THE UNITED ILLUMINATING COMPANY

AUDITED FINANCIAL STATEMENTS

AS OF AND FOR THE YEARS ENDED

DECEMBER 31, 2019 AND 2018

TABLE OF CONTENTS

KPMG LLP
677 Washington Boulevard
Stamford, CT 06901

Independent Auditors' Report

The Board of Directors
The United Illuminating Company:

We have audited the accompanying financial statements of The United Illuminating Company, which comprise the balance sheets as of December 31, 2019 and 2018, and the related statements of income, changes in shareholder's equity, and cash flows for the years then ended, 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 U.S. generally accepted accounting principles; 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 auditors' 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 entity'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 entity'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 United Illuminating Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

KPMG LLP

Stamford, Connecticut
April 14, 2020

THE UNITED ILLUMINATING COMPANY
STATEMENTS OF INCOME
(In Thousands)

	Year Ended December 31, 2019	Year Ended December 31, 2018
Operating Revenues	$ 988,798	$ 970,052
Operating Expenses		
Purchased power	212,948	202,827
Operation and maintenance	377,349	382,544
Depreciation and amortization	99,834	80,481
Taxes other than income taxes	109,020	109,999
Total Operating Expenses	799,151	775,851
Operating Income	189,647	194,201
Other Income and (Expense), net	(6,195)	(9,178)
Interest Expense, net	42,923	42,734
Income from Equity Investments	8,697	11,038
Income Before Income Tax	149,226	153,327
Income Tax	26,605	37,388
Net Income	$ 122,621	$ 115,939

The accompanying Notes to Financial
Statements are an integral part of the financial statements.

THE UNITED ILLUMINATING COMPANY
STATEMENTS OF CASH FLOWS
(In Thousands)

	Year Ended December 31, 2019	Year Ended December 31, 2018
Cash Flows From Operating Activities		
Net income	$ 122,621	$ 115,939
Adjustments to reconcile net income		
to net cash provided by operating activities:		
Depreciation and amortization	101,338	81,762
Deferred income taxes	15,752	(3,751)
Uncollectible expense	28,064	25,736
Pension expense	22,296	24,144
Allowance for funds used during construction (AFUDC) - equity	(5,560)	(1,457)
Undistributed (earnings) in equity investments	(8,697)	(11,038)
Regulatory assets/liabilities amortization	5,189	7,277
Regulatory assets/liabiities carrying cost	1,291	(1,310)
Other non-cash items, net	1,866	1,010
Changes in:		
Accounts receivable and unbilled revenues, net	(57,046)	(18,420)
Accounts payable and accrued liabilties	13,115	16,752
Cash distribution received from GenConn	8,782	10,866
Taxes accrued and refundable	(18,684)	726
Pension and post-retirement	(16,660)	(14,071)
Regulatory assets/liabilities	(15,876)	38,636
Environmental liabilities	1,357	(11,033)
Other assets	(475)	(111)
Other liabilities	886	842
Total Adjustments	76,938	146,560
Net Cash provided by Operating Activities	199,559	262,499
Cash Flows from Investing Activities		
Plant expenditures including AFUDC debt	(169,444)	(254,929)
Proceeds from sale of building	-	6,206
Cash distribution from GenConn	4,722	3,853
Notes receivable from affiliates	(8,525)	(10,850)
Net Cash used in Investing Activities	(173,247)	(255,720)
Cash Flows from Financing Activities		
Issuances of long-term debt	50,000	214,460
Payment of long-term debt	-	(100,000)
Line of credit borrowings	(31,000)	(100,000)
Notes payable to affiliates	(145)	(68,543)
Payment of common stock dividend	(90,000)	-
Equity infusion from parent	47,000	50,000
Other	(365)	(1,865)
Net Cash used in Financing Activities	(24,510)	(5,948)
Cash, Restricted Cash, and Cash Equivalents:		
Net change for the period	1,802	831
Balance at beginning of period	2,819	1,988
Balance at end of period	$ 4,621	$ 2,819
Cash paid during the period for:		
Interest (net of amount capitalized)	$ 38,744	$ 39,286
Non-cash investing activity:		
Plant expenditures included in ending accounts payable	$ 29,913	$ 25,786

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THE UNITED ILLUMINATING COMPANY
BALANCE SHEETS
ASSETS
(In Thousands)

	December 31, 2019	December 31, 2018
Assets		
Current Assets		
Cash and cash equivalents	$ 3,643	$ 1,305
Accounts receivable and unbilled revenues, net	150,352	165,140
Accounts receivable from affiliates	56,498	13,028
Notes receivable from affiliates	19,375	10,850
Regulatory assets	35,086	26,430
Materials and supplies	5,986	5,619
Derivative assets	331	3,413
Refundable taxes	7,100	-
Prepayments and other current assets	3,244	3,492
Total Current Assets	281,615	229,277
Other Investments		
Equity investment in GenConn	93,647	98,473
Other	12,771	9,990
Total Other Investments	106,418	108,463
Net Property, Plant and Equipment	2,568,455	2,481,423
Operating lease right of use assets	12,220	-
Regulatory Assets	472,693	454,358
Deferred Charges and Other Assets		
Derivative assets	1,807	1,942
Other	3,033	3,213
Total Deferred Charges and Other Assets	4,840	5,155
Total Assets	$ 3,446,241	$ 3,278,676

The accompanying Notes to Financial
Statements are an integral part of the financial statements.

THE UNITED ILLUMINATING COMPANY
BALANCE SHEETS
LIABILITIES AND CAPITALIZATION
(In Thousands)

	December 31, 2019	December 31, 2018
Liabilities		
Current Liabilities		
Current portion of long-term debt	$ 50,000	$ 31,000
Accounts payable and accrued liabilities	123,637	108,178
Accounts payable to affiliates	52,794	45,529
Regulatory liabilities	17,326	5,395
Interest accrued	11,362	11,189
Taxes accrued	14,642	26,226
Derivative liabilities	11,442	11,966
Operating lease liabilities	1,790	-
Other liabilities	18,411	23,893
Total Current Liabilities	301,404	263,376
Deferred Income Taxes	340,930	318,169
Regulatory Liabilities	444,520	443,064
Other Noncurrent Liabilities		
Pension and post-retirement	260,828	252,545
Derivative liabilities	63,382	67,969
Environmental remediation costs	15,461	8,104
Operating lease liabilities	14,484	-
Other	14,422	14,474
Total Other Noncurrent Liabilities	368,577	343,092
Capitalization		
Long-term debt	811,768	811,554
Common Stock Equity		
Common stock	1	1
Paid-in capital	806,230	759,230
Retained earnings	372,811	340,190
Net Common Stock Equity	1,179,042	1,099,421
Total Capitalization	1,990,810	1,910,975
Total Liabilities and Capitalization	$ 3,446,241	$ 3,278,676

The accompanying Notes to Financial
Statements are an integral part of the financial statements.

THE UNITED ILLUMINATING COMPANY
STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
December 31, 2019
(Thousands of Dollars)

	Common Stock		Paid-in	Retained	
	Shares	Amount	Capital	Earnings	Total
Balance as of December 31, 2017	100	$ 1	$ 709,230	$ 224,251	$ 933,482
Net income				115,939	115,939
Equity infusion from parent			50,000		50,000
Balance as of December 31, 2018	100	$ 1	$ 759,230	$ 340,190	$ 1,099,421
Net income				122,621	122,621
Payment of common stock dividend				(90,000)	(90,000)
Equity infusion from parent			47,000		47,000
Balance as of December 31, 2019	100	$ 1	$ 806,230	$ 372,811	$ 1,179,042

The accompanying Notes to Financial
Statements are an integral part of the financial statements.

THE UNITED ILLUMINATING COMPANY

NOTES TO FINANCIAL STATEMENTS

(A) BUSINESS ORGANIZATION AND STATEMENT OF ACCOUNTING POLICIES

The United Illuminating Company (UI) is a regulated operating electric public utility established in 1899. UI is engaged principally in the purchase, transmission, distribution and sale of electricity for residential, commercial and industrial purposes. UI is regulated as an electric distribution company by the Connecticut Public Utilities Regulatory Authority (PURA) and is also subject to regulation by the Federal Energy Regulatory Commission (FERC).

UI is a wholly owned subsidiary of UIL Holdings Corporation (UIL Holdings). UIL Holdings, whose primary business is ownership of its operating regulated utility businesses, is a wholly owned subsidiary of Avangrid Networks, Inc. (Networks), which is a wholly-owned subsidiary of Avangrid, Inc., which is a 81.5% owned subsidiary of Iberdrola, S.A., a corporation organized under the law of the Kingdom of Spain.

UI is also a party to a joint venture with Clearway Energy, Inc., a subsidiary of Global Infrastructure Partners (GIP), pursuant to which UI holds 50% of the membership interests in GCE Holding LLC, whose wholly owned subsidiary, GenConn Energy LLC, or GenConn, operates peaking generation plants in Devon, Connecticut, or GenConn Devon, and Middletown, Connecticut, or GenConn Middletown.

Accounting Records

The accounting records of UI are maintained in conformity with accounting principles generally accepted in the United States of America (GAAP) and in accordance with the uniform systems of accounts prescribed by the FERC and the PURA.

Basis of Presentation

The preparation of financial statements in conformity with GAAP requires management to use estimates and assumptions that affect (1) the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and (2) the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

UI's total comprehensive income is equal to net income for the years ended December 31, 2019 and 2018.

UI has evaluated subsequent events through the date its financial statements were available to be issued, April 14, 2020.

We consider the following policies to be the most critical in understanding the judgments that are involved in preparing our consolidated financial statements:

Revenues

UI presents revenue in accordance with Accounting Standards Codification (ASC), Topic 606 "Revenue from Contracts with Customers" (ASC 606). UI derives its revenues primarily from tariff-based sales of electricity. For such revenues, UI recognizes revenues in an amount derived from the electricity delivered to customers. Other major sources of revenue are electricity transmission and wholesale sales of electricity.

Tariff-based sales are subject to PURA, which determines prices and other terms of service through the ratemaking process. Customers have the option to obtain the electricity directly from the UI or from another supplier. For customers that receive their electricity from another supplier, UI acts as an agent and delivers the electricity by that supplier. Revenue in those cases is only for providing the service of delivery of the electricity. UI calculates revenue earned but not yet billed based on the number of days not billed in the month, the estimated amount of energy delivered during those days and the estimated average price per customer class for that month. Differences between actual and estimated unbilled revenue are immaterial.

Transmission revenue results from others' use of UI's transmission system to transmit electricity and is subject to FERC regulation, which establishes the prices and other terms of service. Long-term wholesale sales of electricity are based on individual bilateral contracts. Short-term wholesale sales of electricity are generally on a daily basis based on market prices and are administered by an independent entity, ISO-New England, Inc.

