nationalgrid

National Grid USA and Subsidiaries

Consolidated Financial Statements

For the years ended March 31, 2021 and 2020

NATIONAL GRID USA AND SUBSIDIARIES

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INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
National Grid USA and Subsidiaries

We have audited the accompanying consolidated financial statements of National Grid USA and Subsidiaries (the "Company"), which comprise the consolidated balance sheets and statements of capitalization as of March 31, 2021 and 2020, and the related consolidated statements of operations and comprehensive income, cash flows, and changes in shareholders' equity for the years then ended, and the related notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

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

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the consolidated financial statements 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, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of National Grid USA and Subsidiaries as of March 31, 2021 and 2020, and the results of their operations and their cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Emphasis of Matter

As discussed in Note 1 and Note 17 to the consolidated financial statements, the Company signed an agreement to sell its 100% indirect ownership interest in The Narragansett Electric Company. Therefore, the associated assets and liabilities that will form part of the sale have been presented as held for sale in the consolidated balance sheets as of March 31, 2021. Our opinion is not modified with respect to this matter.

Deloitte & Touche LLP

September 28, 2021

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

	Years Ended March 31,	
	2021	2020
Operating revenues	**$ 12,356**	$ 12,211
Operating expenses:		
Purchased electricity	**1,547**	1,713
Purchased gas	**1,582**	1,662
Operations and maintenance	**4,777**	4,375
Depreciation and amortization	**1,342**	1,230
Other taxes	**1,354**	1,308
Total operating expenses	**10,602**	10,288
Operating income	**1,754**	1,923
Other income (deductions):		
Interest on long-term debt, net	**(557)**	(538)
Other interest, including affiliate interest, net	**(107)**	(71)
Other income, net	**150**	88
Total other income (deductions)	**(514)**	(521)
Income before income taxes	**1,240**	1,402
Income tax expense	**321**	358
Net income	**919**	1,044
Net income attributed to non-controlling interests	**(3)**	(3)
Dividends on preferred stock	**(592)**	(592)
Net income attributed to common shareholders	**$ 324**	$ 449
Other comprehensive income, net of taxes:		
Unrealized gains on securities, net of tax expense (benefit) of $0 and $3 in 2021 and 2020, respectively	**1**	8
Change in pension and other postretirement obligations, net of tax expense (benefit) of $82 and ($52) in 2021 and 2020, respectively	**229**	(127)
Total other comprehensive income	**230**	(119)
Comprehensive income	**$ 1,149**	$ 925
Less: Comprehensive income attributed to non-controlling interest	**(3)**	(3)
Comprehensive income attributed to common shareholders	**$ 1,146**	$ 922

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, 2021	2020
Operating activities:		
Net income	**$ 919**	$ 1,044
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**1,342**	1,230
Deferred income tax expense and amortization of investment tax credits	**284**	323
Bad debt expense	**412**	279
Losses (gains) from financial investments	**(173)**	43
Allowance for equity funds used during construction	**(74)**	(52)
Net pension and postretirement benefit expense	**152**	138
Other, net	**67**	69
Pension and postretirement benefits contributions	**(149)**	(192)
Environmental remediation payments	**(179)**	(103)
Changes in operating assets and liabilities:		
Accounts receivable and unbilled revenues, net	**(781)**	144
Accounts receivable from/payable to affiliates, net	**19**	(2)
Inventory	**53**	(82)
Regulatory assets and liabilities, net	**28**	(446)
Derivative instruments	**(85)**	169
Prepaid and accrued taxes, net	**(37)**	(103)
Accounts payable and other liabilities	**449**	(78)
Other assets and liabilities, net	**118**	(91)
Net cash provided by operating activities	**2,365**	2,290
Investing activities:		
Capital expenditures	**(3,773)**	(3,845)
Cost of removal	**(260)**	(287)
Proceeds from sales of property, plant and equipment	**29**	61
Intercompany Money Pool	**(141)**	(300)
Purchases of financial investments	**(91)**	(69)
Proceeds from sales of financial investments	**97**	73
Other, net	**6**	4
Net cash used in investing activities	**(4,133)**	(4,363)
Financing activities:		
Preferred stock dividends	**(592)**	(592)
Payments on long-term debt	**(320)**	(1,026)
Proceeds from long-term debt	**2,600**	600
Payment of debt issuance costs	**(14)**	(2)
Commercial paper issued	**1,002**	5,911
Commercial paper paid	**(1,820)**	(6,255)
Intercompany Money Pool	**10**	43
Advances from affiliates	**1,459**	3,454
Net cash provided by financing activities	**2,325**	2,133
Net increase in cash, cash equivalents, restricted cash and special deposits, including cash classified within assets held for sale	**557**	60
Less: Net decrease in cash classified within assets held for sale	**(6)**	-
Net increase in cash, cash equivalents, restricted cash and special deposits	**551**	60
Cash, cash equivalents, restricted cash and special deposits, beginning of year	**646**	586
Cash, cash equivalents, restricted cash and special deposits, end of year	**$ 1,197**	$ 646
Supplemental disclosures:		
Interest paid	**$ (659)**	$ (581)
Income taxes paid	**(56)**	(98)
Significant non-cash items:		
Capital-related accruals included in accounts payable	**265**	202
Parent tax loss (income) allocation	**7**	(29)
Distribution of interests in affiliated entities to National Grid North America	**-**	298
ROU assets obtained in exchange for operating lease liabilities	**136**	869

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, 2021	March 31, 2020
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 1,146**	$ 592
Restricted cash and special deposits	**51**	54
Accounts receivable	**2,644**	2,259
Allowance for doubtful accounts	**(841)**	(551)
Accounts receivable from affiliates	**167**	117
Intercompany Money Pool	**735**	594
Unbilled revenues	**447**	491
Inventory	**422**	526
Regulatory assets	**492**	607
Derivative instruments	**14**	15
Prepaid taxes	**278**	212
Other	**129**	151
Assets held for sale	**5,436**	-
Total current assets	**11,120**	5,067
Equity method investments	**2**	2
Property, plant and equipment, net	**37,002**	37,854
Non-current assets:		
Regulatory assets	**4,969**	6,254
Goodwill	**6,349**	7,129
Derivative instruments	**3**	2
Postretirement benefits	**973**	377
Financial investments	**749**	572
Other	**99**	189
Total non-current assets	**13,142**	14,523
Total assets	**$ 61,266**	$ 57,446

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, 2021	March 31, 2020
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	**$ 1,597**	$ 1,575
Accounts payable to affiliates	**207**	138
Intercompany Money Pool	**178**	168
Advances from affiliates	**8,067**	6,608
Commercial paper	**-**	811
Current portion of long-term debt	**58**	221
Taxes accrued	**146**	156
Interest accrued	**142**	134
Regulatory liabilities	**670**	868
Derivative instruments	**45**	117
Renewable energy certificate obligations	**246**	264
Payroll and benefits accruals	**401**	331
Environmental remediation obligations	**173**	216
Other	**598**	531
Liabilities held for sale	**2,707**	-
Total current liabilities	**15,235**	12,138
Non-current liabilities:		
Regulatory liabilities	**6,668**	6,226
Asset retirement obligations	**100**	105
Deferred income tax liabilities, net	**4,059**	3,699
Postretirement benefits	**1,242**	2,615
Environmental remediation obligations	**2,016**	2,219
Derivative instruments	**67**	86
Operating lease liabilities	**676**	654
Other	**657**	658
Total non-current liabilities	**15,485**	16,262
Commitments and contingencies (Note 13)		
Long-term debt	**12,871**	11,952
Equity:		
Common stock and additional paid-in capital	**14,076**	14,052
Retained earnings	**3,508**	3,184
Accumulated other comprehensive income (loss)	**25**	(205)
Common shareholders' equity	**17,609**	17,031
Non-controlling interests	**66**	63
Total equity	**17,675**	17,094
Total liabilities and equity	**$ 61,266**	$ 57,446

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

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

			March 31,	
			2021	2020
Common shareholders' equity			**$ 17,609**	$ 17,031
Non-controlling interests			**66**	63
Long-term debt [(1)]:	Interest Rate	Maturity Date		
Notes Payable	1.73% - 9.05%	September 2021 – October 2050	**12,128**	11,033
Promissory Notes to National Grid North America Inc.[(2)]	3.13% - 3.25%	June 2027 - April 2028	**138**	156
First Mortgage Bonds	6.90% - 8.80%	July 2022 – April 2028	**75**	104
State Authority Financing Bonds	3.23% - 3.48%	December 2023 – July 2029	**424**	424
State Authority Financing Bonds	Variable	October 2022 – August 2042	**223**	410
Term Loan[(3)]	Variable	March 2022	**-**	100
Total debt			**12,988**	12,227
Unamortized debt issuance costs			**(59)**	(54)
Current portion of long-term debt			**(58)**	(221)
Total long-term debt			**12,871**	11,952
Long-term debt classified as held-for-sale[(4)]			**1,510**	
Total capitalization			**$ 32,056**	$ 29,046

(1) See Note 10, "Capitalization" for additional details.
(2) See Note 15, "Related Party Transactions" for additional details.
(3) Prepaid in October 2020, see Note 10, "Capitalization".
(4) See Note 17, “Held for sale”.

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, 2019	$ -	$ 35	$ 14,346	$ 6	$ (8)	$ (15)	$ (17)	$ 2,689	$ 25	$ 17,078
Net income	-	-	-	-	-	-	-	1,041	3	1,044
Other comprehensive income (loss):										
Unrealized gains on securities, net of $3 tax expense (benefit)	-	-	-	8	-	-	8	-	-	8
Change in pension and other postretirement obligations, net of ($52) tax expense (benefit)	-	-	-	-	(127)	-	(127)	-	-	(127)
Total comprehensive income										925
Other transfer	-	(35)	-	-	-	-	-	-	35	-
Parent tax income allocation	-	-	-	-	-	-	-	(29)	-	(29)
Impact of adoption of reclassification of certain tax effects from accumulated other comprehensive income standard	-	-	-	(1)	(72)	(2)	(75)	75	-	-
Reclassification of AOCI components	-	-	-	(12)	(2)	14	-	-	-	-
Stock-based compensation	-	-	10	-	-	-	-	-	-	10
Distribution of interests in affiliated entities to NGNA	-	-	(304)	6	-	-	6	-	-	(298)
Preferred stock dividends	-	-	-	-	-		-	(592)	-	(592)
Balance as of March 31, 2020	$ -	$ -	$ 14,052	$ 7	$ (209)	$ (3)	$ (205)	$ 3,184	$ 63	$ 17,094
Net income	-	-	-	-	-	-	-	916	3	919
Other comprehensive income (loss):										
Unrealized gains on securities, net of zero tax expense (benefit)	-	-	-	1	-	-	1	-	-	1
Change in pension and other postretirement obligations, net of $82 tax expense (benefit)	-	-	-	-	229	-	229	-	-	229
Total comprehensive income										1,149
Parent tax loss allocation	-	-	7	-	-	-	-	-	-	7
Stock-based compensation	-	-	17	-	-	-	-	-	-	17
Preferred stock dividends	-	-	-	-	-	-	-	(592)	-	(592)
Balance as of March 31, 2021	$ -	$ -	$ 14,076	$ 8	$ 20	$ (3)	$ 25	$ 3,508	$ 66	$ 17,675

(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 372,641 shares of cumulative preferred stock authorized, issued and outstanding, with par values of either $100 or $50 per share at March 31, 2021 and 2020. 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 five 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 states of Massachusetts and Rhode Island. The Company's Electric Services business primarily consists of five electric distribution subsidiaries which provide electric services to customers in the areas of eastern, central, northern, and western New York, as well as the states of Massachusetts and Rhode Island. The Company also operates electric transmission facilities in Massachusetts, New Hampshire, Rhode Island, 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"), The Narragansett Electric Company ("Narragansett"), 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).

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-transmision electric companies are not material to the Company's consolidated financial statements.

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.

On March 17, 2021, NGUSA announced the sale of its Rhode Island business (Narragansett) to PPL Energy Holdings, LLC for $3.8 billion (excluding long-term debt). As the sale of Narragansett is considered probable and is expected to complete within a year, once all regulatory approvals have been obtained, the associated assets and liabilities that will form part of the sale have been presented as Held for sale in the consolidated balance sheets as of March 31, 2021. The assets and liabilities of Narragansett are not classified as held for sale for the comparative period dated March 31, 2020. See Note 17, "Held for sale".

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 novel coronavirus ("COVID-19") pandemic has disrupted the U.S. and global economies and continues to have a significant impact on global health. Due to this continued uncertainty, the valuations of certain assets and liabilities are necessarily more subjective. In particular, we identified the recoverability of customer receivables in relation to retail customers, in consideration of the suspension of certain debt collection and customer termination activities as an area of estimation uncertainty at both March 31, 2021 and March 31, 2020. In March 2020, the Company ceased certain customer cash collection activities in response to regulatory instructions and to changes in State, Federal and City level regulations and guidance, and actions to minimize risk to employees. The Company also ceased customer termination activities as requested by relevant local authorities.

The Company has seen adverse impacts from COVID-19 on earnings and cash flow. Earnings are impacted by increased incremental operating costs, increased bad debt expense, and reduced late payment revenues, slightly offset by reduced costs and other mitigation efforts by the Company. Cash flow is negatively impacted by the higher level of operating costs and lower cash collections. As of March 31, 2021, the Company recorded additional reserves for uncollectible accounts related to the COVID-19 impact for the gas businesses.

The Company has evaluated subsequent events and transactions through September 28, 2021, the date of issuance of these consolidated financial statements.

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 include the impact of the ongoing COVID-19 pandemic and 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"), the Massachusetts Department of Public Utilities ("DPU"), and the Rhode Island Public Utilities Commission ("RIPUC") 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, DPU and RIPUC 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 revenues 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, 2021 and 2020, were $179 million and $170 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") and collateral paid to the Company's counterparties for outstanding commodity and financial derivative instruments. Special deposits primarily consist of health care deposits, a release of property account for mortgaged property under a mortgage trust indenture, and amounts reserved for potential environmental violations. The Company had restricted cash of $4 million and $11 million and special deposits of $47 million and $43 million as of March 31, 2021 and 2020, 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 $412 million and $279 million for the years ended March 31, 2021 and 2020, respectively, within operations and maintenance in the accompanying consolidated statements of operations and comprehensive income. For the years ended March 31, 2021 and 2020, the bad debt expense is reflective of an additional provision in relation to the impact of COVID-19.

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, 2021 or 2020.

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 are held primarily for consumption. Emission credits are comprised of sulfur dioxide, 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,	
	2021	2020
	(in millions of dollars)	
Materials and supplies	**$ 186**	$ 183
Gas in storage	**123**	182
Purchased RECs	**102**	143
Emission credits	**11**	18
Total inventory	**$ 422**	$ 526

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.

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.

Natural Gas Long-Term Arrangements

Certain of the Company's subsidiaries enter into long-term gas contracts to procure gas to serve their gas customers. Those contracts include Asset Management Agreements, Baseload, and Peaking gas contracts. Similar to the PPAs noted above, the Company evaluates whether such agreements are leases, derivative instruments, or executory contracts and performs an assessment under the guidance for VIEs.

Fair Value Measurements

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

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

Property, Plant and Equipment

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

Depreciation is computed over the estimated useful life of the asset using the composite straight-line method. Depreciation studies are conducted periodically to update the composite rates and are approved by the state authorities. The average composite rates for the years ended March 31, 2021 and 2020 are as follows:

	Composite Rates	
	Years Ended March 31,	
	2021	2020
Electric	**2.7%**	2.7%
Gas	**2.6%**	2.6%
Common	**11.0%**	9.2%

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 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 liability. The Company recognized a regulatory liability for the amount that was in excess of costs incurred of $1.5 billion and $1.7 billion at March 31, 2021 and 2020, respectively, and a regulatory asset for the excess of costs incurred over amounts collected in rates of $97 million and $51 million at March 31, 2021 and 2020, 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 $74 million and $52 million and AFUDC related to debt of $28 million and $39 million for the years ended March 31, 2021 and 2020, respectively. The average AFUDC rates for the years ended March 31, 2021 and 2020 were 5.2% and 5.7%, 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 the years ended March 31, 2021 and 2020, there were $0.2 million and zero of impairment losses recognized for long-lived assets at Genco, respectively.

