The Narragansett Electric Company

Financial Statements

For the years ended March 31, 2019, 2018, and 2017

THE NARRAGANSETT ELECTRIC COMPANY

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Deloitte.

Deloitte & Touche LLP
30 Rockefeller Plaza
New York, NY 10112
USA

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

INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
The Narragansett Electric Company

We have audited the accompanying financial statements of The Narragansett Electric Company (the "Company"), which comprise the balance sheets and statements of capitalization as of March 31, 2019 and 2018 and the related statements of income, cash flows, and changes in shareholders' equity for the two years in the period ended March 31, 2019, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these 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 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 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 financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the 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 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 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 financial statements referred to above present fairly, in all material respects, the financial position of The Narragansett Electric Company as of March 31, 2019 and 2018, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Predecessor Auditors' Opinion on 2017 Financial Statements

The financial statements of the Company as of and for the year ended March 31, 2017, were audited by other auditors whose report, dated July 14, 2017, expressed an unmodified opinion on those statements.

Deloitte + Touche LLP

July 12, 2019

THE NARRAGANSETT ELECTRIC COMPANY
STATEMENTS OF INCOME
(in thousands of dollars)

	Years Ended March 31,		
	2019	2018	2017
Operating revenues	**$ 1,556,597**	$ 1,445,025	$ 1,263,354
Operating expenses:			
Purchased electricity	**439,140**	359,726	302,210
Purchased gas	**173,829**	180,576	132,919
Operations and maintenance	**507,911**	474,341	418,499
Depreciation	**111,095**	105,686	103,923
Other taxes	**135,020**	132,057	120,461
Total operating expenses	**1,366,995**	1,252,386	1,078,012
Operating income	**189,602**	192,639	185,342
Other income and (deductions):			
Interest on long-term debt	**(51,573)**	(43,247)	(43,758)
Other interest, including affiliate interest	**(4,060)**	(3,619)	(3,199)
Loss on sale of assets	**-**	-	(2,468)
Other income (deductions), net	**468**	(213)	749
Total other deductions, net	**(55,165)**	(47,079)	(48,676)
Income before income taxes	**134,437**	145,560	136,666
Income tax expense	**24,001**	22,249	48,524
Net income	**$ 110,436**	$ 123,311	$ 88,142

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

THE NARRAGANSETT ELECTRIC COMPANY
STATEMENTS OF COMPREHENSIVE INCOME
(in thousands of dollars)

		Year Ended March 31,
		2017*
Net income	$	88,142
Other comprehensive income, net of taxes:		
Unrealized gains on securities		110
Change in pension and other postretirement obligations		(4)
Unrealized gains on hedges		471
Total other comprehensive income		577
Comprehensive income	$	88,719
Related tax (expense) benefit:		
Unrealized gains on securities	$	(60)
Change in pension and other postretirement obligations		2
Unrealized gains on hedges		(254)
Total tax expense	$	(312)

*2018 and 2019 not presented due to immaterial nature of statement.

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

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

	Years Ended March 31,		
	2019	2018	2017
Operating activities:			
Net income	**$ 110,436**	$ 123,311	$ 88,142
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	**111,095**	105,686	103,923
Regulatory amortizations	**(1,580)**	235	714
Deferred income tax	**36,399**	41,290	27,470
Bad debt expense	**23,856**	19,136	14,105
Amortization of debt discount and issuance costs	**412**	293	293
Pension and postretirement benefit expenses	**(3,203)**	19,031	20,727
Pension and postretirement benefit contributions, net	**(12,294)**	(38,935)	(16,841)
Environmental remediation payments	**(1,847)**	(2,946)	(4,889)
Changes in operating assets and liabilities:			
Accounts receivable, net, and unbilled revenues	**(35,717)**	(66,457)	(35,989)
Accounts receivable from/payable to affiliates	**42,975**	-	-
Inventory	**(4,406)**	(1,604)	4,330
Regulatory assets and liabilities, net	**66,431**	(64,143)	97,822
Derivative instruments	**(3,511)**	7,364	(23,469)
Prepaid and accrued taxes	**14,707**	5,094	5,418
Accounts payable and other liabilities	**30,294**	73,334	19,284
Other, net	**(15,375)**	(30,543)	(1,827)
Net cash provided by operating activities	**358,672**	190,146	299,213
Investing activities:			
Capital expenditures	**(305,013)**	(269,344)	(295,621)
Proceeds from restricted cash and special deposits	**-**	7,834	58,044
Payments on restricted cash and special deposits	**-**	(7,357)	(43,887)
Cost of removal	**(26,652)**	(21,033)	(17,883)
Other	**(480)**	(517)	1,250
Net cash used in investing activities	**(332,145)**	(290,417)	(298,097)
Financing activities:			
Common stock dividends to Parent	**(85,250)**	-	-
Preferred stock dividends	**(110)**	(110)	(110)
Payments on long-term debt	**(15,839)**	(1,375)	(1,375)
Issuance of long-term debt	**350,000**	-	-
Payment of debt issuance costs	**(1,893)**	-	-
Intercompany money pool	**(271,647)**	100,339	(6,238)
Net cash (used in) provided by financing activities	**(24,739)**	98,854	(7,723)
Net increase (decrease) in cash, cash equivalents, and restriced cash	**1,788**	(1,417)	(6,607)
Cash, cash equivalents and restricted cash, beginning of year	**6,865**	7,803	14,410
Cash, cash equivalents and restricted cash, end of year	**$ 8,653**	$ 6,386	$ 7,803
Supplemental disclosures:			
Interest paid	**$ (50,639)**	$ (44,492)	$ (42,574)
Income taxes refunded (paid)	**15,746**	(2,624)	63
Significant non-cash items:			
Capital-related accruals included in accounts payable	**12,625**	18,987	15,775
Parent tax loss allocation	**-**	3,047	-

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

THE NARRAGANSETT ELECTRIC COMPANY
BALANCE SHEETS
(in thousands of dollars)

	March 31,	
	2019	2018
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 8,269**	$ 6,386
Restricted cash	**384**	479
Accounts receivable	**266,065**	251,985
Allowance for doubtful accounts	**(28,492)**	(25,617)
Accounts receivable from affiliates	**20,079**	22,221
Unbilled revenues	**66,806**	66,150
Inventory	**25,061**	23,390
Regulatory assets	**62,584**	87,297
Accrued tax benefit	**5,342**	13,246
Other	**7,948**	4,093
Total current assets	**434,046**	449,630
Property, plant and equipment, net	**3,214,681**	2,984,346
Other non-current assets:		
Regulatory assets	**457,320**	492,361
Goodwill	**724,810**	724,810
Other	**43,841**	37,176
Total other non-current assets	**1,225,971**	1,254,347
Total assets	**$ 4,874,698**	$ 4,688,323

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

THE NARRAGANSETT ELECTRIC COMPANY
BALANCE SHEETS
(in thousands of dollars)

	March 31, 2019	March 31, 2018
LIABILITIES AND CAPITALIZATION		
Current liabilities:		
Accounts payable	**$ 155,981**	$ 170,458
Accounts payable to affiliates	**52,144**	14,430
Current portion of long-term debt	**251,375**	15,839
Taxes accrued	**35,889**	34,534
Customer deposits	**11,924**	10,627
Interest accrued	**7,824**	5,417
Regulatory liabilities	**130,335**	109,484
Intercompany money pool	**56,547**	307,520
Renewable energy certificate obligations	**4,898**	5,746
Other	**47,580**	31,611
Total current liabilities	**754,497**	705,666
Other non-current liabilities:		
Regulatory liabilities	**561,558**	553,343
Asset retirement obligations	**9,629**	9,472
Deferred income tax liabilities, net	**359,119**	324,161
Postretirement benefits	**72,893**	83,234
Environmental remediation costs	**117,441**	137,677
Other	**20,433**	17,423
Total other non-current liabilities	**1,141,073**	1,125,310
Commitments and contingencies (Note 11)		
Capitalization:		
Shareholders' equity	**2,055,538**	2,030,903
Long-term debt	**923,590**	826,444
Total capitalization	**2,979,128**	2,857,347
Total liabilities and capitalization	**$ 4,874,698**	$ 4,688,323

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

THE NARRAGANSETT ELECTRIC COMPANY
STATEMENTS OF CAPITALIZATION
(in thousands of dollars)

			March 31,	
			2019	2018
Total shareholders' equity			**$ 2,055,538**	$ 2,030,903
Long-term debt:	Interest Rate	Maturity Date		
Unsecured notes:				
Senior Note	4.53%	March 15, 2020	**250,000**	250,000
Senior Note	5.64%	March 15, 2040	**300,000**	300,000
Senior Note	4.17%	December 10, 2042	**250,000**	250,000
Senior Note	3.92%	August 1, 2028	**350,000**	-
			1,150,000	800,000
First Mortgage Bonds ("FMB"):				
FMB Series S	6.82%	April 1, 2018	**-**	14,464
FMB Series N	9.63%	May 30, 2020	**10,000**	10,000
FMB Series O	8.46%	September 30, 2022	**12,500**	12,500
FMB Series P	8.09%	September 30, 2022	**2,500**	3,125
FMB Series R	7.50%	December 15, 2025	**5,250**	6,000
			30,250	46,089
Total debt			**1,180,250**	846,089
Unamortized debt discount			**(1,859)**	(2,076)
Unamortized debt issuance costs			**(3,426)**	(1,730)
Total debt less unamortized costs			**1,174,965**	842,283
Current portion of long-term debt			**251,375**	15,839
Total long-term debt			**923,590**	826,444
Total capitalization			**$ 2,979,128**	**$ 2,857,347**

