement, approved by the NYPSC on March 18, 2021, authorizes The Brooklyn Union Gas Company and KeySpan Gas East Corporation to establish a deferral at shareholder expense for its portion of the settlement of $15 million and $6 million for the benefit of customers to offset the costs of the New York Gas Companies' approved energy efficiency and demand response programs, respectively. On August 12, 2021, the NYPSC approved the New York Gas Companies rate case which authorized to use the $15 million and $6 million settlement amount to offset the revenue requirement of The Brooklyn Union Gas Company and KeySpan Gas East Corporation in the current rate plan, respectively.

Proceeding on Energy Affordability Programs and Effects of COVID-19 on Utility Service

Refer to "Proceeding on Energy Affordability Programs and Effects of COVID-19 on Utility Service" section under Niagara Mohawk.

COVID-19 Recovery

Refer to "COVID-19 Recovery" section under Niagara Mohawk.

Different from Niagara Mohawk, on December 16, 2021, the New York Gas Companies notified the NYPSC that under its current rate plan provisions the New York Gas Companies have met the requirements during Rate Year 1 to defer, for ratemaking purposes, the unbilled fees (late payment charges and other waived fees, net of related savings) resulting from New York State's COVID-19 related orders and legislation. On February 7, 2022, the downstate New York Gas Companies jointly petitioned for approval of an alternative recovery mechanism for the COVID-19 related unbilled fees that are deferred during the term of the rate plans. On June 16, 2022, the NYPSC approved the New York Gas Companies petition for alternative recovery mechanism of COVID-19 unbilled fees, whereby, The Brooklyn Union Gas Company and KeySpan Gas East Corporation will collect its deferral for Rate Year 1 of $13 million and $6 million through a surcharge effective July 1, 2022, through June 30, 2023, respectively. In addition, the NYPSC authorizes the New York Gas Companies to surcharge or credit the deferred COVID-19 unbilled fees, net of related savings, for Rate Years 2 and 3 under its rate plan during the periods from July 1, 2023, through June 30, 2024, and July 1, 2024, through June 30, 2025, respectively. The order also approved The Brooklyn Union Gas Company and KeySpan Gas East Corporation's proposal to commit $1 million and $0.4 million of the deferred unbilled fee toward customer arrearages, respectively, discussed below. In June 2022, the New York Gas Companies met the requirements under U.S. GAAP to recognize the revenues for the COVID-19 unbilled fees for the amounts deferred through June 30, 2022. Accordingly, The Brooklyn Union Gas Company and KeySpan Gas East Corporation recorded the revenue related to the COVID-19 unbilled fees deferral, in fiscal year 2023, of $21 million and $10 million, to revenue from regulatory mechanisms and the associated interest income of $2 million and $1 million, on the deferral to other income, net, respectively.

Energy Affordability Programs

Refer to "Energy Affordability Programs" section under Niagara Mohawk.

Different from Niagara Mohawk, in accordance with the order, the joint utilities filed tariff modification updates to their respective Energy Affordability Program bill discounts on November 1,2022, effective December 1, 2022, initiating an annual cycle of Energy Affordability Policy tariff statement updates for low-income discounts. The order also established an Energy Affordability Policy working group ("EAP Working Group"), in which the New York Gas Companies are members.

Phase 1 Arrears Reduction Program

Refer to "Phase 1 Arrears Reduction Program" section under Niagara Mohawk.

Different from Niagara Mohawk, pursuant to the requirements of the UARP, the NYS budget enacted in April 2022 directed the DPS to establish a residential arrears reduction program for electric and gas customers, in consultation with the EAP Working Group, to first prioritize the $250 million allocation of State funds, of which The Brooklyn Union Gas Company and KeySpan Gas East Corporation's portions are approximately $10 million and $1 million, to eligible low-income customers no later than August 1, 2022, respectively.

On June 16, 2022, the NYPSC approved the recommendations made in the Phase 1 Arrears Report discussed above. The order authorized the implementation of the Phase 1 Arrears Reduction Program, whereby The Brooklyn Union Gas Company and KeySpan Gas East Corporation's total EAP arrears reduction one-time bill credits are to be funded by approximately $10 million and $1 million from the NYS budget allocation, a shareholder contribution of $1.2 million and $0.4 million under The Brooklyn Union Gas Company and KeySpan Gas East Corporation's approved petition for alternative recovery mechanism of COVID-19 unbilled fees, with the remaining balance to be recovered from customers through a surcharge over a three and a half year and a twelve month recovery period effective on August 1, 2022, respectively. The Brooklyn Union Gas Company and KeySpan Gas East Corporation issued a total of approximately $50 million and $5 million of Phase 1 EAP one-time bill credits to its gas customers through March 31, 2023, respectively.

Phase 2 Arrears Reduction Program

Refer to "Phase 2 Arrears Reduction Program" section under Niagara Mohawk.

Different from Niagara Mohawk, in total, the Phase 2 program provided approximately $82 million and $17 million of one-time bill credits, to eligible customers who did not receive relief under the Phase 1 program, respectively. For The Brooklyn Union Gas Company, the cost of the Phase 2 program bill credits and carrying costs will be funded by customers through a customer surcharge over an eleven-year period. For KeySpan Gas East Corporation, the cost of the Phase 2 program bill credits and carrying costs will be funded by a combination of approximately $1 million in economic development program deferrals, with the remaining balance to be recovered from customers through a customer surcharge over a three-year period. On February 21, 2023, in accordance with the Phase 2 Order, National Grid submitted a compliance filing and also requested a proposed uncollectible expense reconciliation mechanism in exchange for a future adjustment of the Phase 2 program customer surcharge, which the New York Gas Companies do not expect will have a material impact to the financial statements. It is uncertain as to when the NYPSC will respond to this proposal.

Community Investment

Refer to "Community Investment" section under Niagara Mohawk.

The Massachusetts Electric Companies

General Rate Case

On November 15, 2018, the Massachusetts Electric Company and its affiliate, Nantucket Electric, filed an application for new base distribution rates that became effective October 1, 2019. On September 30, 2019, and updated on October 11, 2019, the DPU approved for the Massachusetts Electric Company and Nantucket Electric an overall net increase in base distribution revenue of approximately $40 million based upon a 9.6% ROE, with a 53.49% equity, 46.43% long-term debt, and 0.08% preferred stock capital structure. The DPU approved a five-year performance-based ratemaking ("PBR") plan, which adjusts base distribution revenue annually based on a pre-determined formula. With the approval of the PBR plan, Massachusetts Electric Company and Nantucket Electric agreed not to file for an effective change in base distribution rates outside of the operation of the PBR plan for five years. Also, the Capital Investment Recovery Mechanism ("CIRM") has been discontinued after a transition period that concluded with recovery of vintage year 2019 investments through September 30, 2021, at which point the recovery of capital investments has fully transitioned to the PBR plan. The approved net increase includes an increase in annual funding of the storm fund from $11 million to $16 million per year and an extension of the storm fund replenishment factor through November 2023.

PBR Plan Filing

On June 15, 2021, the Massachusetts Electric Company and Nantucket Electric filed the second annual PBR plan filing for rates effective October 1, 2021. The PBR plan filing adjusts base distribution rates pursuant to a revenue cap formula, provides a credit to customers for any customer share of excess earnings pursuant to the earnings sharing mechanism, and recovers from or credits customers for the impact of costs in excess of a threshold associated with exogenous events, including storms having incremental costs in excess of $30 million. The result of the revenue cap formula was a proposed increase to base distribution revenue of 2.71%, or $23 million. On September 8, 2021, the DPU approved the Massachusetts Electric Company and Nantucket Electric's proposed PBR and Capital Expenditure Adjustment filing, effective October 1, 2021, subject to further investigation and reconciliation in the second phase of the proceeding. On February 23, 2022, the DPU issued its final approval of the Massachusetts Electric Company and Nantucket Electric's proposed base distribution rates resulting from the PBR adjustment and capital expenditure adjustment.

On June 17, 2022, the Massachusetts Electric Company and Nantucket Electric filed the third annual PBR plan filing for rates effective October 1, 2022. The Massachusetts Electric Company and Nantucket Electric requested approval of a PBR adjustment of $44 million, based on a PBR percentage of 4.92%. This adjustment reflects the implementation of the Massachusetts Electric Company and Nantucket Electric's proposed voluntary one-time customer impact mitigation plan, which the Massachusetts Electric Company proposed due to the extreme economic circumstances and high inflation rates currently impacting customers. On September 26, 2022, the DPU approved the Massachusetts Electric Company and Nantucket Electric's proposed PBR adjustment and customer impact mitigation plan, effective October 1, 2022. The DPU also stated that it will conduct its review of the Massachusetts Electric Company and Nantucket Electric's proposed amortization of the exogenous storm event with incremental costs in excess of $30 million as part of the Massachusetts Electric Company and Nantucket Electric's next PBR plan filing.

The Massachusetts Electric Company and Nantucket Electric made its annual PBR filing on June 15, 2023. The filing requests a PBR Adjustment for effect October 1, 2023 of $67 million, plus recovery of $14 million annually over five years associated with an exogenous storm event in which the Massachusetts Electric Company and Nantucket Electric incurred incremental costs in excess of $30 million, resulting in a total of $80 million. The filing includes a voluntary Customer Impact Mitigation Plan, that reduces what the Massachusetts Electric Company and Nantucket Electric would have otherwise requested under its PBR formula by $15 million, from $81 million to $67 million (not inclusive of the storm event costs). 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 ($7 million for the year ended March 31, 2022 and $1 million for the year ended March 31, 2023).

Recovery of Transmission Costs

The Massachusetts Electric Company’s transmission facilities are currently operated in combination with the transmission facilities of its New England affiliate, NEP, as a single integrated system, with NEP designated as the combined operator.

In accordance with the provisions in the Integrated Facilities Agreement “IFA” between NEP and the Massachusetts Electric Company, the Massachusetts Electric Company is compensated for its actual monthly transmission costs, with its authorized maximum ROE of 11.74% on its transmission assets. The amounts remitted by NEP to the Massachusetts Electric Company is included in NEP’s Local and Regional Network Service rates for recovery from wholesale transmission customers. The amounts remitted by NEP to the Massachusetts Electric Company for the years ended March 31, 2023 and 2022 were $22 million and $24 million, respectively.

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

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

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

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

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

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

Tax Act

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

Grid Modernization Plan

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

The Massachusetts Electric Company, together with Nantucket Electric filed its proposed four-year GMP (for calendar years 2022–2025) on July 1, 2021, which included proposals to continue the previously-approved investments (designated as "Track 1" in the proceeding), invest in a distributed energy resource management system ("DERMS"), conduct two demonstration projects, and deploy AMI (all designated as "Track 2" in the proceeding). The Massachusetts Electric Company, together with Nantucket Electric requested authorization for $316 million in grid-facing investments over four years, consisting of $289 million for Track 1 investments, $8 million for DERMS investments, $6 million for the two demonstration projects, and $13 million to support the implementation of FERC Order No. 2222. On October 7, 2022, the DPU issued its final order on Track 1, preauthorizing a $301 million budget for the Massachusetts Electric Company and Nantucket Electric's continuing grid-facing investments in (1) monitoring and control ($4 million); (2) volt/volt-amps reactive optimization ($76 million); (3) advanced distribution automation ($38 million); (4) an advanced distribution management system ($61 million); (5) information/operational technology ($19 million); and (6) communications ($103 million) for the 2022-2025 GMP. On

November 30, 2022, the DPU issued its Track 2 Order, preauthorizing $35 million in new grid-facing investments for the years 2022-2025 grid modernization plan. Accelerated cost recovery for these investments will continue through the separate grid modernization factor. The DPU also has preauthorized $391 million in spending for our AMI "core" investments for the years 2023-2027, and created a new AMI factor for accelerated cost recovery for these costs. The DPU separated some of AMI investments into a new category of "supporting" AMI investments and provided preliminary approval for a budget of $96 million for these investments. The Massachusetts Electric Company, together with Nantucket Electric will seek cost recovery for these supporting investments through annual AMI factor filings.

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 Massachusetts Electric 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 ("C&I") moratorium was lifted effective September 1, 2020.

On December 31, 2020, the DPU approved the following implementation items related to the ratemaking treatment of the COVID-19 customer assistance programs on which the Massachusetts local distribution companies and the Massachusetts Attorney General's ("AG") office had reached consensus: (1) the distribution companies should be allowed to record, defer and track their bad debt and other COVID-related expenses; (2) cost recovery should be limited to the incremental costs incurred; and (3) certain costs must be extraordinary to qualify for recovery. As of March 31, 2023, the Massachusetts Electric Company has deferred $27 million of delivery bad debt (for both the Massachusetts Electric Company and Nantucket Electric) and $1 million of other COVID-related costs, as the Massachusetts Electric Company believes that these amounts are probable of recovery.

The DPU decided that the contested issues, including the extent to which the distribution companies will be allowed to recover their COVID-19 costs, should be fully adjudicated in a new docket, D.P.U. 20-91.