Goodwill

The Company tests goodwill for impairment annually on January 1, 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. The Company tests goodwill residing at NGUSA based upon four identified reporting units, aligned with its jurisdictional operational model. The Company has the following reporting units for consolidated reporting at NGUSA: New York, Massachusetts, Rhode Island, and FERC.

The Company has adopted Accounting Standards Update ("ASU") No. 2017-04, "Intangibles—Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment," which eliminates step two from the two-step goodwill impairment test previously required under the former standard. 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, then 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.

For the New York reporting unit, the Company uses a variety of valuation methodologies to estimate a reporting unit's fair value, principally discounted projected future net cash flows and market-based multiples, commonly referred to as the income approach and market approach. Key assumptions include, but are not limited to, the use of estimated future cash flows; multiples of earnings; and an appropriate discount rate. In estimating future cash flows, the Company incorporates current market information, as well as historical factors. As such, the determination of fair value incorporates significant unobservable inputs and the assumptions require the Company to make significant judgements, whereby actual results may differ from assumed and estimated amounts. The Company uses 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 reporting unit's estimated fair value.

In March 2021, the Company announced that it was selling its investment in Narragansett to PPL for an equity value of $3.8 billion as part of the transaction involving the Parent's acquisition of Western Power Distribution from PPL. The Narragansett sale represents a triggering event and, as such, the Company performed a separate quantitative analysis to determine whether a goodwill impairment exists in connection with the reclassification of Narragansett's assets into the held-for-sale disposal group. The Company determined that no impairment existed as of March 31, 2021.

The Company elected to perform a qualitative assessment for the Massachusetts and FERC reporting units to determine whether it is more likely than not that the fair value of the reporting unit is below its carrying value and an impairment exists. The qualitative assessment is commonly referred to as the “Step 0” test and requires the Company to evaluate relevant events and circumstances including, but not limited to, macroeconomic conditions, industry and market considerations, cost factors, and other relevant entity-specific events that may indicate the existence of a decline in fair value that is other than temporary. The qualitative assessment indicated that it was not more likely than not that the fair value of the reporting unit is below its carrying value and, as such, no impairment loss exists for the year ended March 31, 2021.

Based on the resulting fair values from the annual assessment, either from a Step 0 or a Step 1 assessment as stated above, the Company did not record any goodwill impairment during the years ended March 31, 2021 and 2020.

Financial Investments

The Company holds a range of financial investments, including short-term money funds, 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,	
	2021	2020
	(in millions of dollars)	
COLI/TOLI	**$ 389**	$ 273
Debt securities[(1)]	**184**	162
Equity securities[(1)]	**137**	103
SERPs	**39**	34
Total financial investments	**$ 749**	$ 572

(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. During the year ended March 31, 2021, the Company performed a new study of its asset retirement obligations. The study did not result in a material change to the Company's asset retirement obligations.

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 change in benchmark also affects discount rates which can impact valuations. The Company is managing the risk by planning to replace US LIBOR cash flows with ARRs, mainly Sterling Overnight Interbank Average Rate ("SONIA"), 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, 2021 and 2020.

Leases

The Company adopted Topic 842 during the year-end ended March 31, 2020. The Company elected the practical expedient "package" in which any expired contracts were not reassessed to determine whether they met the definition of a lease; classification of leases that commenced prior to the adoption of this standard was not reassessed; and any initial direct costs for existing leases were not reassessed. Additionally, the Company elected the practical expedient to not reassess existing easements that were not previously accounted for as leases under Topic 840.

The Company elected to not evaluate whether sales tax and other similar taxes are lessor and lessee costs. Instead, such costs are deemed lessee costs. The Company does not combine lease and non-lease components for contracts in which the Company is the lessee or the lessor.

Certain building leases provide the Company with an option to extend the lease term. The Company has included the periods covered by an extension options in its determination of the lease term when management believes it is reasonably certain the Company will exercise its option.

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, 2021 and 2020. The Company does not reflect short-term leases on the consolidated balance sheets. Expense related to short-term leases was not material for the years ended March 31, 2021 and 2020.

Right-of-use 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. Right-of-use assets are amortized over the lease term.

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

Fair Value

In August 2018, the FASB issued ASU No. 2018-13 "Fair Value Measurement (Topic 820), Disclosure Framework–Changes to the Disclosure Requirements for Fair Value Measurement" which modifies certain disclosure requirements on fair value measurements in Topic 820, Fair Value Measurement*,* including certain disclosure requirements relating to Level 3 fair value measurements, and eliminates disclosure requirements for transfers between Level 1 and Level 2 fair value measurements. The standard also added certain other disclosure requirements for Level 3 fair value measurements. The Company adopted the new guidance on April 1, 2020 requiring certain revisions to disclosures related to recurring fair value measurements in Note 8, "Fair Value Measurements". Upon adoption, the amendments in the standard were applied retrospectively to all periods presented, except the amendments on changes in unrealized gains and losses, the range and weighted average of significant unobservable inputs used to develop Level 3 fair value measurements, and the narrative description of measurement uncertainty, which were applied prospectively for only the most recent annual period presented. The amendments did not materially affect the Company's disclosures and did not affect the Company's financial position, results of operations, or cash flows.

Pension and Postretirement Benefits

In August 2018, the FASB issued ASU No. 2018-14 "Compensation—Retirement Benefits—Defined Benefit Plans—General (Subtopic 715-20): Disclosure Framework—Changes to the Disclosure Requirements for Defined Benefit Plans," which modifies the disclosure requirements for employers that sponsor define benefit pension or other postretirement plans, including elimination of certain current disclosure requirements. The Company adopted the new guidance on April 1, 2020 using a retrospective basis to all period presented, resulting in certain revisions to disclosures related to the Company's defined benefit plans in Note 8, "Employee Benefits". The amendments did not materially affect the Company's disclosures related to its defined benefit postretirement benefit plans and did not affect the Company's financial position, results of operations, or cash flows.

Internal-Use Software

In August 2018, the FASB issued ASU No. 2018-15 "Intangibles – Goodwill and Other – Internal-Use Software (Subtopic 350-40), Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract" to help entities evaluate the accounting for fees paid by a customer under a cloud computing arrangement that is a service contract. The amendment aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. Under this standard, the Company applies Subtopic 350-40 to determine which implementation costs related to a hosting arrangement should be capitalized or expensed. The Company expenses the capitalized implementation costs of a hosting arrangement that is a service contract over the term of the arrangement. The Company adopted this new guidance prospectively on April 1, 2020. The amendments did not materially impact the Company's financial position, results of operations, or cash flows.

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 for all entities. No elections to apply the amendments have been made at March 31, 2021. The Company is still assessing the potential impact related to replacing LIBOR ARRs.

As the Company has not amended any of its current agreements that have LIBOR as a reference rate between the March 12, 2020 effective date and March 31, 2021, this accounting standard update did not impact the Company's financial position, results of operations, nor its cash flows for the year ended March 31, 2021.

Accounting Guidance Not Yet Adopted

Income Taxes

In December 2019, the FASB issued ASU No. 2019-12 "Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes" which simplifies various aspects of the accounting for income taxes by eliminating certain exceptions to current requirements. The standard also enhances and simplifies other requirements, including tax basis step-up in goodwill obtained in a transaction that is not a business combination, ownership changes in investments, and interim-period accounting for enacted changes in tax law. For public business entities, the standard is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2020. For all other entities, the standard is effective for fiscal years beginning after December 15, 2021, and interim periods within fiscal years beginning after December 15, 2022. Early adoption is permitted. The Company plans to early adopt this standard on April 1, 2021, and interim periods within. The Company does not expect the adoption to have a material impact on its financial statements.

Investments – Equity Securities

In January 2020, the FASB issued ASU No. 2020-01 "Investments—Equity Securities (Topic 321), Investments—Equity Method and Joint Ventures (Topic 323), and Derivatives and Hedging (Topic 815): Clarifying the Interactions between Topic 321, Topic 323, and Topic 815 (a consensus of the FASB Emerging Issues Task Force)" which clarifies that an entity should consider transaction prices for purposes of measuring the fair value of certain equity securities immediately before applying or upon discontinuing the equity method. This accounting standard also clarifies that when accounting for contracts entered into to purchase equity securities, an entity should not consider whether, upon the settlement of the forward contract or exercise of the purchased option, the underlying securities would be accounted for under the equity method or the fair value option. For public business entities, the standard is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2020. For all other entities, the standard is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2021. Early adoption is permitted. The Company plans to early adopt this standard on April 1, 2021, and interim periods within. The Company does not expect the adoption to have a material impact on its financial statements.

Callable Debt Securities

In October 2020, the FASB issued ASU No. 2020-08 "Codification Improvements to Subtopic 310-20, Receivables – Nonrefundable Fees and Other Costs" to clarifies that an entity should reevaluate whether a callable debt security that has multiple call dates is within the scope of paragraph ASC 310-20-35-33 for each reporting period, such that the premium should be amortized over the period ending at the earliest call date. For public business entities, the standard is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2020. Early application is not permitted for public business entities. For all other entities, the standard is effective for fiscal years beginning after December 15, 2021, and interim periods within fiscal years beginning after December 15, 2022. Early application is permitted for all other entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2020. The Company plans to early adopt this standard on a prospective basis on April 1, 2021, and interim periods within. The Company does not expect the adoption to have a material impact on its financial statements.

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 to be presented at the net amount expected to be collected. The accounting standards provide a new model for recognizing credit losses on financial instruments based on an estimate of current expected credit losses that replaces the incurred loss impairment methodology of delayed recognition of credit losses. A broader range of reasonable and supportable information must be considered in developing the credit loss estimates. The allowance for credit losses is a valuation account that is deducted from the amortized cost basis of the financial asset 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, with the exception of held-to-maturity debt securities. For the Company, the requirements in these updates, as amended in November 2019 by ASU 2019-10 “Financial Instruments—Credit Losses (Topic 326), Derivatives and Hedging (Topic 815), and Leases (Topic 842): Effective Dates”, will be effective for the fiscal years beginning after December 15, 2022 (beginning April 1, 2023 for the Company), including interim periods within. The Company is currently assessing the application of this standard to determine if it will 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, 2021 and 2020, 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	
	2021	2020
	(in millions of dollars)	
Revenue from contracts with customers:		
Electric services	**$ 6,313**	$ 5,935
Gas distribution	**5,263**	5,201
Off system sales	**164**	146
Total revenue from contracts with customers	**11,740**	11,282
Revenue from regulatory mechanisms	**6**	413
Other revenue	**610**	516
Total operating revenues	**$ 12,356**	$ 12,211

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.

Generation revenue is derived from billings to LIPA for the electric generation capacity and, to the extent requested, energy from the Company's existing oil and gas-fired generating plants.

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 include various deferral mechanisms such as capital trackers, energy efficiency programs, storm deferral, and other programs that also 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.

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,	
	2021	2020
	(in millions of dollars)	
Regulatory assets		
Current:		
Derivative instruments	**$ 95**	$ 177
Gas cost adjustment mechanism	**130**	77
Rate adjustment mechanisms	**101**	155
Renewable energy certificates	**87**	72
Revenue decoupling mechanism	**45**	93
Other	**34**	33
Total	**492**	607
Non-current:		
Cost of removal	**97**	51
Environmental response costs	**2,428**	2,618
Net metering deferral	**191**	220
Postretirement benefits	**883**	2,004
Property taxes	**173**	130
Recovery of acquisition premium	**151**	159
Storm costs	**292**	334
Temperature control/interruptible sharing	**152**	152
Other	**602**	586
Total	**4,969**	6,254
Regulatory liabilities		
Current:		
Energy efficiency	**346**	410
Gas cost adjustment mechanism	**89**	110
Rate adjustment mechanisms	**20**	68
Revenue decoupling mechanism	**153**	178
Transmission service	**18**	62
Other	**44**	40
Total	**670**	868
Non-current:		
Carrying charges	**346**	292
Cost of removal	**1,512**	1,670
Environmental response costs	**139**	150
Postretirement benefits	**845**	144
Regulatory tax liability	**2,542**	2,795
Other	**1,284**	1,175
Total	**6,668**	6,226

As of March 31, 2021, other than $316 million of the regulatory assets summarized above ($232 million of Postretirement benefits, $54 million of Environmental response costs, and $30 million of Other costs), all regulatory assets earn a rate of return.

As of March 31, 2021, $223 million of allowances for earnings on shareholders' investment were capitalized for rate-making purposes but not for US GAAP.

Carrying charges: The Company records carrying charges on regulatory balances for which cash expenditures have been made and are subject to recovery, or for which cash has been collected and is subject to refund. Carrying charges are not recorded on items for which expenditures have not yet been made.

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. This 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.

Property taxes: The property tax regulatory asset represents 85% of actual property and special franchise tax expenses above the rate allowance for future collection from Brooklyn Union Gas Company and KeySpan Gas East Corporation ("New York Gas Companies") customers. The property tax regulatory liability (reported within 'Other non-current regulatory liabilities') represents the balance of property tax refunds received by the New York Gas Companies due to be refunded to customers.

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.

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

Regulatory tax liability: 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 Rhode Island and 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 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.

Temperature control/interruptible ("TC/IT") sharing: Under a previous rate agreement, the New York Gas Companies were subject to an annual price cap on interruptible and temperature control customers and was allowed to defer related amounts, subject to sharing with customers – 90% to customers and 10% to shareholders. This mechanism was discontinued under the current rate agreement. In conjunction with its 2019 rate case filing (see Note 5, "Rate Matters", for additional details), the New York Gas Companies proposed to combine this and other regulatory assets and liabilities into a single net deferral liability to offset the revenue requirement in the pending rate case to mitigate rate increases over the term of the rate plan.

Transmission service: Massachusetts Electric and Nantucket (the "Massachusetts Electric Companies") arrange transmission service on behalf of their customers and bill the costs of those services to customers, pursuant to the transmission service cost adjustment provision. Any over or under recoveries of these costs are passed on to customers receiving transmission service over the subsequent year.

5. RATE MATTERS

Niagara Mohawk

Electric and Gas Filing

On March 15, 2018, the NYPSC issued a final order approving the Joint Proposal ("NIMO-JP1") for a three-year rate for the period ending March 31, 2021. The NIMO-JP1 reflected the new federal tax law changes and provided a cumulative revenue requirement increase of $241 million and $61 million for the electric and gas business, respectively, based on a 9.0% return on equity and 48% common equity ratio. To promote rate stability and mitigate bill impacts to customers, the NIMO-JP1 provided a gradual transition to full cost-of-service rates by phasing in the delivery rate increases over the time of the rate plan.

As of March 31, 2018, resulting from the order, a new electric rate plan settlement credit of $45 million and a new gas rate plan settlement credit of $28 million were established. Niagara Mohawk applied $38 million of existing regulatory liabilities towards the creation of these credits.

Due to the impacts of COVID-19, Niagara Mohawk filed petitions to postpone for four months the electric and gas delivery rate increases that were scheduled to go into effect on April 1, 2020 and recover the annual authorized rate increase over the eight-month period August 1, 2020 through March 31, 2021. The petitions were approved by NYPSC on an emergency basis.