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

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

				Accumulated Other Comprehensive Income (Loss)					
	Common Stock	Cumulative Preferred Stock	Additional Paid-in Capital	Unrealized Gain (Loss) on Available-For-Sale Securities	Pension and Other Postretirement Benefits	Hedging Activity	Total Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total
Balance as of March 31, 2016	**$ 56,624**	**$ 2,454**	**$ 1,354,977**	**$ 795**	**$ 1,206**	**$ (3,672)**	**$ (1,671)**	**$ 403,276**	**$ 1,815,660**
Net income	-	-	-	-	-	-	-	88,142	88,142
Other comprehensive income:									
Unrealized gains on securities, net of $60 tax expense	-	-	-	110	-	-	110	-	110
Change in pension and other postretirement obligations, net of $2 tax benefit	-	-	-	-	(4)	-	(4)	-	(4)
Unrealized gains on hedges, net of $254 tax expense	-	-	-	-	-	471	471	-	471
Total comprehensive income									88,719
Share based compensation	-	-	31	-	-	-	-	-	31
Preferred stock dividends	-	-	-	-	-	-	-	(110)	(110)
Balance as of March 31, 2017	**$ 56,624**	**$ 2,454**	**$ 1,355,008**	**$ 905**	**$ 1,202**	**$ (3,201)**	**$ (1,094)**	**$ 491,308**	**$ 1,904,300**
Net income	-	-	-	-			-	123,311	123,311
Other comprehensive income:									
Unrealized gains on securities, net of $38 tax expense	-	-	-	26	-	-	26	-	26
Change in pension and other postretirement obligations, net of $29 tax expense	-	-	-	-	99	-	99	-	99
Unrealized gains on hedges, net of $93 tax expense	-	-	-	-	-	228	228	-	228
Total comprehensive income									123,664
Parent tax loss allocation	-	-	3,047	-	-	-	-	-	3,047
Share based compensation	-	-	2	-	-	-	-	-	2
Preferred stock dividends	-	-	-	-	-	-	-	(110)	(110)
Balance as of March 31, 2018	**$ 56,624**	**$ 2,454**	**$ 1,358,057**	**$ 931**	**$ 1,301**	**$ (2,973)**	**(741)**	**$ 614,509**	**2,030,903**
Net income	-	-	-	-			-	110,436	110,436
Other comprehensive loss:									
Unrealized losses on securities, net of $3 tax benefit	-	-	-	(12)	-	-	(12)	-	(12)
Change in pension and other postretirement obligations, net of $182 tax benefit	-	-	-	-	(683)	-	(683)	-	(683)
Unrealized gains on hedges, net of $67 tax expense	-	-	-	-	-	254	254	-	254
Total comprehensive income									109,995
Common stock dividends to Parent	-	-	-	-	-	-	-	(85,250)	(85,250)
Preferred stock dividends	-	-	-	-	-	-	-	(110)	(110)
Impact of adoption of recognition and measurement of financial assets and liabilities standard		-	-	(896)	-	-	(896)	896	-
Balance as of March 31, 2019	**$ 56,624**	**$ 2,454**	**$ 1,358,057**	**$ 23**	**$ 618**	**$ (2,719)**	**$ (2,078)**	**$ 640,481**	**$ 2,055,538**

The Company had 1,132,487 shares of common stock authorized, issued and outstanding, with a par value of $50 per share and 49,089 shares of cumulative preferred stock authorized, issued and outstanding, with a par value of $50 per share at March 31, 2019 and 2018.

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

THE NARRAGANSETT ELECTRIC COMPANY
NOTES TO THE FINANCIAL STATEMENTS

1. NATURE OF OPERATIONS AND BASIS OF PRESENTATION

The Narragansett Electric Company ("the Company") is a retail distribution company providing electric service to approximately 506,000 customers and gas service to approximately 273,000 customers in 38 cities and towns in Rhode Island. The Company's service area covers substantially all of Rhode Island.

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

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

The Company has evaluated subsequent events and transactions through July 12, 2019, the date of issuance of these financial statements, and concluded that there were no events or transactions that require adjustment to, or disclosure in, the financial statements as of and for the year ended March 31, 2019.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

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

Regulatory Accounting

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

Revenue Recognition

Revenues are recognized for energy service provided on a monthly billing cycle basis. The Company records unbilled revenues for the estimated amount of services rendered from the time meters were last read to the end of the accounting period (See Note 3, "Revenue" for additional details).

Other Taxes

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

The Company's policy is to accrue for property taxes on a calendar year basis, taking into account the assessment period. The Company had accrued for property taxes of $18.3 million and $18.0 million at March 31, 2019 and 2018, respectively.

Income Taxes

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

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

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

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

Restricted cash consists of collateral paid to the Company's counterparties for outstanding derivative instruments. The Company had restricted cash of $0.4 million and $0.5 million at March 31, 2019 and 2018, respectively.

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

	Year ended March 31, 2019	
	(in thousands of dollars)	
Cash and Cash Equivalents as reported on the Balance Sheets	$	8,269
Restricted Cash as reported on the Balance Sheets		384
Cash, Cash Equivalents and Restricted Cash reported on the Statements of Cash Flows	$	8,653

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 $23.9 million, $19.1 million, and $14.1 million for the years ended March 31, 2019, 2018, and 2017, respectively, within operations and maintenance in the statements of income.

Inventory

Inventory is comprised of materials and supplies, purchased Renewable Energy Certificates ("RECs"), and gas in storage. Materials and supplies are stated at weighted average cost, which represents net realizable value, and are expensed or capitalized as used. Purchased RECs are stated at cost. There were no significant write-offs of obsolete inventory for the years ended March 31, 2019, 2018, or 2017.

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

The Company had materials and supplies of $13.5 million and $11.8 million, purchased RECs of $2.4 million and $5.1 million, and gas in storage of $9.2 million and $6.5 million at March 31, 2019 and 2018, respectively.

Renewable Energy Standard Obligation

RECs are stated at cost and are used to measure compliance with State renewable energy standards. RECs support new renewable generation standards and are held primarily to be utilized in fulfilment of the Company's compliance obligations. At March 31, 2019 and 2018, the Company recorded a renewable energy standard obligation of $4.9 million and $5.7 million, respectively, within renewable energy certificate obligations.

Derivative Instruments

The Company uses derivative instruments to manage commodity price risk. All derivative instruments, except those that qualify for the normal purchase normal sale exception, are recorded on the balance sheet at fair value. All commodity costs, including the impact of derivative instruments, are passed on to customers through the Company's 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 gains or losses on the settlement of these contracts are recognized as purchased electricity and purchased gas on the statements of income and then refunded to, or collected from, customers consistent with regulatory requirements.

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 were to determine that a contract no longer qualifies for the normal purchase normal sale exception, then the Company would recognize the fair value of the contract and 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 recorded within restricted cash on the balance sheet.

Power Purchase Agreements

The Company enters into power purchase agreements to procure electricity to serve its customers. The Company evaluates whether such agreements are leases, derivative instruments, or executory contracts, and performs an assessment under the guidance for Variable Interest Entities ("VIE"), included in Topic 810, "Consolidations." Power purchase agreements that do not qualify as leases or derivative instruments are accounted for as executory contracts and are, therefore, recognized as the electricity is purchased. In making its determination of the accounting for power purchase agreements, the Company considers many factors, including: the source of the electricity; the level of output from any specified facility that the Company is taking under the contract; the involvement, if any, that the Company has in operating the specified facility; and the pricing mechanisms in the contract.

Natural Gas Long-Term Arrangements

The Company enters into long-term gas contracts to procure gas to serve its customers. Those contracts include Asset Management Agreements, Baseload, and Peaking gas contracts. Similar to the power purchase agreements noted above, the Company evaluates whether such agreements are leases, derivative instruments, or executory contracts, and performs an assessment under the guidance for VIE included in Topic 810, "Consolidations," and applies the appropriate accounting treatment.

Fair Value Measurements

The Company measures derivative instruments, available-for-sale securities, and pension and postretirement benefits other than pension plan assets at fair value. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The following is the fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value:

- Level 1: quoted prices (unadjusted) in active markets for identical assets or liabilities that a company has the ability to access as of the reporting date;
- Level 2: inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data;
- Level 3: unobservable inputs, such as internally-developed forward curves and pricing models for the asset or liability due to little or no market activity for the asset or liability with low correlation to observable market inputs; and
- Not categorized: certain investments are not 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, derived from the underlying securities' quoted prices in active markets.

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

Property, Plant, and Equipment

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

Depreciation is computed over the estimated useful life of the asset using the composite straight-line method. Depreciation studies are conducted periodically to update the composite rates and are approved by the FERC and RIPUC. The average composite rates for the years ended March 31, 2019, 2018, and 2017 are as follows:

	Electric			Gas		
	Years Ended March 31,			Years Ended March 31,		
	2019	2018	2017	**2019**	2018	2017
Composite rates	**3.0%**	2.9%	2.9%	**3.4%**	3.4%	3.2%

Depreciation expense 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 $221.9 million and $217.0 million at March 31, 2019 and 2018, 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 the accompanying statements of income as non-cash income in other income (deductions), net. The debt component of AFUDC is reported as a non-cash offset to other interest, including affiliate interest. After construction is completed, the Company is permitted to recover these costs through their inclusion in rates. The Company recorded AFUDC related to equity of $4.3 million, $0.1 million, and $(0.1) million reflecting adjustments to plant balances for the years ended March 31, 2019, 2018 and 2017. The Company recorded AFUDC related to debt was $2.5 million, $1.4 million, and $1.0 million for the years ended March 31, 2019, 2018, and 2017, respectively. The average AFUDC rates for the years ended March 31, 2019, 2018, and 2017 were 5.7%, 1.7%, and 1.1%, respectively.