The performance obligation in all arrangements is satisfied over time because the customer simultaneously receives and consumes the benefits as UI delivers or sells the electricity or provides the transmission service. UI records revenue for all of those sales based upon the regulatory-approved tariff and the volume delivered or transmitted, which corresponds to the amount that UI has a right to invoice. There are no material initial incremental costs of obtaining a contract in any of the arrangements. UI does not adjust the promised consideration for the effects of a significant financing component if it expects, at contract inception, that the time between the delivery of promised goods or service and customer payment will be one year or less. UI does not have any material significant payment terms because it receives payment at or shortly after the point of sale.

UI also records revenue from Alternative Revenue Programs (ARPs), which is not ASC 606 revenue. Such programs represent contracts between the UI and their regulators. UI's ARPs include revenue decoupling mechanisms, other ratemaking mechanisms and annual revenue requirement reconciliations. UI recognizes and records only the initial recognition of "originating" ARP revenues (when the regulatory-specified conditions for recognition have been met). When UI subsequently includes those amounts in the price of utility service billed to customers, they record such amounts as a recovery of the associated regulatory asset or liability. When they owe amounts to customers in connection with ARPs, they evaluate those amounts on a quarterly basis and include them in the price of utility service billed to customers and do not reduce ARP revenues.

UI also has various other sources of revenue including billing, collection, other administrative charges, sundry billings, rent of utility property, and miscellaneous revenue. It classifies such revenues as other ASC 606 revenues to the extent they are not related to revenue generating activities from leasing, derivatives, or ARPs.

Revenues disaggregated by major source are as follows:

(Thousands)	Year Ended December 31, 2019	Year Ended December 31, 2018
Regulated operations – electricity	$ 946,733	$ 924,929
Other (a)	7,087	8,935
Revenue from contracts with customers	**953,820**	**933,864**
Leasing revenue	1,318	2,829
Alternative revenue programs	32,154	31,861
Other Revenue	1,506	1,498
Total operating revenues	**$ 988,798**	**$ 970,052**

(a) Primarily includes certain intra-month trading activities, billing, collection, and administrative charges, sundry billings, and other miscellaneous revenue.

Refer to "New Accounting Pronouncements" and Note (H) "Leases" for details on the adoption of ASC 842 including a discussion regarding the classification of lease revenues.

Regulatory Accounting

Generally accepted accounting principles for regulated entities in the United States of America allow UI to give accounting recognition to the actions of regulatory authorities in accordance with the provisions of ASC 980 "Regulated Operations." In accordance with ASC 980, UI has deferred recognition of costs (a regulatory asset) or has recognized obligations (a regulatory liability) if it is probable that such costs will be recovered or obligations refunded in the future through the ratemaking process. UI is allowed to recover all such deferred costs and is required to refund such obligations to customers through its regulated rates. See

Note (C) “Regulatory Proceedings”, for a discussion of the recovery of certain deferred costs and the refund of certain obligations, as well as a discussion of the regulatory decisions that provide for such recovery and require such refunding.

UI also has obligations under long-term power contracts, the recovery of which is subject to regulation. If UI, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs would be required in the year in which such criteria are no longer met (if such deferred costs are not recoverable in the portion of the business that continues to meet the criteria for application of ASC 980). UI expects to continue to meet the criteria for application of ASC 980 for the foreseeable future. If a change in accounting were to occur, it could have a material adverse effect on the earnings and retained earnings of UI in that year and could also have a material adverse effect on the ongoing financial condition of UI.

Unless otherwise stated below, all of UI’s regulatory assets earn a return. UI’s regulatory assets and liabilities as of December 31, 2019 and December 31, 2018 included the following:

	Remaining Period	December 31, 2019	December 31, 2018
		(In Thousands)	
Regulatory Assets:			
Unamortized redemption costs	2 to 14 years	$ 6,567	$ 7,347
Pension and other post-retirement benefit plans	(a)	217,917	217,503
Unfunded future income taxes	(b)	154,538	148,391
Contracts for differences	(c)	72,686	74,580
Deferred transmission expense	(e)	10,967	11,316
Other	(f)	45,104	21,651
Total regulatory assets		507,779	480,788
Less current portion of regulatory assets		35,086	26,430
Regulatory Assets, Net		$ 472,693	$ 454,358
Regulatory Liabilities:			
Accumulated deferred investment tax credits	15.5 - 19 years	$ 13,015	$ 13,586
Excess generation service charge	(d)	11,418	6,686
Middletown/Norwalk local transmission network service collections	31 years	17,962	18,535
Pension and other post-retirement benefit plans	(a)	14,861	17,368
Asset removal costs	(f)	65,452	65,332
Tax reform	(g)	316,378	309,018
Other	(f)	22,760	17,934
Total regulatory liabilities		461,846	448,459
Less current portion of regulatory liabilities		17,326	5,395
Regulatory Liabilities, Net		$ 444,520	$ 443,064

(a) Life is dependent upon timing of final pension plan distribution; balance, which is fully offset by a corresponding asset/liability, is recalculated each year in accordance with ASC 715 "Compensation-Retirement Benefits." See Note (F) “Pension and Other Benefits” for additional information.

(b) The balance will be extinguished when the asset, which is fully offset by a corresponding liability, has been realized or settled.

(c) Asset life is equal to delivery term of related contracts (which vary from approximately 3 - 10 years); balance fluctuates based upon quarterly market analysis performed on the related derivatives (Note J); amount, which does not earn a return, is fully offset by corresponding derivative asset/liability. See “Contracts for Differences” discussion above for additional information.

(d) Regulatory asset or liability which defers generation-related and nonbypassable federally mandated congestion costs or revenues for future recovery from or return to customers. Amount fluctuates based upon timing differences between revenues collected from rates and actual costs incurred.

(e) Regulatory asset or liability which defers transmission income or expense and fluctuates based upon actual revenues and revenue requirements.

(f) Amortization period and/or balance vary depending on the nature, cost of removal and/or remaining life of the underlying assets/liabilities; asset amount as of December 31, 2019 includes decoupling ($7.5 million) and certain other amounts that are not currently earning a return.

(g) Balance includes customer impacts of deferred tax remeasurement as of December 2017, as well as the post 2017 impact of the tax rate decrease related to the passage of the federal Tax Cuts and Jobs Act of 2017 on December 22, 2017. The amount and timing of potential settlement are determined by the regulated utilities' respective rate regulators and IRS Normalization rules.

Property, Plant and Equipment

The cost of additions to property, plant and equipment and the cost of renewals and betterments are capitalized. Costs consist of labor, materials, services and certain indirect construction costs, including AFUDC. The costs of current repairs, major maintenance projects and minor replacements are charged to appropriate operating expense accounts as incurred. The original cost of utility property, plant and equipment retired or otherwise disposed of and the cost of removal, less salvage, are charged to the accumulated provision for depreciation.

UI accrues for estimated costs of removal for certain of its plant-in-service. Such removal costs are included in the approved rates used to depreciate these assets. At the end of the service life of the applicable assets, the accumulated depreciation in excess of the historical cost of the asset provides for the estimated cost of removal. In accordance with ASC 980 "Regulated Operations," the accrued costs of removal have been recorded as a regulatory liability.

UI's property, plant and equipment as of December 31, 2019 and 2018 were comprised as follows:

	2019	2018
	(In Thousands)	
Distribution plant	$ 1,577,357	$ 1,486,969
Transmission plant	859,524	845,262
Software	258,608	225,581
Land	55,162	55,203
Building and improvements	249,214	234,997
Other plant	161,991	152,869
Total property, plant & equipment	3,161,856	3,000,881
Less accumulated depreciation	768,057	700,827
	2,393,799	2,300,054
Construction work in progress	174,656	181,369
Net property, plant & equipment	$ 2,568,455	$ 2,481,423

Allowance for Funds Used During Construction

In accordance with the uniform systems of accounts, the UI capitalizes allowance for funds used during construction (AFUDC), which represents the approximate cost of debt and equity capital devoted to plant under construction. The portion of the allowance applicable to borrowed funds is presented as interest expense, net and the portion of the allowance applicable to equity funds is presented as other income in the Statement of Income. Although the allowance does not represent current cash income, it has been recoverable under the ratemaking process over the service lives of the related properties. Weighted-average AFUDC rates for 2019 and 2018 were 7.51% and 3.34%, respectively. The portion of the allowance applicable to equity funds for 2019 and 2018 was $5.6 million and $1.5 million, respectively.

Depreciation

Provisions for depreciation on utility plant for book purposes are computed on a straight-line basis, using composite rates based on the estimated service lives of the various classes of assets. For utility plant other than software, service lives are determined by independent depreciation consultants and subject to review and approval by PURA. Software service life is based upon management's estimate of useful life and subject to review and approval by PURA. The aggregate annual provisions for depreciation for 2019 and 2018 were approximately $99.8 million and $80.5 million, respectively or 3.2% and 2.8%, respectively, of the original cost of depreciable property.

Derivatives

UI is party to contracts, and involved in transactions, that are derivatives.

Contracts for Differences (CfDs)

Pursuant to Connecticut's 2005 Energy Independence Act, PURA solicited bids to create new or incremental capacity resources in order to reduce federally mandated congestion charges, and selected four new capacity resources. To facilitate the transactions between the selected capacity resources and Connecticut electric customers, and provide the commitment necessary for owners of these resources to obtain necessary financing, PURA required that UI and The Connecticut Light and Power Company (CL&P) execute long-term contracts with the selected resources. In August 2007, PURA approved four CfDs, each of which specifies a capacity quantity and a monthly settlement that reflects the difference between a forward market price and the contract price. UI executed two of the contracts and CL&P executed the other two contracts. The costs or benefits of each contract will be paid by or allocated to customers and will be subject to a cost-sharing agreement between UI and CL&P pursuant to which approximately 20% of the cost or benefit is borne by or allocated to UI customers and approximately 80% is borne by or allocated to CL&P customers.

PURA has determined that costs associated with these CfDs will be fully recoverable by UI and CL&P through electric rates, and in accordance with ASC 980 "Regulated Operations," UI has deferred recognition of costs (a regulatory asset) or obligations (a regulatory liability). The CfDs are marked-to-market in accordance with ASC 815 "Derivatives and Hedging." For those CfDs signed by CL&P, UI records its approximate 20% portion pursuant to the cost-sharing agreement noted above. As of December 31, 2019, UI has recorded a gross derivative asset of $2.1 million, a regulatory asset of $72.7 million and a gross derivative liability of $74.8 million ($72.2 million of which is related to UI's portion of the CfD signed by CL&P). See Note (J) "Fair Value of Financial Instruments" for additional CfD information.