On July 31, 2020, Niagara Mohawk filed a rate case to increase its base electric and gas delivery revenues by $100 million and $42 million per year, respectively, beginning with the twelve-month period July 1, 2021 through June 30, 2022 ("Rate Year"). To facilitate a potential multi-year settlement, Niagara Mohawk submitted comprehensive financial information for two additional Data Years ending June 30, 2023 and June 30, 2024. The filings propose to invest approximately $3.5 billion across the Rate Year and Data Years and present a comprehensive framework to advance New York State's energy goals outlined in the Climate Leadership and Community Protection Act. Niagara Mohawk filed Corrections and Updates on October 14, 2020, which requested rate increases of $103 million for electric delivery and $37 million for gas delivery. To facilitate settlement discussions by the parties, the NYPSC approved Niagara Mohawk's extension of the suspension period in these proceedings, such that new rates would become effective March 1, 2022. This extension is subject to a make whole provision that would assure that Niagara Mohawk is restored to the same financial position it would have been in had there been no extension and new rates went into effect on July 1, 2021.

Outside of the rate filing on September 29, 2020, Niagara Mohawk filed a petition for approval to implement a COVID-19 Customer Assistance Program which deploys up to $50 million of deferred economic development and low-income funds to provide immediate COVID-19 relief to support our most economically vulnerable residential customers, as well as businesses that are struggling because of COVID-19 in Niagara Mohawk's upstate NY territory. Niagara Mohawk anticipates NYPSC consideration of its proposal in the later part of fiscal year 2022 as part of the NYPSC's Affordability and COVID-19 proceeding.

On November 20, 2020, the NYPSC approved Niagara Mohawk's proposal for the deployment of Advanced Metering Infrastructure ("AMI"), also referred to as smart meters. The upstate NY 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 meter deployment) to begin in the second quarter of 2021.

On September 27, 2021, Niagara Mohawk, DPS Staff and other settlement parties filed a Joint Proposal ("NIMO-JP2") 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 and services for low and moderate income customers; initiatives to reduce methane emissions and deploy clean energy solutions, including electric vehicles, battery storage and energy efficiency and demand response programs, in support of New York's Climate Leadership and Community Protection Act ("CLCPA"); support for deploying Advanced Metering Infrastructure; and funding for $3.3 billion in capital projects to improve safety, resiliency and reliability of our energy networks. If approved by the NYPSC, the proposed revenue increases would be 1.4% for electric operations and 1.8% for gas operations in Rate Year One and 1.9% for both electric and gas operations in Rate Year Two and Rate Year Three. In addition, the NIMO-JP2 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 $53 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-JP2 includes earnings sharing mechanisms by which customers will share annual earnings in excess of a 9.5% calculated return on equity ("ROE").

COVID-19 Affordability Programs

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 are working 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 20, 2021, the Department of Public Service ("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 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. These modifications address; the identification of low-income customers through data sharing and file matching between utilities and the New York State Office of Temporary and Disability Assistance ("OTDA") and a customer self-certification mechanism; the stratification of low-income customers into additional tiers or usage groups to enhance bill discount targets; and, the identification of highest usage low-income customers for participation in energy efficiency programs. The NYPSC also adopted modifications to the bill discount calculation methodology to move further toward achieving the NYPSC's six percent energy burden goal. In the order, the NYPSC directs the joint utilities to update their respective Energy Affordability program 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. Niagara Mohawk along with the other New York State utilities continue to evaluate the ongoing impact of COVID-19 on both customers and financial performance, and will continue to work with regulators to adjust the its affordability programs and implement the new protections for NY customers impacted by COVID-19.

Tax Act

On November 21, 2019, the FERC issued Order 864 to address ratemaking and regulatory reporting of excess or deficient Accumulated Deferred Income Taxes ("ADIT"), related to the Tax Act. The order applies to public utility transmission providers with formula rates and stated rates and provides that public utilities with formula rates submit a compliance filing within 30 days of the effective date of the final rule or in the public utilities next annual informational filing following the issuance of the final rule. The compliance filing must demonstrate how the public utilities formula rate adjusts rate base via a Rate Adjustment mechanism, returns or recovers excess or deficient ADIT via an Income Tax Allowance Mechanism and must include an ADIT worksheet to support the excess or deficient ADIT calculation and amortization. The ADIT worksheet must be populated and will be a new and permanent worksheet. The mechanisms and worksheet must remain applicable to any future changes to tax rates that give rise to excess or deficient ADIT, including changes to state and local tax rates. Excess or deficient ADIT associated with future tax rate changes will automatically be included in a public utility's formula rate without the need for a Section 205 filing. The order does not prescribe a recovery/refund period for deficient/excess ADIT for unprotected excess/deficient ADIT that it not subject to the normalization requirements. FERC will evaluate proposed amortization periods on a case by case basis. Niagara Mohawk submitted a compliance filing with the June 15, 2020 annual informational filing proposing adjustments to the formula rate for the inclusion of the Rate Adjustment and Income Tax Allowance Mechanisms. The filing also included a populated and unpopulated proposed permanent ADIT worksheet. Niagara Mohawk requested leave to submit the proposed amortization period to be used in the Transmission Services Charge ("TSC") for unprotected excess or deficient ADIT associated with the Tax Act to the FERC in a subsequent compliance filing after the NYPSC approves an amortization period for unprotected excess or deficient ADIT in Niagara Mohawk's upcoming retail rate case.

On July 24, 2020, Niagara Mohawk filed an amended compliance filing including a proposed amortization period of 10 years for unprotected non-plant based deficient ADIT and the use of Average Rate Assumption Method ("ARAM") for protected and unprotected plant based excess ADIT. Niagara Mohawk estimates that approximately 9% of the transmission related portion of Niagara Mohawk's $704 million net electric excess ADIT balance will be returned to TSC wholesale customers. Niagara Mohawk received a deficiency letter in May 2021 in response to its amended compliance filing. On July 1, 2021, Niagara Mohawk made a filing at FERC addressing the issues from the FERC's deficiency letter, and is currently awaiting a response from the FERC. Niagara Mohawk does not anticipate the resolution of the compliance filing will have a material impact on Niagara Mohawk's results of operations, financial position, or cash flows.

New York Management Audit

Under the New York Public Service Law, the NYPSC is required to conduct periodic audits of various aspects of public utility activities. In 2018 the NYPSC initiated a comprehensive management and operations audit of our three New York regulated businesses. New York law requires periodic management audits of all utilities at least once every five years. National Grid's

New York regulated business last underwent a New York management audit in 2014 and 2015, when the NYPSC audited our New York gas business.

In September 2018, the NYPSC selected Saleeby Consulting Group as the independent auditor to perform the audit. Niagara Mohawk was fully committed to the audit with the goal of demonstrating its full capabilities and receiving meaningful feedback that would drive useful recommendations to improve Niagara Mohawk's electric and gas operations for the benefit of its customers. The audit began in November 2018 and ran until August 2019, with a final report due in September 2019. Unexpectedly, in October 2019, the NYPSC employees advised us that they were terminating the contract with the auditors, effective immediately, because of concerns with the quality of the draft audit report by the auditor, with no fault whatsoever on the part of Niagara Mohawk. NYPSC staff completed the audit using their own internal staff and a final report was approved by the NYPSC and released to the public on November 19, 2020. Niagara Mohawk filed the required Management Audit Implementation Plan on December 21, 2020 and the Plan was subsequently approved by the NYPSC on May 13, 2021. Niagara Mohawk is required to implement the plan and file quarterly updates, with the first report due to the NYPSC on October 31, 2021.

The New York Gas Companies

Rate Case Filing

On April 30, 2019, the New York Gas Companies filed to increase revenues for the twelve-month ending March 31, 2021 ("Rate Year"). The New York Gas Companies filed Corrections and Updates to their original April 30, 2019 filing on July 3, 2019, which requested rate increases of $195 million for the Brooklyn Union Gas Company and $61 million for KeySpan Gas East Corporation. The filings propose to invest over $1.5 billion in the Rate Year to modernize the New York Gas Companies' gas infrastructure by replacing aging pipelines, implementing safety improvements, enhancing storm hardening and resiliency, and reducing methane emissions. The filings also include proposals to enhance gas safety and promote a sustainable and affordable path toward a low-carbon energy future. After a series of litigation hearings held February 10, 2020 through February 25, 2020 before administrative law judges, on June 5, 2020 the New York Gas Companies informed the NYPSC and the administrative law judges of the intention to resume settlement discussions. Settlement discussions resumed on June 15, 2020. To facilitate those discussions, the New York Gas Companies further requested an extension of the suspension period, such that new rates would now become effective September 1, 2021. Pursuant to the terms of the latest rate case, during the period following the expiration of the New York Gas Companies' rate plans, the New York Gas Companies are required to continue all the provisions of the DSNY-JP1, except as expressly stated otherwise, until changed by order of the NYPSC. The final approved rate order will include a make-whole provision that will assure the New York Gas Companies are restored to the same financial position they would have been in had new rates gone into effect on April 1, 2020.

On May 14, 2021, the Department of Public Service ("DPS") Staff and the New York Gas Companies filed a Joint Proposal ("DSNY-JP2") for a three-year rate plan beginning April 1, 2020 and ending March 31, 2023. The total revenue increase for Brooklyn Union Gas Company is: 0% in rate year one and 2% in rate years two and three. The revenue increase for KeySpan Gas East Corporation is: 0% in rate year one and 1.8% in rate years two and three. To mitigate the potential bill impacts on customers, the settlement applies nearly $100 million of credits over the three years of the rate plan. The revenue requirement under the DSNY-JP2 provides immediate benefit to ratepayers who would otherwise experience higher rates at a time when the economy is still in recovery from the COVID-19 pandemic. The DSNY-JP2 also 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% ROE and 48% common equity ratio and includes earnings sharing mechanism providing that customers will share earnings when the New York Gas Companies' ROE is in excess of 9.3%.

On August 12, 2021, the NYPSC approved and adopted the DSNY-JP2 and supporting schedules with limited additional requirements. The NYPSC stated in its approval that the agreed upon rate plans will result in sufficient mitigation of rate impacts on customers while preserving the New York Gas Companies' operational and financial stability; are consistent with the environmental, social and economic policies of the NYPSC and the State of New York; 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. The DSNY-JP2 contains a Make Whole Provision which is designed to ensure the New York Gas Companies are restored to the same financial position they would have been in had rates gone into effect on April 1, 2020. Based on our analysis, the impact of this provision for Rate Year One on the New York Gas Companies' financial position, results of operations or cash flows. The Company estimates the impact of DSNY-JP2 to result in a reduction of regulatory assets and liabilities of approximately $445 million and $453 million, respectively, and an increase in earnings of approximately $8 million.

Downstate Gas Moratorium

On May 15, 2019, the New York Gas Companies stopped fulfilling applications for new firm service connections, or requests for additional firm load from existing customers, in the affected areas of its service territory because the available firm gas supplies are insufficient to keep pace with forecast demand. On October 11, 2019, the NYPSC issued an "Order Instituting Proceeding and to Show Cause" that directed the New York Gas Companies to provide gas service to a subset of previously denied applicants and show cause why the New York Gas Companies should not be subject to financial penalties.

On November 24, 2019, the New York Gas Companies reached settlements resolving the Order to Show Cause relating to the downstate gas moratorium (the "Settlement Agreement"). The settlement was approved November 26, 2019 in a one Commissioner Order by the NYPSC. Specifically, the New York Gas Companies are lifting the moratorium for approximately two years and implementing $35 million in customer assistance, demand response, energy efficiency and other shareholder funded programs. The settlement also provides for the appointment of a monitor to oversee gas supply operations and compliance with the settlement.

On February 25, 2021, the DPS Staff and the New York Gas Companies entered into the Second Amendment to the Settlement Agreement. The purpose of the Second Amendment, approved by the NYPSC on April 15, 2021, is to repurpose the $20 million of shareholder funding designated to support clean energy projects under the original Settlement Agreement. This will be accomplished through the establishment of a deferral for the benefit of customers to offset the costs of the New York Gas Companies' NYPSC approved energy efficiency and demand response programs. On August 12, 2021, the NYPSC approved the New York Gas Companies' rate case which authorizes to use the $20 million settlement amount to offset costs of the New York Gas Companies' approved energy efficiency and demand response programs in the current rate plan.

The New York Gas Companies also agreed to develop a range of options to address the natural gas constraints facing the region, which were presented at a series of public meetings in the downstate New York service territory. These meetings were designed to facilitate a dialogue with customers, residents, advocates, business leaders and local elected officials on potential solutions. Following the public meetings, the New York Gas Companies published a report that summarized the public feedback and provided additional information and analysis on the various long-term natural gas supply options. The New York Gas Companies are now working with regulators, stakeholders, and customers to find long-term solutions to the gas supply constraints in the region.

Downstate Order to Show Cause

On November 15, 2018, the NYPSC issued an Order to Show Cause against the New York Gas Companies for violations of gas safety regulations designed to ensure underground gas pipelines are protected from corrosion. The New York Gas Companies filed a response to the allegations.

On July 12, 2019, the NYPSC initiated a proceeding requiring the New York Gas Companies to demonstrate why a penalty action should not be commenced for more than 1,600 alleged gas safety violations. The alleged violations concern the NYPSC's investigation of improper operator qualification and related issues following a 2016 anonymous letter alleging a contractor had facilitated employees cheating on operator qualification exams. The NYPSC also alleges violations for the New York Gas Companies' employees and other contractors' workers whose qualifications had lapsed.

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 authorizes the New York Gas Companies 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 Brooklyn Union Gas Company and KeySpan Gas East Corporation's approved energy efficiency and demand response programs respectively. The use of the settlement funds will be subject to separate approval by the NYPSC in the ongoing rate case filed by the New York Gas Companies. On March 18, 2021, the NYPSC approved the settlement agreement. On August 12, 2021, the NYPSC approved the New York Gas Companies' rate case which authorizes the New York Gas Companies to use the $15 million and $6 million settlement amount to offset costs of Brooklyn Union Gas Company and KeySpan Gas East Corporation's approved energy efficiency and demand response programs in the current rate plan respectively.

Tax Act

In response to the Tax Act, the NYPSC issued an order instituting proceeding under Case 17-M-0815 - proceeding on motion of the NYPSC on changes in law that may affect rates. This proceeding was instituted to solicit comments on the Tax Act's implications and places the utilities on notice of the NYPSC's intent to protect ratepayers' interest and to ensure that any cost reductions from the changes in federal income taxes are deferred for future ratepayer benefit. On August 9, 2018, the NYPSC issued an order in its generic proceeding considering the impacts of federal tax reform. NYPSC Staff had advocated that all New York utilities implement a sur-credit by October 1, 2018 that would reflect the immediate effects of the Tax Act and also return any deferred benefits to customers. In response, the New York Gas Companies filed a proposal to (i) delay any sur-credit to January 1 to offset scheduled rate increases and (ii) retain any deferred benefits, including accumulated deferred federal income taxes ("ADFIT"), for future rate moderation.

The NYPSC's order effectively approved all aspects of the New York Gas Companies' proposal. The NYPSC agreed that the New York Gas Companies should be allowed to defer both the pass back of calendar year 2018 tax savings and the amortization of excess ADFIT balances and use the benefits as a rate moderator when base rates are next revised in 2020/2021. Specifically, the NYPSC approved the New York Gas Companies' proposal to implement a sur-credit to reflect the lower tax rate effective January 1, 2019 to offset planned rate increases and retain the calendar year 2018 deferred amounts for future rate mitigation and/or to offset investments. Deferring the tax benefits until January 1, 2019 results in a deferred balance of $40 million and $31 million for Brooklyn Union Gas Company and KeySpan Gas East Corporation respectively.

New York Management Audit

Refer to "New York Management Audit" section under Niagara Mohawk.

COVID-19 Affordability Programs

Refer to "COVID-19 Affordability Programs" section under Niagara Mohawk.