Impairment of Long-Lived Assets

The Company tests the impairment of long-lived assets when events or changes in circumstances indicate that the carrying amount of the asset may not be recoverable. The recoverability of an asset is determined by comparing its carrying value to the estimated undiscounted cash flows that the asset is expected to generate. If the comparison indicates that the carrying value is not recoverable, an impairment loss is recognized for the excess of the carrying value over the estimated fair value. For the years ended March 31, 2019 and 2018, there were no impairment losses recognized for long-lived assets. For the year ended March 31, 2017, there was $2.5 million of impairment losses recognized for long-lived assets.

Goodwill

The Company tests goodwill for impairment annually on January 1, and when events occur or circumstances change that would more likely than not reduce the fair value of the Company below its carrying amount. The Company has early 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 required under the current standard. The one-step approach requires a recoverability test performed based on the comparison of the Company's estimated fair value with its carrying value, including goodwill. If the estimated fair value exceeds the carrying value, 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 carrying amount of goodwill.

Historically, the fair value of the Company was calculated for the annual goodwill impairment test utilizing both the income and market-based approaches. For the year ended March 31, 2019, the fair value of the Company was calculated utilizing only the income approach. The Company believes that this approach provides the most reliable information about the Company's estimated fair value. Based on the resulting fair value from the annual analyses, the Company determined that no adjustment to the goodwill carrying value was required at March 31, 2019 or 2018.

Asset Retirement Obligations

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

The following table represents the changes in the Company's asset retirement obligations:

	Years Ended March 31,	
	2019	2018
	(in thousands of dollars)	
Balance as of the beginning of the year	**$ 9,909**	$ 10,150
Accretion expense	**381**	385
Liabilities settled	**(268)**	(626)
Balance as of the end of the year	**$ 10,022**	$ 9,909

The Company had a current portion of asset retirement obligations of $0.4 million included in other current liabilities on the balance sheets at March 31, 2019 and 2018.

Employee Benefits

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

New and Recent Accounting Guidance

Accounting Guidance Adopted

Pension and Postretirement Benefits

In March 2017, the Financial Accounting Standards Board ("FASB") issued ASU No. 2017-07, "Compensation-Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost," which changes certain presentation and disclosure requirements for employers that sponsor defined benefit pension and other postretirement benefit plans. The ASU requires the service cost component of the net benefit cost to be classified within the same line item as other compensation in operating income in an entity's statements of income and the other components of net benefit cost to be classified outside of operating income on a retrospective basis. In addition, as prescribed by the ASU, only the service cost component will be eligible for capitalization when applicable, on a prospective basis.

The Company adopted this new guidance on April 1, 2018. Although required by the standard, the Company elected not to retrospectively adjust the accompanying 2018 and 2017 financial statements as management determined that such retrospective application, is not material to the Company's statements of income for the years ended March 31, 2018 and

2017 presented herein. The adoption of this ASU did not have a material effect on the Company's results of operations, cash flows, and financial position.

Statement of Cash Flows

In November 2016, the FASB issued ASU No. 2016-18, "Statement of Cash Flows (Topic 230): Restricted Cash," which requires entities to show the changes in the total of cash, cash equivalents, restricted cash, and restricted cash equivalents in the statement of cash flows. The Company has adopted the new guidance in the current fiscal year. The application of the new guidance did not have a material impact on the Company's presentation of its statements of cash flows in the current year. Although required by the standard, the Company elected not to retrospectively adjust the accompanying 2018 and 2017 financial statements as management determined that such retrospective application, is not material to the Company's statements of cash flows for the years ended March 31, 2018 and 2017 presented herein.

In August 2016, the FASB issued ASU No. 2016-15, "Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments," which provides guidance about the classification of certain cash receipts and payments within the statement of cash flows, including debt prepayment or extinguishment costs, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims and policies, and distributions received from equity method investments. The Company adopted the new guidance in the current fiscal year and applied it retrospectively for each prior period presented. The application of the new guidance did not have a material impact on the Company's presentation of its statements of cash flows.

Revenue Recognition

In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)." The FASB further amended ASC 606 through various updates issued thereafter. The underlying principle of this ASU is that an entity will recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to, in exchange for those goods or services. The Company adopted the new guidance on April 1, 2018, using the modified retrospective method applied to contracts that were not completed as of April 1, 2018, and the Company did not recognize an adjustment to retained earnings for the cumulative effect of adopting the standard.

The adoption of ASC 606 did not have a material impact on the presentation of the Company's results of operations, cash flows, or financial position. The Company has added additional disclosures as required under ASC 606 (See Note 3, "Revenue," for additional details).

Financial Instruments – Classification and Measurement

In January 2016, the FASB issued ASU No. 2016-01, "Financial Instruments–Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities." The new guidance eliminates the available-for-sale and cost method classification for equity securities and requires that all equity investments, other than those accounted for using the equity method of accounting, be measured and recorded at fair value with any changes in fair value recognized through net income. However, for equity investments that do not have a readily determinable fair value an entity may choose to measure equity investments at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for identical or similar investments. If any entity elects to use the measurement alternative for equity investments without readily determinable fair values, those investments must be qualitatively assessed for impairment at each reporting period and, if impairment exists, the investment is required to be measured at fair value. The guidance does not impact the classification or measurement of investments in debt securities. The guidance also amended certain disclosure requirements related to financial instruments. The Company adopted the guidance on April 1, 2018 using a modified retrospective transition approach, with a cumulative effect adjustment to retained earnings, which was reclassified from accumulated other comprehensive income for $0.9 million related to equity investments that were previously classified as available-for-sale.

Accounting Guidance Not Yet Adopted

Leases

In February 2016, the FASB issued ASU 2016-02, “Leases,” (Topic 842) related to lease accounting. For the Company, the new standard is effective for the fiscal year ending March 31, 2020, and interim periods within. Under the new standard, a lease is defined as a contract, or part of a contract, that conveys the right to control the use of identified assets for a period of time in exchange for consideration. Under the requirements of the new standard, lessees will need to recognize leases on the balance sheet as a right-of-use asset and a related lease liability, which will be equal to the present value of the estimated future lease payments. The right-of-use asset at inception will be based on the liability, subject to certain adjustments, such as initial direct costs. The new standard requires leases to be classified as either operating or financing which will impact the amount and classification of lease related expenses on the statements of income. Under the new standard, lessor accounting is largely unchanged. The new standard also has additional disclosure requirements.

The new standard provides the Company with transition practical expedients including a package of three expedients that must be taken together and allows the Company to: not reassess whether existing contracts contain leases, carry forward the existing classification of any leases, and not reassess initial direct costs associated with existing leases. The Company has exercised its option to elect the package of practical expedients. The Company will make the election under the new standard to not reflect a right-of-use asset or related liability for leases with a term of 12 months or less. The Company has also elected the practical expedient to not reevaluate land easements existing at adoption if they were not previously accounted for as leases. The Company will not make the election to combine the lease components and the associated non-lease components of an arrangement and account for this as a single lease component and will also not elect the expedient to use hindsight in determining the lease term for existing leases at the time of adoption.

The Company will recognize and measure the cumulative effect of the new standard at the beginning of the earliest period presented using the modified retrospective approach. The Company determined the impact the ASU will have on its financial statements by reviewing its lease population and identifying lease data needed for the disclosure requirements. The Company has various operating leases, primarily related to fleet vehicles. The Company will implement a new lease accounting system in fiscal year 2020 to ensure ongoing compliance with the ASU’s requirements. The Company recognized approximately $25.1 million of operating lease liabilities as right-of-use assets on the balance sheets upon transition at April 1, 2019. The implementation of the new guidance will not materially impact the Company’s results of operations or cash flows, as the Company does not expect significant changes to its pattern of expense recognition as a result of the new standard. The Company’s operating leases are further discussed in Note 11, “Commitments and Contingencies.”

Financial Instruments

In June 2016, the FASB issued ASU No. 2016-13, “Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses on Financial Statements,” which requires a financial asset (or a group of financial assets) measured at amortized cost basis to be presented at the net amount expected to be collected. The FASB further amended Topic 326 through additional updates issued thereafter. The allowance for credit losses is a valuation account that is deducted from the amortized cost basis of the financial asset(s) to present the net carrying value at the amount expected to be collected on the financial asset. Credit losses relating to available-for-sale debt securities should be recorded through an allowance for credit losses. For the Company, the requirements of the new standard will be effective for the fiscal year ending March 31, 2022, and interim periods within, with early adoption permitted from the fiscal year ending March 31, 2020 and interim periods within. The Company is currently assessing the impact of this standard.

Reclassifications

Certain reclassifications have been made to the prior years’ financial statements to conform the prior years’ data to the current year’s presentation. These reclassifications had no effect on reported income, total assets, or shareholders’ equity as previously reported.

3. REVENUE

The following table presents, for the year ending March 31, 2019, revenue from contracts with customers, as well as additional revenue from sources other than contracts with customers, disaggregated by major source:

	Year ended March 31, 2019
	(in thousands of dollars)
Revenue from Contracts with Customers:	
Electric Transmission	$ **211,544**
Electric Distribution	**919,074**
Gas Distribution	**466,336**
Other Revenue from Contracts with Customers	**16,457**
Total Revenue from Contracts with Customers	**1,613,411**
Revenue from Regulatory Mechanisms	**(56,814)**
Total Operating Revenues	$ **1,556,597**

Electric and Gas Distribution: The Company owns, maintains and operates an electric and natural gas distribution network in Rhode Island. Distribution revenues are primarily from the sale of electricity, gas, and related services to retail customers. Distribution sales are regulated by the RIPUC, which is responsible for determining the prices and other terms of services as part of the ratemaking process. The arrangement where a utility provides a service to a customer in exchange for a price approved by a regulator is referred to as a tariff sales contract. Gas 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 the products and services provided, along with a return on investment.