The AG opposes recovery by distribution companies with PBR plans (including the Massachusetts Electric Company, together with Nantucket Electric) 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 Massachusetts Electric Company and Nantucket Electric are required to continue to track bad-debt write-offs for the two-year period of July 1, 2022 through June 30, 2024, with a report to be filed on August 1, 2024, depending on each utility's timing of base distribution rate case filings, and to submit filings to the DPU after that point to commence recovery of the demonstrated incremental amount.

Massachusetts Petition for Waiver of Jurisdiction Regarding the Rhode Island Sale

On May 3, 2021, PPL Energy Holdings, LLC assigned its right to acquire Narragansett 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 Narragansett. The DPU approved NGUSA's request for a waiver of G.L. c. 164, § 96(c), regarding the sale of Narragansett in July 2021. Following that approval there was an appeal process which concluded in May 2022 with a settlement agreement with the AG and on May 25, 2022, Narragansett was sold to PPL Rhode Island.

As a result of NGUSA's settlement with the AG and the sale of Narragansett to PPL Rhode Island, the Massachusetts Electric Company, together with Nantucket Electric, incurred or expects to incur the following costs:

• In June 2022, the Massachusetts Electric Company, together with Nantucket Electric forgave $3 million in arrearages for low-income electric distribution customers with arrears above $500 that were over 90 days past due.

• In June 2022, the Massachusetts Electric Company, together with Nantucket Electric contributed $0.6 million to the AG's residential energy assistance grant program.

• As compensation to customers for potential future increases in IASC costs during the first five years after the Narragansett divestiture, the Massachusetts Electric Company, together with Nantucket Electric, provided a one-time credit of $4 million to customers during the six-month period between November 2022 and April 2023.

• On July 15, 2022, the Massachusetts Electric Company and Nantucket Electric disclosed their IASC costs to the AG's office. The Massachusetts Electric Company and Nantucket Electric will be responsible for costs associated with the AG's retention of a certified public accountant to verify the IASC costs.

Storm Threshold Deferral Requests

On June 17, 2022, the Massachusetts Electric Company and Nantucket Electric petitioned the DPU for authorization to defer for future recovery from the storm fund $6 million in storm cost threshold amounts associated with four qualifying major storm events that occurred in calendar year 2021. On January 19, 2023, DPU issued an order allowing the Massachusetts Electric Company to apply deferral accounting treatment to threshold amounts associated with three major storm events, totaling $5 million. DPU disallowed $2 million of threshold costs associated with the October 26, 2021 Wind/Rain Event because it would be considered as an exogenous event. DPU will determine the appropriate level of recovery for the excess storm fund threshold amount (if any) in the Massachusetts Electric Company's next base distribution rate case.

Municipal Fiscal Year 2022 Property Tax Exogenous Event Request

The Massachusetts Department of Revenue (DOR) has required municipalities to change the way they calculate property taxes, resulting in property tax increases to the Massachusetts Electric Company and Nantucket Electric. On October 18, 2022, the Massachusetts Electric Company and Nantucket Electric filed to be able to recover the costs of this change as an "exogenous event" under their performance-based ratemaking (PBR) plan, along with Nantucket Electric and Boston Gas Company. On May 17, 2023, the DPU approved the Massachusetts Electric Company and Nantucket Electric's request to recover incremental FY 2022 property tax expenses due to certain municipalities changing their assessment methodology after DOR changed its certification standards. The approval is $7 million for the Massachusetts Electric Company and Nantucket Electric. The Massachusetts Electric Company was directed to propose a recovery method for the approved amounts in the next Performance-Based Ratemaking (PBR) filing due on June 15, 2023. After a favorable ruling in a separate case allowing Eversource to recover these type of incremental property taxes, the Massachusetts Electric Company and Nantucket Electric added a request to recover FY 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 Massachusetts Electric Company and Nantucket Electric requested recovery of these fiscal year 2021 amounts and fiscal year 2023 incremental costs in its PBR filing made June 15, 2023.

The Boston Gas Company

General Rate Case

On November 13, 2020, the Boston Gas Company filed a rate case with the DPU, including a request for approval of a PBR Plan and related proposals. The Boston Gas Company requested that the DPU approve new distribution rates to increase distribution revenues by $221 million, including the transfer of $82 million of recovery of the Boston Gas 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 Boston Gas Company for distribution rates is $139 million, or an incremental increase in distribution revenue of 18.1%.

On September 30, 2021, the DPU issued an Order in the Boston Gas Company's rate case. The Order allowed an increase in base revenues of $145 million. On October 20, 2021, the Attorney General filed a motion for recalculation. On October 22, 2021, the Boston Gas 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 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 Boston Gas Company which is applicable to both core capital expenditures and operational expenditures, and which allows the Boston Gas 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 million annually, and also approved an Earnings Sharing Mechanism, pursuant to which the Boston Gas 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 Boston Gas 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 Boston Gas Company. The Boston Gas Company did not elect to use its one-time adjustment of LNG investments this year.

As per this rate order, the Boston Gas 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 million resulting from this indirect disallowance that has been recorded in the accompanying statement of operations and comprehensive income for the year ended March 31, 2022 and consolidated balance sheet as of March 31, 2022 respectively. On June 17, 2022, the Boston Gas 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 Boston Gas Company's next base distribution rate proceeding following the conclusion of the PBR Plan.

On August 17, 2022, the DPU denied the Boston Gas Company's Motion for Clarification. DPU 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 Boston Gas 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 Boston Gas Company requested approval of a base distribution rate adjustment effective October 1, 2022 of approximately $64 million based on a PBR Percentage of 4.80% 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 Boston Gas Company's proposed one-time Customer Impact Mitigation Plan, which the Boston Gas Company proposed due to the extreme economic circumstances currently impacting customers at this time. In the absence of the Customer Impact Mitigation Plan, the Boston Gas Company would be proposing a base distribution rate adjustment of $77 million based on a PBR Percentage of 6.35% and the capital investment adjustment noted above, in accordance with the PBR Tariff. On September 26, 2022, the DPU approved the Boston Gas Company's proposed base distribution rate adjustment and Customer Impact Mitigation Plan.

The Boston Gas Company made its annual PBR filing on June 15, 2023. The filing requests a PBR Adjustment for effect October 1, 2023 of approximately $57 million. It includes a voluntary Customer Impact Mitigation Plan by the Boston Gas Company in light of continuing high inflation; the mitigation plan reduces what the Boston Gas Company would have otherwise requested under its PBR formula by $14 million, from $71 million to $57 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 million for the year ended March 31, 2022 and $0.2 million for the year ended March 31, 2023).

COVID-19 Moratorium on Utility Shut Offs

Refer to “COVID-19 Moratorium on Utility Shut Offs” section under The Massachusetts Electric Companies.

Gas System Enhancement Plan (GSEP)

On April 30, 2022, the DPU approved recovery of approximately $82 million in revenue requirements, related to approximately $403 million of anticipated investments in 2022 under an accelerated pipe replacement program, through GSEP. The rates are effective from May 2022 to April 2023. The DPU approved the Boston Gas Company’s plan for replacing of leak-prone infrastructure in 2022, finding that the Boston Gas Company’s GSEP accomplishes the continued accelerated replacement of leak-prone infrastructure consistent with the requirements of state law.

On October 31, 2022, the Boston Gas Company filed with the DPU its proposed GSEP plan for calendar year 2023. The plan proposes to invest approximately $427 million in the replacement of leak-prone pipe in that timeframe. On April 28, 2023, the DPU issued an order approving in part the proposed CY2023 GSEP. The DPU approved the Boston Gas Company’s 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 joint-sealing technology, as well as to spend $2 million to repair Grade 3 Significant Environmental Impact leaks. This allows the Boston Gas Company to recover $127 million in revenue requirements for its CY2023 GSEP, starting May 1, 2023. The DPU denied the Boston Gas Company’s proposal to combine the GSEP plans for legacy Boston Gas and former Colonial Gas, and to combine their revenue requirements and cost recovery factors. The DPU also denied the Boston Gas Company’s request to extend the end of the replacement schedules for legacy Boston Gas from 2039 to 2044, and for former Colonial Gas from 2034 to 2044.

Massachusetts Petition for Waiver of Jurisdiction regarding the Rhode Island Sale

Refer to “Massachusetts Petition for Waiver of Jurisdiction Regarding the Rhode Island Sale” section under The Massachusetts Electric Companies.

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.

As a result of NGUSA’s settlement with the AGO and the sale of Narragansett to PPL Rhode Island, the Boston Gas Company incurred the following costs:

• The Boston Gas Company recorded a regulatory liability of up to $2 million relating to the potentially excess recovery of indirectly attributable service company (“IASC”) costs. The Boston Gas Company will ultimately need to provide a credit to customers equal to any incremental amount of IASC costs above the calendar year 2021 baseline level, and the Boston Gas Company will true-up the regulatory liability accordingly.

• The Boston Gas Company forgave $1 million in arrearages for low-income gas distribution customers with arrears above $500 and over 90 days.

• $0.4 million contribution from the Boston Gas Company to the AGO’s residential energy assistance grant program.

• One-time credit of $4 million to gas distribution customers through the RDM for the period November 2022 to April 2023.

• Costs related to the AGO hiring a CPA to verify the IASC costs for 2021 submitted to their office on July 15, 2022.

Geothermal District Energy Demonstration Program

On December 15, 2021, the DPU approved the Boston Gas Company's petition for a five-year, $16 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 Boston Gas 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 Boston Gas 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 emissions for low-income customers and environmental justice communities. On May 16, 2022, the Boston Gas Company filed its geothermal energy demonstration program implementation plan for DPU review and approval. On September 13, 2022, the DPU approved the Boston Gas Company's implementation plan. The Boston Gas Company selected the first site project in Lowell, Massachusetts and has been conducting outreach to enroll gas customers in the program.

Investigation into the Future of Natural Gas

On October 29, 2020, the DPU opened an investigation into the role of local gas distribution companies ("LDCs") in achieving the Commonwealth's 2050 climate goals. The investigation will explore 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 or before March 18, 2022, each company was required to submit a proposal to the MADPU that includes its recommendations and plans for helping Massachusetts achieve its 2050 climate goals, supported by an independent consultants' report, that incorporates feedback and advice obtained through a stakeholder process. Supported by the consultants' analysis, the Boston Gas Company's proposal envisions 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 on the consultants' report, LDC plans, and any alternative proposals may be submitted to the DPU until 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. The Boston Gas Company is now awaiting the DPU's Order in the proceeding and cannot predict the outcome of this proceeding.

Municipal Fiscal Year 2022 Property Tax Exogenous Event Request

Refer to "Municipal Fiscal Year 2022 Property Tax Exogenous Event Deferral Request" section under The Massachusetts Electric Companies.

Different from the Massachusetts Electric Companies, the DPU approved $4 million for the Boston Gas Company's request to recover incremental FY 2022 property tax expenses due to certain municipalities changing their assessment methodology after DOR changed its certification standards.

NEP

Stranded Cost Recovery

Under the settlement agreements approved by state commissions and the FERC, NEP is permitted to recover stranded costs (those costs associated with its former generating investments (nuclear and non-nuclear) and related contractual commitments that were not recovered through the sale of those investments). NEP earns a ROE related to stranded cost recovery consisting of nuclear-related investments. In Massachusetts and Rhode Island, the current ROEs are 9.2% and

10.46%, respectively. NEP will recover its remaining non-nuclear stranded costs until the costs associated with the decommissioned nuclear units cease.

Tax Act

Refer to “Tax Act” section under The Massachusetts Electric Companies.

6. PROPERTY, PLANT AND EQUIPMENT

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

	March 31,	
	2023	2022
	(in millions of dollars)	
Plant and machinery	**$ 46,255**	**$ 43,024**
Assets in construction	**3,729**	**3,581**
Land and buildings	**2,302**	**2,218**
Software and other intangibles	**2,592**	**1,910**
Operating leases ROU assets	**1,121**	**922**
Total property, plant and equipment	**55,999**	**51,655**
Accumulated depreciation – Tangible assets	**(10,830)**	**(10,278)**
Accumulated amortization – Software and other intangibles	**(1,395)**	**(1,183)**
Accumulated amortization – Operating lease ROU assets	**(386)**	**(344)**
Property, plant and equipment, net	**$ 43,388**	**$ 39,850**

The Company capitalizes costs incurred during the application development stage of internal use software projects to property, plant and equipment. The Company amortizes capitalized software costs ratably over the expected lives of the software, primarily ranging from 7 to 10 years and commencing upon operational use. Amortization expense for capitalized software was $212 million and $181 million for the years ended March 31, 2023 and 2022, respectively. As of March 31, 2023, amortization expense is estimated to be $212 million, $201 million, $187 million, $168 million, and $143 million for 2024 through 2028, respectively.