The gross derivative assets and liabilities as of December 31, 2019 and December 31, 2018 were as follows:

	December 31, 2019	December 31, 2018
	(In Thousands)	
Gross derivative assets:		
Current Assets	$ 331	$ 3,413
Deferred Charges and Other Assets	$ 1,807	$ 1,942
Gross derivative liabilties:		
Current Liabilities	$ 11,442	$ 11,966
Noncurrent Liabilities	$ 63,382	$ 67,969

The unrealized gains and losses from fair value adjustments to these derivatives, which are recorded in regulatory assets or regulatory liabilities, for the years ended December 31, 2019 and 2018, were as follows:

	Year Ended December 31, 2019	Year Ended December 31, 2018
	(In Thousands)	
Regulatory Assets - Derivative liabilities	$ (1,894)	$ 7,134

Equity Investments

UI is party to a 50-50 joint venture with Clearway Energy, Inc., in GenConn, which operates two peaking generation plants in Connecticut. UI's investment in GenConn is being accounted for as an equity investment, the carrying value of which was $93.6 million and $98.5 million as of December 31, 2019 and December 31, 2018, respectively. As of December 31, 2019, there was $0.1 million of undistributed earnings from UI's equity investment in GenConn.

UI's pre-tax income from its equity investment in GenConn was $8.7 million and $11.0 million for the years ended December 31, 2019 and 2018, respectively.

Cash distributions from GenConn are reflected as either distributions of earnings or as returns of capital in the operating and investing sections of the Statement of Cash Flows, respectively. UI received cash distributions from GenConn of $13.5 million and $14.7 million during the years ended December 31, 2019 and 2018, respectively.

The following represents summarized financial information of GenConn as of and for the years ended December 31:

	2019	2018
	(In Thousands)	
Current assets	$ 36,938	$ 42,268
Noncurrent assets	$ 341,693	$ 358,231
Current liabilities	$ 16,470	$ 22,099
Noncurrent liabilities	$ 175,539	$ 181,863
Operating revenues	$ 60,006	$ 65,319
Income	$ 17,093	$ 21,652

Impairment of Long-Lived Assets and Investments

ASC 360 "Property, Plant, and Equipment" requires the recognition of impairment losses on long-lived assets when the book value of an asset exceeds the sum of the expected future undiscounted cash flows that result from the use of the asset and its eventual disposition. If impairment arises, then the amount of any impairment is measured based on discounted cash flows or estimated fair value.

ASC 360 also requires that rate-regulated companies recognize an impairment loss when a regulator excludes all or part of a cost from rates, even if the regulator allows the company to earn a return on the remaining costs allowed. Under this standard, the probability of recovery and the recognition of regulatory assets under the criteria of ASC 980 must be assessed on an ongoing basis. As discussed in the description of ASC 980 in this Note (A) under "Regulatory Accounting," determination that certain regulatory assets no longer qualify for accounting as such could have a material impact on the financial condition of UI.

ASC 323 "Investments" requires that a loss in the value of an investment that is other than a temporary decline should be recognized. In accordance with ASC 323, UI reviews its investments accounted for by the equity method for impairment by identifying and measuring losses in the value based upon a comparison of fair value to carrying value. At December 31, 2019, UI did not have any equity investments that were impaired under this standard.

Unrestricted cash and temporary cash investments

UI considers all of its highly liquid debt instruments with an original maturity of three months or less at the date of purchase to be unrestricted cash and temporary cash investments.

Restricted Cash

UI's restricted cash at December 31, 2019 and 2018 totaled $1.0 million and $1.5 million, respectively, which primarily relates to electric distribution and transmission capital projects, which have been withheld by UI and will remain in place until the verification of fulfillment of contractor obligations. UI's restricted cash balances are included in other long-term assets on the balance sheet.

Accounts receivable and unbilled revenues

Accounts receivable at December 31, 2019 and 2018 include unbilled revenues of $46.6 million and $47.9 million, respectively and are shown net of an allowance for doubtful accounts of $3.1 million and $2.8 million for 2019 and 2018, respectively. Accounts receivable do not bear interest, although late fees may be assessed.

Unbilled revenues represent estimates of receivables for products and services provided but not yet billed. The estimates are determined based on various assumptions, such as current month energy load requirements, billing rates by customer classification and weather**.** Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

The allowance for doubtful accounts is management's best estimate of the amount of probable credit losses in the existing accounts receivable, determined based on experience. Each month, UI reviews the allowance for doubtful accounts and past due accounts by age. When management believes that a receivable will not be recovered, the account balance is charged off against the allowance. Changes in assumptions about input factors and customer receivables, which are inherently uncertain and susceptible to change from period to period, could significantly affect the allowance for doubtful accounts estimates.

Leases

UI determines if an arrangement is a lease at inception. UI classifies a lease as a finance lease if it meets any one of specified criteria that in essence transfers ownership of the underlying asset to us by the end of the lease term. If a lease does not meet any of those criteria, UI classifies it as an operating lease. On the balance sheets, UI includes, for operating leases: "Operating lease right-of-use (ROU) assets", and "Operating lease liabilities (current and non-current)"; and for finance leases: finance lease ROU assets in "Other assets," and liabilities in "Other current liabilities" and "Other liabilities."

ROU assets represent UI's right to use an underlying asset for the lease term and lease liabilities represent our obligation to make lease payments arising from the lease. UI recognizes lease ROU assets and liabilities at commencement of an arrangement based on the present value of lease payments over the lease term. Most of UI's leases do not provide an implicit rate, so UI uses its incremental borrowing rate based on information available at the lease commencement date to determine the present value of future payments. A lease ROU asset also includes any lease payments made at or before commencement date, minus any lease incentives received, and includes initial direct costs incurred. UI does not record leases with an initial term of 12 months or less on the balance sheet, for all classes of underlying assets, and UI recognizes lease expense for those leases on a straight-line basis over the lease term. UI includes variable lease payments that depend on an index or a rate in the ROU asset and lease liability measurement based on the index or rate at the commencement date, or upon a modification. UI does not include variable lease payments that do not depend on an index or a rate in the ROU asset and lease liability measurement. A lease term includes options to extend or terminate the lease when it is reasonably certain that we will exercise that option. UI recognizes lease (rent) expense for operating lease payments on a straight-line basis over the lease term, or the amount eligible for recovery under UI's rate plan. UI amortizes finance lease ROU assets on a straight-line basis over the lease term and recognize interest expense based on the outstanding lease liability.

UI has lease agreements with lease and non-lease components, and account for lease components and associated non-lease components together as a single lease component, for all classes of underlying assets.

Materials and supplies

Materials and supplies inventories are used for construction of new facilities and repairs of existing facilities. The inventories are carried and withdrawn at lower of cost and net realizable value.

Other Investments

UI's other investments consist of noncurrent investments available for sale and life insurance policies.

Asset removal costs

UI meets the requirements concerning accounting for regulated operations, and recognizes a regulatory liability, for the difference between removal costs collected in rates and actual costs incurred. UI classifies those amounts as asset removal costs.

Pension and Other Postretirement Benefits

UI accounts for pension plan costs and other postretirement benefits, consisting principally of health and life insurance, in accordance with the provisions of ASC 715 "Compensation - Retirement Benefits." See Note (F), "Pension and Other Benefits".

Income Taxes

In accordance with ASC 740 "Income Taxes," UI has provided deferred taxes for all temporary book-tax differences using the liability method. The liability method requires that deferred tax balances be adjusted to reflect enacted future tax rates that are anticipated to be in effect when the temporary differences reverse. In accordance with generally accepted accounting principles for regulated industries, UI has established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences. For ratemaking purposes, investment tax credits related to recoverable plant investments are deferred when earned and amortized over the estimated lives of the related assets.

Under ASC 740, UI may recognize the tax benefit of an uncertain tax position only if management believes it is more likely than not that the tax position will be sustained on examination by the taxing authority based upon the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based upon the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. UI's policy is to recognize interest accrued and penalties associated with uncertain tax positions as a component of operating expense. See – Note (E), "Income Taxes" for additional information.

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Tax Act) was signed into law. The Tax Act contains significant changes to the federal tax structure, including among other things, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017. PURA instituted proceedings in Connecticut to review and address the implications associated with the Tax Act on the utilities providing service in the state and rendered a final decision on January 23, 2019. PURA directed UI to establish a regulatory liability in the amount of the income tax expense to be returned to customers and propose a method of returning such amount to customers in its next rate case filing.

Variable Interest Entities

UI has identified GenConn as a variable interest entity (VIE), which is accounted for under the equity method. UI is not the primary beneficiary of GenConn, as defined in ASC 810 "Consolidation," because it shares control of all significant activities of GenConn with its joint venture, Clearway Energy, Inc. As such, GenConn is not subject to consolidation. GenConn recovers its costs through CfDs, which are cost of service-based and have been approved by PURA. As a result, with the achievement of commercial operation by GenConn Devon and GenConn Middletown, UI's exposure to loss is primarily related to the potential for unrecovered GenConn operating or capital costs in a regulatory proceeding, the effect of which would be reflected in the carrying value of UI's 50% ownership position in GenConn and through "Income from Equity Investments" in UI's Financial Statements. Such exposure to loss cannot be determined at this time. For further discussion of GenConn, see "Equity Investments" as well as Note (C) "Regulatory Proceedings – Electric Distribution and Transmission – Equity Investment in Peaking Generation."

UI has identified the selected capacity resources with which it has CfDs as VIEs and has concluded that it is not the primary beneficiary as it does not have the power to direct any of the significant activities of these capacity resources. As such, UI has not consolidated the selected capacity resources. UI's maximum exposure to loss through these agreements is limited to the settlement amount under the CfDs as described in "Derivatives – Contracts for Differences (CfDs)" above. UI has no requirement to absorb additional losses nor has UI provided any financial or other support during the periods presented that were not previously contractually required.

UI has identified the entities for which it is required to enter into long-term contracts to purchase Renewable Energy Credits (RECs) as VIEs. In assessing these contracts for VIE identification and reporting purposes, UI has aggregated the contracts based on similar risk characteristics and significance to UI. UI is not the primary beneficiary as it does not have the power to direct any of the significant activities of these entities. UI's exposure to loss is primarily related to the purchase and resale of the RECs, but, any losses incurred are recoverable through electric rates. For further discussion of RECs, see Note (C) "Regulatory Proceedings – Electric Distribution and Transmission – New Renewable Source Generation."

Adoption of New Accounting Pronouncements

<u>Leases</u>

In February 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Codification (ASC) Topic 842, "Leases", with subsequent amendments issued in 2018. The new leases guidance affects all companies and organizations that lease assets, and requires them to record on their balance sheet ROU assets and lease liabilities for the rights and obligations created by those leases. Under ASC 842, a lease is an arrangement that conveys the right to control the use of an identified asset for a period of time in exchange for consideration. The new guidance retains a distinction between finance leases and operating leases, while requiring companies to recognize both types of leases on their balance sheet. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the criteria for distinguishing between capital leases and operating leases in legacy U.S. GAAP - ASC 840. Lessor accounting remains substantially the same as ASC 840, but with some targeted improvements to align lessor accounting with the lessee accounting model and with the revised revenue recognition guidance under ASC 606. The new standard and amendments require new qualitative and quantitative disclosures for both lessees and lessors.