NYPSC Investigation

On June 17, 2021, five former National Grid employees in the downstate New York facilities department were arrested on federal charges alleging fraud and bribery. It is National Grid's understanding that the investigation by the US Attorney's Office and FBI remains ongoing; National Grid is a victim of the alleged crimes and will continue to comply with the government's investigation. On June 23, 2021, based on the US Attorney's announcement, the NYPSC issued an order commencing a proceeding to examine certain programs and related capital and operations and maintenance ("O&M") expenditures of NGUSA, and the New York Gas Companies. In compliance with the Order, National Grid submitted an initial report that includes, among other items, a description of all controls related to the capital and O&M contracting process and a listing of all contractor costs and open contract costs incurred by or on behalf of the facilities department for the period from 2013 through 2020. At this time, it is not possible to predict the outcome of the regulatory review or determine the amount, if any, of any potential liabilities that may be incurred by the Company related to this matter. However, National Grid does not expect this matter will have a materially adverse effect on its results of operations, financial position or cash flows.

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, and the Capital Investment Recovery Mechanism ("CIRM") will be discontinued after a transition period that concludes with nine months of recovery of vintage year 2019 investments through September 30, 2021, at which point the recovery of capital investments will fully transition 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, 2020, the Massachusetts Electric Company and Nantucket Electric filed the first annual PBR plan filing for rates effective October 1, 2020. 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 3.237%, or $26 million. On September 23, 2020, the DPU approved the Massachusetts Electric Company and Nantucket Electric's proposed PBR and Capital Expenditure Adjustment filing, effective October 1, 2020, subject to further investigation and reconciliation in the second phase of the proceeding. On February 25, 2021, the DPU provided its final approval of the Massachusetts Electric Company and Nantucket Electric's proposed PBR and Capital Expenditure Adjustment filing.

On June 15, 2021, the Massachusetts Electric Company and Nantucket Electric filed the next annual PBR plan filing for rates effective October 1, 2021. The result of the revenue cap formula is a proposed increase to base distribution revenue of 2.71%, or $23 million. The Massachusetts Electric Company and Nantucket Electric cannot predict the outcome of this request.

Recovery of Transmission Costs

The Massachusetts Electric Company's transmission facilities are operated in combination with the transmission facilities of its New England affiliates, Narragansett and NEP, as a single integrated system, with NEP designated as the combined operator. NEP collects the costs of the combined transmission asset pool, including a return on those facilities, under NEP's Tariff No. 1 from the Independent System Operator – New England ("ISO-NE"). The ISO-NE allocates these costs among transmission customers in New England, in accordance with the ISO-NE Open Access Transmission Tariff ("ISO-NE OATT").

According to the FERC's orders, 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 for the years ended March 31, 2021 and 2020 were $23 million and $20 million, respectively, which are reflected as credits within operations and maintenance expenses in the consolidated statements of operations and comprehensive income.

In November 2019, the FERC issued an order in the Midcontinent Independent System Operator ("MISO") ROE complaint dockets, changing the way it arrives at a just and reasonable ROE. The effects of these changes resulted in drastically reduced base ROEs in the MISO region. In the MISO order, the FERC made statements that it is setting new ROE policy nationwide. In December 2019, the New England Transmission Owners ("NETO") filed a supplemental brief in the New England ROE complaint dockets, showing the FERC the detrimental effects on New England if the MISO order was applied to New England. In the brief, the NETOs asked the FERC to reopen the record in New England so that the NETOs can 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 January 21, 2020, the FERC issued an order granting a rehearing for further consideration to give the FERC more time to act on the substantive issues of the MISO ROE proceedings. On May 21, 2020, the FERC revised its 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. ROEs were reduced from 10.32% to 9.88% when the FERC applied the revised methodology in two MISO ROE complaints. The May 2020 order relies on three models to estimate ROEs. The application of this new methodology increased ROEs in the MISO complaints from 9.88% to 10.02%. 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

In February 2018, the DPU opened an investigation to examine the effect of the Tax Act on the rates of the investor-owned utilities in Massachusetts as of January 1, 2018 and directed the utilities to account for any revenues associated with the difference between the previous and current corporate income tax rates and establish a regulatory liability for excess recovery in rates of ADIT. On December 21, 2018, the DPU issued an order requiring all utilities to begin crediting in rates the amortization of excess deferred federal income taxes, to the extent such amortization was not already included in base distribution rates, through the combination of factors associated with certain reconciling mechanisms and a separate factor for the amortization of the remaining amounts.

In February 2019, the DPU issued an order finding that the Massachusetts utilities were not required to refund tax savings previously accrued from January 1, 2018 through June 30, 2018, as a result of the federal income tax rate reduction.

On March 7, 2019, the Massachusetts Attorney General's ("AG") Office filed a motion for clarification and reconsideration, requesting that the DPU provide additional clarity regarding its February 2019 ruling, and reconsider its determination to allow utilities to keep the federal tax savings accrued from January 1, 2018 through June 30, 2018. To date, the DPU has not acted on or given any indication that it intends to act on the AG's motion.

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 and Nantucket Electric, submitted a compliance filing to address the application of Order 864 in NEP's Tariff No. 1. The filing proposes changes to various revenue requirement calculations in the tariff for the inclusion of the Rate Adjustment and Income Tax Allowance mechanisms. The filing also includes 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 and Nantucket Electric to amortize transmission-related, protected property-related excess or deficient ADIT associated with the 2017 Tax Act using the 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.

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, with four different proposed investment scenarios. On May 10, 2018, the DPU issued an order in this proceeding. The order approved $82 million in grid-facing investments over three years in: (1) conservation voltage reduction and volt/volt-amps reactive optimization; (2) advanced distribution automation; (3) feeder monitors; (4) communications and information / operational technologies; and (5) advanced distribution management / distribution supervisory control and data acquisition. The DPU allowed recovery of both operation and maintenance expenses and capital costs through a reconciling mechanism, and in the future will consider GMPs in separate dockets (i.e., not through rate cases). The DPU did not approve any customer-facing (i.e., advanced metering infrastructure) investments; the DPU will address these in a further investigation to see if there are ways to achieve cost-effective deployment of advanced metering functionality ("AMF"). The DPU found there needs to be widespread adoption of dynamic pricing for AMF to be successful, and the DPU needs to address how to facilitate this first. The DPU also refined its grid modernization objectives to place additional focus on improved access to the distribution system planning process. The Massachusetts Electric Company, together with Nantucket Electric have filed annual reports and cost recovery filings with the DPU for its GMP in 2019 and 2020. The Massachusetts Electric Company, together with Nantucket Electric filed its next proposed four-year GMP (for calendar years 2022–2025) on July 1, 2021. Additionally, on July 2, 2020, the DPU opened the next phase of its grid modernization investigation, in which it is investigating the potential deployment of AMF for electric vehicle ("EV") customers. So far, as part of this investigation, the DPU has received initial comments and held four technical sessions.

Operational and Management Audit

On September 30, 2019, in its decision regarding the Massachusetts Electric Company and Nantucket Electric's most recent request for a change in base distribution rates, the DPU stated that pursuant to its supervisory authority, it would require a comprehensive independent management audit of the Massachusetts Electric Company and Nantucket Electric, including a review of its relationship with National Grid USA Service Company. On November 25, 2019, the DPU formally opened the investigation to undertake an independent audit. The draft audit report was provided to the Massachusetts Electric Company and Nantucket Electric on March 1, 2021 for review and factual corrections, and the final report was submitted to the DPU on March 29, 2021. On April 30, 2021, the Massachusetts Electric Company and Nantucket Electric filed a comprehensive response to the audit report, formally adopting the findings and recommendations, with certain modifications, for the DPU's consideration. On June 30, 2021, the AG's office filed written comments in response to the final audit report. The Massachusetts Electric Company and Nantucket Electric and the independent auditor filed reply comments to the AG on July 21, 2021. This matter is currently pending before the DPU.

COVID-19 Moratorium on Utility Shut Offs

Starting with the first set of orders dated March 24, 2020, the Chairman of the DPU issued a series of orders in response to the Massachusetts Governor's declaration of a state of emergency due to the COVID-19 pandemic. In the first set of orders, the DPU prohibited the Massachusetts utilities from terminating service to any customer, including residential and commercial and industrial ("C&I") customers, for non-payment of utility bills until the state-of-emergency is lifted. Since that time, the state-of-emergency has been extended several times. On July 29, 2020, the DPU issued an order lifting the moratorium for C&I customers effective September 1, 2020. On September 10, 2020 (and renewed on October 23, 2020), the DPU extended the shut-off moratorium for residential customers until November 16, 2020 and prohibited utility companies from issuing communications prior to October 15, 2020 to any residential customers threatening the shut-off of utility service for failure to pay their bills. On November 18, 2020, the shut-off moratorium for residential customers was extended through April 1, 2021, and it was further extended under the eighth set of orders until July 1, 2021. Effective July 1, 2021, the Massachusetts Electric Company has 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.

On May 11, 2020, the DPU opened an inquiry into establishing policies and practices regarding customer assistance and ratemaking measures for electric and gas companies in response to the effects of the COVID-19 pandemic, and established a Customer Assistance and Ratemaking Working Group ("the Working Group") to develop appropriate policies and practices for the resumption of collections activities and to address ratemaking issues facing utilities. The Working Group's first report on customer assistance issues contained a four-phased plan for customer communications and outreach, which was approved by the DPU on June 26, 2020.

The highlights of the Customer Assistance Report of the Working Group filed on May 29, 2020 and approved on July 31, 2020 are as follows:

- Extended deferred payment arrangements - up to 12 months for residential and small C&I customers, with the ability to extend to 18 months for unique circumstances; up to six months for large C&I customers, with the terms to be determined on a case-by-case basis.

- Waiver of late fees for C&I customers (not applicable to residential customers).

- Revisions to existing residential Arrearage Management Plans ("AMPs") (to provide more flexible enrollment terms and an increase in arrearages forgiven from $4,000 to $12,000 on a temporary basis related to COVID-19). In the Massachusetts distribution companies' 2021 AMP filings, submitted on February 26, 2021, the distribution companies extended the terms of the COVID-19 AMP for the 2021 program year, but reserved the right to revert to the terms of their pre-COVID AMPs (e.g. lower arrearage forgiveness amounts) if financial circumstances for customers improved.

- Established a COVID-19 small C&I Arrearage Forgiveness Program ("AFP") to be in place through December 31, 2020. The small C&I AFP has since been extended through September 30, 2021.

Consistent with the approved customer outreach plan, the Massachusetts Electric Company and Nantucket Electric began notifying affected C&I customers of the resumption of collections and shutoff activities in August 2020, with terminations commencing during Fall 2020, and, as noted above, with the end of the residential moratorium on July 1, 2021, notifications to residential customers related to the possibility of terminations have resumed. The Massachusetts Electric Company and Nantucket Electric still continue to work collaboratively with the DPU and other Massachusetts local distribution companies through the Working Group process to address COVID-19 related customer outreach issues.

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 parties 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. However, 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. On March 1, 2021, the distribution companies filed their initial testimony in D.P.U. 20-91, which was further supplemented on April 30, 2021, on the following contested issues: (1) whether the distribution companies with PBR plans, including the Massachusetts Electric Company and Nantucket Electric, should be permitted to recover incremental bad debt costs and COVID-19 expenses; and (2) whether the distribution companies and their shareholders should absorb some losses associated with the pandemic and resulting economic downturn (the AG's position is that the distribution companies should only recover 50% of their COVID-19 costs). On March 8, 2021, the Massachusetts Electric Company and Nantucket Electric also submitted a proposal in D.P.U. 20-91 to offer residential customers a fee-free credit/debit card payment option that will allow customers to pay their bills electronically without an upfront transaction fee. Discovery in the proceeding is ongoing.

Massachusetts Petition for Waiver of Jurisdiction Regarding the Rhode Island Sale

On March 17, 2021, NGUSA announced the sale of its Rhode Island business to PPL Energy Holdings, LLC. 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 will own 100 percent of the outstanding shares of common stock in Narragansett. On May 4, 2021, NGUSA filed a petition with the DPU for a waiver of jurisdiction under G.L. c. 164, § 96(c), based on a finding that the sale of Narragansett will have no adverse impacts on any electric or gas distribution company held by NGUSA that is subject to the DPU's jurisdiction, as applicable, or the customers of any such electric or gas company. On July 16, 2021, the DPU issued an order approving NGUSA's request for a waiver of Section 96 regarding the sale of Narragansett.

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%. The Boston Gas Company's last rate case was filed in 2017.

On July 16, 2021, in response to allegations that five former New York-based National Grid employees accepted bribes and kickbacks from contractors, the DPU issued an interlocutory order to reopen the rate case record. This allowed the Massachusetts Attorney General to submit an additional discovery question related to these allegations. The Boston Gas Company responded to this discovery on July 30, 2021, with supplemental briefs by both the Massachusetts Attorney General and the Boston Gas Company filed on August 6, 2021. At this time, it is not possible to predict the outcome of the regulatory review or determine the amount, if any, of any potential liabilities that may be incurred by the Company related to this matter. However, National Grid does not expect this matter will have a materially adverse effect on its results of operations, financial position or cash flows.

Tax Act

Refer to "Tax Act" section under The Massachusetts Electric Companies.

COVID-19 Moratorium on Utility Shut Offs

Starting with the first set of orders dated March 24, 2020, the Chairman of the DPU issued a series of orders in response to the Massachusetts Governor's declaration of a state of emergency due to COVID-19 pandemic (refer to "COVID-19 Moratorium on Utility Shut Offs" section under The Massachusetts Electric Companies).

Gas System Enhancement Plan (GSEP)

On April 30, 2020, the DPU approved recovery of approximately $85 million in revenue requirements, related to approximately $283 million of anticipated investments in 2020 under an accelerated pipe replacement program, through GSEP. The rates effective from May 2020 to April 2021. The DPU also approved the Boston Gas Company's request to extend the timeline for replacement of leak-prone pipe in the former Colonial Gas Company service territory by nine years, moving the end date of the program from the year 2025 to 2034. The DPU also allowed for recovery of incremental costs of the repair of Grade 3 Significant Environmental Impact ("G3SEI") leaks, based on new requirements for the repair of G3SEI leaks.

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. The LDCs are required to jointly engage an independent consultant to review the Commonwealth's recently released 2050 Decarbonization Roadmap Study and Interim Clean Energy Climate Plan identifying potential pathways to achieve the state's objectives, identify any additional pathways and prepare LDC-specific proposals for achieving the state's objectives. The report and LDC-specific proposals are due to the DPU on March 1, 2022, with a status update filed on September 1, 2021.

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.

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 its decommissioned nuclear units cease.

Recovery of Transmission Costs

Transmission revenues are based on a formula rate that recovers NEP's actual costs plus a return on investment. Approximately 74% of NEP's transmission facilities are included under regional network service ("RNS") rates. NEP earns an additional 0.5% ROE incentive adder on RNS-related transmission facilities approved under the Regional Transmission Organization's ("RTO") Regional System Plan and placed in service on or before December 31, 2008. It also earns a 1.25% ROE incentive on its portion of New England East-West Solution ("NEEWS") (see the "New England East-West Solution" section).

NEP's transmission rates applicable to transmission service through October 15, 2014 reflected a base ROE of 11.14% applicable to NEP's transmission facilities, plus an additional 0.5% RTO participation adder applicable to transmission facilities included under the RNS rate. On October 16, 2014, the FERC issued an order, Opinion No. 531-A, reducing the base ROE applicable to transmission assets from 11.14% to 10.57% effective as of the date of the order and establishing a maximum ROE of 11.74%. On March 3, 2015, the FERC issued an Order on Rehearing, Opinion No. 531-B, affirming the 10.57% base ROE and clarifying that the 11.74% maximum ROE applies to all individual transmission projects with ROE incentives previously granted by the FERC. On April 14, 2017, the U.S. Court of Appeals for the D.C. Circuit (Court of Appeals) vacated and remanded FERC's Opinion No. 531 (and successor orders), through which the FERC had lowered the NETOs return on equity from 11.14% to 10.57% and capped the total incentives at 11.74%.