The performance obligation related to distribution sales is to provide electricity and natural gas to the customers on demand. The electricity and 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 the distribution sales based upon the approved tariff rate and the volume delivered to the customers, which corresponds with the amount the Company has the right to invoice.

The distribution revenue also includes estimated unbilled amounts, which represent the estimated amounts due from retail customers for 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.

Electric Transmission: The Company owns an electric transmission system in Rhode Island. Transmission systems generally include overhead lines, underground cables, and substations, connecting generation and interconnectors to the distribution system. The Company's transmission services are regulated by both the Independent System Operator ("ISO") – New England and by the FERC. Additionally, the Company makes available its transmission facilities to New England Power ("NEP," an NGUSA affiliate), for operation and control pursuant to an integrated facilities agreement, Service Agreement No. 23 (Integrated Facilities Agreement or "IFA"). See Note 12 "Related Party Transactions" for additional details.

Electric transmission revenues arise under tariff/rate agreements and are collected primarily from the Company's Rhode Island distribution customers.

Other Revenue from Contracts with Customers: Other Revenue from Contracts with Customers consists of off-system sales, which represent direct sales of gas to participants in the wholesale natural gas marketplace, which occur after customer demands are satisfied.

Revenue from Regulatory Mechanisms: The Company records revenues in accordance with accounting principles for rate-regulated operations that are arrangements between the Company and the regulator, which are not accounted for as contracts with customers. These include various deferral mechanisms such as capital trackers, energy efficiency programs, storm deferral, and programs that qualify as Alternative Revenue Programs ("ARPs"). ARPs enable the Company to adjust rates in the future, in response to past activities or completed events. The Company's electric and gas distribution rates both have a Revenue Decoupling Mechanism ("RDM"), which allows for annual adjustments to the Company's delivery rates as a result of the reconciliation between allowed revenue and billed revenue. The Company also has other ARPs related to the achievement of certain objectives, demand side management initiatives, and certain other ratemaking mechanisms. The Company recognizes ARPs with a corresponding offset to a regulatory asset or liability account when the regulatory specified events or conditions have been met, when the amounts are determinable, and are probable of recovery (or payment) through future rate adjustments.

4. REGULATORY ASSETS AND LIABILITIES

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

	2019	2018
	(in thousands of dollars)	
Regulatory assets:		
Current:		
Derivative instruments	**$ -**	$ 2,784
Gas costs adjustment	**-**	35,159
Rate adjustment mechanisms	**57,089**	34,890
Renewable energy certificates	**2,530**	642
Revenue decoupling mechanism	**1,735**	13,822
Other	**1,230**	-
Total	**62,584**	87,297
Non-current:		
Environmental response costs	**121,166**	140,002
Postretirement benefits	**170,545**	187,087
Storm costs	**130,907**	142,269
Other	**34,702**	23,003
Total	**457,320**	492,361
Regulatory liabilities:		
Current:		
Derivative instruments	**793**	-
Energy efficiency	**23,817**	43,089
Gas cost adjustment	**3,806**	-
Rate adjustment mechanisms	**45,293**	37,297
Revenue decoupling mechanism	**22,890**	15,289
Transmission service	**33,572**	13,809
Other	**164**	-
Total	**130,335**	109,484
Non-current:		
Cost of removal	**221,907**	216,983
Energy efficiency	**18,190**	-
Environmental response costs	**15,641**	12,840
Postretirement benefits	**651**	14,904
Regulatory tax liability, net	**278,052**	276,728
Other	**27,117**	31,888
Total	**561,558**	553,343
Net regulatory liabilities	**$ (171,989)**	$ (83,169)

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

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

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 RIPUC.

Environmental response costs: The regulatory asset represents deferred costs associated with the Company's share of the estimated costs to investigate and perform certain remediation activities at sites with which it may be associated. The Company's rate plans provide for specific rate allowances for these costs, with variances deferred for future recovery from, or return to, customers. The 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 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 actual revenues and the underlying cost being recovered, as approved by the RIPUC. These amounts will be refunded to or recovered from customers over the next year.

Postretirement benefits: The regulatory asset represents the Company's non-cash accrual of net actuarial gains and losses and the excess amounts received in rates over actual costs of the Company's pension and PBOP plans that are to be passed back in future periods.

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

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

Renewable energy certificates: Represents deferred costs associated with the Company's compliance obligation with the Rhode Island Renewable Portfolio Standard ("RPS"). 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: As approved by the RIPUC, 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 actual billed revenues. Any difference is recorded as a regulatory asset or regulatory liability.

Storm costs: The Company is allowed to recover storm costs from all 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.

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

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, as approved in accordance with the RIPUC. Carrying charges are not recorded on items for which expenditures have not yet been made.

5. RATE MATTERS

General Rate Case

The Company reached a settlement agreement with the Division and several other intervening parties to increase distribution revenue for its electric and gas operations over the three-year period commencing September 1, 2018, which was approved by the RIPUC on August 24, 2018. This settlement is an agreement that was reached in response to the base distribution revenue increase requests that the Company filed with the RIPUC on November 27, 2017. Pursuant to the settlement, electric distribution revenue will increase by approximately $14 million, $11 million, and $4 million and gas distribution revenue will increase by approximately $6 million, $8 million, and $4 million annually, on September 1, 2018, September 1, 2019 and September 1, 2020, respectively. The settlement reflects an allowed return on equity ("ROE") rate of 9.275% based on a common equity ratio of approximately 51%. Previously, the Company was entitled to earn an allowed ROE of 9.5%, with a common equity ratio of approximately 49.1%.

These revenue increases are intended to fund significant systems-related investments, including the replacement of several aging operational systems used in the Company's electric and gas businesses with newer integrated systems that will be shared by the Company and its electric and gas affiliates. The settlement 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 settlement identifies several additional metrics for tracking and reporting purposes only, some of which may become eligible for a financial performance incentive during the term of the multi-year rate plan. The increases set in place for the second and third years of the settlement may be reopened for recovery of the implementation of advanced metering and grid modernization costs.

Recovery of Transmission Costs

The Company's transmission facilities are operated in combination with the transmission facilities of its New England affiliates, Massachusetts Electric Company ("MECO") 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 ISO. The ISO allocates these costs among transmission customers in New England, in accordance with the ISO Open Access Transmission Tariff ("ISO-NE OATT").

According to the FERC order, the Company is compensated for its actual monthly transmission costs, with its authorized maximum ROE of 11.74% on its transmission assets. The amounts remitted by NEP to the Company for the years ended March 31, 2019, 2018, and 2017 were $144.8 million, $155.1 million, and $143.0 million, respectively, which are eliminated as operating revenues and operations and maintenance expenses within the accompanying statements of income (See Note 12 "Related Party Transactions" for additional details). 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 from 11.14% to 10.57% effective as of October 16, 2014 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 New England Transmission Owners ("NETO") 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 complaints 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 are merely preliminary.

Tax Cuts and Jobs Act

On March 15, 2018, the FERC initiated multiple proceedings intended to adjust FERC-jurisdictional rates to reflect the corporate tax changes as a result of the passage of the Tax Act. Of the proceedings initiated relevant to the Company is the Notice of Inquiry ("NOI") seeking comments on the effects of the Tax Act on all FERC-jurisdiction rates and a Notice of

Proposed Rulemaking (NOPR) issued as a result of the NOI. In response to the FERC NOI, the Company made recommendations designed to mitigate the cash flow impacts of the expected refunds including providing flexibility regarding the methods used to refund accumulated deferred income tax (“ADIT”) to customers and providing flexibility regarding the time period of the flow back. In the NOPR, FERC proposed to give the flexibility the company proposed. Comments on the NOPR were due on January 22, 2019. The Company is awaiting a final rule from FERC.

The RIPUC opened a docket to address the change in the federal corporate income tax rate and other changes resulting from the Tax Act that was signed into law in December 2017. Specifically, the RIPUC requested the Company’s proposal for how it planned to reduce rates associated with the income taxes recovered from customers on the equity component of the return on investment included in revenue taxed at the new lower income tax rate of 21% effective January 1, 2018, and how it planned to return to customers the reduction in its net deferred income tax liabilities resulting from the 14% decrease in the federal income tax rate from 35%. Effective September 1, 2018, the Company reduced its revenue requirement for the distribution electric and gas rates in effect for the impacts of the Tax Act as appropriate. On January 24, 2019, the Company filed with the RIPUC a settlement agreement among the Company, the Division, the Office of Energy Resources, and the State of Rhode Island Office of the Lieutenant Governor, pursuant to which approximately $4.8 million and $3.1 million will be provided to electric and gas customers, respectively, which reflect the benefits of the Company’s reduced federal corporate income tax payment obligations for the period January 1, 2018 through August 31, 2018. The RIPUC approved the settlement agreement on May 17, 2019, as filed.