7. DERIVATIVE INSTRUMENTS AND HEDGING

The Company utilizes derivative instruments to manage commodity price and foreign currency rate risk associated with its natural gas and electricity purchases, its long-term funding activities, and its Euro commercial paper program. The Company’s commodity risk management strategy is to reduce fluctuations in firm gas and electricity sales prices to its customers. The Company’s currency rate risk management policy is to borrow in the most advantageous market available, and to hedge the risk associated with foreign currency borrowings by utilizing instruments to convert principal and interest payments into U.S. dollars.

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.

Notional Amounts

The notional contract amount represents the gross nominal value of the outstanding derivative contracts.

Volumes of outstanding commodity derivative instruments measured in dekatherms (“dths”) and megawatts hour (“mwhs”) are as follows:

	March 31,	
	2023	2022
	(in millions)	
Gas contracts (dths)	**129**	126
Electric contracts (mwhs)	**15**	14

Summary of Derivative Instruments on Consolidated Balance Sheets

The following tables reflect the gross and net amounts of the Company’s derivative assets and liabilities at March 31, 2023 and 2022:

	March 31, 2023 (in millions of dollars)		
	Gross amount	**Gross amount not offset on the Consolidated Balance Sheet**	**Net amount**
	A	***B***	***C = A-B***
ASSETS:			
Current assets			
Gas contracts	**$ 12**	**$ 9**	**$ 3**
Electric contracts	**57**	**25**	**32**
Other non-current assets			
Gas contracts	**-**	**-**	**-**
Electric contracts	**9**	**3**	**6**
Total	**78**	**37**	**41**
LIABILITIES:			
Current liabilities			
Gas contracts	**95**	**9**	**86**
Electric contracts	**70**	**25**	**45**
Other non-current liabilities			
Gas contracts	**5**	**-**	**5**
Electric contracts	**46**	**3**	**43**
Total	**216**	**37**	**179**
Net assets (liabilities)	**$ (138)**	**$ -**	**$ (138)**

	March 31, 2022					
	(in millions of dollars)					
	Gross amount		**Gross amount not offset on the Consolidated Balance Sheet**		**Net amount**	
	A		***B***		***C = A-B***	
ASSETS:						
Current assets						
Gas contracts	$	102	$	(7)	$	109
Electric contracts		219		1		218
Other non-current assets						
Gas contracts		1		-		1
Electric contracts		44		7		37
Total		366		1		365
LIABILITIES:						
Current liabilities						
Gas contracts		8		1		7
Other non-current liabilities						
Gas contracts		1		-		1
Electric contracts		12		7		5
Total		21		8		13
Net assets (liabilities)	$	345	$	(7)	$	352

Effect of Derivative Instruments on Statements of Operations and Comprehensive Income

Changes in fair value of the Company's rate recoverable contracts (commodity contracts only, hedge contracts are not rate recoverable) are offset by changes in regulatory assets and liabilities. As a result, changes in the fair value of those contracts do not affect earnings. Realized gains or losses on the settlement of the Company's commodity derivative contracts are refunded to, or collected from, customers consistent with regulatory requirements.

The following table summarizes amounts recognized in earnings for commodity derivative instruments not designated as hedging instruments for the years ended March 31, 2023 and 2022:

		Year Ended March 31,			
	Location	**2023**		2022	
		(in millions of dollars)			
Electric contracts	Purchased electricity	**$**	**179**	$	145
Gas contracts	Purchased gas		**(17)**		129
Total gains (losses) recognized in earnings		**$**	**162**	$	274

The following table summarizes changes in the fair value of commodity derivative instruments not designated as hedging instruments that are offset by change in regulatory assets and liabilities for the years ended March 31, 2023 and 2022:

	Location	Year Ended March 31, 2023		Year Ended March 31, 2022	
		(in millions of dollars)			
Electric contracts	Regulatory Assets (Liabilities)	**$**	**50**	$	(250)
Gas contracts[1]	Regulatory Assets (Liabilities)		**88**		(157)
Total changes in regulatory assets		**$**	**138**	$	(407)

[1] Amounts reported include $40 million regulatory assets reported as Held for sale for the year ended March 31, 2022.

Credit and Collateral

The Company is exposed to credit risk related to transactions entered into for commodity price, interest rate, and foreign currency rate 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 Company enters into enabling agreements that allow for payment netting with its counterparties, which reduces its exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty.

Commodity Transactions

The Company enters into commodity transactions on the NYMEX. The NYMEX clearing houses act as the counterparty to each trade. Transactions on the NYMEX must adhere to comprehensive collateral and margining requirements. As a result, transactions on the NYMEX are significantly collateralized and have limited counterparty credit risk.

The credit policy for commodity transactions is managed and monitored by the Finance Committee to the Parent'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 Head of Treasury Risk and Operations, 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 liability of $138 million and an asset of $345 million as of March 31, 2023 and 2022, respectively.

The aggregate fair value of the Company's commodity derivative instruments with credit-risk-related contingent features that were in a liability position as of March 31, 2023 and 2022 was $139 million and $1 million, respectively. The Company had $21 million and zero collateral posted for these instruments as of March 31, 2023 and 2022, respectively. At March 31, 2023, if the Company's credit rating were to be downgraded by one, two, or three levels, it would be required to post additional collateral to its counterparties of $21 million, $85 million, or $124 million, respectively. At March 31, 2022, if the Company's credit rating had been downgraded by one, two, or three levels, it would have been required to post additional collateral to its counterparties of zero, $6 million, or $6 million, respectively. The counterparties had no collateral posted to the Company as of March 31, 2023.

Financing Transactions

The credit policy for financing transactions is managed by a central treasury department under policies approved by the Finance Committee. In accordance with these treasury policies, counterparty credit exposure utilizations are monitored daily against the counterparty credit limits. Counterparty credit ratings and market conditions are reviewed continually with limits being revised and utilization adjusted, if appropriate. Management does not expect any significant losses from non-performance by these counterparties.

8. FAIR VALUE MEASUREMENTS

The following tables present assets and liabilities measured and recorded at fair value on the consolidated balance sheets on a recurring basis and their level within the fair value hierarchy as of March 31, 2023 and 2022:

	March 31, 2023			
	Level 1	**Level 2**	**Level 3**	**Total**
		(in millions of dollars)		
Assets:				
Derivative instruments				
Gas contracts	**$ -**	**$ 11**	**$ 1**	**$ 12**
Electric contracts	**-**	**65**	**1**	**66**
Financial instruments				
Securities	**26**	**215**	**-**	**241**
Total	**26**	**291**	**2**	**319**
Liabilities:				
Derivative instruments				
Gas contracts	**-**	**53**	**47**	**100**
Electric contracts	**-**	**113**	**3**	**116**
Total	**-**	**166**	**50**	**216**
Net assets (liabilities)	**$ 26**	**$ 125**	**$ (48)**	**$ 103**

	March 31, 2022			
	Level 1	Level 2	Level 3	Total
		(in millions of dollars)		
Assets:				
Derivative instruments				
Gas contracts	$ -	$ 58	$ 46	$ 104
Electric contracts	-	255	7	262
Financial instruments				
Securities	37	235	-	272
Total	37	548	53	638
Liabilities:				
Derivative instruments				
Gas contracts	-	7	1	8
Electric contracts	-	13	-	13
Total	-	20	1	21
Net assets (liabilities)	$ 37	$ 528	$ 52	$ 617

Derivative Instruments

The Company's Level 2 fair value derivative instruments primarily consist of commodity swap contracts with pricing inputs obtained from NYMEX and the Intercontinental Exchange ("ICE"). 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 spread 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 primarily consist of OTC commodity option contracts and structured physical gas purchase contracts, which are valued based on internally-developed models. A derivative is designated Level 3 when it is valued based on a forward curve that is internally developed, extrapolated, or derived from market observable curves with correlation coefficients less than 95%, where optionality is present, or if non-economic assumptions are made.

The Company did not have any Level 1 derivative instruments at either March 31, 2023 or March 31, 2022.

Financial Investments - Securities

Securities are included in financial investments on the consolidated balance sheets and primarily include equity and debt investments based on quoted market prices (Level 1) and municipal and corporate bonds based on quoted prices of similar traded assets in open markets (Level 2).

Debt Securities

The following table sets forth the amortized cost and fair value of the Company's available for sale debt securities.

		Amortized Cost		**Fair Value**	
	Longest	March 31,			
	maturity date	**2023**	2022	**2023**	2022
		(in millions of dollars)			
Rabbi Trust municipal bonds	2057	**$ 225**	$ 240	**$ 217**	$ 235

The following table summarizes gains and losses recorded by the Company in relation to available for sale debt securities. No other than temporary impairments were recorded in earnings or other comprehensive income during the years ended March 31, 2023 and March 31, 2022:

		March 31,	
		2023	2022
	Location	*(in millions of dollars)*	
Gross realized gains	Other income, net	**$ 2**	$ 3
Gross realized losses	Other income, net	**(5)**	(6)
Net unrealized gains (losses) on debt securities	OCI	**(10)**	-

Equity Securities

The following table summarizes gains and losses recorded by the Company in relation to investments in equity securities.

		March 31,	
		2023	2022
	Location	*(in millions of dollars)*	
Gross realized gains	Other income, net	**$ -**	$ 114
Gross realized losses	Other income, net	-	(1)
Net unrealized gains (losses) on equity securities	Other income, net	-	-

9. EMPLOYEE BENEFITS

The Company sponsors several qualified and non-qualified non-contributory defined benefit plans (the “Pension Plans”) and post-retirement benefits other than pension (PBOP) plans (together with the Pension Plan (the “Plans”)), covering substantially all employees.

The Company’s regulated subsidiaries have regulatory recovery of virtually all of these costs and therefore have recorded related regulatory assets (liabilities) on the consolidated balance sheets. The Company records amounts for its unregulated subsidiaries to AOCI on the consolidated balance sheets.

Pension Plans

The Pension Plans are defined benefit plans which provide union employees, as well as non-union employees with a retirement benefit. For non-union employees, the plans were closed to new entrants as of December 31, 2010. Non-union employees hired on or after January 1, 2011 are provided with a defined contribution plan. For union employees, the plans were closed, with one exception, to new entrants at varying dates from December 31, 2010 through June 2, 2019. Union employees hired on or after the closing of the pension plans to new entrants are provided with a defined contribution plan. Supplemental non-qualified, non-contributory executive retirement programs provide additional defined pension benefits for certain executives. During the years ended March 31, 2023 and 2022, the Company made contributions of approximately $66 million and $132 million, respectively, to the qualified pension plans. The Company expects to contribute $21 million to the qualified pension plans during the year ending March 31, 2024.

Benefit payments to pension plan participants for the years ended March 31, 2023 and 2022 were approximately $594 million and $451 million, respectively.

In May 2022, the Company agreed to purchase a group annuity contract that transferred approximately $694 million of pension obligations and related plan assets to an insurance company. This transaction resulted in a settlement gain of approximately $66 million, which was deferred as a regulatory liability.

As described in Note 17, “Sale of Narragansett,” the Company sold a subsidiary, including pension and PBOP plans related to that business. This sale resulted in a curtailment and settlement loss of approximately $52 million as well as a net asset transfer charge of approximately $46 million within the Company’s employee benefit plans. Employee benefit plan balances related to the sold company were presented as asset held for sale as of March 31, 2022.

PBOP Plans

The PBOP plans provide health care and life insurance coverage to eligible retired employees. Eligibility is based on age and length of service requirements, and, in most cases, retirees must contribute to the cost of their coverage. During the years ended March 31, 2023 and 2022, the Company made contributions of $10 million and $0.5 million, respectively, to the PBOP plans. The Company expects to contribute $7 million to the PBOP plans during the year ending March 31, 2024.

Benefit payments to PBOP plan participants for the years ended March 31, 2023 and 2022 were approximately $185 million and $217 million, respectively.

Net Periodic Benefit Costs

The Company's net periodic benefit pension cost for the years ended March 31, 2023 and 2022 was $89 million and $141 million, respectively.

The Company's net periodic benefit PBOP benefit for the years ended March 31, 2023 and 2022 was $(116) million and $(66) million, respectively.

Amounts Recognized in AOCI and Regulatory Assets/Liabilities

The following tables summarize other pre-tax changes in plan assets and benefit obligations recognized primarily in regulatory assets/liabilities and AOCI for the years ended March 31, 2023 and 2022:

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2023	2022	**2023**	2022
		(in millions of dollars)		
Net actuarial loss (gain)	**$ 437**	$ (458)	**$ (82)**	$ (387)
Reversal of net actuarial gain (loss) from settlements	**(9)**	12	**23**	-
Reversal of net actuarial (loss) due to curtailment	**(40)**	-	**-**	-
Prior service cost	**9**	3	**-**	-
Amortization of net actuarial (loss) gain	**(43)**	(175)	**76**	59
Amortization of prior service cost, net	**(6)**	(6)	**-**	-
Total	**$ 348**	$ (624)	**$ 17**	$ (328)
Changes in regulatory assets (liabilities)	**$ 401**	$ (626)	**$ (7)**	$ (294)
Changes in AOCI	**(53)**	2	**24**	(34)
Total	**$ 348**	$ (624)	**$ 17**	$ (328)

The Company's regulated subsidiaries have regulatory recovery of these obligations and therefore amounts are included in regulatory assets/liabilities on the consolidated balance sheets. Costs of non-regulated subsidiaries are recorded as part of AOCI on the consolidated balance sheets.