On October 16, 2018, the FERC issued an order on all four of NEP's ROE complaints (see the "FERC ROE Complaints" section in Note 13, "Commitments and Contingencies") describing how it intends to address the issues that were remanded by the Court. 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 stated that these calculations were merely preliminary and asked the parties to the NE Complaint cases to brief FERC and check the numbers. NEP along with other NETOs filed a brief supporting FERC's new methodology and confirming the illustrative numbers that FERC arrived at in the October 2018 order containing a 10.41% base ROE. FERC has not issued a final order on the briefs submitted by NEP and the base ROE in NE remains at a 10.57%.

On November 21, 2019, the FERC issued an order on the Midcontinent ISO transmission owners ("MISO") ROE complaint docket addressing transmission ROEs. In that order, the FERC adopted a new methodology for determining base ROEs for the MISO and expressed that it was setting new ROE policies nationwide, which differed significantly from the methodology and framework set forth in its October 16, 2018 FERC order on the NETOs' ROE dockets. On December 23, 2019, the NETOs filed a Supplemental Paper Hearing Brief and a Motion to supplement the record in the NETO ROE dockets to respond to the new methodology proposed in the MISO order. There is uncertainty to whether the order is applicable to the NETOs' cases and if so, would have a negative effect on NEP's base ROE. On January 21, 2020, the FERC issued an order granting rehearing for further consideration to give the FERC more time to act on the substantive issues of the MISO ROE proceedings.

On May 21, 2020, the FERC issued a revised order on the MISO ROE complaint docket addressing the substantive issues identified with the November 21, 2019 order. The November 19, 2019 order proposed the application of the average of two models to judge whether ROEs are just and reasonable which resulted in a reduced ROE of 9.88%, from 10.32%, when the proposed methodology is applied to the two MISO ROE complaints. The May 2020 order proposes the average of three models to judge whether ROEs are just and reasonable. When applied to the two MISO ROE complaints the revised methodology using the average of three models resulted in a base ROE of 10.02%, an increase from the methodology proposed in the November 19, 2019 order. In November 2020, FERC issued an order largely affirming the May 21, 2020 order and dismissing rehearings.

The FERC orders on the MISO ROE complaint proceedings, and the proposed revised ROE methodology, are specific to MISO however the FERC could order the revised methodology be applied to all transmission companies including our own ROE complaint proceedings. On May 12, 2020, NEP filed jointly with other NETOs supplemental arguments in the ROE Notice of Inquiry ("NOI") docket, which was commenced on March 21, 2019 and to which NEP previously responded, addressing concerns with ROE policy making and the methodologies proposed by the FERC in the MISO ROE compliant proceedings. From NEP's perspective, the May 21, 2020 FERC order on the MISO ROE complaint proceedings represents an improvement from the November 19, 2019 order but it does not address all the arguments filed jointly by NEP and the NETOs.

As of January 2021, the FERC has a full complement of commissioners and has the ability to apply the MISO orders to the NE Complaint proceedings at any time but has not done so as of the date of these financial statements. Until the FERC issues a final decision on NEP's own ROE complaints or an order applying the revised ROE methodology proposed in the MISO orders to all transmission companies, there is significant uncertainty, and, at this time, NEP does not know the impact to its current base ROE.

Transmission Incentive Policy Inquiry

On March 21, 2019, the FERC announced a NOI seeking comments on possible improvements to its electric transmission incentives policy to ensure that it appropriately encourages the development of the infrastructure needed to ensure grid reliability and reduce congestion to reduce the cost of power for consumers. NEP filed comments in the NOI docket on June 26, 2019 and filed reply comments on August 26, 2019.

On March 19, 2020, the FERC issued a Notice of Proposed Rulemaking ("NOPR"). In the NOPR, the FERC proposes to shift the test for transmission incentives from risks and challenges to an approach based on benefits to customers. The NOPR also proposes to: 1) Increase the incentives for joining and remaining a member of a Regional Transmission Organization, an Independent System Operator or other FERC-approved transmission organization from 50 basis points to 100 basis points; 2) Provide 50 basis point to transmission projects that meet a pre-construction benefit-to-cost ratio in the top 25% of projects examined over a sample period and an additional 50 basis points for projects that meet a post-construction benefit-to-cost ratio in the top 10% percent of projects over the same sample period; 3) Provide 50 basis points for projects that demonstrate reliability benefits by providing quantitative analysis and 4) Offer a 100 basis point incentive for transmission technologies that enhance reliability, efficiency, and capacity as well as improve the operation of new or existing transmission facilities. The NOPR also proposes a 250 basis point cap on total ROE incentives rather than limitation to the zone of reasonableness. Comments are requested within 90 days of publication in the Federal Register after which, at some point, the FERC will issue a final rule. NEP filed comments in response to the NOPR on July 1, 2020.

On April 15, 2021, the FERC issued a Supplemental Notice of Proposed Rulemaking (the "Supplemental NOPR") reversing its proposal in the March 19, 2020 NOPR to increase the incentives for joining and remaining a member of a Regional Transmission Organization, an Independent System Operator or other FERC-approved transmission organization from 50 basis points to 100 basis points. In the Supplemental NOPR, the FERC proposed that the incentive remain at 50 basis points and that the 50-basis-point increase in ROE be available for only the first three years after the transmitting utility transfers operational control of its facilities to an RTO/ISO. The FERC also stated that the statutory language actually only requires incentives to a utility that joins an RTO/ISO but not for remaining in an RTO/ISO in perpetuity. Comments on the Supplemental NOPR are currently due on May 26, 2021 but parties have asked for a 30-day extension to June 25, 2021. The FERC has granted the extension request. NEP filed joint comments on June 25, 2021 with other NETOs opposing the Supplemental NOPR.

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 (refer to "Tax Act" section under Niagara Mohawk). FERC will evaluate proposed amortization periods on a case by case basis.
On July 30, 2020, NEP, along with the NETOs, submitted a compliance filing to address the application of Order 864 in RNS and local network service ("LNS") rates. In the compliance filing, NEP has proposed to amortize protected and unprotected property related excess ADIT associated with the 2017 Tax Act using the ARAM and a 10-year amortization period on unprotected other excess or deficient balances. An effective date of January 1, 2021 was requested in order to align with the effective date that the NETOs had proposed for the new formula rate templates associated with the settlement filing in the FERC 206 Proceeding on Rate Transparency ("Settled Formula Rate").

On December 28, 2020, the FERC issued the settlement agreement order approving the settlement filing in the FERC 206 Proceeding on Rate Transparency. The FERC's approval order was issued after November 1, 2020, and under the terms of the settlement agreement, the effective date of the new formula rate templates will be January 1, 2022.
Given that the Settled Formula Rate will become effective January 1, 2022, the NETOs submitted a supplemental compliance filing on February 12, 2021 to propose tariff changes to the currently effective version of Attachment F to the ISO-NE OATT in order to comply with Order No. 864 for the period January 1, 2020 through December 31, 2021.

On March 1, 2021, ISO-NE, on behalf of NEP, submitted a supplemental compliance filing to supplement the July 30 compliance filing with respect to LNS under Schedule 21-NEP to the ISO-NE OATT. As with the RNS filing, NEP proposed that the compliance revisions to Schedule 21-NEP submitted in the LNS filing be in effect for an interim period from January 1, 2020, through December 31, 2021. For the period commencing January 1, 2022, compliance with Order No. 864 for LNS provided by NEP will be governed by the compliance revisions to the ISO-NE OATT submitted by NEP and the other NETOs in the FERC 206 Proceeding on Rate Transparency. NEP has proposed the same amortization method and periods for protected and unprotected balances as proposed in the initial filing.

In compliance with Order 864, NEP has also submitted additional compliance filings to amend various service agreements and contracts to include the Rate Adjustment and Income Tax Allowance mechanisms as well as the new permanent ADIT worksheet. The FERC has not yet acted on any of these compliance filings.

NEP estimates that the net excess ADIT balance associated with the TCJA of $295 million will result in an annual reduction in revenue requirement of $1 million.

New England East-West Solution ("NEEWS") Project

In September 2008, NEP, its affiliate Narragansett, and Northeast Utilities jointly filed an application with the FERC to recover financial incentives for the NEEWS project, pursuant to the FERC's Transmission Pricing Policy Order No. 679. NEEWS consists of a series of inter-related transmission upgrades identified in the New England Regional System Plan and is being undertaken to address a number of reliability problems in Connecticut, Massachusetts, and Rhode Island. Effective November 18, 2008, the FERC granted (1) an incentive ROE of 12.89% (125 basis points above the approved base ROE of 11.64% including the RTO participation adder), (2) 100% construction work in progress in rate base, and (3) recovery of plant abandoned for reasons beyond the companies' control. As discussed in the preceding section, effective October 16, 2014, the FERC issued a series of orders establishing a maximum ROE of 11.74% that effectively caps the NEEWS incentive ROE at that level. The NEEWS upgrades were placed in service in December 2015.

Narragansett

General Rate Case

On August 24, 2018 and pursuant to Report and Order No. 23823 issued May 5, 2020, the Rhode Island Public Utilities Commission ("RIPUC") approved the terms of an Amended Settlement Agreement ("ASA"). The ASA reflects an allowed ROE rate of 9.275% based on a common equity ratio of approximately 51%. We are currently in year three of the multi-year rate plan. On June 30, 2021, the Rhode Island Division of Public Utilities and Carriers ("Division") consented to an extension of the term of the Rate Plan such that Narragansett is not required to file the next rate case so that new rates take effect no later than September 1, 2022. The ASA will remain in effect and Narragansett will continue to operate under the current Rate Plan until a new Rate Plan is approved by the RIPUC. Narragansett filed a copy of the Division consent letter with the RIPUC on July 15, 2021. Base distribution rates will remain at the existing Rate Year 3 levels until the next base rate case.
The ASA includes an Electric Transportation Initiative (the ET Initiative or Program) to facilitate the growth of EV adoption and scaling of the market for EV charging equipment to advance Rhode Island's zero emission vehicles and greenhouse gas emissions policy goals. The ET Initiative includes the following five components: (i) Off-Peak Charging Rebate Pilot, (ii) Charging Station Demonstration Program, (iii) Discount Pilot for Direct Current Fast Charging ("DCFC") Station Accounts, (iv) Fleet Advisory Services, and (v) Electric Transportation Initiative Evaluation. As of the end of Rate Year 2, the Charging Station Demonstration Program achieved 72% of ET Initiative targets for Level 2 ports and 7% of the target for DCFC ports. The ASA also includes two energy storage demonstration projects because storage is critical for achieving Rhode Island's clean energy future as it provides the ability to optimize system performance over time and allows intermittent renewable resources to make a larger contribution to overall generation; both projects are on track for timely completion.

The ASA also introduces a new incentive-only performance incentive for System Efficiency: Annual Megawatt ("MW") Capacity Savings, with maximum earnings ranging from approximately $0.4 million in 2019 to $0.9 million in 2021. In addition, the ASA identifies several additional metrics for tracking and reporting purposes only.

Recovery of Transmission Costs

Narragansett's transmission facilities are operated in combination with the transmission facilities of its New England affiliates, Massachusetts Electric Company and Nantucket Electric and NEP, as a single integrated system with NEP designated as the combined operator (refer to "Recovery of Transmission Costs" section under The Massachusetts Electric Companies). The amounts remitted by NEP to Narragansett Electric Company for the years ended March 31, 2021 and 2020 were $160 million and $142 million, respectively, which are eliminated as operating revenues and operations and maintenance expenses within the consolidated statement of operations and comprehensive income.

On October 16, 2014, the FERC issued an order, Opinion No. 531-A, resetting the base ROE applicable to transmission assets under the ISO-NE OATT (refer to "Recovery of Transmission Costs" section under NEP).

On October 16, 2018, the FERC issued an order on all four complaints describing how it intends to address the issues that were remanded by the Court (refer to "Recovery of Transmission Costs" section under NEP). FERC has not issued a final order on our briefs and the base ROE in NE remains at a 10.57%. In November 2019, FERC issued an order in the Midcontinent Independent System Operator ("MISO") ROE complaint dockets changing the way it arrives at a just and reasonable ROE. The effects of these changes result in drastically reduced base ROEs in the MISO region. In that MISO order, FERC made statements that it is setting new ROE policy nationwide. In December 2019, the NETOs filed a supplemental brief in the NE ROE complaint dockets showing FERC the detrimental effects on NE if the MISO order were applied to NE. In that brief, the NETOs ask FERC to reopen the record in NE so that we can submit more testimony. Other stakeholders had an opportunity to reply to our supplemental brief by January 21, 2021 and did so, arguing that our request should be denied, and that the record in NE should not be reopened.

On January 21, 2020, the FERC issued an order granting rehearing for further consideration to give the FERC more time to act on the substantive issues of the MISO ROE proceedings. On May 21, 2020, FERC revised the methodology to determine MISO transmission owner ROEs. FERC's November order proposed to create "zones of reasonableness" based on averages of two (rather than four) models to judge whether ROEs are just and reasonable. ROEs were reduced from 10.32% to 9.88% when

FERC applied the revised methodology in two MISO ROE complaints. The May order relies on three models to estimate ROEs. The application of this new methodology increased ROEs in the MISO complaints from 9.88% to 10.02%. Narragansett does not believe the outcomes of these complaints will have a material impact on Narragansett'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 (refer to "Tax Act" under Niagara Mohawk). On April 16, 2020, the FERC issued Order No. 864-A addressing requests for clarification, or in the alternative, rehearing, submitted in the proceeding. FERC will evaluate proposed amortization periods on a case by case basis.

On June 29, 2020, NEP, on behalf of Narragansett, submitted a compliance filing to address the application of Order 864 in NEP Tariff No. 1 (refer to "Tax Act" under The Massachusetts Electric Companies). Narragansett's transmission related net excess ADIT balance associated with the Tax Act is $100 million.

New England East-West Solution ("NEEWS") Project

Refer to "New England East-West Solution ("NEEWS") Project" section under NEP.

Suspension of Service Terminations and Certain Collections Activities

At an open meeting on March 16, 2020, the RIPUC issued an order prohibiting all electric, natural gas, water, and sewer utilities from engaging in certain collections activities, including termination of residential and non-residential service for nonpayment (the "Order"). This moratorium expired on July 18, 2020 for commercial and industrial customers, on September 30 for residential customers, and on November 1, 2020 for customers eligible for the low-income rate. On July 25, 2021, the RIPUC's extension of the moratorium on service disconnections for National Grid's protected status customers, including those on National Grid's low-income rate, expired. Per the RIPUC's June 25, 2021 order extending the moratorium to July 25, 2021, there will be no further extensions, unless there is substantial evidence of a major resurgence of the COVID-19 pandemic. To date, the RIPUC has not ordered any additional extensions of the moratorium so the moratorium is no longer in effect. The RIPUC's order directing Narragansett to temporarily suspend late fees, interest charges, credit card fees, debit card fees and ACH fees remains in effect, and Narragansett continues to track these costs for later review by the RIPUC. The RIPUC will review these costs in Narragansett's cost recovery filing in a separate docket (RIPUC Docket No. 5154). Narragansett continues to offer the 18-24-36 month payment plans per the RIPUC's order.

On May 15, 2020, pursuant to the RIPUC's directive, Narragansett filed a plan with the RIPUC and the Division that details Narragansett's plans for recommencing collection activities when the RIPUC lifts the moratorium on utility terminations (the "Plan"). The Plan consists of a four-phase approach, including initial efforts primarily focused on "bill health" messaging and assuring that customers are aware of the programs and services available to assist them with managing and paying their bills. Narragansett continues to progress through the phases of the Plan and submit arrearage data to the RIPUC and the Division on a weekly and monthly basis, respectively. On September 2, 2021, Narragansett filed its responses to the RIPUC's data requests regarding waived fees.