Storm Contingency Fund

On December 29, 2016, the Company filed with the RIPUC a petition to implement a Storm Fund Replenishment Factor (“SFRF”) effective July 1, 2017 to collect approximately $84.3 million over a four-year period to be credited to the Company’s Storm Contingency Fund (“Storm Fund”) to restore the Storm Fund to a surplus position. In addition, the Company also requested to extend the annual $3 million of supplemental base distribution rate contributions beyond the current expiration date of January 31, 2019, to coincide with the four-year replenishment period. The Division, which is the primary intervener in Rhode Island on rate matters, filed testimony challenging the recovery of $10.6 million of the $84.3 million being sought through the SFRF. On June 21, 2017, the RIPUC unanimously approved the Company’s request to collect the $84.3 million. On April 27, 2018, the RIPUC approved the Joint Proposal Settlement Agreement, which proposed a Storm Fund deficit balance reduction of $2 million, instead of $10.6 million as previously challenged. The SFRF is applicable to all retail electric delivery service customers effective July 1, 2017 for a four-year period. In addition, the RIPUC unanimously approved the Company’s request to extend the annual $3 million of supplemental base distribution rate contributions to the Storm Fund, which the RIPUC authorized in the Company’s 2012 rate case, for an additional 26-month period beyond its current expiration to March 31, 2021.

New England East-West Solution (“NEEWS”) Project

In September 2008, the Company, NEP, 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. The Company’s share of the NEEWS-related transmission investment was approximately $560 million. The Company is fully reimbursed for its transmission revenue requirements on a monthly basis by NEP through NEP’s Tariff No. 1. 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%), (2) 100% construction work in progress (“CWIP”) 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.

6. PROPERTY, PLANT, AND EQUIPMENT

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

	March 31,	
	2019	2018
	(in thousands of dollars)	
Plant and machinery	**$ 3,881,079**	$ 3,637,419
Land and buildings	**123,628**	118,334
Assets in construction	**191,324**	152,852
Software and other intangibles	**23,974**	20,513
Property held for future use	**15,028**	15,028
Total property, plant and equipment	**4,235,033**	3,944,146
Accumulated depreciation and amortization	**(1,020,352)**	(959,800)
Property, plant and equipment, net	**$ 3,214,681**	$ 2,984,346

7. EMPLOYEE BENEFITS

The Company participates with other NGUSA subsidiaries in qualified and non-qualified non-contributory defined benefit plans (the "Pension Plans") and PBOP plans (together with the Pension Plan (the "Plans")), covering substantially all employees.

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

Pension Plans

The Qualified Pension Plan is a defined benefit plan which provides most union employees, as well as non-union employees hired before January 1, 2011, with a retirement benefit. Supplemental non-qualified, non-contributory executive retirement programs provide additional defined pension benefits for certain executives. During the years ended March 31, 2019, 2018, and 2017, the Company made contributions of approximately $12.0 million, $28.9 million, and $13.2 million, respectively, to the Qualified Pension Plans. The Company expects to contribute approximately $1.8 million to the Qualified Pension Plans during the year ending March 31, 2020.

Benefit payments to Pension Plan participants for the years ended March 31, 2019, 2018, and 2017 were approximately $27.6 million, $29.5 million, and $24.0 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, 2019, 2018, and 2017, the Company made contributions of approximately zero, $9.7 million, and $3.3 million, respectively, to the PBOP Plans. The Company does not expect to contribute to the PBOP Plans during the year ending March 31, 2020.

Benefit payments to PBOP plan participants for the years ended March 31, 2019, 2018, and 2017 were approximately $9.8 million, $10.5 million, and $9.9 million, respectively.

Defined Contribution Plan

NGUSA has a defined contribution pension plan that covers substantially all employees. For the years ended March 31, 2019, 2018 and 2017, the Company recognized an expense in the accompanying statements of income of $3.1 million, $3.1 million and $2.8 million, respectively, for matching contributions.

Net Periodic Benefit Costs

The Company's net periodic benefit pension costs for the years ended March 31, 2019, 2018, and 2017 were $9.8 million, $9.9 million, and $12.2 million, respectively.

The Company's net periodic benefit PBOP costs for the years ended March 31, 2019, 2018, and 2017 were $2.8 million, $3.5 million, and $6.9 million, respectively.

Amounts Recognized in OCI and Regulatory Assets

The following tables summarize the Company's changes in actuarial gains/losses and prior service costs recognized primarily in regulatory assets as well as other comprehensive income for the years ended March 31, 2019, 2018, and 2017:

	Pension Plans		
	Years Ended March 31,		
	2019	2018	2017
	(in thousands of dollars)		
Net actuarial loss (gain)	**$ 7,362**	$ 2,080	$ (14,509)
Amortization of net actuarial loss	**(9,659)**	(9,565)	(10,917)
Amortization of prior service cost, net	**(20)**	(20)	(20)
Total	**$ (2,317)**	$ (7,505)	$ (25,446)
Included in regulatory assets	**$ (3,182)**	$ (7,377)	$ (25,453)
Included in AOCI	**865**	(128)	7
Total	**$ (2,317)**	$ (7,505)	$ (25,446)

	PBOP Plans		
	Years Ended March 31,		
	2019	2018	2017
	(in thousands of dollars)		
Net actuarial (gain) loss	**$ (7,013)**	$ (3,869)	$ (33,082)
Amortization of net actuarial loss	**(1,275)**	(1,730)	(3,952)
Amortization of prior service benefit, net	**20**	23	225
Total	**$ (8,268)**	$ (5,576)	$ (36,809)
Included in regulatory assets	**$ (8,268)**	$ (5,576)	$ (36,809)
Total	**$ (8,268)**	$ (5,576)	$ (36,809)

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

The following tables summarize the Company's amounts recognized in regulatory assets and accumulated other comprehensive income on the balance sheet that have not yet been recognized as components of net actuarial loss at March 31, 2019, 2018 and 2017:

	Pension Plans		
	At March 31,		
	2019	2018	2017
	(in thousands of dollars)		
Net actuarial loss	**$ 153,304**	$ 155,601	$ 163,086
Prior service cost	**17**	37	57
Total	**$ 153,321**	$ 155,638	$ 163,143
Included in regulatory assets	**$ 152,321**	$ 155,502	$ 162,879
Included in AOCI	**1,000**	136	264
Total	**$ 153,321**	$ 155,638	$ 163,143

	PBOP Plans		
	At March 31,		
	2019	2018	2017
	(in thousands of dollars)		
Net actuarial loss	**$ 19,510**	$ 27,798	$ 33,397
Prior service benefit	**(25)**	(45)	(68)
Total	**$ 19,485**	$ 27,753	$ 33,329
Included in regulatory assets	**$ 19,485**	$ 27,753	$ 33,329
Total	**$ 19,485**	$ 27,753	$ 33,329

The amount of net actuarial loss to be amortized from regulatory assets during the year ending March 31, 2020 for the Pension and OPEB Plans is $9.2 million and $1.0 million, respectively.

Amounts Recognized on the Balance Sheet

The following table summarizes the portion of the funded status that is recognized on the Company's balance sheet at March 31, 2019 and 2018:

	Pension Plans		PBOP Plans	
	March 31,		March 31,	
	2019	2018	**2019**	2018
	(in thousands of dollars)			
Projected benefit obligation	**$ (562,887)**	$ (560,190)	**$ (213,390)**	$ (223,753)
Allocated fair value of plan assets	**542,261**	534,883	**160,798**	165,530
Total	**$ (20,626)**	$ (25,307)	**$ (52,592)**	$ (58,223)
Current liabilities	**$ (195)**	$ (149)	**$ (130)**	$ (147)
Other non-current liabilities	**(20,431)**	(25,158)	**(52,462)**	(58,076)
Total	**$ (20,626)**	$ (25,307)	**$ (52,592)**	$ (58,223)

Expected Benefit Payments

Based on current assumptions, the following benefit payments are expected subsequent to March 31, 2019 in respect of the Company:

(in thousands of dollars) **Years Ended March 31,**	**Pension Plans**	**PBOP Plans**
2020	$ 32,274	$ 9,899
2021	33,353	10,321
2022	34,461	10,773
2023	35,690	11,148
2024	37,034	11,429
2025-2029	202,788	61,939
Total	**$ 375,600**	**$ 115,509**

Assumptions Used for Employee Benefits Accounting

	Pension Plans		
	Years Ended March 31,		
	2019	2018	2017
Benefit Obligations:			
Discount rate	**4.10%**	4.10%	4.30%
Rate of compensation increase	**3.50%**	3.50%	3.50%
Expected return on plan assets	**6.50%**	6.25%	6.50%
Net Periodic Benefit Costs:			
Discount rate	**4.10%**	4.30%	4.25%
Rate of compensation increase	**3.50%**	3.50%	3.50%
Expected return on plan assets	**6.25%**	6.50%	6.50%

	PBOP Plans		
	Years Ended March 31,		
	2019	2018	2017
Benefit Obligations:			
Discount rate	**4.10%**	4.10%	4.30%
Rate of compensation increase	**n/a**	n/a	n/a
Expected return on plan assets	**6.50%-7.25%**	6.25%-6.75%	6.50%-6.75%
Net Periodic Benefit Costs:			
Discount rate	**4.10%**	4.30%	4.25%
Rate of compensation increase	**n/a**	n/a	n/a
Expected return on plan assets	**6.25%-6.75%**	6.50%-6.75%	6.50%-6.75%

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 Hewitt AA Above Median 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

	March 31,	
	2019	2018
Health care cost trend rate assumed for next year		
Pre 65	**7.25%**	7.50%
Post 65	**5.75%**	5.75%
Prescription	**9.75%**	10.25%
Rate to which the cost trend is assumed to decline (ultimate)	**4.50%**	4.50%
Year that rate reaches ultimate trend		
Pre 65	**2028**	2028
Post 65	**2026**	2026
Prescription	**2027**	2027

Plan Assets

NGUSA, as the Plans' sponsor, manages the benefit plan investments to minimize the long-term cost of operating the Plans, with a reasonable level of risk. Risk tolerance is determined as a result of a periodic study which analyzes the Plans' liabilities and funded status and results in the determination of the allocation of assets across equity and fixed income securities. 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. Small investments are also approved for private equity, real estate, and infrastructure, with the objective of 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 study. Investment risk and return are reviewed by NGUSA's Investment Committee on a quarterly basis.