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

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

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2023	2022	**2023**	2022
	(in millions of dollars)			
Net actuarial loss (gain)	**$ 426**	$ 81	**$ (967)**	$ (984)
Prior service cost	**34**	31	**-**	-
Total	**$ 460**	$ 112	**$ (967)**	$ (984)
Included in regulatory assets (liabilities)	**$ 406**	$ 5	**$ (842)**	$ (835)
Included in AOCI	**54**	107	**(125)**	(149)
Total	**$ 460**	$ 112	**$ (967)**	$ (984)

Amounts Recognized on the Consolidated Balance Sheets

The following table summarizes the portion of the funded status that is recognized on the Company's consolidated balance sheets at March 31, 2023 and 2022:

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2023	2022	**2023**	2022
	(in millions of dollars)			
Projected benefit obligation	**$ (7,013)**	$ (8,896)	**$ (3,129)**	$ (3,729)
Fair value of plan assets	**7,464**	9,572	**3,224**	3,791
Total	**$ 451**	$ 676	**$ 95**	$ 62
Non-current assets	**$ 739**	$ 914	**$ 524**	$ 630
Current liabilities	**(24)**	(24)	**(10)**	(12)
Non-current liabilities	**(264)**	(214)	**(419)**	(556)
Total	**$ 451**	$ 676	**$ 95**	$ 62

The benefit obligation shown above is the projected benefit obligation for the Pension Plans and the accumulated projected benefit obligation ("APBO") for the PBOP Plans. The Pension Plans had APBO balances that did not exceed the fair value of plan assets as of March 31, 2023 and 2022. The aggregate APBO balance for the Pension Plans was $6.8 billion and $8.5 billion as of March 31, 2023 and 2022, respectively.

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.

For the year end 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 less than expected.

Expected Benefit Payments

Based on current assumptions, the Company expects to make the following benefit payments subsequent to March 31, 2023:

(in millions of dollars) **Years Ended March 31,**	**Pension Plans**	**PBOP Plans**
2024	$ 434	$ 174
2025	430	178
2026	427	182
2027	424	185
2028	420	187
2029-2033	1,988	963
Total	$ 4,123	$ 1,869

Assumptions Used for Employee Benefits Accounting

	Pension Plans		**PBOP Plans**	
	Years Ended March 31,		**Years Ended March 31,**	
	2023	2022	**2023**	2022
Benefit Obligations:				
Discount rate	**4.85%**	3.65%	**4.85%**	3.65%
Rate of compensation increase (non-union)	**4.30%**	4.30%	**N/A**	N/A
Rate of compensation increase (union)	**4.70%**	4.80%	**N/A**	N/A
Weighted-average interest crediting rate for cash balanced plans	**5.00%**	3.00%	**N/A**	N/A
Net Periodic Benefit Costs:				
Discount rate	**3.65% - 5.05%**	2.95% - 3.25%	**3.65% - 4.30%**	3.25%
Rate of compensation increase (non-union)	**4.30%**	4.10%	**N/A**	N/A
Rate of compensation increase (union)	**4.25%**	4.50%	**N/A**	N/A
Expected return on plan assets	**4.25% - 5.75%**	4.00% - 5.50%	**5.00% - 6.00%**	5.00% - 5.50%
Weighted-average interest crediting rate for cash balanced plans	**3.00%**	2.90%	**N/A**	N/A

Discount rates used for remeasuring the annual pension expense and obligation for the sale of Narragansett and the purchase of the group annuity contract were 4.30% and for the payouts of lump sums in excess of the threshold as prescribed in ASC715 was 5.05%.

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 small premium is added for active management of both equity and fixed income securities. The rates of return for each asset class are then weighted in accordance with the actual asset allocation, resulting in a long-term return on asset rate for each plan.

Assumed Health Cost Trend Rate

	Years Ended March 31,	
	2023	2022
Health care cost trend rate assumed for next year		
Pre 65	**6.40%**	6.60%
Post 65	**5.20%**	5.00%
Prescription	**7.10%**	7.40%
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	**2031+**	2031+

Plan Assets

The Pension Plan is a trusted 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 the Company. Life insurance and medical benefits are provided for eligible retirees, dependents, and surviving spouses of the Company.

The Company 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, to 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 contribution and expense 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 its funds across asset classes, investment styles and fund managers. An asset/liability analysis typically is conducted periodically to determine whether the current strategic asset allocation continues to represent the appropriate balance of expected risk and reward for the plan to meet expected liabilities. Each study considers the investment risk of the asset allocation and determines the optimal mix of assets for the plan. The target asset allocation for fiscal year-end 2023 reflects the results of such a pension asset/liability analysis conducted and implemented in fiscal year 2023. As a result of that asset liability analysis, the asset mix for the National Grid Pension Plan and Niagara Mohawk Pension Plan were changed to further reduce investment risk given the increased funded status of the plans and to better hedge the respective plan liabilities. The Union PBOP Plan asset liability study was conducted in 2023. As a result of that study the RPC approved changes to the Union PBOP asset allocation effective in fiscal year 2023. The Non-Union PBOP Plan asset liability study is expected to be run within the next 6-12 months.

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, 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, 2023 and 2022 are as follows:

	National Grid Pension Plans		**Union PBOP Plans**		**Non-Union PBOP Plans**	
	March 31,		**March 31,**		**March 31,**	
	2023	2022	**2023**	2022	**2023**	2022
Equity	**22%**	25%	**15%**	39%	**70%**	70%
Diversified alternatives	**7%**	7%	**5%**	11%	**0%**	0%
Fixed income securities	**61%**	59%	**80%**	50%	**30%**	30%
Private equity	**5%**	4%	**0%**	0%	**0%**	0%
Real estate	**3%**	3%	**0%**	0%	**0%**	0%
Infrastructure	**2%**	2%	**0%**	0%	**0%**	0%
	100%	100%	**100%**	100%	**100%**	100%

Fair Value Measurements

The following tables provide the fair value measurement amounts for the pension and PBOP assets:

	March 31, 2023				
	Level 1	Level 2	Level 3	Not categorized	Total
			(in millions of dollars)		
Pension assets:					
Investments					
Equity	$ 191	$ -	$ -	$ 886	$ 1,077
Diversified alternatives	105	-	-	351	456
Corporate bonds	-	2,703	-	605	3,308
Government securities	10	633	-	629	1,272
Private equity	-	-	-	772	772
Real estate	-	-	-	369	369
Infrastructure	-	-	-	326	326
Total assets	$ 306	$ 3,336	$ -	$ 3,938	$ 7,580
Pending Transactions					(116)
Total net assets					$ 7,464
PBOP assets:					
Investments					
Equity	$ 90	$ -	$ -	$ 630	$ 720
Diversified alternatives	124	-	-	12	136
Corporate bonds	-	1,650	-	-	1,650
Government securities	75	429	-	1	505
Private Equity	-	-	-	-	-
Insurance contracts	-	-	-	181	181
Total assets	$ 289	$ 2,079	$ -	$ 824	$ 3,192
Pending Transactions					32
Total net assets					$ 3,224

	March 31, 2022				
	Level 1	Level 2	Level 3	Not categorized	Total
			(in millions of dollars)		
Pension assets:					
Investments					
Equity	$ 422	$ -	$ -	$ 1,854	$ 2,276
Diversified alternatives	211	-	-	483	694
Corporate bonds	-	3,118	-	852	3,970
Government securities	(13)	1,096	-	947	2,030
Private equity	-	-	-	888	888
Real estate	-	-	-	387	387
Infrastructure	-	-	-	238	238
Total assets	$ 620	$ 4,214	$ -	$ 5,649	$ 10,483
Assets held for sale					(633)
Pending Transactions					(278)
Total net assets					$ 9,572
PBOP assets:					
Investments					
Equity	$ 253	$ -	$ -	$ 1,396	$ 1,649
Diversified alternatives	197	-	-	165	362
Corporate bonds	-	999	-	-	999
Government securities	360	344	-	1	705
Private Equity	-	-	-	-	-
Insurance contracts	-	-	-	242	242
Total assets	$ 810	$ 1,343	$ -	$ 1,804	$ 3,957
Assets held for sale					(168)
Pending Transactions					2
Total net assets					$ 3,791

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 assets 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 includes 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 includes US agency and treasury securities, as well as state and local municipal bonds. The plans also include a small amount of Non-US government debt which is also captured here. US Government money market funds are also included. In addition, interest rate futures and swaps are held as a tool to manage interest rate risk.

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

Real estate: Real estate consists of limited partnership investments primarily in US 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.

Pending Transactions: Accounts receivable and accounts payable are short term cash transactions that are expected to settle within a few days of the measurement date.

Defined Contribution Plans

The Company has two defined contribution pension plans that cover substantially all employees. For the years ended March 31, 2023 and 2022, the Company recognized an expense in the accompanying consolidated statements of operations and comprehensive income of $92 million and $96 million, respectively.

10. CAPITALIZATION

Total capitalization for the Company at March 31, 2023 and 2022 is as follows:

			March 31,	
			2023	2022
			(in millions of dollars)	
Common shareholders' equity			**$ 19,497**	$ 18,248
Non-controlling interest			**62**	68
Long-term debt:	Interest Rate	Maturity Date		
Brooklyn Union Unsecured Notes:				
Senior Note	3.41%	March 10, 2026	**500**	500
Senior Note	3.87%	March 4, 2029	**550**	550
Senior Note	4.50%	March 10, 2046	**500**	500
Senior Note	4.27%	March 15, 2048	**650**	650
Senior Note	4.49%	March 4, 2049	**450**	450
Senior Note	4.63%	August 5, 2027	**400**	-
Senior Note	4.87%	August 5, 2023	**400**	-
Brooklyn Union Notes			**3,450**	2,650
KeySpan Gas East Unsecured Notes:				
Senior Note	5.82%	April 1, 2041	**500**	500
Senior Note	2.74%	August 15, 2026	**700**	700
Senior Note	3.59%	January 18, 2052	**400**	400
Senior Note	5.99%	March 6, 2033	**500**	-
KeySpan Gas East Notes			**2,100**	1,600
Boston Gas Unsecured Notes:				
Senior Note	3.15%	August 1, 2027	**500**	500
Senior Note	3.13%	October 5, 2027	**150**	150
Senior Note	3.00%	August 1, 2029	**500**	500
Senior Note	3.76%	March 16, 2032	**400**	400
Senior Note	4.49%	February 15, 2042	**500**	500
Senior Note	4.63%	March 15, 2042	**25**	25
Boston Gas Medium-Term Notes:				
MTN Series 1992 A	8.33%	July 5, 2022	**-**	10
MTN Series 1995 C	6.95%	December 1, 2023	**10**	10
MTN Series 1994 B	6.98%	January 15, 2024	**6**	6
MTN Series 1995 C	6.95%	December 1, 2024	**5**	5
MTN Series 1995 C	7.25%	October 1, 2025	**20**	20
MTN Series 1995 C	7.25%	October 1, 2025	**5**	5
Boston Gas Notes			**2,121**	2,131

National Grid USA MTN	8.00%	November 15, 2030	**250**	250
National Grid USA Unsecured Notes:				
Senior Note	5.80%	April 1, 2035	**307**	307
Senior Note	5.88%	April 1, 2033	**150**	150
National Grid USA Notes			**707**	707
Niagara Mohawk Unsecured Notes:				
Senior Note	2.72%	November 28, 2022	**-**	300
Senior Note	3.51%	October 1, 2024	**500**	500
Senior Notes	4.28%	December 15, 2028	**500**	500
Senior Notes	1.96%	June 27, 2030	**600**	600
Senior Notes	2.76%	January 10, 2032	**400**	400
Senior Note	4.28%	October 1, 2034	**400**	400
Senior Note	4.12%	November 28, 2042	**400**	400
Senior Note	3.03%	June 27, 2050	**500**	500
Senior Note	5.78%	September 16, 2052	**500**	-
Niagara Mohawk Notes			**3,800**	3,600
Massachusetts Electric Unsecured Notes:				
Senior Note	1.73%	November 24, 2030	**500**	500
Senior Note	5.90%	November 15, 2039	**800**	800
Senior Note	4.00%	August 15, 2046	**500**	500
Massachusetts Electric Notes:			**1,800**	1,800
New England Power Unsecured Notes:				
Senior Notes	3.80%	December 5, 2047	**400**	400
Senior Notes	2.81%	October 6, 2050	**400**	400
Senior Notes	5.94%	November 25, 2052	**300**	-
New England Power Notes:			**1,100**	800
Total Notes Payable			**15,078**	13,288
Promissory Notes to NGNA	3.13%-3.25%	June 2027 - April 2028	**102**	120
First Mortgage Bonds	6.90% - 7.38%	October 2025 – April 2028	**50**	75
State Authority Financing Bonds	3.23% - 3.48%	December 2023 – July 2029	**424**	424
State Authority Financing Bonds	Variable	December 2027 – August 2042	**117**	223
Term Loans	Variable	December 2024	**200**	400
Total debt			**15,971**	14,530

Unamortized debt premium (discount)	**5**	(1)
Unamortized debt issuance costs	**(75)**	(61)
Current portion of long-term debt	**(104)**	(859)
Total long-term debt	**15,797**	13,609
Total debt classified as held-for-sale[1]	**-**	1,510
Total capitalization	**$ 35,356**	$ 33,435

[1] Related to Sale of Narragansett, see Note 17 "Sale of Narragansett".