Advanced Metering Functionality and Grid Modernization

On January 21, 2021, Narragansett filed its updated AMF Business Case and GMP with the RIPUC in accordance with the rate case settlement. The updated AMF Business Case - a foundational component of the GMP – seeks approval to deploy smart meters throughout the service territory. The updated AMF Business Case includes approximately $224 million (20-year net present value)/$344 million (20-year nominal) of investment in smart meters and the associated communications infrastructure, as well as customer education and engagement based on a joint deployment scenario with New York. The GMP consists of a five-year implementation plan and ten-year roadmap that serve as a guide for addressing anticipated distribution system needs. Although Narragansett is not seeking cost recovery for any specific GMP investment at this time, Narragansett is seeking approval of the GMP business case and benefit-cost analysis, which will provide regulatory clarity when seeking to implement such projects and pursue cost recovery as part of the Infrastructure, Safety and Reliability Plan or a future rate case. Pursuant to written order issued on July 14, 2021, the RIPUC stayed the AMF and GMP proceedings pending further consideration following the issuance of a final Order by the Division on the PPL Transaction. The RIPUC did not rule on whether or not to consolidate the matters.

COVID-19 Deferral Filing

On April 30, 2021, Narragansett filed a petition for approval to recognize regulatory assets related to COVID-19 impacts (RIPUC Docket No. 5154). In its Petition, Narragansett seeks the RIPUC's authorization to recognize regulatory assets and consideration of future cost recovery for the following COVID-19 Costs: (1) the increased cost of customer accounts receivable that Narragansett will be unable to collect as a result of the COVID-19 pandemic, and the executive orders and RIPUC orders restricting Narragansett's collection activities as a result of the pandemic, which will result in increased net charge-offs; (2) lost revenue from unassessed late payment charges; and (3) charges to Narragansett for other fees that Narragansett has waived pursuant to the RIPUC's orders in RIPUC Docket No. 5022. Narragansett will continue to monitor the proceeding, pending any updates or new directive issued by the RIPUC.

PPL Transaction

Pursuant to a Share Purchase Agreement dated March 17, 2021, by and among PPL Energy Holdings, LLC, PPL Corporation ("PPL"), and National Grid USA (the "Transaction"), National Grid USA has agreed to sell 100 percent of the outstanding shares of common stock in Narragansett to PPL Rhode Island Holdings, LLC ("PPL Rhode Island"), a wholly owned indirect subsidiary of PPL. On May 4, 2021, PPL, PPL Rhode Island, National Grid USA, and Narragansett filed a joint petition with the Division seeking the Division's consent and approval of the Transaction, which is currently pending in Docket No. D-21-09.

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,	
	2021	2020
	(in millions of dollars)	
Plant and machinery	**$ 40,312**	$ 41,902
Assets in construction	**2,792**	2,539
Land and buildings	**2,172**	2,259
Software and other intangibles	**1,592**	1,365
Operating leases ROU assets	**989**	888
Total property, plant and equipment	**47,857**	48,953
Accumulated depreciation – Tangible assets	**(9,615)**	(10,063)
Accumulated amortization – Software and other intangibles	**(1,003)**	(894)
Accumulated amortization – Operating lease ROU assets	**(237)**	(142)
Property, plant and equipment, net	**$ 37,002**	$ 37,854

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 $131 million in the year ended March 31, 2021. At March 31, 2022, amortization expense is estimated to be $140 million, $123 million, $100 million, $89 million and $69 million for 2021 through 2026, 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. The financing derivatives consisted of foreign exchange forward contracts of zero and $339 million at March 31, 2021 and 2020.

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

	March 31,	
	2021	2020
	(in millions)	
Gas contracts (dths)	**123**	133
Electric contracts (mwhs)	**13**	13

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, 2021 and 2020:

	March 31, 2021 (in millions of dollars)		
	Gross amounts of recognized assets (liabilities)	**Gross amounts not offset on the Consolidated Balance Sheet**	**Net amount**
	A	*B*	*C = A-B*
ASSETS:			
Current assets			
Gas contracts	$ 3	$ (3)	$ 6
Electric contracts	11	6	5
Other non-current assets			
Electric contracts	3	3	-
Total	17	6	11
LIABILITIES:			
Current liabilities			
Gas contracts	21	1	20
Electric contracts	24	6	18
Other non-current liabilities			
Gas contracts	47	-	47
Electric contracts	20	3	17
Total	112	10	102
Net assets (liabilities)	$ (95)	$ (4)	$ (91)

	March 31, 2020 (in millions of dollars)		
	Gross amounts of recognized assets (liabilities)	**Gross amounts not offset on the Consolidated Balance Sheet**	**Net amount**
	A	*B*	*C = A - B*
ASSETS:			
Current assets			
Gas contracts	$ 10	$ 5	$ 5
Electric contracts	5	3	2
Other non-current assets			
Electric contracts	2	1	1
Total	17	9	8
LIABILITIES:			
Current liabilities			
Gas contracts	44	1	43
Electric contracts	63	3	60
Foreign exchange forward contracts	10	1	9
Other non-current liabilities			
Gas contracts	46	-	46
Electric contracts	40	10	30
Total	203	15	188
Net assets (liabilities)	$ (186)	$ (6)	$ (180)

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 does 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, 2021 and 2020:

	Location	Year Ended March 31,			
		2021		2020	
		(in millions of dollars)			
Electric contracts	Purchased electric	**$**	**(57)**	$	(80)
Gas contracts	Purchased gas		**(20)**		(36)
Total gains (losses) recognized in earnings		**$**	**(77)**	$	(116)

The following table summarizes changes in 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, 2021 and 2020:

	Location	Year Ended March 31,			
		2021		2020	
		(in millions of dollars)			
Electric contracts	Regulatory Assets	**$**	**30**	$	97
Gas contracts(1)	Regulatory Assets		**72**		80
Total changes in regulatory assets		**$**	**102**	$	177

(1) Amount reported includes $7 million regulatory assets reported as Held for sale.

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 $91 million and $172 million as of March 31, 2021 and 2020, 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, 2021 and 2020 was $34 million and $106 million, respectively. The Company had zero and $10 million collateral posted for these instruments as of March 31, 2021 and 2020, respectively. At March 31, 2021, 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 $4 million, $20 million, or $36 million, respectively. At March 31, 2020, 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 $9 million, $27 million, or $109 million, respectively.

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.

In relation to the Company's financial derivative instruments, if the Company's credit rating were to be downgraded by one level it would not be required to post any additional collateral at March 31, 2021 and 2020, respectively. At March 31, 2021, if the Company's credit rating were to be downgraded by two or three levels, it would not be required to post any additional collateral to its counterparties for each downgrade. At March 31, 2020, if the Company's credit rating were to be downgraded by two or three levels, it would be required to post additional collateral to its counterparties of $12 million for each downgrade.

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, 2021 and 2020:

	March 31, 2021			
	Level 1	Level 2	Level 3	Total
	(in millions of dollars)			
Assets:				
Derivative instruments				
Gas contracts	$ -	$ 2	$ 1	$ 3
Electric contracts	-	13	1	14
Financial instruments				
Securities	176	184	-	360
Total	176	199	2	377
Liabilities:				
Derivative instruments				
Gas contracts	-	60	8	68
Electric contracts	-	42	2	44
Total	-	102	10	112
Net assets (liabilities)	$ 176	$ 97	$ (8)	$ 265

	March 31, 2020			
	Level 1	Level 2	Level 3	Total
	(in millions of dollars)			
Assets:				
Derivative instruments				
Gas contracts	$ -	$ 9	$ 1	$ 10
Electric contracts	-	5	2	7
Financial instruments				
Securities	136	162	-	298
Total	136	176	3	315
Liabilities:				
Derivative instruments				
Gas contracts	-	73	17	90
Electric contracts	-	102	1	103
Foreign exchange forward contracts	-	10	-	10
Total	-	185	18	203
Net assets (liabilities)	$ 136	$ (9)	$ (15)	$ 112

The Company’s Level 2 fair value derivative instruments primarily consist of over-the-counter (“OTC”) currency swap transactions, and 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, 2021 or March 31, 2020.

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.

	Longest maturity date	Amortized Cost		Fair Value	
		March 31,			
		2021	2020	**2021**	2020
		(in millions of dollars)			
Rabbi Trust municipal bonds	2057	**$ 175**	$ 143	**$ 184**	$ 162

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, 2021 and March 31, 2020:

	Location	March 31,	
		2021	2020
		(in millions of dollars)	
Gross realized gains	Other income, net	**$ 2**	$ -
Gross realized losses	Other income, net	**(2)**	-
Net unrealized gains (losses) on debt securities	OCI	**1**	8

Equity Securities

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

	Location	March 31,	
		2021	2020
		(in millions of dollars)	
Gross realized gains	Other income, net	**$ 15**	$ 7
Gross realized losses	Other income, net	**(3)**	(1)
Net unrealized gains (losses) on equity securities	Other income, net	**61**	(11)

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, 2021 and 2020, the Company made contributions of approximately $123 million and $173 million, respectively, to the qualified pension plans. The Company expects to contribute $126 million to the qualified pension plans during the year ending March 31, 2022.

Benefit payments to pension plan participants for the years ended March 31, 2021 and 2020 were approximately $498 million and $481 million, respectively.

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, 2021 and 2020, the Company made contributions of $20 million and $7 million, respectively, to the PBOP plans. The Company does not expect to contribute to the PBOP plans during the year ending March 31, 2022.

Benefit payments to PBOP plan participants for the years ended March 31, 2021 and 2020 were approximately $190 million and $201 million, respectively.

Net Periodic Benefit Costs

The Company's net periodic benefit pension cost for the years ended March 31, 2021 and 2020 was $213 million and $137 million, respectively.

The Company's net periodic benefit PBOP cost for the years ended March 31, 2021 and 2020 was $35 million and $7 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 and AOCI for the years ended March 31, 2021 and 2020:

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2021	2020	**2021**	2020
	(in millions of dollars)			
Net actuarial loss (gain)	**$ (703)**	$ 700	**$ (991)**	$ 337
Amortization of net actuarial loss	**(214)**	(188)	**(31)**	(15)
Amortization of prior service (cost) credit, net	**(6)**	(8)	**-**	4
Total	**$ (923)**	$ 504	**$ (1,022)**	$ 326
Included in regulatory assets (liabilities)	**$ (751)**	$ 393	**$ (883)**	$ 263
Included in AOCI	**(172)**	111	**(139)**	63
Total	**$ (923)**	$ 504	**$ (1,022)**	$ 326

The Company's regulated subsidiaries have regulatory recovery of these obligations and therefore amounts are included in regulatory assets 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

The following tables summarize the Company's amounts in regulatory assets and AOCI on the consolidated balance sheets that have not yet been recognized as components of net actuarial loss as of March 31, 2021 and 2020:

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2021	2020	**2021**	2020
	(in millions of dollars)			
Net actuarial loss (gain)	**$ 702**	$ 1,811	**$ (656)**	$ 391
Prior service cost (credit)	**34**	41	**-**	-
Total	**$ 736**	$ 1,852	**$ (656)**	$ 391
Including in regulatory assets (liabilities)	**$ 631**	$ 1,573	**$ (541)**	$ 367
Including in AOCI	**105**	279	**(115)**	24
Total	**$ 736**	$ 1,852	**$ (656)**	$ 391

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, 2021 and 2020:

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2021	2020	**2021**	2020
	(in millions of dollars)			
Projected benefit obligation	**$ (9,468)**	$ (9,552)	**$ (4,194)**	$ (4,374)
Fair value of plan assets	**9,501**	8,659	**3,862**	2,995
Total	**$ 33**	$ (893)	**$ (332)**	$ (1,379)
Non-current assets	**$ 597**	$ 374	**$ 376**	$ 3
Current liabilities	**(22)**	(24)	**(8)**	(9)
Non-current liabilities	**(542)**	(1,243)	**(700)**	(1,373)
Total	**$ 33**	$ (893)	**$ (332)**	$ (1,379)

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 exceeded the fair value of plan assets as of March 31, 2021 and 2020. The aggregate APBO balance for the Pension Plans was $9.1 billion and $9.2 billion as of March 31, 2021 and 2020, respectively.

For the year end March 31, 2021, the net actuarial gain for pension and PBOP was largely the result of asset performance well above expectations and favorable contract negotiations for PBOP, partially offset by liability losses generated from the discount rate decrease and census data experience. For the year end March 31, 2020, the net actuarial loss for pension and PBOP was primarily driven by the discount rate decrease and asset performance below expectations. This loss was partially offset by a gain related to a change in the mortality assumption and a PBOP assumption change for post-65 participation rates.

Expected Benefit Payments

Based on current assumptions, the Company expects to make the following benefit payments subsequent to March 31, 2021:

(in millions of dollars) **Years Ended March 31,**	**Pension Plans**	**PBOP Plans**
2022	$ 514	$ 175
2023	494	181
2024	484	187
2025	481	192
2026	477	196
2027-2031	2,302	1,019
Total	$ 4,752	$ 1,950

Assumptions Used for Employee Benefits Accounting

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2021	2020	**2021**	2020
Benefit Obligations:				
Discount rate	**3.25%**	3.65%	**3.25%**	3.65%
Rate of compensation increase (non-union)	**4.10%**	3.50%	**N/A**	N/A
Rate of compensation increase (union)	**4.50%**	3.50%	**N/A**	N/A
Weighted-average interest crediting rate for cash balanced plans	**2.90%**	3.30%	**N/A**	N/A
Net Periodic Benefit Costs:				
Discount rate	**3.65%**	4.10%	**3.65%**	4.10%
Rate of compensation increase	**3.50%**	3.50%	**N/A**	N/A
Expected return on plan assets	**5.00% - 6.00%**	6.00% - 6.50%	**6.50% - 7.00%**	6.00% - 7.25%
Weighted-average interest crediting rate for cash balanced plans	**3.30%**	N/A	**N/A**	N/A

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,	
	2021	2020
Health care cost trend rate assumed for next year		
Pre 65	**6.80%**	7.00%
Post 65	**5.40%**	5.50%
Prescription	**7.70%**	8.00%
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 study 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 2021 reflects the results of such a pension study conducted in 2019. As a result of that asset liability study the asset mix for the Niagara Mohawk Pension Plan was changed to further reduce investment risk given the overfunded nature and shorter duration of liabilities in that plan compared to the other pension plans. The Union PBOP Plan asset liability study was conducted in 2021. As a result of that study the RPC approved changes to the Union PBOP asset allocation effective in fiscal year 2022. The Non-Union PBOP Plan asset liability study is expected to be run within the next 12-18 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, 2021 and 2020 are as follows:

	Pension Plans		Union PBOP Plans		Non-Union PBOP Plans	
	March 31,		March 31,		March 31,	
	2021	2020	**2021**	2020	**2021**	2020
Equity	**37%**	37%	**63%**	63%	**70%**	70%
Diversified alternatives	**10%**	10%	**17%**	17%	**0%**	0%
Fixed income securities	**40%**	40%	**20%**	20%	**30%**	30%
Private equity	**5%**	5%	**0%**	0%	**0%**	0%
Real estate	**5%**	5%	**0%**	0%	**0%**	0%
Infrastructure	**3%**	3%	**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, 2021				
	Level 1	Level 2	Level 3	Not categorized	Total
			(in millions of dollars)		
Pension assets:					
Investments					
Equity	$ 804	$ -	$ -	$ 2,844	$ 3,648
Diversified alternatives	245	-	-	671	916
Corporate bonds	-	2,315	-	743	3,058
Government securities	4	1,140	-	777	1,921
Private equity	-	-	-	628	628
Real estate	-	-	-	364	364
Infrastructure	-	-	-	179	179
Total assets	$ 1,053	$ 3,455	$ -	$ 6,206	$ 10,714
Assets held for sale					(625)
Pending Transactions					(588)
Total net assets					$ 9,501
PBOP assets:					
Investments					
Equity	$ 606	$ -	$ -	$ 1,888	$ 2,494
Diversified alternatives	268	-	-	249	517
Corporate bonds	-	22	-	-	22
Government securities	77	695	-	2	774
Private Equity	-	-	-	-	-
Insurance contracts	-	-	-	237	237
Total assets	$ 951	$ 717	$ -	$ 2,376	$ 4,044
Assets held for sale					(185)
Pending Transactions					3
Total net assets					$ 3,862

	March 31, 2020				
	Level 1	Level 2	Level 3	Not categorized	Total
			(in millions of dollars)		
Pension assets:					
Investments					
Equity	$ 581	$ -	$ -	$ 2,026	$ 2,607
Diversified alternatives	201	-	-	575	776
Corporate bonds	-	1,986	-	639	2,625
Government securities	(17)	1,158	-	902	2,043
Private equity	-	-	-	489	489
Real estate	-	-	-	381	381
Infrastructure	-	-	-	173	173
Insurance contracts	-	-	-	4	4
Total assets	$ 765	$ 3,144	$ -	$ 5,189	$ 9,098
Pending Transactions					(439)
Total net assets					$ 8,659
PBOP assets:					
Investments					
Equity	$ 438	$ -	$ -	$ 1,287	$ 1,725
Diversified alternatives	201	-	-	199	400
Corporate bonds	-	18	-	-	18
Government securities	66	610	-	2	678
Private Equity	-	-	-	1	1
Insurance contracts	-	-	-	164	164
Total assets	$ 705	$ 628	$ -	$ 1,653	$ 2,986
Pending Transactions					9
Total net assets					$ 2,995

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

Corporate Bonds: Corporate Bonds consists 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 consists of Trust Owned Life Insurance.