UI adopted ASC 842 effective January 1, 2019, and elected the optional transition method under which the standard was initially applied on that date without adjusting amounts for prior periods, which UI continues to present in accordance with ASC 840, including related disclosures. UI recorded the cumulative effect of applying the new leases guidance as an adjustment to beginning retained earnings. In connection with our adoption, UI:

- did not elect the package of three practical expedients available under the transition provisions which would have allowed them to not reassess: (i) whether expired or existing contracts were or contained leases, (ii) the lease classification for expired or existing leases, and (iii) whether previously capitalized initial direct costs for existing leases would qualify for capitalization under ASC 842.
- elected the land easement practical expedient and did not reassess land easements that did not meet the definition of a lease prior to adoption.
- used hindsight for determining the lease term and assessing the likelihood that a lease purchase option will be exercised in applying the new leases guidance.
- did not separate lease and associated non-lease components for transitioned leases, but instead are accounting for them together as a single lease component.

In March 2019, the FASB issued additional amendments to ASC 842 for minor codification improvements, which UI early applied effective January 1, 2019, with no material effect to its results of operations, financial position and cash flows.

The cumulative effects of the changes to UI's balance sheet as of January 1, 2019, were as follows:

(In Thousands)	Balance at December 31, 2018	Adjustment Due to Topic 842	Balance at January 1, 2019
Assets			
Operating lease right of use assets	$ -	$ 15,664	$ 15,664
Liabilities			
Operating lease liabilities	$ -	$ 15,664	$ 15,664

UI's adoption did not change the classification of lease-related expenses in its statements of income, nor did it result significant changes to its pattern of expense recognition. As a result, the adoption did not materially affect UI's cash flows.

In comparison to our operating leases obligations disclosed as of December 31, 2018, certain land easement contracts that previously met the definition of a lease do not meet the ASC 842 definition of a lease, and therefore UI excluded them from the transition adjustment. UI's accounting for finance (formerly capital) leases is substantially unchanged. Refer to Note (H) "Leases" for further details.

Derivatives and Hedging

In August 2017, the FASB issued ASU 2017-12 "Derivatives and Hedging". The ASU contains targeted amendments with the objective to better align hedge accounting with an entity's risk management activities in the financial statements, and to simplify the application of hedge accounting. The amendments address concerns of financial statement preparers over difficulties with applying hedge accounting and limitations for hedging both nonfinancial and financial risks and concerns of financial statement users over how hedging activities are reported in financial statements. Changes to the hedge accounting guidance to address those concerns will: 1) expand hedge accounting for nonfinancial and financial risk components and amend measurement methodologies to more closely align hedge accounting with an entity's risk management activities; 2) eliminate the separate measurement and reporting of hedge ineffectiveness, to reduce the complexity of preparing and understanding hedge results; 3) enhance disclosures and change the presentation of hedge results to align the effects of the hedging instrument and the hedged item in order to enhance transparency, comparability, and understandability of hedge results; and 4) simplify the way assessments of hedge effectiveness may be performed to reduce the cost and complexity of applying hedge accounting. The amendments ease the administrative burden of hedge documentation requirements and assessing hedge effectiveness going forward. UI adopted the hedge accounting amendments January 1, 2019 and had no cumulative-effect adjustment to retained earnings because there were no amounts of ineffectiveness recorded for any existing hedges as of that date. Concurrently with the above targeted improvements, we adopted the additional amendments the FASB issued in October 2018 that permit use of the Overnight Index Swap rate based on the Secured Overnight Financing Rate as a U.S. benchmark interest rate for hedge accounting purposes. Use of that rate is in addition to the already eligible benchmark interest rates, which are: interest rates on direct Treasury obligations of the U.S. government, the London Interbank Offered Rate swap rate, the OIS Rate based on the Fed Funds Effective Rate and the Securities Industry and Financial Markets Association Municipal Swap Rate.

Reclassification of certain tax effects from accumulated other comprehensive income

In February 2018, the FASB issued ASU 2018-02 "Income Statement-Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income" which contains amendments to address a narrow-scope financial reporting issue that arose as a consequence of the Tax Cuts and Jobs Act of 2017 (the Tax Act) enacted on December 22, 2017 by the U.S. federal government. Under current guidance, the adjustment of deferred taxes for the effect of a change in tax laws or rates is required to be included in income from continuing operations, thus the associated tax effects of items within accumulated other comprehensive income (AOCI) (referred to as stranded tax effects) do not reflect the appropriate tax rate. The amendments allow a reclassification from AOCI to retained earnings for stranded tax effects resulting from the Tax Act. As a result, the amendments eliminate the stranded tax effects resulting from the Tax Act and will improve the usefulness of information reported to financial statement users. The amendments only relate to the reclassification of the income tax effects of the Tax Act, and do not affect the underlying guidance that requires the effect of a change in tax laws or rates to be included in income from continuing operations. UI adopted the amendments effective January 1, 2019, which had no impact on its results of operations, financial position and cash flows.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements issued as indicated, that UI has evaluated or is evaluating to determine their effect on its financial statements.

Changes to the disclosure requirements for fair value measurement and defined benefit plans

In August 2018, the FASB issued amendments related to disclosure requirements for both fair value measurement and defined benefit plans. The amendments concerning fair value measurement remove, modify and add certain disclosure requirements, in order to improve the overall usefulness of the disclosures and reduce unnecessary costs to companies to prepare the disclosures. The amendments to fair value measurement disclosures are effective for all entities for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted as specified. Certain amendments are to be applied prospectively, and all others are to be applied retrospectively. UI's adoption of the amendments on January 1, 2020, will not materially affect its disclosures.

The amendments concerning disclosure requirements for defined benefit plans are narrow in scope and apply to all employers that sponsor defined benefit pension or other postretirement plans. They remove disclosures that are no longer considered cost beneficial, add certain new relevant disclosures and clarify specific requirements of disclosures concerning information for defined benefit pension plans. The amendments to defined benefit plan disclosures are effective for fiscal years ending after December 15, 2020. Early adoption is permitted and application is to be on a retrospective basis. UI's adoption of the amendments on January 1, 2020, will not materially affect its disclosures.

Clarifying guidance for certain collaborative arrangements with respect to revenue recognition

The FASB issued amendments in November 2018 to clarify the interaction between the guidance for certain collaborative arrangements and the guidance applicable to ASC 606. A collaborative arrangement is a contractual arrangement under which two or more parties actively participate in a joint operating activity and are exposed to significant risks and rewards that depend on the activity's commercial success. The targeted improvements clarify that certain transactions between collaborative arrangement participants are within the scope of ASC 606 and thus subject to all of its guidance. The amendments are effective for public business entities for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted, including adoption in any interim period for which financial statements have not been issued. Retrospective application to the date of initial application of ASC 606 is required. UI's adoption of the amendments on January 1, 2020, will not materially affect its results of operations, financial position, cash flows and disclosures.

Simplifying the accounting for income taxes

In December 2019, the FASB issued an accounting standards update that is intended to reduce complexity in accounting for income taxes. The amendments remove specific exceptions to the general principles in ASC 740, Income Taxes, eliminating the need for an entity to analyze whether the following apply in a given period: (1) exception to the incremental approach for intra-period tax allocation, (2) exceptions to accounting for basis differences when there are ownership changes in foreign investments and (3) exception in interim period income tax accounting for year-to-date losses that exceed anticipated losses. The amendments also improve financial statement preparers' application of income-tax related guidance and simplify U. S. GAAP for (1) franchise taxes that are partially based on income, (2) transactions with a government that result in a step up in the tax basis of goodwill, (3) separate financial statements of legal entities that are not subject to tax and (4) enacted changes in tax laws in interim periods. The amendments are effective for public business entities for fiscal years beginning after December 15, 2020, and interim periods within those fiscal years. Early adoption is permitted, including adoption in any interim period for which financial statements have not been issued, with adoption of all amendments in the same period. Application is on a retrospective and/or modified retrospective basis, or a prospective basis, depending on the amendment aspect. UI expects its adoption will not materially affect its results of operations, financial position, and cash flows.

(B) CAPITALIZATION

Common Stock

UI had 100 shares of common stock, no par value, outstanding at December 31, 2019 and December 31, 2018.

In October 2019, UI received a $47.0 million equity infusion from UIL Holdings in order to maintain its allowed capitalization ratio which was impacted by the long-term debt activity noted below.

Long-term debt

As of December 31,		2019		2018	
(Thousands)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
Senior unsecured debt	2020 - 2049	$ 866,960	3.61%-6.61%	$ 847,960	2.80%-6.61%
Unamortized debt (costs) premium, net		(5,192)		(5,406)	
Total Debt		**$ 861,768**		**$ 842,554**	
Less: debt due within one year, included in current liabilities		50,000		31,000	
Total Non-current Debt		**$ 811,768**		**$ 811,554**	

The estimated fair value of debt amounted to $1,004.8 million and $905.3 million as of December 31, 2019 and 2018, respectively. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the natural gas industry and the credit ratings of the borrowers in each case. The fair value hierarchy for the fair value of debt is considered as Level 2. The expenses to issue long-term debt are deferred and amortized over the life of the respective debt issue or the fixed interest-rate period in the case of pollution control revenue bonds.

Information regarding maturities and mandatory redemptions/repayments are set forth below:

	2020	2021	2022	2023	2024 & thereafter	Total
			(In Thousands)			
Maturities	$ 50,000	$ -	$ 162,500	$ 139,460	$ 515,000	$ 866,960

Under various debt agreements, UI is required to maintain a ratio of consolidated debt to consolidated capital of not greater than 65% (debt ratio). As of December 31, 2019, UI's debt ratio was 42%.

On January 15, 2019, UI executed a note purchase agreement issued $50 million of senior unsecured notes maturing in 2049 at an interest rate of 4.52%.

(C) REGULATORY PROCEEDINGS

Rates

Utilities are entitled by Connecticut statutes to charge rates that are sufficient to allow them an opportunity to cover their reasonable operating and capital costs, to attract needed capital and to maintain their financial integrity, while also protecting relevant public interests.

UI's approved three-year distribution rate schedules became effective January 1, 2017 and include, among other things, annual tariff increases and an ROE of 9.10% based on a 50% equity ratio, continuation of UI's existing earnings sharing mechanism (ESM) pursuant to which UI and its customers share on a 50/50 basis all distribution earnings above the allowed ROE in a calendar year, continuation of the existing decoupling mechanism, and the continuation of a requested storm reserve. Any dollars due to customers from the ESM continue to be first applied against any storm regulatory asset balance (if one exists at that time) or refunded to customers through a bill credit if such storm regulatory asset balance does not exist.