The aggregate maturities of long-term debt for the years subsequent to March 31, 2023 are as follows:

(in millions of dollars) **March 31,**	**Maturities of Long-Term Debt**
2024	$ 104
2025	723
2026	648
2027	788
2028	1,186
Thereafter	12,522
Total	$ 15,971

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. The Company's subsidiaries also have restrictions on the payment of dividends which relate to their debt to equity ratios. As of March 31, 2023 and 2022, the Company was in compliance with all such covenants.

Significant Debt Facilities

Promissory Notes to NGNA

On November 20, 2015, Genco entered into multiple intercompany loans with NGNA totaling $227 million, composed of a $165 million intercompany loan with an interest rate of 3.25% due to mature on April 30, 2028 and a $62 million intercompany loan with an interest rate of 3.13% due to mature on June 1, 2027. The intercompany loans have an annual sinking fund requirement totaling $18 million. Genco had outstanding debt of $102 million and $120 million as of March 31, 2023 and 2022, respectively, of which $18 million is included in current portion of long-term debt on the consolidated balance sheets as of March 31, 2023 and 2022. Please refer to Note 15, "Related Party Transactions" for intercompany related disclosures.

First Mortgage Bonds ("FMB")

The assets of Boston Gas are subject to liens and other charges and are provided as collateral over borrowings of non-callable FMB of $50 million at March 31, 2023. These FMB indentures include, among other provisions, limitations on the issuance of long-term debt.

State Authority Financing Bonds

At March 31, 2023, the Company had outstanding $541 million of State Authority Financing Bonds, of which $490 million were issued through the New York State Energy Research and Development Authority ("NYSERDA") and the remaining $51 million were issued through various other state agencies, for the subsidiaries listed below.

Niagara Mohawk had outstanding $424 million of tax-exempt revenue bonds issued by the NYSERDA in a fixed rate interest mode ranging from 3.23% to 3.48%.

Genco had $41 million of 1999 Series A Pollution Control Revenue Bonds due October 1, 2028. The interest rate on the various variable rate series ranged from 0.38% to 4.75% during the year ended March 31, 2023 and 0.04% to 2.55% during the year ended March 31, 2022. Genco also has outstanding $25 million of variable rate 1997 Series A Electric Facilities Revenue Bonds due December 1, 2027 issued through NYSERDA. The interest rate on the various variable rate series ranged from 0.55% to 4.75% during the year ended March 31, 2023 and 0.06% to 0.65% during the year ended March 31, 2022.

Nantucket had $51 million of Electric Revenue Bonds in tax exempt commercial paper mode, with maturity dates ranging from March 2039 to August 2042. The Electric Revenue Bonds were issued by the Massachusetts Development Finance Agency in connection with Nantucket's financing of its first and second underground and submarine cable projects.

Term Loans

On September 28, 2021, the Brooklyn Union Gas Company entered into a $400 million term loan with a maturity date of December 28, 2022. The interest rate was based on the daily compounded SOFR finalized at the end of the term plus a credit spread. On August 11, 2022, the term loan was fully repaid.

On December 1, 2022, the Boston Gas Company entered into a $200 million term loan. The term loan has a maturity date of December 1, 2023 and includes an option to extend by an additional thirteen months, which management intends to exercise. The interest rate is based on the daily compounded SOFR that will be finalized at the end of the term plus a credit spread.

Standby Bond Purchase Agreement

Nantucket has a Standby Bond Purchase Agreement, which expires on May 31, 2028. This agreement provides liquidity support for the $51 million long-term bonds in tax-exempt commercial paper mode, as noted under the *State Authority Financing Bonds* section above. The Company has classified the debt as long-term due to its intent and ability to refinance the debt on a long-term basis in the event of a failure to remarket the bonds.

Committed Facility Agreements

At March 31, 2023, the Company, NGNA, and the Parent had committed revolving credit facilities of $3.7 billion, of which $2.4 billion was due to mature in May 2024, $1.1 billion matures in June 2024, $0.2 billion matures in June 2025. These facilities have not been drawn against. The Company, NGNA, and the Parent can all draw on these facilities in a variety of currencies as needed, but the aggregate borrowings across the group cannot exceed the $3.7 billion limit. The terms of the facilities restrict the borrowing of all U.S. subsidiaries of the Company to $25 billion excluding intercompany indebtedness. Additionally, these facilities have a number of non-financial covenants which the Company is obliged to meet. At March 31, 2023 and 2022, the Company, NGNA, and the Parent were in compliance with all covenants. On April 3, 2023, new facilities were agreed to with a three-year term and two one-year options to extend, which provides the Company, NGNA and the Parent with approximately $6.7 billion in credit.

Commercial Paper and Revolving Credit Agreements

At March 31, 2023, the Company had two commercial paper programs approximately totaling $8.3 billion; a $4 billion U.S. commercial paper program and a €4 billion Euro commercial paper program. In support of these programs, the Company was a named borrower under the Parent's credit facilities with $3.7 billion available to the Company. These facilities support both the Parent's and the Company's commercial paper programs for ongoing working capital needs. At March 31, 2023, there were $61 million of borrowings outstanding on the U.S. commercial paper program and $596 million outstanding on the Euro commercial paper program. At March 31, 2022, there were $637 million of borrowing outstanding on the U.S. commercial paper and zero outstanding on the Euro commercial paper program.

The credit facilities allow both the Parent and the Company to borrow in multi-currencies. The current annual commitment fees range from 0.09% to 0.34%. If for any reason the Company was not able to issue sufficient commercial paper or source funds from other sources, the facilities could be drawn upon to meet cash requirements. The facilities contain certain affirmative and negative operating covenants, including restrictions on the Company's utility subsidiaries' ability to mortgage, pledge, encumber, or otherwise subject their utility property to any lien, as well as financial covenants that require the Company and the Parent to limit the total indebtedness in U.S. and non-U.S. subsidiaries to pre-defined limits. Violation of these covenants could result in the termination of the facilities and the required repayment of amounts borrowed thereunder, as well as possible cross defaults under other debt agreements.

Debt Authorizations

Niagara Mohawk

Niagara Mohawk has regulatory approval from the FERC to issue up to $1.0 billion of short-term debt. The authorization was renewed with an effective date of October 15, 2022 and expires on October 14, 2024. Niagara Mohawk had no external short-term debt as of March 31, 2023 and 2022.

On September 13, 2021 the NYPSC authorized Niagara Mohawk to issue up to $2.3 billion of long-term debt in one or more transactions through June 30, 2024. Under the authorization, Niagara Mohawk issued a $400 million senior unsecured long-term debt at a fixed rate of 2.76% on January 10, 2022 with a maturity date of January 10, 2032. On September 16, 2022, the Company issued $500 million 30-year unsecured long-term debt with a fixed rate of 5.78% with a maturity date of September 16, 2052.

Brooklyn Union

On February 8, 2019 the NYPSC authorized Brooklyn Union to issue up to $1.4 billion of long-term debt in one or more transactions through March 31, 2022. Under the authorization, on February 27, 2019, Brooklyn Union issued $550 million of unsecured senior long-term debt at a fixed rate of 3.87% with a maturity date of March 4, 2029 and $450 million of unsecured senior long-term debt at a fixed rate of 4.49% with a maturity date of March 4, 2049. With the remaining authorization, Brooklyn Union entered into a $400 million bank term loan at a variable rate with a maturity of December 28, 2022, which has been fully repaid.

On June 17, 2022, the NYPSC authorized Brooklyn Union to issue up to $1.8 billion of new long-term debt securities, requesting that the authorization be valid for a period beginning on the effective date of the commission's order and ending on March 31, 2025. Under this authorization, on August 5, 2022, the Company issued $400 million 10-year and $400 million 5-year unsecured long-term debt with fixed rates of 4.87% and 4.63%, respectively.

KeySpan Gas East

On February 8, 2019 the NYPSC authorized KeySpan Gas East to issue up to $400 million of long-term debt in one or more transactions through March 31, 2022. Under the authorization, KeySpan Gas East issued a $400 million senior unsecured long-term debt at a fixed rate of 3.59% on January 18, 2022 with a maturity date of January 18, 2052.

On June 17, 2022, the NYPSC authorized KeySpan Gas East to issue up to $890 million of new long-term debt securities, requesting that the authorization be valid for a period beginning on the effective date of the commission's order and ending on March 31, 2025. Under the authorization, on March 6, 2023, the Company issued $500 million 10-year unsecured long-term debt with a fixed rate of 5.99%.

Boston Gas

On November 24, 2021 the DPU authorized Boston Gas to issue up to $1.5 billion of long-term debt in one or more transactions through November 24, 2024. Under the authorization, Boston Gas issued a $400 million senior unsecured long-term debt at a fixed rate of 3.76% on March 16, 2022 with a maturity date of March 16, 2032.

In October 2022, the Company injected $90 million in equity to Boston Gas.

Massachusetts Electric

Massachusetts Electric has regulatory approval from the FERC to issue up to $750 million of short-term debt. The authorization was renewed with an effective date of October 15, 2022 and expires on October 14, 2024. Massachusetts Electric had no external short-term debt as of March 31, 2023 and 2022.

On August 31, 2020, Massachusetts Electric received approval from the DPU to issue up to $1.1 billion of long-term debt in one or more transactions through August 31, 2023. In November 2020, Massachusetts Electric issued $500 million of unsecured long-term debt at 1.73% with a maturity date of November 24, 2030, resulting in $600 million of remaining authorization.

NEP

NEP has regulatory approval from the FERC to issue up to $1.5 billion of short-term debt. The authorization was renewed with an effective date of October 15, 2022 and expires on October 14, 2024. NEP had no short-term debt outstanding as of March 31, 2023 and 2022.

On May 23, 2017, the Company had received all required approvals from the Massachusetts Department of Public Utilities, New Hampshire Public Utilities Commission and Vermont Public Service Board authorizing the Company to issue up to $800 million of long-term debt in one or more transactions through May 23, 2020. On November 30, 2017, the Company issued $400 million of unsecured senior long-term debt with a maturity date of December 5, 2047.

On August 31, 2020, the Company received additional approvals from the Massachusetts Department of Public Utilities, New Hampshire Public Utilities Commission and Vermont Public Service Board authorizing the Company to issue up to $1.1 billion of long-term debt in one or more transactions through August 31, 2023. On October 6, 2020, the Company issued $400 million of unsecured senior long-term debt with a maturity date of October 6, 2050. On November 25, 2022, the company issued $300 million of unsecured senior long-term debt with a maturity date of November 25, 2052, resulting in $400 million of remaining authorization.

Genco

Genco has regulatory approval from the FERC to issue up to $250 million of short-term debt. The authorization was renewed with an effective date of October 15, 2022 and expires on October 14, 2024. Genco had no short-term debt outstanding to third-parties as of March 31, 2023 or 2022.

Nantucket

Nantucket has regulatory approval from the FERC to issue up to $15 million of short-term debt. The authorization was renewed with an effective date of October 15, 2022 and expires on October 14, 2024. Nantucket had no external short-term debt as of March 31, 2023 and 2022.

11. INCOME TAXES

Components of Income Tax Expense

	Years Ended March 31,	
	2023	2022
	(in millions of dollars)	
Current tax expense (benefit):		
Federal	**$ 193**	$ 16
State	**42**	(26)
Total current tax expense (benefit)	**235**	(10)
Deferred tax expense:		
Federal	**243**	61
State	**187**	222
Total deferred tax expense	**430**	283
Amortized investment tax credits [1]	**(3)**	(2)
Total deferred tax expense	**427**	281
Total income tax expense	**$ 662**	$ 271

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

Statutory Rate Reconciliation

The Company's effective tax rates for the years ended March 31, 2023 and 2022 are 27.1% and 18.7%, respectively. The following table presents a reconciliation of income tax expense (benefit) at the federal statutory tax rate of 21% to the actual tax expense:

	Years Ended March 31,	
	2023	2022
	(in millions of dollars)	
Computed tax	**$ 513**	$ 304
Change in computed taxes resulting from:		
State income tax, net of federal benefit	**172**	79
State apportionment reset – Narragansett sale, net of federal benefit	**9**	76
Goodwill – Narragansett Sale	**114**	-
Amortization of regulatory tax liability, net	**(137)**	(158)
R&D Credit, net of reserves	**(12)**	(31)
Other	**3**	1
Total changes	**149**	(33)
Total income tax expense	**$ 662**	$ 271

The Company is included in the NGNA and subsidiaries consolidated federal income tax return and Massachusetts and New York unitary state income tax returns. 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% corporate alternative minimum tax ("CAMT") on the "adjusted financial statement income" of certain large corporations for tax years beginning after December 31, 2022. The Company expects to be subject to the new CAMT on its federal income tax return for the tax year ending March 31, 2024. While under Accounting Standard Codification ("ASC") 740, "Income Taxes", changes in income tax rates and law are accounted for in the period of enactment, the accounting implications of the CAMT provision in the IRA are only expected to impact its financial statements prospectively.