Pending Transactions/Receivables/Payables: Accounts receivable and accounts payable 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, 2021 and 2020, the Company recognized an expense in the accompanying consolidated statements of operations and comprehensive income of $88 million and $79 million, respectively.

10. CAPITALIZATION

The aggregate maturities of long-term debt for the years subsequent to March 31, 2021 are as follows:

(in millions of dollars) **March 31,**	**Maturities of Long-Term Debt**
2022	$ 58
2023	459
2024	104
2025	523
2026	648
Thereafter	11,196
Total	$ 12,988

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, 2021 and 2020, the Company was in compliance with all such covenants.

Significant Debt Facilities

Notes Payable

The following table represents the Company's notes payable for the years ended March 31, 2021 and 2020:

	Interest Rate	Maturity Date	March 31, 2021	2020
			(in millions of dollars)	
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
Brooklyn Union Notes			**2,650**	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
KeySpan Gas East Notes			**1,200**	1,200
Boston Gas Unsecured Notes:				
Senior Note	3.30%	March 15, 2022	**25**	25
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	4.49%	February 15, 2042	**500**	500
Senior Note	4.63%	March 15, 2042	**25**	25
Boston Gas Medium-Term Notes:				
MTN Series 1990 A	9.75%	December 1, 2020	**-**	5
MTN Series 1990 A	9.05%	September 1, 2021	**15**	15
MTN Series 1992 A	8.33%	July 5, 2022	**10**	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			**1,771**	1,776
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**	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**	-
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**	-
Niagara Mohawk Notes			**3,200**	2,100
Narragansett Electric Unsecured Notes:				
Senior Note (1)	3.92%	August 1, 2028	**350**	350
Senior Note (1)	3.40%	April 9, 2030	**600**	-
Senior Note (1)	5.64%	March 15, 2040	**300**	300
Senior Note (1)	4.17%	December 10, 2042	**250**	250
Narragansett Electric Notes			**1,500**	900
Massachusetts Electric Unsecured Notes:				
Senior Note	1.73%	November 24, 2030	**500**	-
Senior Note	5.90%	November 15, 2039	**800**	800
Senior Note	4.00%	August 15, 2046	**500**	500
Massachusetts Electric Notes:			**1,800**	1,300
New England Power Unsecured Notes:				
Senior Notes	3.80%	December 5, 2047	**400**	400
Senior Notes	2.81%	October 6, 2050	**400**	-
New England Power Notes:			**800**	400
Total			**$ 13,628**	$ 11,033

(1) Related to held for sale, see Note 17 "Held for sale".

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 $138 million and $156 million as of March 31, 2021 and 2020, respectively, of which $18 million is included in current portion of long-term debt on the consolidated balance sheets as of March 31, 2021 and 2020. 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 with interest rage ranging from 6.90% to 8.80% of $75 million at March 31, 2021 and 2020. These FMB indentures include, among other provisions, limitations on the issuance of long-term debt.

State Authority Financing Bonds

At March 31, 2021, the Company had outstanding $647 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 $157 million were issued through various other state agencies.

At March 31, 2021, 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 has $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 1.00% to 10.44% during the year ended March 31, 2021 and 0.85% to 10.44% during the year ended March 31, 2020. 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 0.06% to 5.15% during the year ended March 31, 2021 and 0.90% to 5.15% during the year ended March 31, 2020.

At March 31, 2021, NEP had outstanding $106 million of Pollution Control Revenue Bonds in tax-exempt commercial paper mode and Nantucket had $51 million of Electric Revenue Bonds in tax exempt commercial paper mode. 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

NEP had an outstanding Term Loan of zero and $100 million as of March 31, 2021 and 2020, respectively. The Term Loan was due to mature in March 2022, with variable interest rate range at 3-month LIBOR plus 0.55%. On October 30, 2020, the Company prepaid the $100 million bank term loan at par.

On September 28, 2021, the Brooklyn Union Gas Company entered into a $400 million Term Loan. The Term Loan has a maturity date of December 2022

Standby Bond Purchase Agreement

NEP and Nantucket have a Standby Bond Purchase Agreement, which expires on June 14, 2023. This agreement provides liquidity support for the $157 million long-term bonds in tax-exempt commercial paper mode. 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, 2021, the Company, NGNA, and the Parent had committed revolving credit facilities of $3.6 billion, of which $2.1 billion was due to mature in May 2022, $0.4 billion matures in June 2023, $0.9 billion matures in June 2024 and $0.2 billion matures in June 2025. The $2.1 billion of facilities due to mature in May 2022 were renegotiated in the period after March 31, 2021. The renegotiated facilities have the size of $2.7 billion, a new maturity date of May 2024 and include two one-year extension options to May 2025 and May 2026. 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 $3.6 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, 2021 and 2020, the Company, NGNA, and the Parent were in compliance with all covenants.

Commercial Paper and Revolving Credit Agreements

At March 31, 2021, the Company had two commercial paper programs approximately totaling $4.4 billion; a $2 billion U.S. commercial paper program and a €2 billion Euro commercial paper program. In support of these programs, the Company was a named borrower under the Parent's credit facilities with $3.6 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, 2021 the Company had zero outstanding commercial papers. At March 31, 2020, there were $483 million of borrowings outstanding on the U.S. commercial paper program and $328 million outstanding on the Euro commercial paper program. The Company's two commercial paper programs were terminated in May 2021 as NGNA replaced the Company as the main commercial paper issuer entity in the US.

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 January 11, 2021 and expires on October 14, 2022. Niagara Mohawk had no external short-term debt as of March 31, 2021 and 2020.

The NYPSC authorized Niagara Mohawk to issue up to $2.1 billion of incremental long-term debt in one or more transactions through March 31, 2020. The authorization includes the option to issue up to $430 million of the total authorization for a refunding of Niagara Mohawk's existing debt.

Under the authorization, Niagara Mohawk converted $424 million of tax-exempt revenue bonds from a variable interest rate into a fixed rate and issued $500 million of unsecured long-term debt at 4.28%. Prior to the expiration, Niagara Mohawk filed and received approval from the NYPSC for a one-year extension of the remaining $1.1 billion of authorization through March 31, 2021. Prior to the expiration/under the extended authorization, on June 25, 2020, Niagara Mohawk issued $600 million of unsecured senior long-term debt at a fixed rate of 1.96% with a maturity date of June 27, 2030 and $500 million of unsecured senior long-term debt at a fixed rate of 3.03% with a maturity date of June 27, 2050.

On April 1, 2021, Niagara Mohawk petitioned the NYPSC for authorization to issue, from time to time, through June 30, 2024, new long-term debt in an amount not to exceed $3 billion. On September 13, 2021, the NYPSC authorized Niagara Mohawk to issue up to $2.3 billion of new long-term debt securities. The authorized securities will enable Niagara Mohawk to fund the construction of utility plant, refinance maturing and/or redeemed issues of debt, redemption of preferred stock, refinance callable debt, refinance short-term debt with long-term debt, finance the capital needs of Niagara Mohawk, and meet other general corporate purposes through June 30, 2024, subject to the terms of the order. In addition, Niagara Mohawk is seeking the ability to redeem the preferred stock of approximate $29 million under the requested authorization in lieu of a New Debt issuance, should the economics demonstrate a benefit to customers.

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. As of March 31, 2021, $400 million of debt authorization remains under the NYPSC order.

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. KeySpan Gas East did not issue any debt under the authorization during the year ended March 31, 2021.

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 January 11, 2021 and expires on October 14, 2022. Massachusetts Electric had no external short-term debt as of March 31, 2021 and 2020.

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 1.7% 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, 2020 and expires on October 14, 2022. NEP had no short-term debt outstanding as of March 31, 2021 and 2020.

On May 23, 2017, NEP had received all required approvals from the Massachusetts Department of Public Utilities, New Hampshire Public Utilities Commission and Vermont Public Service Board authorizing NEP to issue up to $800 million of long-term debt in one or more transactions through May 23, 2020. On November 30, 2017, NEP issued $400 million of unsecured senior long-term debt with a maturity date of December 5, 2047. In addition, NEP entered into a bank term loan for $100 million on March 31, 2020 with a maturity date of March 31, 2022. On October 30, 2020, the Company prepaid the $100 million bank term loan.

On August 31, 2020, NEP received additional approvals from the Massachusetts Department of Public Utilities, New Hampshire Public Utilities Commission and Vermont Public Service Board authorizing NEP to issue up to $1.1 billion of long-term debt in one or more transactions through August 31, 2023. On October 6, 2020, NEP issued $400 million of unsecured senior long-term debt with a maturity date of October 6, 2050, resulting in $700 million of remaining authorization.

Genco

Genco has had regulatory approval from the FERC to issue up to $250 million of short-term debt. The authorization was renewed with an effective date of January 11, 2021 and expires on October 14, 2022. Genco had no short-term debt outstanding to third-parties as of March 31, 2021 or 2020.

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 January 11, 2021 and expires on October 14, 2022. Nantucket had no external short-term debt as of March 31, 2021 and 2020.

Narragansett (Held for sale)

Narragansett, which is reported as Held for sale as of March 31, 2021 (see Note 17, "Held for sale"), has regulatory approval from the FERC to issue up to $400 million of short-term debt. The authorization was renewed with an effective date of January 11, 2021 and expires on October 14, 2022. Narragansett had no external short-term debt as of March 31, 2021 and 2020. A new financing petition was filed with the RIPUC and approved on January 19, 2020 authorizing the issuance of up to $900 million of new long-term debt through March 31, 2023. In April 2020, Narragansett issued $600 million of unsecured long-term debt at 3.395% with a maturity date of April 9, 2030, resulting in $300 million of remaining authorization.

11. INCOME TAXES

Components of Income Tax Expense

	Years Ended March 31,	
	2021	2020
	(in millions of dollars)	
Current tax expense (benefit):		
Federal	**$ 49**	$ (3)
State	**(12)**	38
Total current tax expense	**37**	35
Deferred tax expense:		
Federal	**168**	245
State	**117**	80
Total deferred tax expense	**285**	325
Amortized investment tax credits [1]	**(1)**	(2)
Total deferred tax expense	**284**	323
Total income tax expense	**$ 321**	$ 358

[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, 2021 and 2020 are 25.9% and 25.6%, 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,	
	2021	2020
	(in millions of dollars)	
Computed tax	**$ 260**	$ 294
Change in computed taxes resulting from:		
State income tax, net of federal benefit	**83**	93
Audit and related reserve movements	**29**	(6)
Amortization of regulatory tax liability	**(25)**	(26)
Cash surrender value	**(24)**	4
Other	**(2)**	(1)
Total changes	**61**	64
Total income tax expense	**$ 321**	$ 358

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.

Deferred Tax Components

	March 31,	
	2021	2020
	(in millions of dollars)	
Deferred tax assets:		
Allowance for doubtful accounts	**$ 239**	$ 145
Environmental remediation costs	**643**	677
Reserves not currently deducted	**278**	265
Net operating losses	**530**	607
Postretirement benefits and other employee benefits	**469**	796
Regulatory liabilities	**1,549**	1,446
Other	**284**	284
Total deferred tax assets	**3,992**	4,220
Deferred tax liabilities:		
Property-related differences	**6,179**	5,782
Regulatory assets	**1,440**	1,799
Other	**391**	302
Total deferred tax liabilities	**8,010**	7,883
Net deferred income tax liabilities	**4,018**	3,663
Deferred investment tax credits	**41**	36
Deferred income tax liabilities, net	**$ 4,059**	$ 3,699

In April 2021, New York State enacted the 2021/2022 state budget, which included several tax related provisions. The enacted budget includes raising the corporate franchise tax rate to 7.25% and reinstating the capital base of the franchise tax at 0.1875% for three years as part of a three-year COVID recovery plan. The new legislation is effective for tax years beginning on or after January 1, 2021 and before January 1, 2024, which for the Company includes fiscal years ending March 31, 2022 through March 31, 2024. The Company is evaluating the impact of the new legislation, but in accordance with US GAAP, no adjustments have been made as of the balance sheet date.

Net Operating Losses

The amounts and expiration dates of the Company's net operating loss carryforwards as of March 31, 2021 are as follows:

	Gross Carryforward Amount *(in millions of dollars)*		Expiration Period
Federal	$ 2,968		2033 – 2038
Federal – No Expiration	174		Indefinite
New York	2,175	(1)	2035 - 2041
New York City	368	(1)	2035 - 2041
Massachusetts	352		2035 - 2041

(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 loss carryforwards reflected on the income tax returns.

Status of Income Tax Examinations

During the year ended March 31, 2021, the Company reached a settlement with the IRS for the years ended March 31, 2013 through March 31, 2015. As a result of the settlement, the Company incurred an income tax expense of $30 million and made a payment for tax and interest of $13 million.

During the year ended March 31, 2021, the IRS informed the Company that it does not intend to audit the Company's income tax returns for the periods ended March 31, 2016 and 2017 and commenced its examination of the next audit cycle which includes periods ended March 31, 2018 and 2019. While the income tax returns for fiscal years 2016 and 2017 are not currently being audited by the IRS, the statute of limitations for these tax periods does not expire until December 31, 2021. Therefore, the income tax returns for the years ended March 31, 2016 through March 31, 2021 remain subject to examination by the IRS.

The state of New York is in the process of examining the Company's New York State income tax returns. The following table presents the subsidiaries and years currently under examination. The income tax returns for the subsequent years through March 31, 2021 remain subject to examination by the state of New York.

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

Companies	Years Under Examination
Niagara Mohawk	March 31, 2013 through March 31, 2015
KeySpan Gas East	March 31, 2009 through March 31, 2012
Brooklyn Union	March 31, 2009 through March 31, 2012
KeySpan Energy Corporation	March 31, 2013 through March 31, 2015

The city of New York is in the process of examining the Company's New York City income tax returns. The following table presents the subsidiaries and years currently under examination. The income tax returns for the subsequent years through March 31, 2021 remain subject to examination by the city of New York.