Power Supply Arrangements

Under Connecticut law, UI's retail electricity customers are able to choose their electricity supplier while UI remains their electric distribution company. UI purchases power for those of its customers under standard service rates who do not choose an alternative retail electric supplier and have a maximum demand of less than 500 kilowatts, as well as its customers under supplier of last resort service who are not eligible for standard service rates and do not choose to purchase electric generation service from an alternate retail electric supplier. The cost of the purchased power is a "pass-through" to those customers through the General Services Charge (GSC) charge on their bills.

UI must procure the power to serve its standard service load pursuant to a procurement plan approved by PURA. Under the procurement plan, UI procures wholesale power for its standard service customers on a full requirements basis pursuant to contracts with a maximum duration of 12 months, with the delivery of such wholesale power to commence no later than one year from the applicable bid day.

UI has wholesale power supply agreements in place for its entire standard service load for the first half of 2020, 70% of its standard service load for the second half of 2020 and 40% of its standard service load for the first half of 2021. Supplier of last resort service is procured on a quarterly basis and UI has wholesale power supply agreement in place for the second quarter of 2020. However, from time to time there are no bidders in the procurement process for supplier of last resort service and, in such cases, UI manages the load directly.

UI determined that its contracts for standard service and supplier of last resort service are derivatives under ASC 815 "Derivatives and Hedging" and elected the "normal purchase, normal sale" exception under ASC 815 "Derivatives and Hedging." UI regularly assesses the accounting treatment for its power supply contracts. These wholesale power supply agreements contain default provisions that include required performance assurance, including certain collateral obligations, in the event that UI's credit rating on senior debt were to fall below investment grade. If such an event had occurred as of December 31, 2019, UI would have had to post an aggregate of approximately $17.9 million in collateral.

New Renewable Source Generation

Under Connecticut Public Act (PA) 11-80, Connecticut electric utilities are required to enter into long-term contracts to purchase Connecticut Class I RECs from renewable generators located on customer premises. Under this program, UI is required to enter into contracts totaling approximately $200 million in commitments over an approximate 21-year period. The obligations were initially expected to phase in over a six-year solicitation period and peak at an annual commitment level of about $14 million per year after all selected projects are online. PA 17-144, PA 18-50, and PA 19-35 extended the original six-year solicitation period of the program by adding seventh, eighth, ninth, and tenth years, and increased the original funding level of this program by adding up to $64 million in additional commitments by UI. Upon purchase, UI accounts for the RECs as inventory. UI expects to partially mitigate the cost of these contracts through the resale of the RECs. PA 11-80 provides that the remaining costs (and any benefits) of these contracts, including any gain or loss resulting from the resale of the RECs, are fully recoverable from (or credited to) customers through electric rates.

In October of 2018, UI entered into five PPAs totaling approximately 50 MW from developers of offshore wind and fuel cell generation. These PPAs originated from an RFP issued by DEEP, under PA 17-144 which provides that the net costs of the PPAs are recoverable through electric rates. The PPAs were filed for PURA approval on October 25, 2018. On December 19, 2018, PURA issued its final decision approving the five PPAs, and approved UI's use of the non by-passable federally mandated congestion charges for all customers to recover the net costs of the PPAs.

On December 28, 2018, DEEP issued a directive to UI to negotiate and enter into PPAs with twelve projects, totaling approximately 12 million MWh, that were selected as a result of the Zero Carbon RFP issued by DEEP pursuant to PA 17-3, which provides that the net costs of the PPAs are recoverable through electric rates. One of the selected projects is the Millstone nuclear facility located in Waterford, Connecticut which is owned by Dominion Energy, Inc. UI completed negotiations and executed the PPA with the Millstone nuclear facility. UI filed the PPA with PURA on March 29, 2019, and PURA approved the PPA in September 2019. UI finalized negotiations and executed ten PPAs with ten of the remaining selected projects that were filed with PURA on May 31, 2019. At the direction of PURA, UI refiled Amended and Restated PPA's for nine of these projects in November 2019 and PURA approved those nine PPAs also in November 2019. The remaining PPA has been executed and submitted for approval to PURA. The twelfth selected project has declined to continue negotiations.

In August 2019, DEEP issued a RFP for up to 2,000 MW of offshore wind. On December 5, 2019, DEEP announced that it had selected Vineyard Wind, an affiliate of UI, to provide 804 MW of offshore wind through the development of its Park City Wind Project. DEEP also ordered Eversource and UI to negotiate PPAs with Vineyard Wind. Similar to the case with the zero carbon PPAs discussed above, the net costs of the PPAs are recoverable through electric rates.

Transmission

PURA decisions do not affect the revenue requirements determination for UI's transmission business, including the applicable ROE. UI's transmission rates are determined by a tariff regulated by the FERC and administered by ISO New England, Inc. (ISO-NE). Transmission rates are set annually pursuant to a FERC authorized formula that allows for recovery of direct and allocated transmission operating and maintenance expenses, and for a return of and on investment in assets. For 2019, UI's overall allowed weighted-average ROE for its transmission business was 11.28%.

On December 28, 2015, the FERC issued an order instituting section 206 proceedings and establishing hearing and settlement judge procedures. Pursuant to section 206 of the FPA, the FERC instituted proceedings because it found that ISO-NE Transmission, Markets, and Services Tariff is unjust, unreasonable, and unduly discriminatory or preferential. The FERC stated that ISO-NE's Tariff lacks adequate transparency and challenge procedures with regard to the formula rates for ISO-NE Participating Transmission Owners, including UI. The FERC also found that the current Regional Network Service (RNS) and Local Network Service (LNS) formula rates appear to be unjust, unreasonable, unduly discriminatory or preferential or otherwise unlawful as the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates. A settlement judge was appointed and on August 17, 2018, the PTOs submitted a formula rate settlement contested by certain parties and supported by the settlement judge. On May 22, 2019, the FERC rejecting the contested settlement finding that there was not enough of a record to determine whether the rates were just and reasonable based on the allegations of the contesting parties. The PTOs continue to work toward settlement and if settlement cannot be reached and the case is set to hearing an initial decision will be issued on August 6, 2020. UI is unable to predict the outcome of this proceeding at this time.

On September 30, 2011, the Massachusetts Attorney General, DPU, PURA, New Hampshire Public Utilities Commission, Rhode Island Division of Public Utilities and Carriers, Vermont Department of Public Service, numerous New England consumer advocate agencies and transmission tariff customers collectively filed a joint complaint with the FERC, pursuant to sections 206 and 306 of the Federal Power Act, against several New England Transmission Owners (NETOs) claiming that the approved base ROE of 11.14% used by NETOs in calculating formula rates for transmission service under the ISO-New England Open Access Transmission Tariff (OATT) was not just and reasonable and seeking a reduction of the base ROE with refunds to customers for the 15-month refund periods beginning October 1, 2011 (Complaint I), December 27, 2012 (Complaint II), July 31, 2014 (Complaint III) and April 29, 2016 (Complaint IV).

On October 16, 2014, the FERC issued its decision in Complaint I setting the base ROE at 10.57% and a maximum total ROE of 11.74% (base plus incentive ROEs) for the October 2011 – December 2012 period as well as prospectively from October 16, 2014. On March 3, 2015, the FERC upheld its decision and further clarified that the 11.74% ROE cap will be applied on a project specific basis and not on a transmission owner's total average transmission return. The complaints were consolidated and the administrative law judge issued an initial decision on March 22, 2016. The initial decision determined that, (1) for the fifteen month refund period in Complaint II, the base ROE should be 9.59% and that the ROE Cap (base ROE plus incentive ROEs) should be 10.42% and (2) for the fifteen month refund period in Complaint III and prospectively, the base ROE should be 10.90% and that the ROE Cap should be 12.19%. The initial decision in Complaints II and III is the administrative law judge's recommendation to the FERC Commissioners. UI reserved for refunds for Complaints I, II and III consistent with the FERC's March 3, 2015 decision in Complaint I. Refunds were provided to customers for Complaint I. UI's total reserve associated with Complaints II and III is $6.6 million as of December 31, 2019, which has not changed since December 31, 2018, except for the accrual of carrying costs. If adopted as final by the FERC, the impact of the initial decision by the FERC administrative law judge would be an additional aggregate reserve for Complaints II and III of $4.3 million, which is based upon currently available information for these proceedings.

Following various intermediate hearings, orders and appellate decisions, on October 16, 2018, the FERC issued an order directing briefs and proposing a new methodology to calculate the NETOs ROE that is contained in NETOs' transmission formula rate on file at the FERC (the October 2018 Order). The FERC proposes to use this new methodology to resolve Complaints I, II, III and IV filed by the New England state consumer advocates.

The new proposed ROE methodology set forth in the October 2018 Order considers more than just the two-step discounted cash flow (DCF) analysis adopted in the FERC order on Complaint I vacated by the Court. The new proposed ROE methodology uses three financial analyses (i.e., DCF, the capital-asset pricing model and the expected earnings analysis) to produce a range of returns to narrow the zone of reasonableness when assessing whether a complainant has met its initial burden of demonstrating that the utility's existing ROE is unjust and unreasonable. The new proposed ROE methodology establishes a range of just and reasonable ROEs of 9.60% to 10.99% and proposes a just and reasonable base ROE of 10.41% with a new ROE cap of 13.08%. Pursuant to the October 2018 Order, the NETOs filed initial briefs on the proposed methodology in all four Complaints on January 11, 2019 and replied to the initial briefs on March 8, 2019. On November 21, 2019, the FERC issued rulings on two complaints challenging the base return on equity for Midcontinent Independent System Operator, or MISO transmission owners. These rulings established a new zone of reasonableness based on equal weighting of the DCF and capital-asset pricing model for establishing the base return on equity. This resulted in a base return on equity of 9.88% as the midpoint of the zone of reasonableness. Various parties have requested rehearing on this decision. UI cannot predict the outcome of this proceeding, and the potential impact it may have in establishing a precedent for our pending four Complaints.

Equity Investment in Peaking Generation

UI is party to a 50-50 joint venture with Clearway Energy, Inc. in GenConn, which operates two peaking generation plants in Connecticut. The two peaking generation plants, GenConn Devon and GenConn Middletown, are both participating in the ISO-New England markets. PURA had approved revenue requirements for the period from January 1, 2020 through December 31, however GenConn filed to reopen the related docket with PURA on April 3, 2020, for the purposes of resetting 2020 revenue requirements after a recalculation of excess deferred income taxes. GenConn expects the results of this reopened filing to occur prior to the final decisions associated with its planned 2021 revenue requirements filing which is expected in the fourth quarter of 2020.