Since the enactment of the IRA, the U.S. Treasury issued various Notices that provide interim guidance on several provisions of the IRA, including the CAMT. The Notices state that the U.S. Treasury anticipates issuing additional guidance including proposed and final regulations. Many aspects of the IRA remain unclear and in need of further guidance; therefore, the impact the IRA will have on the Company's financial statements is subject to continued evaluation.

Deferred Tax Components

	March 31,	
	2023	2022
	(in millions of dollars)	
Deferred tax assets:		
Allowance for doubtful accounts	**$ 170**	$ 247
Environmental remediation costs	**700**	696
Net operating losses	**14**	457
Postretirement benefits	**214**	228
Regulatory liabilities	**1,594**	1,691
Reserves not currently deducted	**260**	224
Other items, net	**511**	428
Total deferred tax assets	**3,463**	3,971
Deferred tax liabilities:		
Property related differences	**6,611**	6,591
Regulatory assets	**1,592**	1,276
Other items	**389**	606
Total deferred tax liabilities	**8,592**	8,473
Net deferred income tax liabilities	**5,129**	4,502
Deferred investment tax credits	**43**	45
Deferred income tax liabilities, net	**$ 5,172**	$ 4,547

The deferred tax assets associated with the tax credit carryforward are presented net with the deferred tax liability in the Company's consolidated balance sheets.

Net Operating Losses

The amounts and expiration dates of the Company's net operating losses carryforward as of March 31, 2023 are as follows:

	Gross Carryforward Amount *(in millions of dollars)*		Expiration Period
Federal	$ 27		2038
Federal – No Expiration	180		Indefinite
New York	1,146	(1)	2035 - 2042
New York City	370	(1)	2035 - 2042

[(1)] The amount contains net operating losses that were incurred before the tax year ended March 31, 2015 that have been converted into a Prior Net Operating Loss Conversion subtraction that can be utilized beginning fiscal year 2017.

As a result of the accounting for uncertain tax positions, the amount of deferred tax assets reflected in the consolidated 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.

Tax Years Subject to Examination

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

Jurisdiction	Tax Years
Federal	March 31, 2020
Massachusetts	March 31, 2013
New York	March 31, 2010
New York City	March 31, 2010

In May 2022, the Company reached an audit settlement agreement with the IRS for the years ended March 31, 2018 and March 31, 2019. The outcome of the settlement did not have a material impact on the Company's results of operations, financial position, or cash flows.

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 (deductions), net, in the accompanying consolidated statements of operations and comprehensive income. As of March 31, 2023 and 2022, the Company has accrued for interest related to unrecognized tax benefits of $23 million and $18 million, respectively. During the years ended March 31, 2023 and 2022, the Company recorded interest income of $5 million and $30 million, respectively. No tax penalties were recognized during the years ended March 31, 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 other additional increases or decreases would be material to its results of operations, financial position, or cash flows.

12. 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.

Air

Genco's generating facilities are subject to increasingly stringent emissions limitations under current and anticipated future requirements of the EPA and the DEC. In addition to efforts to improve both ozone and particulate matter air quality, there has been an increased focus on greenhouse gas emissions in recent years. Genco's previous investments in low NOx boiler combustion modifications, the use of natural gas firing systems at its steam electric generating stations, and the compliance flexibility available under cap-and-trade programs have enabled Genco to achieve its prior emission reductions in a cost-effective manner. These investments include the installation of enhanced NOx controls and efficiency improvement projects at certain of Genco's Long Island based electric generating facilities. The total cost of these improvements was approximately $106 million, all of which have been placed in service as of the date of this report; a mechanism for recovery from LIPA of these investments has been established. An additional NOx reduction system installation has been completed at the Glenwood Unit 2 gas turbine system, and is ongoing at E.F. Barrett and East Hampton gas turbine units. A mechanism for recovery from LIPA of these investments has been established. Genco will continue to make investments for additional emissions reductions, as needed. Genco has developed a compliance strategy to address anticipated future requirements and is closely monitoring the regulatory developments to identify any necessary changes to its compliance strategy. At this time, Genco is unable to predict what effect, if any, these future requirements will have on its financial position, results of operations, and cash flows.

Water

Additional capital expenditures associated with the renewal of the surface water discharge permits for Genco's steam electric power plants have been required by the DEC pursuant to Section 316 of the Clean Water Act to mitigate the plants' alleged cooling water system impacts to aquatic organisms. Final permits have been issued for Port Jefferson and Northport. Capital improvements have been completed at Port Jefferson and are in the design, procurement, and construction phase for Northport. Genco continues to engage in discussions with the DEC regarding the nature of capital upgrades or other mitigation measures necessary to reduce any impacts at E.F. Barrett. Genco is awaiting a final permit from the DEC to proceed with the improvements at E.F. Barrett. Total capital costs for these improvements at Northport and E.F. Barrett are estimated to be approximately $79 million costs associated with these capital improvements are reimbursable from LIPA under the A&R PSA.

Land, Manufactured Gas Plants and Related Facilities

Federal and state environmental regulators, as well as private parties, have alleged that several of the Company's subsidiaries are potentially responsible parties under Superfund laws for the remediation of numerous contaminated sites in New York and New England. The Company's greatest potential Superfund liabilities relate to MGP facilities formerly owned or operated by its subsidiaries or their predecessors. MGP byproducts include fuel oils, hydrocarbons, coal tar, purifier waste, and other waste products which may pose a risk to human health and the environment.

Several lawsuits have been filed which allege damages resulting from contamination associated with the historic operations of a former MGP located in Bay Shore, New York. The Company has been conducting remediation at this location pursuant to Administrative Order on Consent with the DEC. The Company intends to contest these proceedings vigorously.

At March 31, 2023 and 2022, the Company's total reserve for estimated MGP-related environmental matters is $2.5 billion and $2.4 billion, respectively. The Company had a current portion of environmental remediation costs of $168 million and $172 million included in other current liabilities on the consolidated balance sheets at March 31, 2023 and 2022, respectively. Management believes that obligations imposed on the Company because of the environmental laws will not have a material adverse effect on its operations, financial position, or cash flows. Through various rate orders issued by the NYPSC and the DPU, costs related to MGP environmental cleanup activities are recovered in rates charged to gas distribution customers. Accordingly, the Company has reflected a net regulatory asset of $2.5 billion and $2.3 billion on the consolidated balance sheets at March 31, 2023 and 2022, respectively. Expenditures incurred for the years ended March 31, 2023 and 2022 were approximately $110 million and $119 million, respectively. The Company is pursuing claims against other potentially responsible parties to recover investigation and remediation costs it believes are the obligations of those parties. The Company cannot predict the likelihood of success of such claims.

The Company believes that its ongoing operations, and its approach to addressing conditions at historic sites, are in substantial compliance with all applicable environmental laws, and that the obligations imposed on it because of the environmental laws will not have a material impact on its results of operations or financial position since, as noted above, environmental expenditures incurred by the Company are generally recoverable from customers.

The Company is pursuing environmental insurance recoveries in connection with several legal proceedings that are ongoing between the Company and insurance companies who have provided historic coverage over environmentally impacted sites. Following any favorable resolution of these claims, the Company is expected to return insurance recoveries to customers through the Company's regulatory mechanisms. However, legal proceedings in each case still have a number of stages to complete, any of which could modify the amount of any eventual claim. As such it is not currently practicable to provide a reliable estimate of the amount of likely eventual recoveries.

13. COMMITMENTS AND CONTINGENCIES

Purchase Commitments

The Company's electric subsidiaries have several long-term contracts for the purchase of electric power. Substantially all of these contracts require power to be delivered before the subsidiaries are obligated to make payment. Additionally, the Company's gas distribution subsidiaries have 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's gas distribution subsidiaries are 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 and intangible assets.

The Company's commitments under these long-term contracts for the years subsequent to March 31, 2023 are summarized in the table below:

(in millions of dollars) Years Ending March 31,	**Energy Purchases**	**Capital Commitments**
2024	$ 1,707	$ 225
2025	1,098	99
2026	907	42
2027	719	14
2028	616	-
Thereafter	2,331	-
Total	$ 7,378	$ 380

Not included in the above are committed solar and wind contracts for which the payments are unknown at this time. In addition, any costs incurred by the Company will be recoverable.

Long-term Contracts for Renewable Energy

Offshore Wind Energy Procurement

On July 31, 2018, the Massachusetts Electric Companies entered into two separate 20-year PPAs with Vineyard Wind LLC ("Vineyard Wind") for the purchase of 46.16% of the electricity and renewable energy credits generated by two offshore wind farms proposed by Vineyard Wind, with each individual windfarm having a capacity of up to 400 MW. The contracts with Vineyard Wind were entered into pursuant to Section 83C of the Green Communities Act. On April 12, 2019, the DPU approved the contracts, and the Massachusetts Electric Companies will be able to recover the costs incurred under the agreements, including 2.75% remuneration on the annual payments made. Based on the terms of the contracts, the commercial operations date for the first wind farm was initially expected to be in January 2022, with the second wind farm anticipated in May 2022. On October 21, 2021, the DPU approved two amendments to the PPAs for both wind farms, which extend the critical milestone dates by twenty-four months, including the commercial operations dates. The new guaranteed commercial operations dates are January 15, 2024 for the first wind farm and May 31, 2024 for the second wind farm.

Offshore Wind Energy Procurement: Round 2

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

Offshore Wind Energy Procurement: Round 3

On April 8, 2022, the Massachusetts Electric Companies entered into a 20-year PPA with Commonwealth Wind LLC ("Commonwealth Wind") for the purchase of 43.87% of the electricity and renewable energy credits generated by a proposed offshore wind farm with a nameplate capacity of 1,232 MWs. On April 15, 2022, the Massachusetts Electric Companies entered into a 20-year PPA with Mayflower Wind for the purchase of 38.003% of the electricity and renewable energy credits generated by a proposed offshore wind farm with a nameplate capacity of 480 MWs. Both PPAs were filed with the DPU for its review and approval on May 25, 2022. These contracts were entered into pursuant to Section 83C of the Green Communities Act. The Commonwealth Wind project has a commercial operations date of November 2027, and the Mayflower Wind project has a commercial operations date of March 2028.

On October 20, 2022, Avangrid, the developer of the Commonwealth Wind project, requested a one-month delay in the DPU's review of the Commonwealth Wind contract to allow time for Avangrid to renegotiate the contracted electricity price. Avangrid cited the war in Ukraine, inflation, supply chain issues, and rising interest rates as factors in its decision to request what it describes as a modest increase in price. Mayflower Wind supported Avangrid's motion for a delay and indicated that it wanted to renegotiate its own contracted electricity price. On November 4, 2022, the DPU issued an order rejecting Avangrid's request for a delay. On November 7, 2022, Mayflower Wind filed a response to the DPU it which it withdrew its support for Avangrid's motion to delay the proceedings and stated that it intends to move forward with the existing PPAs. On November 14, 2022, Avangrid filed its response to the DPU order, stating that "absent the relief that Commonwealth

Wind has previously requested, the Department should not dismiss the [contract review] proceedings." On December 30, 2022, the DPU issued an order approving both proposed contracts. On January 19th, 2023, Commonwealth wind filed a Petition to Appeal. Also on January 19th, 2023, Mayflower Wind filed a motion petitioning for full participant status in the proceeding, and a request for an extension of the appeal period. On March 14, 2023, the DPU issued an order denying both requests.