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

The target asset allocations for the benefit plans as of March 31, 2019 and 2018 are as follows:

	Pension Plans		PBOP Union		PBOP Non-Union	
	March 31,		March 31,		March 31,	
	2019	2018	**2019**	2018	**2019**	2018
			(in thousands of dollars)			
US Equities	**20%**	20%	**34%**	34%	**45%**	45%
Global equities (including US)	**7%**	7%	**12%**	12%	**0%**	0%
Global tactical asset allocation	**10%**	10%	**17%**	17%	**0%**	0%
Non-US equities	**10%**	10%	**17%**	17%	**25%**	25%
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%
Total	**100%**	100%	**100%**	100%	**100%**	100%

Fair Value Measurements

The following tables provide the fair value measurements amounts for the pension and PBOP assets at the Plan level:

	March 31, 2019				
	Level 1	**Level 2**	**Level 3**	**Not Categorized**	**Total**
			(in thousands of dollars)		
Pension Assets:					
Cash and cash equivalents	$ -	$ 1,954	$ -	$ 27,308	$ 29,262
Accounts receivable	50,966	-	-	-	50,966
Accounts payable	(105,196)	-	-	-	(105,196)
Convertible or Exchangeable Securities	-	188	-	-	188
Equity	189,522	-	-	667,776	857,298
Fixed income securities	-	621,152	-	339,857	961,009
Futures contracts	692	-	-	-	692
Preferred securities	-	6,426	-	-	6,426
Private equity	-	-	-	155,902	155,902
Real estate	-	-	-	116,409	116,409
Other	68,624	-	-	198,167	266,791
Total	**$ 204,608**	**$ 629,720**	**$ -**	**$ 1,505,419**	**$ 2,339,747**
PBOP Assets:					
Cash and cash equivalents	$ 8,632	$ 101	$ -	$ 869	$ 9,602
Accounts receivable	2,295	-	-	-	2,295
Accounts payable	(333)	-	-	-	(333)
Equity	161,077	-	-	274,993	436,070
Fixed income securities	-	156,161	-	-	156,161
Futures contracts	(107)	-	-	-	(107)
Other	39,056	-	-	79,657	118,713
Total	**$ 210,620**	**$ 156,262**	**$ -**	**$ 355,519**	**$ 722,401**

	March 31, 2018				
	Level 1	Level 2	Level 3	Not Categorized	Total
	(in thousands of dollars)				
Pension Assets:					
Cash and cash equivalents	$ 575	$ 15,518	$ -	$ 28,149	$ 44,242
Accounts receivable	88,162	-	-	-	88,162
Accounts payable	(133,593)	-	-	-	(133,593)
Equity	303,037	(16)	-	651,355	954,376
Fixed income securities	-	553,463	-	338,944	892,407
Preferred securities	-	5,972	-	-	5,972
Private equity	-	-	-	133,785	133,785
Real estate	-	-	-	110,551	110,551
Other	1,329	-	-	178,235	179,564
Total	**$ 259,510**	**$ 574,937**	**$ -**	**$ 1,441,019**	**$ 2,275,466**
PBOP Assets:					
Cash and cash equivalents	$ 9,111	$ 16	$ -	$ 598	$ 9,725
Accounts receivable	1,998	-	-	-	1,998
Accounts payable	(183)	-	-	-	(183)
Equity	189,026	-	-	281,678	470,704
Fixed income securities	-	165,705	-	-	165,705
Other	14,030	-	-	78,622	92,652
Total	**$ 213,982**	**$ 165,721**	**$ -**	**$ 360,898**	**$ 740,601**

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

Cash and cash equivalents: Cash and cash equivalents that can be priced daily are classified as Level 1. Active reserve funds, reserve deposits, commercial paper, repurchase agreements, and commingled cash equivalents are classified as Level 2. Cash and cash equivalents invested in commingled money market investment funds which have NAV used as a practical expedient pricing per fund share are excluded from the fair value hierarchy.

Accounts receivable and accounts payable: Accounts receivable and accounts payable are classified as Level 1. Such amounts are short-term and settle within a few days of the measurement date.

Equity and preferred securities: Common stocks, preferred stocks, and real estate investment trusts are valued using the official close of the primary market on which the individual securities are traded. Equity securities are primarily comprised of securities issued by public companies in domestic and foreign markets plus investments in commingled funds, which are valued on a daily basis. If the Company can exchange shares of the publicly traded securities and the fair values are primarily sourced from the closing prices on stock exchanges where there is active trading, the securities are classified as Level 1 investments. If there is less active trading, then the publicly traded securities would typically be priced using observable data, such as bid and ask prices, and these measurements are classified as Level 2 investments. Mutual funds with publicly quoted prices and active trading are classified as Level 1 investments. For investments in commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the NAV used as a practical expedient per fund share, derived from the underlying securities' quoted prices in active markets. These investments are excluded from the fair value hierarchy.

Fixed income securities: Fixed income securities (which include corporate debt securities, municipal fixed income securities, U.S. Government and Government agency securities including government mortgage backed securities, index linked government bonds, and state and local bonds), convertible securities, and investments in securities lending collateral (which include repurchase agreements, asset backed securities, floating rate notes and time deposits) are valued with an institutional bid valuation. A bid valuation is an estimated price a dealer would pay for a security (typically in an institutional round lot).

Oftentimes, these evaluations are based on proprietary models, which pricing vendors establish for these purposes. In some cases, there may be manual sources when primary vendors do not supply prices. Fixed income investments are primarily comprised of fixed income securities and fixed income commingled funds. The prices for direct investments in fixed income securities are generated on a daily basis. Prices generated from less active trading with wider bid ask prices are classified as Level 2 investments. Mutual funds with publicly quoted prices and active trading are classified as Level 1 investments. For commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the NAV used as a practical expedient, per fund share. These investments are excluded from the fair value hierarchy.

Private equity and real estate: Commingled equity funds, commingled special equity funds, limited partnerships, real estate, venture capital, and other investments are valued using evaluations (NAV used as a practical expedient per fund share) based on proprietary models, or based on the NAV used as a practical expedient. Investments in private equity and real estate funds are primarily invested in privately held real estate investment properties, trusts, and partnerships as well as equity and debt issued by public or private companies. The Company's interest in a fund or partnership is estimated based on the NAV used as a practical expedient. The Company's interest in these funds cannot be readily redeemed due to the inherent lack of liquidity and the primarily long-term nature of the underlying assets. Distribution is made through the liquidation of the underlying assets. The Company views these investments as part of a long-term investment strategy. These investments are valued by each investment manager based on the underlying assets. The funds utilize valuation techniques consistent with the market, income, and cost approaches to measure the fair value of certain real estate investments. The majority of the underlying assets are valued using significant unobservable inputs and often require significant management judgment or estimation based on the best available information. Market data includes observations of the trading multiples of public companies considered comparable to the private companies being valued. Investments in limited partnerships with redemption restrictions and that use NAV used as a practical expedient are excluded from the fair value hierarchy.

While management believes its valuation methodologies are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the NAV used as a practical expedient could result in a different fair value measurement at the reporting date.

8. CAPITALIZATION

The aggregate maturities of long-term debt for the years subsequent to March 31, 2019 are as follows:

(in thousands of dollars) Years Ending March 31,	
2020	$ 251,375
2021	11,375
2022	1,375
2023	13,875
2024	750
Thereafter	901,500
Total	$ 1,180,250

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. During the years ended March 31, 2019 and 2018, the Company was in compliance with all such covenants.

Debt Authorizations

Since January 12, 2015, the Company had 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, 2019 for a period of two years and expires on January 10, 2021. The Company had no external short-term debt outstanding to third-parties as of March 31, 2019 or 2018. Refer to Note 12, "Related Party Transactions" under "Intercompany Money Pool" for short-term debt outstanding with associated companies.

Since March 21, 2018, the RIPUC authorized the Company to issue up to $730 million through March 21, 2021. On July 24, 2018 the Company issued $350 million of unsecured senior long-term debt at 3.919% due August 1, 2028.

First Mortgage Bonds

At March 31, 2019, the Company had $30.3 million of FMB outstanding. Substantially all of the assets used in the gas business of the Company are subject to the lien of the mortgage indentures under which these FMB have been issued. The FMB have annual sinking fund requirements totaling approximately $1.4 million.

The Company has a maximum 70% of debt-to-capitalization covenant. Furthermore, if at any time the Company's debt exceeds 60% of the total capitalization, each holder of bonds then outstanding, shall receive effective as of the first date of such occurrence, a one time, and permanent, 0.20% increase in the interest rate paid by the Company on its bonds. During the years ended March 31, 2019 and 2018, the Company was in compliance with this covenant.