Tax Cuts and Jobs Act

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Tax Act) was signed into law. The Tax Act significantly changed the federal taxation of business entities including, among other things, implementing a federal corporate tax rate decrease from 35% to 21% for tax years beginning after December 31, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates will result in amounts previously and currently collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates. PURA instituted proceedings in Connecticut to review and address the implications associated with the Tax Act on the utilities providing service in the state and rendered a final decision on January 23, 2019. PURA directed UI to establish a regulatory liability in the amount of the income tax expense to be returned to customers and propose a method of returning such amount to customers in its next rate case filing.

(D) SHORT-TERM CREDIT ARRANGEMENTS

UI funds short-term liquidity needs through an agreement among Avangrid's regulated utility subsidiaries (the Virtual Money Pool Agreement), a bi-lateral intercompany credit agreement with Avangrid (the Bi-Lateral Intercompany Facility) and a bank provided credit facility to which UI is a party (the Avangrid Credit Facility), each of which are described below.

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. UI has a lending/borrowing limit of $100 million under this agreement. There were no borrowings under this agreement as of December 31, 2019 and 2018. There were $19.4 million and $10.9 million in note receivables under this arrangement as of December 31, 2019 and 2018, respectively.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $500 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. There were no borrowings under this agreement as of December 31, 2019 and 2018.

On June 29, 2018, Avangrid, Inc. and its subsidiaries, including UI, entered into a new credit facility agreement with a syndicate of banks (Avangrid Credit Facility) that provides for maximum borrowings of up to $2.5 billion in the aggregate. This Avangrid Credit Facility replaces and supersedes the prior revolving credit facility entered into by Avangrid, Inc. and its subsidiaries on April 6, 2016, which provided maximum borrowings of up to $1.5 billion in the aggregate.

Under the Avangrid Credit Facility, UI has a maximum sublimit of $400 million. Additionally, under the Avangrid Credit Facility, each of the borrowers, including UI, will pay an annual facility fee that is dependent on their credit rating. The facility fees will range from 12.5 to 17.5 basis points. The maturity date for the Avangrid Credit Facility is June 29, 2024. As of December 31, 2019 and 2018, UI did not have any outstanding borrowings under the Avangrid Credit Facility.

(E) INCOME TAXES

	2019	2018
	(In Thousands)	
Income tax expense consists of:		
Income tax provisions (benefits):		
Current		
Federal	$ 13,405	$ 30,397
State	(1,803)	11,480
Total current	11,602	41,877
Deferred		
Federal	13,671	(3,481)
State	2,081	(270)
Total deferred	15,752	(3,751)
Investment tax credits	(749)	(738)
Total income tax expense	$ 26,605	$ 37,388

Total income taxes differ from the amounts computed by applying the federal statutory tax rate to income before taxes. The reasons for the differences are as follows:

	2019	2018
	(In Thousands)	
Book income before income taxes	$ 149,226	$ 153,327
Computed tax at federal statutory rate	$ 31,337	$ 32,199
Increases (reductions) resulting from:		
Property related	(2,868)	(2,314)
State income taxes, net of federal income tax benefits	220	8,856
ITC taken into income	(749)	(738)
Other items, net	(1,335)	(615)
Total income tax expense	$ 26,605	$ 37,388
Effective income tax rates	17.8%	24.4%

The significant portion of UI's income tax expense, including deferred taxes, is recovered through its regulated utility rates. UI's annual income tax expense and associated effective tax rate is impacted by differences between the timing of deferred tax temporary difference activity and deferred tax recovery. UI's effective tax rate is also impacted by permanent differences between the book and tax treatment of certain costs.

UI is subject to the United States federal income tax statutes administered by the IRS. UI is a party to Avangrid, Inc.'s tax allocation agreement under which taxable subsidiaries do not pay any more taxes than they would have otherwise paid had they filed a separate company tax return, and subsidiaries are paid for their losses and other tax attributes generated when utilized. Also pursuant to the tax allocation agreement, UI settles its current tax liability or benefit each year directly with Avangrid, Inc.

As of December 31, 2019 and 2018, UI did not have any gross income tax reserves for uncertain tax positions.

The following table summarizes UI's tax years that remain subject to examination as of December 31, 2019:

Jurisdiction	*Tax years*
Federal	2014 – 2019
Connecticut	2015 – 2019

The following table summarizes UI's deferred income tax assets and liabilities as of December 31, 2019 and 2018.

	2019	**2018**
	(In Thousands)	
Deferred income taxes:		
Property related	$ (377,540)	$ (354,061)
Unfunded future income taxes	(47,990)	(45,704)
Federal and state tax credits	15,273	12,760
Investment in GenConn	(31,838)	(32,186)
Post-retirement benefits	15,828	15,677
Merger settlement agreement	5,582	8,051
Regulatory liability due to tax cuts and jobs act	85,185	82,561
Other	(5,430)	(5,267)
	$ (340,930)	$ (318,169)

As of December 31, 2019, UI had $3.2 million of state tax credit carry forwards that will begin to expire in 2024. As of December 31, 2018 UI had $0.5 million of state tax credit carry forwards.

(F) PENSION AND OTHER POSTRETIREMENT BENEFITS

Defined Benefit Plans (the Plans)

Pension Plans

The UI pension plan provides benefits under a traditional defined benefit formula and was closed to newly-hired employees in 2005. UI also has 2 non-qualified supplemental pension plans for certain employees.

Plan Assets

Networks' pension benefits plan assets were consolidated from three legacy master trusts to one new master trust in 2019. A consolidated trust provides for a uniform investment manager lineup and an efficient, cost effective means of allocating expenses and investment performance to each plan. The primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our risk tolerance. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. The primary means for achieving capital preservation is through diversification of the trusts' investments while avoiding significant concentrations of risk in any one area of the securities markets. Further diversification is achieved within each asset group through utilizing multiple asset managers and systematic allocation to various asset classes and providing broad exposure to different segments of the equity, fixed income and alternative investment markets.

The asset allocation policy is the most important consideration in achieving the objective of superior investment returns while minimizing risk. Networks has established target asset allocation policies within allowable ranges for its pension benefits plan assets within broad categories of asset classes made up of Return-Seeking investments and Liability-Hedging investments. Networks currently has target allocations ranging from 35%-70% for Return-Seeking assets and 34%-65% for Liability-Hedging assets. Return-Seeking assets also include investments in real estate, global asset allocation strategies and hedge funds. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

Other Postretirement Benefits Plans

In addition to providing pension benefits, UI also provides other postretirement benefits, consisting principally of health care and life insurance benefits, for retired employees and their dependents. The healthcare plans are contributory and participants' contributions are adjusted annually. For Medicare eligible non-union retirees, UI provides a subsidy through a Health Reimbursement Account (HRA) for retirees to purchase coverage on the individual market. Medicare eligible union retirees have the option of receiving a subsidy through an HRA or paying contributions and participating in company-sponsored retiree health plans.

Plan Assets

Networks' postretirement benefits plan assets are held with trustees in multiple voluntary employees' beneficiary association (VEBA) and 401(h) arrangements and are invested among and within various asset classes to achieve sufficient diversification in accordance with its risk tolerance. This is achieved for Network's postretirement benefits plan assets through the utilization of multiple institutional mutual and money market funds, providing exposure to different segments of the fixed income, equity and short-term cash markets. Approximately 37% of the postretirement benefits plan assets are invested in VEBA and 401(h) arrangements that are not subject to income taxes with the remainder being invested in arrangements subject to income taxes.

Networks has established a target asset allocation policy within allowable ranges for postretirement benefits plan assets of 45%-65% for equity securities, 25%-45% for fixed income and 5%-25% for all other investment types. Equity investments are diversified across U.S. and non-U.S. stocks, investment styles, and market capitalization ranges. Fixed income investments are primarily invested in U.S. bonds and may also include some non-U.S. bonds. Other asset classes, including alternative investments, are used to enhance long-term returns while improving portfolio diversification. Networks primarily minimize the risk of large losses through diversification but also through monitoring and managing other aspects of risk through quarterly investment portfolio reviews. Systematic rebalancing within target ranges increases the probability that the annualized return on investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The following table represents the change in benefit obligation, change in plan assets and the respective funded status of UI's pension and other postretirement plans as of December 31, 2019 and 2018. Plan assets and obligations have been measured as of December 31, 2019 and 2018.

	Pension Benefits		Other Post-Retirement Benefits	
	2019	2018	2019	2018
Change in Benefit Obligation:		(In Thousands)		
Benefit obligation at beginning of year	$ 563,050	$ 597,466	$ 56,871	$ 63,150
Service cost	5,193	6,420	754	930
Interest cost	22,211	21,841	2,252	2,332
Participant contributions	-	-	-	1,144
Amendments	(2,407)	-	-	-
Settlements	(2,580)	188	-	-
Actuarial (gain) loss	70,321	(22,007)	2,913	(5,234)
Benefits paid (including expenses)	(35,166)	(40,858)	(3,724)	(5,451)
Benefit obligation at end of year	$ 620,622	$ 563,050	$ 59,066	$ 56,871
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 332,756	$ 379,212	$ 26,065	$ 27,118
Actual return on plan assets	68,884	(18,955)	4,142	(554)
Employer contributions	19,623	13,357	523	-
Participant contributions	-	-	-	1,144
Curtailments/Settlements	(2,580)	-	-	-
Benefits paid (including expenses)	(35,166)	(40,858)	(3,724)	(1,643)
Fair value of plan assets at end of year	$ 383,517	$ 332,756	$ 27,006	$ 26,065
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ 237,105	$ 230,294	$ 32,060	$ 30,806
Amounts Recognized in the Balance Sheet consist of:				
Non-current liabilities	$ 237,105	$ 230,294	$ 32,060	$ 30,806
Amounts Recognized as a Regulatory Asset consist of:				
Prior service cost	-	-	(5,667)	(7,204)
Net (gain) loss	216,836	215,605	(6,523)	(8,011)
Total recognized as a regulatory asset	$ 216,836	$ 215,605	$ (12,190)	$ (15,215)
Information on Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:				
Projected benefit obligation	$ 620,622	$ 563,050	N/A	N/A
Accumulated benefit obligation	$ 571,216	$ 514,868	N/A	N/A
Fair value of plan assets	$ 383,517	$ 332,756	N/A	N/A
The following weighted average actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate (Qualified Plans)	3.19%	4.09%	N/A	N/A
Discount rate (Non-Qualified Plans)	3.19%	4.09%	N/A	N/A
Discount rate (Other Post-Retirement Benefits)	N/A	N/A	3.19%	3.80%
Average wage increase	3.80%	3.80%	N/A	N/A
Health care trend rate (current year - pre/post-65)	N/A	N/A	6.75%/5.50%	7.50%/5.75%
Health care trend rate (2029/2025 - pre/post-65)	N/A	N/A	4.50%/4.50%	4.50%/4.50%

N/A – not applicable

UI is allowed to defer as regulatory assets or regulatory liabilities items that would have otherwise been recorded in accumulated OCI pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans. Amounts recognized as regulatory assets or regulatory liabilities for the years ended December 31, 2019 and 2018 are shown above.