Clean Energy Procurement

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

Financial Guarantees

The Company has guaranteed the principal and interest payments on certain outstanding debt of its subsidiaries. Additionally, the Company has issued financial guarantees in the normal course of business, on behalf of its subsidiaries, to various third-party creditors. At March 31, 2023, the following amounts would have to be paid by the Company in the event of non-payment by the primary obligor at the time payment is due:

Guarantees for Subsidiaries:		Amount of Exposure		Expiration Dates
		(in millions of dollars)		
KeySpan Ravenswood LLC Lease	(i)	$	185	May 2040
Surety Bonds	(ii)		201	Revolving
Commodity Guarantees and Other	(iii)		103	August 2025 - August 2042
Letters of Credit	(iv)		177	November 2022 – December 2024
Environmental Remediation Trust	(v)		81	2037
		$	747	

The following is a description of the Company's outstanding subsidiary guarantees:

(i) The Company and the Parent have jointly guaranteed certain payment obligations of a former subsidiary (KeySpan Ravenswood LLC) associated with a merchant electric generating facility leased by that subsidiary under a sale/leaseback arrangement. The subsidiary and the facility were sold in 2008. However, the original lease remains in place and the Company and the Parent will continue to make the required payments under the lease through 2040. The cash consideration from the buyer of the facility included the remaining lease payments on a net present value basis. At March 31, 2023, the Company's obligation related to the lease is $35 million and is reflected in other non-current liabilities on the consolidated balance sheets. In the event the Company and the Parent default on the lease payment obligations, and that causes the buyer to lose beneficial use of the leased facility, the buyer is entitled to the unamortized value of the leased facility purchase price. At March 31, 2023, the unamortized value of the leased facility purchase price is $185 million.

(ii) The Company has agreed to indemnify the issuers of various surety bonds associated with various construction requirements or projects of its subsidiaries. In the event that the Company or its subsidiaries fail to perform their obligations under contracts, the injured party may demand that the surety make payments or provide services under the bond. The Company would then be obligated to reimburse the surety for any expenses or cash outlays it incurs.

(iii) The Company has guaranteed commodity-related and operational payments for certain subsidiaries. These guarantees are provided to third-parties to facilitate physical and financial transactions supporting the purchase and transportation of natural gas, oil, and other petroleum products for gas and electric production and financing activities. The guarantees cover actual transactions by these subsidiaries that are still outstanding as of March 31, 2023.

(iv) The Company has arranged for stand-by letters of credit to be issued to third-parties that have extended credit to certain subsidiaries. Certain vendors require the posting of letters of credit to guarantee subsidiary performance under the Company's contracts and to ensure payment to the Company's subsidiary subcontractors and vendors under those contracts. Certain of the Company's vendors also require letters of credit to ensure reimbursement for amounts they are disbursing on behalf of the Company's subsidiaries, such as to beneficiaries under the Company's self-funded insurance programs. Such letters of credit are generally issued by a bank or similar financial institution. The letters of credit commit the issuer to pay specified amounts to the holder of the letter of credit if the holder demonstrates that the Company has failed to perform specified actions. If this were to occur, the Company would be required to reimburse the issuer of the letter of credit.

(v) Brooklyn Union Gas Company is a guarantor of a lease agreement as part of its participation in a grantor trust established to manage and administer funds contributed towards cleanup efforts for environmental remediation. The trust maintains all obligations for the payment of rent, insurance and property taxes for the leased property. In the unlikely event that the trust was to default on required payments or be dissolved, KEDNY would become responsible for those lease obligations. Total lease obligations over the 15 year term are approximately $81 million.

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, NYPSC 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 NYPSC's investigation. At this time, it is not possible to predict the outcome of the regulatory investigations. However, 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 Investigation

National Grid is performing an internal investigation regarding certain conduct associated with energy efficiency programs at the Company's affiliates. At this time, it is not possible to predict the outcome of the investigation or determine the amount, if any, of any liabilities that may be incurred in connection with it by the Company or 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.

Nassau County Special District Tax Settlement

In August 2021, the KeySpan Gas East Corporation received approval from the Nassau County Legislature in Resolution No. 116-2021 whereby the County has agreed to make payment in the total amount of $62 million to be paid in four equal installments of $15.5 million commencing on December 30, 2021, with the final payment due no later than December 30, 2024, inclusive of principal and statutory interest in full settlement of all possible claims the KeySpan Gas East Corporation may have against the County on this matter. KeySpan Gas East Corporation recorded an undiscounted receivable for $62 million. The benefit was reported as a credit against other taxes of $33 million for the principal portion, Other income, net of $27 million for the interest portion, and Operations and maintenance for $2 million for the costs to achieve the settlement. As authorized in an order of the NYPSC approved in 2007, KeySpan Gas East Corporation is allowed to retain the full settlement related to this litigation for the benefit of shareholders.

Financial Guarantees

The Massachusetts Electric Company unconditionally guarantees the full and prompt payment of the principal, premium, if any, and interest on certain tax-exempt bonds issued by the Massachusetts Development Finance Agency in connection with Nantucket Electric's financing of its first and second underground and submarine cable projects. The Massachusetts Electric Company would be required to make any principal, interest, and premium payments if Nantucket Electric failed to pay. The carrying value of the debt guaranteed is approximately $51 million as of March 31, 2023, and the debt has maturities extending through 2042. This guarantee is absolute and unconditional. As of the date of this report, the Massachusetts Electric Company has not had a claim made against it for this guarantee and has no reason to believe that Nantucket Electric will default on its obligations.

FERC ROE Complaints

Four separate complaints have been filed at the FERC by combinations of New England state attorneys general, state regulatory commissions, consumer advocates, consumer groups, municipal parties and other parties (collectively the "Complainants"). In each of the first three complaints, filed on October 1, 2011, December 27, 2012, and July 31, 2014, respectively, the Complainants challenged the NETO, of which NEP is one, base ROE of 11.14% that had been utilized since 2005 and sought an order to reduce it prospectively from the date of the final FERC order and for the separate 15-month complaint periods. In the fourth complaint, filed April 29, 2016, the Complainants challenged the NETOs' base ROE of 10.57% and the maximum ROE for transmission incentive ("incentive cap") of 11.74%, asserting that these ROEs were unjust and unreasonable. NEP recorded a liability of $39 million and $34 million included in miscellaneous current and accrued liabilities on the consolidated balance sheets as of March 31, 2023 and 2022, respectively, for the potential refund as a result of reduction of the base ROE.

With the exception of the FERC order issued on October 16, 2018, where the FERC proposed a new framework to determine whether an existing ROE is unjust and unreasonable and, if so, how to calculate a replacement ROE, the FERC has not issued a final order on NEP's ROE complaints nor the applicability of the FERC orders on the MISO ROE complaint proceedings on other transmission owners.

Given the significant uncertainty relating to the October 2018 FERC order, and the subsequent orders issued on the MISO ROE complaint proceedings, NEP has concluded that there is no reasonable basis for a change to the reserve or recognized ROEs for any of the complaint periods at this time. Further, NEP believes that the current reserve is the best estimate of the potential loss.

FERC 206 Proceeding on Rate Transparency

On December 28, 2015, FERC initiated a proceeding under Section 206 of the Federal Power Act. It found that ISO-NE Transmission, Markets, and Services Tariff is unjust, unreasonable and unduly discriminatory or preferential. FERC found that ISO-NE's tariff lacks adequate transparency and challenge procedures with regard to the formula rates for ISO-NE Participating Transmission Owners ("PTOs"). In addition, the FERC found that the ISO-NE PTOs', including NEP's, current RNS and LNS formula rates appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful. FERC explained that the formula rates appear to lack sufficient detail to determine how certain costs are derived and recovered in the formula rates. Accordingly, FERC established hearing and settlement judge procedures. Several parties are active in the proceeding, including FERC employees, various interested consumer parties, the New England States Committee on Electricity (NESCOE), and several municipal light departments.

On June 15, 2020, the parties filed a revised settlement agreement with FERC that is supported and signed by all parties, including all six New England states and the parties who opposed the 2018 settlement. The revised settlement reflects a number of transparency-related changes as well as affirmations regarding rate treatment on specific items as requested by FERC trial staff and represented municipal PTF owners. On December 28, 2020, FERC approved the settlement without modification, which went into effect on January 1, 2022. Interim formula rate protocols went into effect on June 15, 2021 and terminate on June 14, 2023, at which point permanent protocols will go into effect. As part of the settlement approved by the FERC, the parties agreed to a moratorium which applies to Section 205 or Section 206 filings seeking to change Attachment F of the ISO-NE OATT, its appendices or the formula rate Protocols developed as part of the settlement, subject to certain exceptions, until December 31, 2024.

Electric Services and LIPA Agreements

Effective May 28, 2013 (and most recently amended on April 1, 2018), Genco provides services to LIPA under an amended and restated ("A&R") PSA. Under the A&R PSA, Genco has a return on equity of 9.75% and a capital structure of 50% debt and 50% equity. Genco's annual revenue requirement for the years ended March 31, 2023 and 2022 were $421 million and $466 million, respectively.

The A&R PSA has a term of fifteen years, provided LIPA has the option to terminate the agreement as early as April 2025 on two years advance notice. Genco accounts for the A&R PSA and PPAs as operating leases under ASC 842. In addition, LIPA has options to ramp down blocks of capacity on two years advance notice for steam generating units and one year advance notice for other generating units covered by the A&R PSA. Should any ramp downs be exercised, Genco is entitled to a ramp down payment equal to the net book value of the retired unit as defined in the A&R PSA plus operating and maintenance expenses for 18 months for steam generating units and 12 months for all generating units. The ramp down payment for a steam unit includes a discount factor. This discount factor ranges from 50% of the unit's net book value if retired with an effective date in 2022 up to 62.5% of the unit's net book value if retired with an effective date thereafter. The earliest ramp down effective date is May 1, 2025 for Barrett Units 1 and/or 2, and for Port Jefferson Units 3 and/or 4.

On April 18, 2022, Genco and LIPA signed a "Letter Agreement to Clarify and Settle Ramp Down Rights and Other Issues under the A&R PSA" ("Letter Agreement"), and on September 22, 2022, GENCO and LIPA signed a "Side Letter to Clarify Post Nassau Tax Settlement Administration of LIPA/National Grid Obligations" ("Side Letter"). In November 2022, GENCO submitted amendments to the A&R PSA to reflect the terms of the Letter Agreement and the Side Letter which were approved by the FERC on January 27, 2023, with an effective date of February 1, 2023. The Letter Agreement provided for further ramp down options, clarification on how a ramp down is calculated in regard to the capacity charge and notional tracking account of $68M, and confirmed recovery of $5 million of previously incurred costs, among other provisions. The Letter Agreement does not change the terms of the A&R PSA, except as explicitly discussed in the letter.

Following approval of the Side Letter, the base property tax amount for each year will be the prior year's actual property tax amount recorded on Genco's books, increased by 4%, and subject to further adjustments for any known and measurable changes for the current year. The capacity charge will be changed each year to reflect the new base year amount. Any differences between the base year property tax amount and the actual property tax amount recorded on Genco's books in each year will be deferred by Genco. The deferred amount, inclusive of the carrying charges, will be billed or credited to LIPA in the fourth month following the year being trued-up.

The A&R PSA provides potential penalties to Genco if it does not maintain the output capability of the generating facilities, as measured by annual industry-standard tests of operating capability, plant availability, and efficiency. These penalties may total $4 million annually. Although the A&R PSA provides LIPA with all the capacity from the generating facilities, LIPA has no obligation to purchase energy from the generating facilities and can purchase energy on a least-cost basis from all available sources consistent with existing transmission interconnection limitations of the transmission and distribution system. Genco must, therefore, operate its generating facilities in a manner such that Genco can remain competitive with other producers of energy. To date, Genco has dispatched to LIPA and LIPA has accepted the level of energy generated at the agreed to price per megawatt hour. Under the terms of the A&R PSA, LIPA is obligated to pay for capacity at rates that reflect recovery of an agreed level of the overall cost of maintaining and operating the generating facilities, including recovery of depreciation and return on its investment in plant. For the years ended March 31, 2023 and 2022, the revenue requirement, which is comprised of the capacity charge, are approximately 87.9% and 92.7% of total revenue and is adjusted each year using cost escalation and inflation factors applied to the prior year's capacity charge. A monthly variable maintenance charge is billed for each unit of energy acquired from the generating facilities. The billings to LIPA under the A&R PSA do not include a provision for fuel costs, as such fuel is owned by LIPA.

Nuclear Contingencies

As of March 31, 2023 and 2022, Niagara Mohawk had a liability of $183 million and $178 million, recorded in non-current liabilities on the consolidated balance sheets, for the disposal of nuclear fuel irradiated prior to 1983. The Nuclear Waste Policy Act of 1982 provides three payment options for liquidating such liability and Niagara Mohawk has elected to delay payment, with interest, until the year in which Constellation Energy Group Inc., which purchased Niagara Mohawk's nuclear assets, initially plans to ship irradiated fuel to an approved Department of Energy ("DOE") disposal facility.

The 2010 Federal budget (which became effective October 1, 2009) eliminated almost all funding for the creation of the Yucca Mountain repository. A Blue Ribbon Commission ("BRC") on America's Nuclear Future, appointed by the U.S. Energy Secretary, released a report on January 26, 2012, detailing comprehensive recommendations for creating a safe, long-term solution for managing and disposing of the nation's spent nuclear fuel and high-level radioactive waste.

In early 2013, the DOE issued an updated "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste" in response to the BRC recommendations. This strategy included a consolidated interim storage facility that was planned to be operational in 2025. However, due to continued delays on the part of the DOE, and the amount of time required for DOE to select a site location and develop the necessary infrastructure for long-term spent nuclear fuel storage, the Company cannot predict the date at which the DOE will begin accepting spent nuclear fuel.