Dividend Restrictions

Pursuant to the preferred stock arrangement, as long as any preferred stock is outstanding, certain restrictions on payment of common stock dividends would come into effect if the common stock equity was, or by reason of payment of such dividends became, less than 25% of total capitalization. The Company was in compliance with this covenant and accordingly, the Company was not restricted as to the payment of common stock dividends under the foregoing provisions at March 31, 2019 or 2018**.**

Cumulative Preferred Stock

The Company has certain issues of non-participating cumulative preferred stock outstanding where the security is guaranteed by National Grid plc and can be redeemed at the option of the Company. There are no mandatory redemption provisions on the Company's cumulative preferred stock. A summary of cumulative preferred stock is as follows:

	Shares Outstanding		**Amount**		
	March 31,		**March 31,**		Call
Series	**2019**	2018	**2019**	2018	Price
	(in thousands of dollars, except per share and number of shares data)				
$50 par value -					
4.50% Series	**49,089**	49,089	**$ 2,454**	$ 2,454	$ 55.000

The Company did not redeem any preferred stock during the years ended March 31, 2019, 2018, or 2017. The annual dividend requirement for cumulative preferred stock was $0.1 million for each of the years ended March 31, 2019, 2018, and 2017.

9. INCOME TAXES

Components of Income Tax Expense

	Years Ended March 31,		
	2019	2018	2017
	(in thousands of dollars)		
Current federal income tax expense (benefit)	**$ (12,398)**	$ (19,040)	$ 21,054
Deferred federal tax expense	**36,415**	41,351	27,576
Amortized investment tax credits [1]	**(16)**	(62)	(106)
Total deferred tax expense	**36,399**	41,289	27,470
Total income tax expense	**$ 24,001**	$ 22,249	$ 48,524

(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, 2019, 2018 and 2017 were 17.9%, 15.2% and 35.5%, respectively. The following table presents a reconciliation of income tax expense at the federal statutory tax rate of 21%, 31.55%, and 35%, respectively, to the actual tax expense:

	Years Ended March 31,		
	2019	2018	2017
	(in thousands of dollars)		
Computed tax	**$ 28,231**	$ 45,923	$ 47,833
Change in computed taxes resulting from:			
Temporary difference flowed through	**(172)**	695	834
Federal rate change	**-**	(23,497)	-
Amortization of excess deferred federal income tax	**(4,121)**	-	-
Other items, net	**63**	(872)	(143)
Total	**(4,230)**	(23,674)	691
Total income tax expense	**$ 24,001**	$ 22,249	$ 48,524

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

On December 22, 2017, the Tax Act was signed into law. The Tax Act includes significant changes to various federal tax provisions applicable to the Company, including provisions specific to regulated public utilities. The most significant changes include the reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018, the elimination of bonus depreciation for certain property acquired or placed in service after September 27, 2017, and the extension of the normalization requirements for ratemaking treatment of excess deferred taxes.

On August 3, 2018, the Internal Revenue Service ("IRS") and the U.S. Department of Treasury released proposed regulations associated with the bonus depreciation rules enacted as part of the Tax Act. The proposed regulations would enable utilities to claim additional bonus depreciation on property acquired and placed in service between September 28, 2017 and March 31, 2018. The Company adopted the guidance in the proposed regulations and claimed the additional six months of bonus depreciation on its fiscal year 2018 federal income tax return.

In accordance with ASC 740, "Income Taxes," the effects of changes in tax law are required to be recognized in the period of enactment, which for the Company was the period ended March 31, 2018. Since the Company's fiscal year end is March 31, the statutory rate applicable for the Company's fiscal year ended March 31, 2018, was a blended tax rate of 31.55%. For the fiscal year ended March 31, 2019 and future periods, the federal income tax rate is 21%. In addition, ASC 740 requires deferred income tax assets and liabilities to be measured at the enacted tax rate expected to apply when temporary differences are to be realized or settled. As a result, the Company remeasured its federal deferred income tax assets and liabilities using the newly enacted tax rate of 21%.

On December 22, 2017, the Securities and Exchange Commission issued Staff Accounting Bulletin ("SAB") 118, which provides guidance on accounting for the effects of the Tax Act. SAB 118 provides a measurement period that should not extend beyond one year from the Tax Act enactment date to complete the accounting under ASC 740, "Income Taxes". To the extent that a company's accounting for certain income tax effects of the Tax Act is incomplete, a company can determine a reasonable estimate for those effects and record a provisional estimate in the financial statements. As of March 31, 2019, any and all provisional amounts previously recorded in accordance with SAB 118 have been adjusted to reflect their final amounts.

As of March 31, 2018, the remeasurement amounted to a decrease in the net deferred income tax liability of $250 million of which $23.7 million benefit was recorded to deferred income tax expense and $226.3 million was recorded as a regulatory liability for the refund of excess accumulated deferred income taxes to the ratepayers ("excess ADIT"). During the current period, the Company adjusted the remeasurement of the net deferred income tax liability by $5.3 million, which was recorded as an increase to the regulatory liability for excess ADIT. As of March 31, 2019, the regulatory liability for excess ADIT on a pre-tax basis prior to amortization amounted to $293 million ($231.6 million post-tax).

Deferred Tax Components

	March 31,	
	2019	2018
	(in thousands of dollars)	
Deferred tax assets:		
Environmental remediation costs	**$ 25,263**	$ 28,912
Net operating losses	**42,197**	50,076
Postretirement benefits and other employee benefits	**18,801**	20,731
Regulatory liabilities - other	**36,445**	21,693
Regulatory liabilities - taxes	**58,391**	58,116
Other items	**11,036**	11,796
Total deferred tax assets	**192,133**	191,324
Deferred tax liabilities:		
Amortization of goodwill	**40,366**	36,613
Property related differences	**401,506**	366,609
Regulatory assets - environmental	**22,160**	26,704
Regulatory assets - postretirement benefits	**35,513**	35,954
Regulatory assets - other	**19,662**	14,841
Regulatory assets - storm costs	**27,990**	30,716
Other items	**4,054**	4,031
Total deferred tax liabilities	**551,251**	515,468
Net deferred income tax liabilities	**359,118**	324,144
Deferred investment tax credits	**1**	17
Deferred income tax liabilities, net	**$ 359,119**	$ 324,161

Net Operating Losses

The amounts and expiration dates of the Company's net operating loss carryforwards as of March 31, 2019 are as follows:

	Carryforward Amount *(in thousands of dollars)*	Expiration Period
Federal	$ 331,026	2033-2038

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

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 statements of income. As of March 31, 2019 and 2018, the Company has accrued for interest related to unrecognized tax benefits of $0.3 million and zero, respectively. During the years ended March 31, 2019, 2018, and 2017, the Company recorded interest expense related to unrecognized tax benefits of $0.3 million for 2019 and zero for 2018 and 2017. No tax penalties were recognized during the years ended March 31, 2019, 2018 and 2017.

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

During the year ended March 31, 2019, the Company reached a settlement with the IRS for the tax years ended August 24, 2007, March 31, 2008 and March 31, 2009. The outcome of the settlement did not have a material impact on the Company's results of operations, financial position, or cash flows. The IRS continues its examination of the next audit cycle which includes the income tax returns for the years ended March 31, 2010 through March 31, 2012. The examination is expected to conclude in the next fiscal year and result in a settlement agreement with the IRS. The Company does not anticipate the settlement will have a material impact on the Company's financial position. As a result of both settlements with the IRS a refund of $8.4 million is expected to be received within the next 12 months. The income tax returns for the years ended March 31, 2013 through March 31, 2019 remain subject to examination by the IRS.

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

Jurisdiction	**Tax Year**
Federal	March 31, 2010

The Company is not subject to state income taxes since the State of Rhode Island does not impose an income tax on public utility companies.

10. ENVIRONMENTAL MATTERS

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

The United States Environmental Protection Agency ("EPA"), the Massachusetts Department of Environmental Protection ("DEP"), and the Rhode Island Department of Environmental Management ("DEM") have alleged that the Company is a potentially responsible party under state or federal law for the remediation of a number of sites at which hazardous waste is alleged to have been disposed. The Company's most significant liabilities relate to former Manufactured Gas Plant ("MGP") facilities formerly owned by the Blackstone Valley Gas and Electric Company and the Rhode Island gas distribution assets of New England Gas. The Company is currently investigating and remediating, as necessary, those MGP sites and certain other properties under agreements with the EPA, DEM and DEP. Expenditures incurred for the year ended March 31, 2019, 2018, and 2017 were $1.8 million, $2.9 million, and $4.9 million, respectively.

The Company estimated the remaining costs of environmental remediation activities were $120.3 million and $137.7 million at March 31, 2019 and 2018, respectively. The Company had a current portion of environmental remediation costs of $2.9 million included in other current liabilities on the balance sheet at March 31, 2019. These costs are expected to be incurred over approximately 40 years, and these undiscounted amounts have been recorded as estimated liabilities on the balance sheet. However, remediation costs for each site may be materially higher than estimated, depending on changing technologies and regulatory standards, selected end use for each site, and actual environmental conditions encountered. The Company has recovered amounts from certain insurers and potentially responsible parties, and, where appropriate, the Company may seek additional recovery from other insurers and from other potentially responsible parties, but it is uncertain whether, and to what extent, such efforts will be successful.

The RIPUC has approved a settlement agreement that provides for rate recovery of remediation costs of former MGP sites and certain other hazardous waste sites located in Rhode Island. Under that agreement, qualified costs related to these sites are paid out of a special fund established as a regulatory liability on the balance sheet. Rate-recoverable contributions of approximately $3 million are added annually to the fund, along with interest and any recoveries from insurance carriers and other third-parties. Accordingly, as of March 31, 2019 and 2018, the Company has recorded environmental regulatory assets of $121.2 million and $140.0 million, respectively, and environmental regulatory liabilities of $15.6 million and $12.8 million, respectively (See Note 4, "Regulatory Assets and Liabilities" for additional details).