Companies	Years Under Examination
KeySpan Corporation and Subsidiaries	December 31, 2003 through March 31, 2009

In September 2021, the Company reached an audit settlement agreement with the State of Massachusetts for the years ended March 31, 2010 through March 31, 2012. The outcome of the settlement did not have a material impact on the Company's results of operations, financial position, or cash flows. The income tax returns for the years ended March 31, 2013 through March 31, 2021 remain subject to examination by the state of Massachusetts.

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

Jurisdiction	Tax Years
Federal	March 31, 2016
Massachusetts	March 31, 2013
New York	March 31, 2009
New York City	December 31, 2003

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, 2021 and 2020, the Company has accrued for interest related to unrecognized tax benefits of $69 million and $61 million, respectively. During the years ended March 31, 2021 and 2020, the Company recorded interest expense of $16 million and $8 million, respectively. No tax penalties were recognized during the years ended March 31, 2021 and 2020.

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 further increase or decrease. However, the Company does not believe any such increases or decreases would be material to its results of operations, financial position, or cash flows.

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 United States Environmental Protection Agency (“EPA”) and the NYS Department of Environmental Conservation (“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. 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, the Company is unable to predict what effect, if any, these future requirements will have on its consolidated 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 the Port Jefferson and Northport facilities. 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 the E.F. Barrett facility. 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 $75 million. Costs associated with these capital improvements are reimbursable from LIPA under the 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.

During the year ended March 31, 2020, a regulated subsidiary of the Company received new information concerning the design and remediation work required at several sites in New York, which resulted in the Company increasing its estimate for environmental reserves. The estimated increases were the result of new information arising from notices received from environmental regulators and updated cost estimates prepared by third party engineers. Based on this new information, the Company's subsidiary has revised the total cost estimate accordingly and has increased its provision by approximately $463 million. After recording an offsetting increase in regulatory assets relating to environmental remediation, there was no impact to the net assets of the subsidiary of the Company.

At March 31, 2021 and 2020, the Company's total reserve for estimated MGP-related environmental matters is $2.2 billion and $2.4 billion, respectively. The Company had a current portion of environmental remediation costs of $173 million and $216 million included in other current liabilities on the consolidated balance sheets at March 31, 2021 and 2020, 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, DPU, and RIPUC, 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 $2.3 billion and $2.5 billion on the consolidated balance sheets at March 31, 2021 and 2020, respectively. Expenditures incurred for the years ended March 31, 2021 and 2020 were approximately $179 million and $103 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.

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.

The Company's commitments under these long-term contracts for the years subsequent to March 31, 2021 are summarized in the table below:

(in millions of dollars) Years Ending March 31,	**Energy Purchases**
2022	$ 1,336
2023	1,036
2024	870
2025	691
2026	606
Thereafter	2,887
Total	$ 7,426

The amounts in the above table exclude total commitments of $858 million related to Narragansett. See Note 19, "Held for sale".

The Company's subsidiaries can purchase additional energy to meet load requirements from independent power producers, other utilities, energy merchants or on the open market through the NYISO or the ISO-NE at market prices.

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, 2021, 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 *(in millions of dollars)*	Expiration Dates
KeySpan Ravenswood LLC Lease	(i)	$ 206	May 2040
Reservoir Woods	(ii)	107	October 2029
Surety Bonds	(iii)	200	Revolving
Commodity Guarantees and Other	(iv)	103	August 2025 - August 2042
Letters of Credit	(v)	167	November 2021
		$ 783	

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, 2021, the Company's obligation related to the lease is $31 million and is reflected in the 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, 2021, the unamortized value of the leased facility purchase price is $206 million.

(ii) The Company has fully and unconditionally guaranteed $107 million in lease payments through 2029 related to the lease of office facilities by its service company at Reservoir Woods in Waltham, Massachusetts. The Reservoir Woods lease is reported as an operating lease on the Company's consolidated balance sheets.

(iii) 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.

(iv) 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, 2021.

(v) 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.

Long-term Contracts for Renewable Energy

Offshore Wind Energy Procurement

On December 6, 2018, Narragansett entered into a 20-year power purchase agreements ("PPA") with DWW Rev I, LLC ("Revolution Wind"), for the purchase of the electricity and renewable energy credits generated by the offshore windfarm proposed by Revolution Wind, that will have a capacity of up to 408 MW. The anticipated commercial operations date for the windfarm is in January 2024. On May 28, 2019, at an open meeting, the RIPUC approved the contract without remuneration. The written order approving the agreement and that Narragansett will be able to recover the cost incurred under the agreement was issued by the RIPUC on June 7, 2019.

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 July 9, 2021, Vineyard Wind exercised its fourth and final option to extend the critical milestones associated with the first wind farm and its second option to extend the critical milestones associated with the second wind farm. On July 20, 2021, the Massachusetts Electric Companies executed an amendment to the PPA for the first wind farm, which extends the critical milestone dates by twenty-four months, including the commercial operations date. This amendment was filed with the DPU on July 21, 2021.

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 is 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 it 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.

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 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.

Annual Solicitations

The 2009 Rhode Island law requires that, beginning on July 1, 2010, Narragansett conduct four annual solicitations for proposals from renewable energy developers and, provided commercially reasonable proposals have been received, enter into long-term contracts for the purchase of capacity, energy, and attributes from newly developed renewable energy resources. In 2014 the Long Term Contracting Standard was amended to allow for additional solicitations until the 90 MW contracting capacity requirement was met.

Narragansett's previous four solicitations resulted in four PPAs that have been approved by the RIPUC. Three of the related facilities reached commercial operation range during the period from 2013 to 2017, The remaining PPA was terminated in 2017 due to one of the required permits for the project was rejected.

On May 11, 2020, under the Fifth Solicitation, the RIPUC approved a 20-year PPA with Gravel Pit Solar II, LLC for a 49.5 MW land based bifacial solar project located in East Windsor, CT. The anticipated commercial operation date is March 31, 2023.

As approved by the RIPUC, Narragansett is allowed to pass through commodity-related / purchased power costs to customers and collect remuneration equal to 2.75%.

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.

NYPSC Investigation

On June 17, 2021, five former National Grid employees in the downstate New York facilities department were arrested on federal charges alleging fraud and bribery. It is National Grid's understanding that the investigation by the US Attorney's Office and FBI remains ongoing; National Grid is a victim of the alleged crimes and will continue to comply with the government's investigation. The New York Public Service Commission, the Massachusetts Department of Public Utilities, and the Rhode Island Public Utilities Commission have each issued request for information related to the alleged criminal conduct. At this time, it is not possible to predict the outcome of the regulatory review or determine the amount, if any, of any potential liabilities that may be incurred by the Company related to this matter. 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 conduct associated with energy efficiency programs at one of 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.

Hempstead Property Tax Settlement

On July 16, 2018, KeySpan Gas East Corporation received a tax refund of $50 million from the Town of Hempstead pursuant to a judgment for claims related to garbage tax levies for the tax years 1996 through 2012. Both parties have appealed certain aspects of the judgment and the Court ruled on December 30, 2020 that the trial court should have applied 9% prejudgment interests instead of 6%. At the time the proceeds were received, KeySpan Gas East Corporation established a regulatory liability for the benefit of customers. In August 2021, the parties agreed to a final settlement of the litigation in which KeySpan Gas East Corporation will receive an additional payment of $14 million on or before November 1, 2021. In addition, the approved NYPSC rate case, allows KeySpan Gas East Corporation to retain its costs to achieve the ultimate refund and 15% of the refund after the cost to achieve plus interest on KeySpan Gas East Corporation's deferred balance since 2018.

Nassau County Special District Tax Settlement

Litigation began over two decades ago to challenge the methodology employed by Nassau County for the purposes of imposing special ad valorem levies upon KeySpan's real property located in non-countywide special districts for the 1998 through 2001 tax years. On August 2, 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 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.

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 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 $33 million and $32 million included in other current liabilities on the consolidated balance sheets as of March 31, 2021 and 2020, 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 (refer to “Recovery of Transmission Costs” section in Note 5, “Rate Matters”), 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, the FERC initiated a proceeding under Section 206 of the FPA. The FERC found that the ISO-NE Transmission, Markets, and Services Tariff is unjust, unreasonable, and unduly discriminatory or preferential. FERC found that the ISO-New England’s Tariff lacks adequate transparency and challenge procedures regarding 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 in order 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. In August 2018, the parties to the proceeding agreed to the terms of a settlement and subsequently filed the proposed settlement with the settlement judge in the proceeding. It was opposed by certain municipal parties, making it a contested settlement. On May 22, 2019, FERC rejected the Formula Rate 206 settlement in its entirety and remanded the matter to the Chief Administrative Law Judge (“ALJ”) for hearing procedures. The parties continued settlement negotiations and were granted multiple suspensions of the procedural schedule to attempt to finalize settlement. The Chief ALJ held hearing procedures in abeyance while settlement discussions were underway.

On June 15, 2020, the parties filed a revised settlement agreement with FERC that is supported and signed by all parties, including all 6 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. The Settling Parties requested that FERC accept the settlement by November 1, 2020 with an effective date of January 1, 2021, but the FERC did not act to do so. However, on December 28, 2020, FERC approved the settlement without modification. The settlement formula rates will go into effect on January 1, 2022. Interim formula rate protocols go 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 the A&R PSA. Under the A&R PSA, Genco has a ROE of 9.75% and a capital structure of 50% debt and 50% equity. Genco's annual revenue requirement for the year ended March 31, 2021 was $447 million.

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. 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. The earliest effective ramp down date for Genco's Northport steam generating units is May 2021; ramp downs for all other units could be effective at any time after consideration of the notice periods. Should any ramp downs be exercised, Genco is entitled to a ramp down payment plus operating and maintenance expenses for 18 months for steam generating units and 12 months for all other generating units. The ramp down payment is equivalent to the net book value of the generating unit, less 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.

In December 2019, LIPA provided advance notice for one non-steam generating unit ramp down, with an effective date in December 2020. This unit is not fully depreciated, and the company incurred a $0.4 million loss. In March 2021, LIPA requested this unit continue to be used and converted to Load Modifier status effective in May 2021.

In February 2020, LIPA provided advance notice for one non-steam generating unit ramp down with an effective date in February 2021. The Company does not expect a material impact from this ramp down. In March 2021, LIPA requested that this unit continue to be used and converted to Load Modifier status effective in March 2021.

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 up to $4 million annually. Although the A&R PSA provides LIPA with all of 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. 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. The revenue requirement, which is comprised of the capacity charge, is approximately 88.6% 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 actually 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, 2021 and 2020, Niagara Mohawk reported a liability of $178 million and $178 million, respectively, recorded in other 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 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.

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 4 and 70 years.

Operating lease ROU assets are included in property, plant and equipment, net, and operating lease liabilities are included in other current liabilities and other noncurrent liabilities on the balance sheet. As of March 31, 2021, the Company does not have any finance leases.

Expense related to operating leases was $146 million and $150 million for the years ended March 31, 2021 and 2020, respectively.

The Company does not have any other material rights or obligations under operating leases that have not yet commenced at March 31, 2021.

The following table presents the components of cash flows arising from lease transactions:

	Years ended March 31,			
	2021		**2020**	
	(in millions of dollars)			
Cash paid for amounts included in lease liabilities				
Operating cash flows from operating leases	**$**	**148**	$	150
Financing cash flows from finance leases		**1**		1
ROU assets obtained in exchange for operating lease liabilities	**$**	**136**	$	869
Weighted-average remaining lease term – operating leases		**15 years**		15 years
Weighted-average discount rate – operating leases		**3.32%**		3.33%

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 undiscounted cash flows of the operating lease liabilities recognized in the comparative balance sheet:

	Operating Leases
	(in millions of dollars)
Year Ending March 31,	
2022	$ **119**
2023	**111**
2024	**94**
2025	**77**
2026	**60**
Thereafter	**560**
Total future minimum lease payments	**1,021**
Less: imputed interest	**246**
Total	$ **775**
Reported as of March 31, 2021:	
Current lease liability	$ **99**
Non-current lease liability	**676**
Total	$ **775**

There are certain leases in which the Company is the lessor. Revenue under such leases was immaterial for the years ended March 31, 2021 and 2020.

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.

A summary of net 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,	
	2021	2020	**2021**	2020
	(in millions of dollars)			
National Grid plc	$ **9**	$ 15	$ **33**	$ -
National Grid North America	**1**	-	**9**	27
NGV and NGP	**157**	100	**163**	110
Other	**-**	2	**2**	1
Total	$ **167**	$ 117	$ **207**	$ 138

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.

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, 2021 and 2020, the Company had zero and $300 million advances under this agreement, respectively.

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, 2021 and 2020, the Company had $8.1 billion and $6.3 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.

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 $138 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, 2021 and 2020, respectively.

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 $735 million and $594 million, and intercompany money pool borrowings of $178 million and $168 million on the consolidated balance sheets as of March 31, 2021 and 2020, respectively. The balances at March 31, 2021 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 0.7% and 2.4% for the years ended March 31, 2021 and 2020, 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, 2021 and 2020, the effect on income before income taxes was $69 million and $30 million, respectively.

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, 2021 and 2020 is presented in the table below. The preferred stock is reported as a non-controlling interest as of March 31, 2021.

		Shares Outstanding		**Amount**		
		March 31,		**March 31,**		Call
Series	Company	**2021**	2020	**2021**	2020	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
$50 par value -						
4.50% Series	Narragansett (1)	**49,089**	49,089	**3**	3	55.000
Golden Shares -	Niagara Mohawk and the New York Gas Companies	**3**	3	**-**	-	Non-callable
Total		**372,641**	372,641	**$ 35**	$ 35	

(1) Related to held for sale, see Note 17 "Held for sale".

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, 2021 or 2020. The annual dividend requirement for cumulative preferred stock was $1 million as of March 31, 2021 and 2020.

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	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020
			(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. HELD FOR SALE

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 is considered probable and is expected to complete within a year, once all regulatory approvals have been obtained, the associated assets and liabilities that will form part of the sale have been presented as held for sale in the consolidated balance sheets as of March 31, 2021.

	March 31, 2021
	(in millions of dollars)
Current assets:	
Cash and cash equivalents	**$ 6**
Accounts receivable	**314**
Allowance for doubtful accounts	**(63)**
Unbilled revenues	**62**
Inventory	**44**
Regulatory assets	**72**
Derivative instruments	**5**
Other	**3**
Total current assets	**443**
Property, plant and equipment, net	**3,734**
Non-current assets:	
Regulatory assets	**452**
Goodwill	**780**
Derivative instruments	**1**
Other	**26**
Total non-current assets	**1,259**
Total assets	**$ 5,436**

		March 31, 2021
		(in millions of dollars)
Current liabilities:		
Accounts payable	**$**	**147**
Current portion of long-term debt		**1**
Taxes accrued		**39**
Interest accrued		**16**
Regulatory liabilities		**109**
Derivative instruments		**6**
Renewable energy certificate obligations		**31**
Payroll and benefits accruals		**15**
Environmental remediation obligations		**23**
Other		**74**
Total current liabilities		**461**
Non-current liabilities:		
Regulatory liabilities		**566**
Asset retirement obligations		**9**
Postretirement benefits		**30**
Environmental remediation obligations		**89**
Derivative instruments		**6**
Operating lease liabilities		**15**
Other		**21**
Total non-current liabilities		**736**
Long-term debt		**1,510**
Total liabilities and equity		**2,707**
Net Assets	**$**	**2,729**

The Company's consolidated statements of operations and comprehensive income include $165 million for the year ended March 31, 2021 and $149 million for the year ended March 31, 2020 of Income before income taxes resulting directly from the operations of Narragansett.