In the Consolidated Appropriations Act, 2021, Congress appropriated funds to the Department for interim storage activities. Interim storage is an important component of a waste management system and will enable near-term consolidation and temporary storage of spent nuclear fuel. This will allow for removal of spent nuclear fuel from reactor sites, provide useful research opportunities, and build trust and confidence with stakeholders and the public by demonstrating a consent-based approach to siting.

DOE anticipates that an interim storage facility would need to operate until the fuel can be moved to final disposal. The duration of the interim period depends on the completion of a series of significant steps, such as the need to identify, license, and construct a facility, plus the time needed to move the spent nuclear fuel.

14. LEASES

The Company has various operating leases, primarily related to a transmission line, buildings, land, real estate, and fleet vehicles used to support the electric and gas operations, with lease terms ranging between 2 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 noncurrent operating lease liabilities on the consolidated balance sheets. As of March 31, 2023 and 2022, the Company does not have any finance leases.

Expense related to operating leases was $151 million and $153 million for the years ended March 31, 2023 and 2022, respectively.

As of March 31, 2023, 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:

	Years ended March 31, 2023	Years ended March 31, 2022
	(in millions of dollars)	
Cash paid for amounts included in lease liabilities		
Operating cash flows from operating leases	**$ 151**	$ 162
ROU assets obtained/(released) in exchange for operating lease liabilities	**$ 309**	$ (49)
Weighted-average remaining lease term – operating leases	**10 years**	9 years
Weighted-average discount rate – operating leases	**3.05%**	2.60%

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

	Operating Leases
Year Ending March 31,	*(in millions of dollars)*
2024	**$ 114**
2025	**98**
2026	**88**
2027	**79**
2028	**71**
Thereafter	**485**
Total future minimum lease payments	**935**
Less: imputed interest	**186**
Total	**$ 749**
Reported as of March 31, 2023:	
Current lease liability	**$ 94**
Non-current lease liability	**655**
Total	**$ 749**

Genco recognizes operating revenue related to the A&R PSA and PPAs whereby LIPA agrees to purchase capacity, energy, and ancillary services from Genco and its subsidiaries. The agreements are classified as operating leases. The revenues earned from the contracts amounted to $478 million for the year ended March 31, 2023.

There are other lease arrangements where the Company is the lessor. Revenue under such leases was immaterial for the years ended March 31, 2023 and March 31, 2022.

15. RELATED PARTY TRANSACTIONS

Accounts Receivable from and Accounts Payable to Affiliates

The Company engages in various transactions with the Parent and its subsidiaries. Certain activities and costs, primarily executive and administrative and some human resources, legal, and strategic planning, are shared between the Company and its affiliates.

The Company also records short-term receivables from, and payables to, certain of its 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 Unconsolidated Affiliates		Accounts Payable to Unconsolidated Affiliates	
	March 31,		March 31,	
	2023	2022	**2023**	2022
	(in millions of dollars)			
National Grid plc	**$ 39**	$ 27	**$ 81**	$ 100
National Grid North America	**1**	1	**9**	-
The NGV US LLC (“NGV”) and National Grid Partners LLC (“NGP”)	**297**	221	**221**	138
Other	**-**	-	**-**	-
Total	**$ 337**	$ 249	**$ 311**	$ 238

Advance from Affiliate

In August 2009, the Company entered into an agreement with the Parent, whereby either party can collectively borrow up to $3.0 billion from time to time for working capital needs. These advances currently bear interest rates of LIBOR plus a margin set to reflect the cost of short-term borrowing rates for the Parent at the time of the borrowing. Outstanding balance are due on demand and reported on a net basis in the consolidated statements of cash flows. At March 31, 2023 and 2022, the Company had zero advances under this agreement.

In August 2008, the Company entered into an agreement with NGNA, whereby the Company can borrow up to $1.5 billion from time to time for working capital needs. The agreement can be amended and restated from time to time with the latest amendment made in October 2020 to increase the borrowing capacity to $12.0 billion. These advances do not bear interest. At March 31, 2023 and 2022, the Company had $6.7 billion and $8.8 billion outstanding advances from NGNA under this agreement.

Amounts advanced under each of these agreements are repayable on demand and can be structured as interest or non-interest bearing subject to the demands of the lender. The advances support general working capital needs with advances and repayments executed on a daily basis.

On May 25, 2022, in connection with the sale of the Narragansett Electric Company business to PPL Corporation, the Company made a repayment of $3.8 billion to NGNA.

Promissory Notes

On November 20, 2015, Genco entered into an intercompany loan with the Parent totaling $227 million, composed of a $165 million intercompany loan with an interest rate of 3.25% due to mature on April 30, 2028 and a $62 million intercompany loan with an interest rate of 3.13% due to mature on June 1, 2027. The remaining intercompany loan of $102 million is reported in long-term debt on the consolidated balance sheets. The intercompany loans also have an annual sinking fund requirement totaling $18 million, which is included in current portion of long-term debt on the accompanying consolidated balance sheets as of March 31, 2023 and 2022.

Intercompany Money Pool

The settlement of the Company's various transactions with its subsidiaries and certain affiliates generally occurs via the Regulated and Unregulated Money Pools, as applicable. Borrowings from the Regulated and Unregulated Money Pools bear interest in accordance with the terms of the applicable money pool agreement. All changes in the intercompany money pool balances are reflected as investing or financing activities in the accompanying consolidated 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 and Unregulated Money Pools are funded by operating funds from participants in the applicable pool. The Company reported short-term intercompany money pool investments of $1,703 million and $987 million, and intercompany money pool borrowings of $808 million and $230 million on the consolidated balance sheets as of March 31, 2023 and 2022, respectively. The balances represent money pool positions between the Company and legal entities that are part of the NGV and NGP business, which remains party to the Unregulated Money Pool. The cash impacts from these money pool positions were reported as either investing or financing activities in the consolidated statements of cash flows.

The average interest rates for the intercompany money pool were 2.9% and 0.4% for the years ended March 31, 2023 and 2022, respectively.

Holding Company Charges

The Company receives charges from National Grid Commercial Holdings Limited (an affiliated company in the United Kingdom) for certain corporate and administrative services provided by the corporate functions of the Parent to its U.S. subsidiaries. For the years ended March 31, 2023 and 2022, the effect on income before income taxes was $73 million.

16. PREFERRED STOCK

Preferred stock of NGUSA subsidiaries

The Company's subsidiaries have certain issues of non-participating cumulative preferred stock outstanding where the security is guaranteed by National Grid plc and can be redeemed only at the option of the Company's subsidiaries. There are no mandatory redemption provisions on the cumulative preferred stock and no conversion options. A summary of the cumulative preferred stock of NGUSA subsidiaries at March 31, 2023 and 2022 is presented in the table below. The preferred stock is reported as a non-controlling interest as of March 31, 2023.

		Shares Outstanding		**Amount**		
		March 31,		**March 31,**		Call
Series	Company	**2023**	2022	**2023**	2022	Price
		(in millions of dollars, except per share and number of shares data)				
$100 par value -						
3.40% Series	Niagara Mohawk	**57,524**	57,524	**$ 6**	$ 6	$ 103.500
3.60% Series	Niagara Mohawk	**137,152**	137,152	**14**	14	104.850
3.90% Series	Niagara Mohawk	**95,171**	95,171	**9**	9	106.000
4.44% Series	Massachusetts Electric	**22,585**	22,585	**2**	2	104.068
6.00% Series	NEP	**11,117**	11,117	**1**	1	Non-callable
$50 par value -						
4.50% Series	Narragansett(1)	**-**	49,089	**-**	3	55.000
Golden Shares -	Niagara Mohawk and the New York Gas Companies	**3**	3	**-**	-	Non-callable
Total		**323,552**	372,641	**$ 32**	$ 35	

(1)Related to sale of Narragansett, see Note 17 "Sale of Narragansett".

In connection with the acquisition of KeySpan by NGUSA, the Company's New York Gas Companies became subject to a requirement to issue a class of preferred stock, having one share (the "Golden Share"), subordinate to any existing preferred stock. The holder of the Golden Share would have voting rights that limit the Company's right to commence any voluntary bankruptcy, liquidation, receivership, or similar proceeding without the consent of the holder of the Golden Share. The NYPSC subsequently authorized the issuance of the Golden Share to a trustee, GSS Holdings, Inc. ("GSS"), who will hold the Golden Share subject to a Services and Indemnity Agreement requiring GSS to vote the Golden Share in the best interests of NYS. On July 8, 2011, the Company issued a total of 3 Golden Shares pertaining to Niagara Mohawk and the New York Gas Companies each with a par value of $1.

The Company's subsidiaries did not redeem any preferred stock during the years ended March 31, 2023 or 2022. The annual dividend requirement for cumulative preferred stock was $1 million as of March 31, 2023 and 2022.

Preferred stock of NGUSA

The Company has cumulative series A through F non-participating non-callable preferred stock (5,000 total shares authorized, 915 outstanding) which have no fixed redemption date and no conversion options. The series A through F shares rank above all common shares, but below the Company's debt holders in an event of liquidation. If the Company does not pay its annual dividend on the A through F series preferred stock due on July 28, it is subject to limitations on the payment of any dividends to its common shareholder. The par value of the series A through F preferred stock is $0.10. The fixed rate on the series A through E preferred stock is 6.5%. The fixed rate on the series F preferred stock is 8.5%. The Company has paid all declared dividends in full.

A summary of preferred stock is as follows:

	Shares Outstanding		**Amount (par)**		**Amount (additional paid-in capital)**		**Dividends Paid**	
	March 31,		**March 31,**		**March 31,**		**March 31,**	
Series	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022
			(in millions of dollars, except per share and number of shares data)					
$0.10 par value -								
Series A	**51**	51	**$ -**	$ -	**$ 400**	$ 400	**$ 26**	$ 26
Series B	**40**	40	**-**	-	**315**	315	**20**	20
Series C	**96**	96	**-**	-	**750**	750	**49**	49
Series D	**79**	79	**-**	-	**616**	616	**40**	40
Series E	**1**	1	**-**	-	**10**	10	**1**	1
Series F	**648**	648	**-**	-	**5,368**	5,368	**456**	456
Total	**915**	915	**$ -**	$ -	**$ 7,459**	$ 7,459	**$ 592**	$ 592

17. SALE OF NARRAGANSETT

On March 17, 2021, the Company signed an agreement to sell its 100% ownership interest in Narragansett for $3.8 billion (excluding long-term debt). The sale was agreed to as part of the Parent's acquisition of Western Power Distribution from PPL. As the sale of Narragansett was considered probable and expected to complete once all regulatory approvals have been obtained, the associated assets and liabilities that form part of the sale have been presented as held for sale in the consolidated balance sheets as of March 31, 2022. The sale was completed on May 25, 2022, with total proceeds of $3.9 billion. A gain on sale of $847M was recognized in the consolidated statements of operations and comprehensive income for the year ended March 31, 2023.

Following the completion of the sale, National Grid will continue to provide certain services under the Transition Service Agreement to PPL until May 25th, 2024. These services mainly include IT services, customer service call centers, customer billing operations, and electric and gas operations.

The Company's consolidated statements of operations and comprehensive income include $14 million and $155 million for the years ended March 31, 2023 and March 31, 2022, respectively of Income before income taxes resulting directly from the operations of Narragansett.

The table below shows the assets and liabilities which were presented as held for sale in the consolidated balance sheets as of March 31, 2022.

	March 31, 2022
	(in millions of dollars)
Current assets:	
Cash and cash equivalents	**$ 8**
Accounts receivable	**318**
Allowance for doubtful accounts	**(62)**
Unbilled revenues	**57**
Inventory	**51**
Regulatory assets	**90**
Derivative instruments	**56**
Other	**16**
Total current assets	**534**
Property, plant and equipment, net	**4,004**
Non-current assets:	
Regulatory assets	**437**
Goodwill	**780**
Postretirement benefits	**44**
Derivative instruments	**12**
Other	**28**
Total non-current assets	**1,301**
Total assets	**$ 5,839**

	March 31, 2022
	(in millions of dollars)
Current liabilities:	
Accounts payable	$ **189**
Current portion of long-term debt	**14**
Taxes accrued	**43**
Interest accrued	**16**
Regulatory liabilities	**177**
Derivative instruments	**3**
Renewable energy certificate obligations	**33**
Payroll and benefits accruals	**14**
Environmental remediation obligations	**8**
Other	**91**
Total current liabilities	**588**
Non-current liabilities:	
Regulatory liabilities	**616**
Asset retirement obligations	**10**
Postretirement benefits	**10**
Environmental remediation obligations	**95**
Derivative instruments	**3**
Operating lease liabilities	**15**
Other	**18**
Total non-current liabilities	**767**
Long-term debt	**1,495**
Total liabilities	**2,850**
Net Assets	$ **2,989**