The discount rate is the rate at which the benefit obligations could presently be effectively settled. The discount rates were determined by developing yield curves derived from a portfolio of high grade noncallable bonds with yields that closely match the duration of the expected cash flows of our benefit obligations.

The components of net periodic benefit cost are:

	For the Year Ended December 31,			
	Pension Benefits		Other Post-Retirement Benefits	
	2019	2018	2019	2018
	(In Thousands)			
Components of net periodic benefit cost:				
Service cost	$ 5,193	$ 6,420	$ 754	$ 930
Interest cost	22,211	21,840	2,252	2,332
Expected return on plan assets	(24,097)	(26,826)	(1,616)	(1,650)
Amortization of prior service costs	(2,407)	(4)	(1,537)	(1,537)
Amortization of actuarial (gain) loss	23,178	23,903	(1,098)	(744)
Settlements	1,126	188	-	-
Net periodic benefit cost	$ 25,204	$ 25,521	$ (1,245)	$ (669)
Other Changes in Plan Assets and Benefit Obligations Recognized as a Regulatory Asset (Liability):				
Net (gain) loss	$ 25,535	$ 23,961	$ 389	$ (3,030)
Prior service cost	(2,407)	-		-
Amortization of prior service costs	2,407	4	1,537	1,537
Amortization of actuarial (gain) loss	(23,178)	(23,902)	1,098	744
Settlements	(1,126)	(188)	-	-
Total recognized as regulatory asset (liability)	$ 1,231	$ (125)	$ 3,024	$ (749)
Total recognized in net periodic benefit costs and regulatory asset (liability)	$ 26,435	$ 25,396	$ 1,779	$ (1,418)
Estimated Amortizations from Regulatory Assets into Net Periodic Benefit Cost for the next 12 month period:				
Amortization of prior service cost	-	(2,407)	(1,537)	(1,537)
Amortization of net (gain) loss	23,290	23,177	(797)	(1,099)
Total estimated amortizations	$ 23,290	$ 20,770	$ (2,334)	$ (2,636)
The following actuarial weighted average assumptions were used in calculating net periodic benefit cost:				
Discount rate	4.09%	3.80%	4.09%	3.80%
Average wage increase	3.80%	3.80%	N/A	N/A
Return on plan assets	7.40%	7.40%	6.25%	6.25%
Health care trend rate (current year - pre/post-65)	N/A	N/A	7.00%/5.75%	7.50%/5.75%
Health care trend rate (2029/2025 - pre/post-65)	N/A	N/A	4.50%/4.50%	4.50%/4.50%

N/A – not applicable

UI utilizes an alternative method to amortize prior service costs and unrecognized gains and losses. Prior service costs for both the pension and other postretirement benefits plans are amortized on a straight-line basis over the average remaining service period of participants expected to receive benefits. Unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans are amortized over the lesser of the average remaining service period or 10 years. For pension benefits, UI does not recognize gains or losses until there is a variance in an amount equal to at least 5% of the greater of the projected benefit obligation or the market-related value of assets. For other postretirement benefits, there is no such allowance for a variance in capturing the amortization of unrecognized gains and losses.

The expected long-term rate of return on plan assets assumption was developed based on a review of long-term historical returns for the major asset classes, the target asset allocations, and the effect of rebalancing of plan assets. The analysis considered current capital market conditions and projected conditions. UI amortizes unrecognized actuarial gains and losses over ten years from the time they are incurred as required by the PURA.

A one percentage point change in the assumed health care cost trend rate would have the following effects:

	1% Increase	1% Decrease
Aggregate service and interest cost components	$ 327	$ (285)
Accumulated post-retirement benefit obligation	$ 6,372	$ (5,305)

Contributions

The funding policy for the Plans is to make annual contributions that satisfy the minimum funding requirements of ERISA but that do not exceed the maximum deductible limits of the Internal Revenue Code. These amounts are determined each year as a result of an actuarial valuation of the Plans. UI currently expects to make pension contributions of approximately $33.1 million in 2020. Such contribution levels will be adjusted, if necessary, based on actuarial calculations.

Estimated Future Benefit Payments

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Year	Pension Benefits	Other Post-Retirement Benefits
	(In Thousands)	
2020	$ 34,589	$ 3,708
2021	$ 35,269	$ 3,696
2022	$ 35,861	$ 3,680
2023	$ 35,430	$ 3,628
2024	$ 39,223	$ 3,504
2025-2029	$ 183,875	$ 16,804

The fair values of the Plans' assets as of December 31, 2019, disclosed below, reflect only the assets attributable to UI's portion of the total assets held in the master trust.

	Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
December 31, 2019		(In Thousands)		
Pension assets				
Cash and cash equivalents	$ -	$ 3,219	$ -	$ 3,219
Registered investment companies	57,204	-	-	57,204
Common collective trusts	-	259,445	-	259,445
	$ 57,204	$ 262,664	$ -	319,868
Other investments measured at net asset value				63,649
TOTAL				$ 383,517
OPEB assets				
Cash and cash equivalents	$ 27,006	$ -	$ -	$ 27,006
TOTAL	$ 27,006	$ -	$ -	$ 27,006
December 31, 2018				
Pension assets				
Common collective trusts	$ -	$ 332,756	$ -	$ 332,756
OPEB assets				
Mutual funds	26,065	-	-	26,065
Fair value of plan assets, December 31, 2018	$ 26,065	$ 332,756	$ -	$ 358,821

As of December 31, 2019, the determination of the fair values of our Plans' Level 2 assets was as follows:

- Cash and cash equivalents - proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- Common collective trusts - primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments measured at net asset value (NAV) – alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

As of December 31, 2018, the determination of fair values of the Level 2 co-mingled mutual funds were based on the Net Asset Value (NAV) provided by the managers of the underlying fund investments and the unrealized gains and losses. The NAV provided by the managers typically reflect the fair value of each underlying fund investment.

Defined Contribution Retirement Plans/401(k)

UI employees are eligible to participate in the UIL Holdings Corporation 401(k) Employee Stock Ownership Plan. Employees may defer a portion of the compensation and invest in various investment alternatives. Matching contributions are made in the form of cash which is subsequently invested in various investment alternatives offered to employees. The matching expense for 2019 and 2018 was $5.3 million and $5.1 million, respectively.

(G) RELATED PARTY TRANSACTIONS

During the years ended December 31, 2019 and 2018, UI received cash distributions from GenConn. See Note (A) Business Organization and Statement of Accounting Policies – Equity Investments.

In October 2019, UI received an equity infusion from UIL Holdings. See Note (B) "Capitalization."

Inter-company Transactions

UI receives various administrative and management services from and enters into certain inter-company transactions with UIL Holdings and its subsidiaries. For the years ended December 31, 2019 and 2018, UI recorded inter-company expenses of $58.0 million and $55.9 million, respectively, which consisted primarily of operation and maintenance expenses. Costs of the services that are allocated amongst UI and other of UIL Holdings' regulated subsidiaries are settled periodically by way of inter-company billings and wire transfers and are included in Accounts receivable from affiliates and Accounts payable to affiliates in the accompanying balance sheets.

Dividends/Capital Contributions

For the year ended December 31, 2019, UI accrued $90.0 million in dividends to UIL Holdings. For the year ended December 31, 2018, UI did not accrue dividends to UIL Holdings.

(H) LEASES

UI has operating leases for land, office buildings, facilities, and certain equipment. UI does not have any finance leases. Certain of UI's lease agreements include rental payments adjusted periodically for inflation or are based on other periodic input measures. UI's leases do not contain any material residual value guarantees or material restrictive covenants. UI's leases have remaining lease terms of 0.83 years to 31 years, some of which may include options to extend the leases, and some of which may include options to terminate. UI considers extension or termination options in the lease term if it is reasonably certain UI will exercise the option.

The components of lease cost and other information related to leases were as follows:

(In Thousands)		Year Ended December 31, 2019
Operating lease cost	$	4,738

(In Thousands)		As of December 31, 2019
Operating Leases		
Operating lease right of use assets	$	12,220
Operating lease liabilities, current	$	1,790
Operating lease liabilities, long-term		14,484
Total operating lease liabilities	$	16,274
Weighted-average Remaining Lease Term (years):		
Operating leases		21.34
Weighted-average Discount Rate:		
Operating leases		3.84%

Supplemental cash flow information related to leases was as follows:

(In Thousands)	Year Ended December 31, 2019	
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$	1,748

As of December 31, 2019, maturities of lease liabilities were as follows:

(In Thousands)	Operating Leases	
Year ending December 31,		
2020	$	1,792
2021		1,724
2022		3,619
2023		766
2024		766
Thereafter		16,906
Total lease payments		25,573
Less: imputed interest		9,299
Total	$	16,274

Most of UI's leases do not provide an implicit rate in the lease; thus UI uses its incremental borrowing rate based on the information available at the commencement date in determining the present value of lease payments. UI used the incremental borrowing rate on January 1, 2019, for operating leases that commenced prior to that date.

Comparative 2018 Leases Disclosures

Operating leases, which are charged to operating expense, consist principally of leases for land office space and facilities, land, railroad rights of way and a wide variety of equipment.

The future minimum lease payments under these operating leases are estimated to be as follows:

Year	(In Thousands) UI	
2019	$	1,919
2020		1,643
2021		1,573
2022		3,543
2023		766
2024-after		29,885
	$	39,329

Rental payments charged to operating expenses in 2018 and 2017 totaled $1.1 million and $5.3 million, respectively.

(I) COMMITMENTS AND CONTINGENCIES

In the ordinary course of business, UI and its subsidiaries are involved in various proceedings, including legal, tax, regulatory and environmental matters, which require management's assessment to determine the probability of whether a loss will occur and, if probable, an estimate of probable loss. When assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated, UI accrues a reserve and discloses the reserve and related matter. UI discloses material matters when losses are probable but for which an estimate cannot be reasonably estimated or when losses are not probable but are reasonably possible. Subsequent analysis is performed on a periodic basis to assess the impact of any changes in events or circumstances and any resulting need to adjust existing reserves or record additional reserves. However, given the inherent unpredictability of these legal and regulatory proceedings, we cannot assure you that our assessment of such proceedings will reflect the ultimate outcome, and an adverse outcome in certain matters could have a material adverse effect on our results of operations or cash flows.

Connecticut Yankee Atomic Power Company

UI has a 9.5% stock ownership share in the Connecticut Yankee Atomic Power Company, an inactive nuclear generating company (Connecticut Yankee), which has completed the physical decommissioning of its generation facilities and is now engaged primarily in the long-term storage of its spent nuclear fuel. Connecticut Yankee collects its costs through wholesale FERC-approved rates from UI and several other New England utilities. UI recovers these costs from its customers through electric rates.