The Company believes that its ongoing operations, and its approach to addressing conditions at historic sites, are in substantial compliance with all applicable environmental laws. Where the Company has regulatory recovery, it believes 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.

11. COMMITMENTS AND CONTINGENCIES

Operating Lease Obligations

The Company has various operating leases relating to fleet vehicles. The future minimum lease payments for the years subsequent to March 31, 2019 are as follows:

(in thousands of dollars)	
Years Ending March 31,	
2020	$ 8,135
2021	7,059
2022	5,742
2023	4,405
2024	2,742
Thereafter	1,963
Total	$ 30,046

Purchase Commitments

The Company has several long-term contracts for the purchase of electric power. Substantially all of these contracts require power to be delivered before the Company is obligated to make payment. Additionally, the Company has entered into various contracts for gas delivery, storage, and supply services. Certain of these contracts require payment of annual demand charges, which are recoverable from customers. The Company is liable for these payments regardless of the level of service required from third-parties.

The Company's commitments under these long-term contracts for the years subsequent to March 31, 2019 are summarized in the table below:

(in thousands of dollars) Years Ending March 31,	Energy Purchases
2020	$ 301,855
2021	102,899
2022	37,276
2023	33,512
2024	33,030
Thereafter	253,912
Total	$ 762,484

Long-term Contracts for Renewable Energy

Deepwater Agreement

The 2009 Rhode Island law required the Company to solicit proposals for a small scale renewable energy generation project of up to eight wind turbines with an aggregate nameplate capacity of up to 30 MW to benefit the Town of New Shoreham. The renewable energy generation project also included a transmission cable to be constructed between Block Island and the mainland of Rhode Island. On June 30, 2010, the Company entered into a 20-year Amended Power Purchase Agreement ("PPA") with Deepwater Wind Block Island LLC ("Deepwater"), which was approved by the RIPUC in August 2010. The wind turbines reached commercial operation on December 12, 2016 and the PPA is being accounted for as a capital lease. The Company also negotiated a Transmission Facilities Purchase Agreement ("Facilities Purchase Agreement") with Deepwater to purchase the permits, engineering, real estate, and other site development work for construction of the undersea transmission cable (collectively, the "Transmission Facilities"). On April 2, 2014, the Division issued its Consent Decision for the Company to execute the Facilities Purchase Agreement with Deepwater. In July 2014, four agreements were filed with the FERC, in part, for approval to recover the costs associated with the transmission cable and related facilities (the "Project") that will be allocated to the Company and Block Island Power Company through transmission rates. On September 2, 2014, the FERC accepted all four agreements, thus approving cost recovery for the Project, with no conditions, that will apply to the Company's costs, as well as those of NEP. The agreements went into effect on September 30, 2014. On January 30, 2015, the Company closed on its purchase of the Transmission Facilities from Deepwater. The Company placed the Transmission Facilities into service on October 31, 2016.

Three-State Procurement

On April 9, 2018, the RIPUC approved eight long-term (20-year) contracts totaling approximately 44 MWs of nameplate capacity between the Company and several counterparties pursuant to the Rhode Island Long-Term Contracting Standard. Because the contracts were approved pursuant to the Rhode Island Long-Term Contracting Standard, the Company may collect 2.75% remuneration on the annual payments made under the contracts. The contracts resulted from a three-state solicitation for renewable energy generation proposals.

Offshore Wind Energy Procurement

On December 6, 2018, the Narragansett Electric Company entered into a 20-year 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 Company will be able to recover the cost incurred under the agreement was issued by the RIPUC on June 7, 2019.

Annual Solicitations

The 2009 Rhode Island law also requires that, beginning on July 1, 2010, the Company 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. The Company's four solicitations have resulted in four PPAs that have been approved by the RIPUC:

- First Solicitation: On July 28, 2011, the RIPUC approved a 15-year PPA with Orbit Energy Rhode Island, LLC for a 3.2 MW anaerobic digester biogas project.
- Second Solicitation: On May 11, 2012, the RIPUC approved a 15-year PPA with Black Bear Development Holdings, LLC for a 3.9 MW run-of-river hydroelectric plant located in Orono, Maine. The facility reached commercial operation on November 22, 2013.
- Third Solicitation: On October 25, 2013, the RIPUC approved a 15-year PPA with Champlain Wind, LLC for a 48 MW land-based wind project located in Carroll Plantation and Kossuth Township, Maine. The PPA was terminated on January 23, 2017 because one of the required permits for the project was rejected. The impact of this termination is that the Company will need to backfill the MW capacity from that project to meet the 90 MW minimum long-term capacity requirements under the state statute.
- Fourth Solicitation: On October 29, 2015, the RIPUC approved a 15-year PPA with Copenhagen Wind Farm, LLC for an 80 MW land-based wind project located in Denmark, New York.

As approved by the RIPUC, the Company is allowed to pass through commodity-related / purchased power costs to customers. The cost of these contracts is accounted for as part of these costs.

Aquidneck Island

On January 21, 2019, the Company suspended gas service to approximately 7,100 gas customers on Aquidneck Island due to a gas transmission supply issue. The recovery effort took approximately nine days, with service restored to essentially all customers by January 30, 2019. On February 28, 2019, the RIPUC opened an investigation into the causes of the outage, in order to comport with the United State Senate's request to do so per Senate Resolution 188 passed on January 31, 2019. On June 4, 2019, the RIPUC issued a "Status Report on the Aquidneck Island Loss of Gas Investigation." In the report, the RIPUC noted that there may have been multiple contributing factors leading to the outage, and that a final report would be released before the upcoming heating season. The RIPUC also noted that following the release of the report, if it is found that the Company contributed to the incident through imprudent management decisions, a subsequent regulatory process would be initiated, through which fines or disallowed costs could be assessed. At this time, the Company is unable to predict or estimate any impact to earnings.

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.

Other Contingencies

At March 31, 2019 and 2018, the Company had accrued workers compensation, auto, and general insurance claims which have been incurred but not yet reported ("IBNR") of $2.1 million and $2.9 million, respectively. IBNR reserves have been established for claims and/or events that have transpired, but have not yet been reported to the Company for payment.

12. RELATED PARTY TRANSACTIONS

Accounts Receivable from and Accounts Payable to Affiliates

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

The Company records short-term receivables from, and payables to, certain of its affiliates in the ordinary course of business. The amounts receivable from, and payable to, its affiliates do not bear interest and are settled through the intercompany money pool. A summary of outstanding accounts receivable from affiliates and accounts payable to affiliates is as follows:

	Accounts Receivable from Affiliates		Accounts Payable to Affiliates	
	March 31,		March 31,	
	2019	2018	**2019**	2018
	(in thousands of dollars)			
New England Power Company	**$ 14,212**	$ 22,221	**$ 21,679**	$ -
NGUSA Service Company	**5,196**	-	**28,024**	12,224
Other	**671**	-	**2,441**	2,206
Total	**$ 20,079**	$ 22,221	**$ 52,144**	$ 14,430

As discussed in Note 4 "Rate Matters," NEP operates the pooled transmission facilities of MECO, the Company, and NEP as a single integrated system ("NEPOOL") under NEP's Tariff No. 1. These transmission services are regulated by both ISO-NE and by the FERC. NEP charges ISO-NE for these transmission services. As NEP is the sole operator of NEPOOL assets, ISO-NE revenues are remitted from NEP to the Company representing the substantial portion of the affiliated accounts receivable due from NEP.

In turn, ISO-NE charges the Company for regional network services ("RNS") with some of those charges being associated with the Company-owned transmission assets in the NEPOOL. As of March 31, 2019, $17.6 million of the unpaid charges from ISO-NE to the Company have been presented as an affiliated payable to NEP related to these Company-owned transmission assets. Additionally, NEP also charges the Company local network service ("LNS") rates. Amounts paid to NEP for LNS for the years ended March 31, 2019, 2018 and 2017 were $46.5 million, $47.3 million and $33.5 million, respectively. These amounts are presented within operations and maintenance expense within the accompanying statements of income.

Advances from Affiliates

Since December 2008, the Company had FERC and board authorization to borrow up to $250 million as deemed necessary for working capital needs. The advance is non-interest bearing. At March 31, 2019 and 2018, the Company had no outstanding advances from affiliates.

Intercompany Money Pool

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

The Regulated Money Pool is funded by operating funds from participants. NGUSA has the ability to borrow up to $3.0 billion from National Grid plc for working capital needs, including funding of the Regulated Money Pool, if necessary. The Company had short-term intercompany money pool borrowings of $56.5 million and $307.5 million at March 31, 2019 and 2018, respectively. The average interest rates for the intercompany money pool were 2.4%, 1.6%, and 1.1% for the years ended March 31, 2019, 2018, and 2017, respectively.

Service Company Charges

The affiliated service companies of NGUSA provide certain services to the Company at their cost. The service company costs are generally allocated to associated companies through a tiered approach. First and foremost, costs are directly charged to the benefited company whenever practicable. Secondly, in cases where direct charging cannot be readily determined, costs are allocated using cost/causation principles linked to the relationship of that type of service, such as number of employees, number of customers/meters, capital expenditures, value of property owned, and total transmission and distribution expenditures. Lastly, all other costs are allocated based on a general allocator determined using a 3-point formula based on net margin, net property, plant, and equipment, and operations and maintenance expense.

Charges from the service companies of NGUSA to the Company are mostly related to traditional administrative support functions, and for the years ended March 31, 2019, 2018, and 2017 were $229.7 million, $201.3 million, and $229.9 million, respectively.