Every six years, pursuant to the statute of limitations, Connecticut Yankee needs to file a lawsuit to recover damages from the Department of Energy (the "Government") for breach of the Nuclear Spent Fuel Disposal Contract to remove Spent Nuclear Fuel and Greater than Class C Waste as required by contract and the Nuclear Waste Policy Act beginning in 1998. The damages are the incremental costs for the Government's failure to take the spent nuclear fuel.

From 2012 to 2016 Connecticut Yankee filed three claims against the DOE (Phase I, II and III) for the years from 1995 to 2012 and received damage awards, which flow through Connecticut Yankee to shareholders (including UI) based on its' percentage of ownership) to reduce retail customer charges. UI refunded its share of such awards to its customers through the nonbypassable federally mandated congestion charge. On May 22, 2017, Connecticut Yankee filed its next case (Phase IV) in the Federal Court of Claims (Court), seeking damages for the period from January 1, 2013 through December 31, 2016 and submitted their claimed Phase IV damages to the DOE in late August 2017. The Court issued its decision on the Phase IV trial on February 21, 2019, awarding Connecticut Yankee $40.7 million. On April 23, 2019, the notice of appeal period expired and the Phase IV trial award became final. The Government has paid Connecticut Yankee the full amount of the damage award which will not be distributed to shareholders and will instead be used to meet its obligations, including storing spent nuclear fuel safely and reliably for 15 years and to pay down its obligation to pay the DOE a one-time fee in connection with pre-1983 spent nuclear fuel.

The trial court decisions, the appeals court decisions in this case, and legal precedents, provide strong support that the Yankee Companies will continue to recover future costs caused by the Government's breach. The Company cannot predict the exact outcome or the timing of these proceedings.

Environmental Matters

In complying with existing environmental statutes and regulations and further developments in areas of environmental concern, including legislation and studies in the fields of water quality, hazardous waste handling and disposal, toxic substances, climate change and electric and magnetic fields, UI may incur substantial capital expenditures for equipment modifications and additions, monitoring equipment and recording devices, as well as additional operating expenses. The total amount of these expenditures is not now determinable. Environmental damage claims may also arise from the operations of our subsidiaries. Significant environmental issues known to UI at this time are described below.

Site Decontamination, Demolition and Remediation Costs

English Station

In January 2012, Evergreen Power, LLC (Evergreen Power) and Asnat Realty LLC (Asnat), then owners of a former generation site on the Mill River in New Haven (the English Station site) that UI sold to Quinnipiac Energy in 2000, filed a lawsuit in federal district court in Connecticut related to environmental remediation at the English Station site. This proceeding was stayed in 2014 pending resolutions of other proceedings before the DEEP concerning the English Station site. In December 2016, the court administratively closed the file without prejudice to reopen upon the filing of a motion to reopen by any party.

In December 2013, Evergreen Power and Asnat filed a subsequent lawsuit related to the English Station site. On April 16, 2018, the plaintiffs filed a revised complaint alleging fraud and unjust enrichment against UIL and UI and adding former UIL officers as named defendants alleging fraud. On February 21, 2019, the court granted our Motion to Strike with respect to all counts except for the count against UI for unjust enrichment. The counts stricken include all counts against the individual defendants as well as against UIL. The plaintiffs have appealed the court's decision to strike. UI cannot predict the outcome of this matter.

On April 8, 2013, DEEP issued an administrative order addressed to UI, Evergreen Power, Asnat and others, ordering the parties to take certain actions related to investigating and remediating the English Station site. This proceeding was stayed while DEEP and UI continue to work through the remediation process pursuant to the consent order described below. Status reports are periodically filed with DEEP.

On August 4, 2016, DEEP issued a partial consent order (the consent order), that, subject to its terms and conditions, requires UI to investigate and remediate certain environmental conditions within the perimeter of the English Station site. Under the consent order, to the extent that the cost of this investigation and remediation is less than $30 million, UI will remit to the State of Connecticut the difference between such cost and $30 million to be used for a public purpose as determined in the discretion of the Governor of the State of Connecticut, the Attorney General of the State of Connecticut and the Commissioner of DEEP. UI is obligated to comply with the terms of the consent order even if the cost of such compliance exceeds $30 million. Under the terms of the consent order, the state will discuss options with UI on recovering or funding any cost above $30 million such as through public funding or recovery from third parties; however, it is not bound to agree to or support any means of recovery or funding. UI has initiated its process to investigate and remediate the environmental conditions within the perimeter of the English Station site pursuant to the consent order.

As of December 31, 2019 and December 31, 2018, the amount reserved for this matter was $16.4 million and $20.0 million, respectively. UI cannot predict the outcome of this matter.

Other

In May 2019, UI obtained an updated remediation evaluation of the property adjacent to the New Haven Harbor Generating Station. As a result, UI recorded an additional $6.0 million reserve in June 2019, the minimum of the range of remediation estimates. As of December 31, 2019 and December 31, 2018, the amount reserved for this property was $7.8 million and $1.9 million, respectively.

(J) FAIR VALUE MEASUREMENTS

As required by ASC 820 “Fair Value Measurements and Disclosures,” financial assets and liabilities are classified in their entirety, based on the lowest level of input that is significant to the fair value measurement. UI’s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following tables set forth the fair value of UI's financial assets and liabilities, other than pension benefits and other postretirement benefits, as of December 31, 2019 and December 31, 2018:

	Fair Value Measurements Using							
	Quoted Prices in Active Markets for Identical Assets (Level 1)		Significant Other Observable Inputs (Level 2)		Significant Unobservable Inputs (Level 3)		Total	
December 31, 2019			(In Thousands)					
Assets:								
Derivative assets	$	-	$	-		2,138	$	2,138
Supplemental retirement benefit trust life insurance policies		-		12,568		-		12,568
		-		12,568		2,138		14,706
Liabilities:								
Derivative liabilities		-		-		74,824		74,824
		-		-		74,824		74,824
Net fair value assets/(liabilities), December 31, 2019	$	-	$	12,568	$	(72,686)	$	(60,118)
December 31, 2018								
Assets:								
Derivative assets	$	-	$	-	$	5,355	$	5,355
Supplemental retirement benefit trust life insurance policies		-		9,806		-		9,806
		-		9,806		5,355		15,161
Liabilities:								
Derivative liabilities		-		-		79,935		79,935
		-		-		79,935		79,935
Net fair value assets/(liabilities), December 31, 2018	$	-	$	9,806	$	(74,580)	$	(64,774)

Fair value measurements categorized in Level 3 of the fair value hierarchy are prepared by individuals with expertise in valuation techniques, pricing of energy and energy-related products, and accounting requirements. The derivative assets consist primarily of CfDs. The determination of fair value of the CfDs was based on a probability-based expected cash flow analysis that was discounted at the December 31, 2019 or December 31, 2018 risk-free interest rates, as applicable, and an adjustment for non-performance risk using credit default swap rates. Certain management assumptions were required, including development of pricing that extended over the term of the contracts. UI believes this methodology provides the most reasonable estimates of the amount of future discounted cash flows associated with the CfDs.

Additionally, on a quarterly basis, UI performs analytics to ensure that the fair value of the derivatives is consistent with changes, if any, in the various fair value model inputs. Additional quantitative information about Level 3 fair value measurements is as follows:

	Unobservable Input	Range at December 31, 2019	Range at December 31, 2018
Contracts for differences	Risk of non-performance	0.05% - 0.45%	0.87% - 0.88%
	Discount rate	1.69% - 1.83%	2.51% - 2.63%
	Forward pricing ($ per MW)	$3.80 - $7.03	$4.30 - $9.55

Significant isolated changes in the risk of non-performance, the discount rate or the contract term pricing would result in an inverse change in the fair value of the CfDs.

The determination of the fair value of the supplemental retirement benefit trust life insurance policies was based on quoted prices as of December 31, 2019 and December 31, 2018 in the active markets for the various funds within which the assets are held.

The following tables set forth a reconciliation of changes in the fair value of the assets and liabilities above that are classified as Level 3 in the fair value hierarchy for the years ended December 31, 2019 and 2018:

	Year Ended December 31, 2019 (In Thousands)
Net derivative assets/(liabilities), December 31, 2018	$ (74,580)
Unrealized gains and (losses), net	1,894
Net derivative assets/(liabilities), December 31, 2019	$ (72,686)
Change in unrealized gains (losses), net relating to net derivative	$ 1,894

	Year Ended December 31, 2018 (In Thousands)
Net derivative assets/(liabilities), December 31, 2017	$ (67,446)
Unrealized gains and (losses), net	(7,134)
Net fair value assets/(liabilities), December 31, 2018	$ (74,580)
Change in unrealized gains (losses), net relating to net derivative assets/(liabilities), still held as of December 31, 2018	$ (7,134)

(K) SUBSEQUENT EVENTS

In March 2020 the World Health Organization declared a global pandemic due to the outbreak of COVID-19. UI is assessing the possible impacts to its business and financial results.

CONNECTICUT NATURAL GAS CORPORATION

AUDITED FINANCIAL STATEMENTS

AS OF AND FOR THE YEARS ENDED

DECEMBER 31, 2019 AND 2018

TABLE OF CONTENTS

KPMG LLP
677 Washington Boulevard
Stamford, CT 06901

Independent Auditors' Report

The Board of Directors
Connecticut Natural Gas Corporation:

We have audited the accompanying financial statements of Connecticut Natural Gas Corporation, which comprise the balance sheets as of December 31, 2019 and 2018, and the related statements of income, changes in shareholder's equity, and cash flows for the years then ended, 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 U.S. generally accepted accounting principles; 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 auditors' 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 entity'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 entity'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 Connecticut Natural Gas Corporation as of December 31, 2019 and 2018, and the results of its operations and its cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

KPMG LLP

Stamford, Connecticut
March 30, 2020

CONNECTICUT NATURAL GAS CORPORATION
STATEMENTS OF INCOME
(In Thousands)

	Year Ended December 31, 2019	Year Ended December 31, 2018
Operating Revenue	$ 403,334	$ 380,671
Operating Expenses		
Natural gas purchased	180,139	184,123
Operation and maintenance	99,588	97,806
Depreciation and amortization	42,540	35,615
Taxes other than income taxes	30,233	25,956
Total Operating Expenses	352,500	343,500
Operating Income	50,834	37,171
Other Income and (Expense), net	(3,213)	(5,557)
Interest Expense, net	9,382	8,381
Income Before Income Tax	38,239	23,233
Income Tax	12,164	4,754
Net Income	$ 26,075	$ 18,479
Less: Preferred Stock Dividends of Subsidiary, Noncontrolling Interests	27	20
Net Income attributable to Connecticut Natural Gas Corporation	$ 26,048	$ 18,459

The accompanying Notes to Financial Statements
are an integral part of the financial statements.

CONNECTICUT NATURAL GAS CORPORATION
STATEMENTS OF CASH FLOWS
(In Thousands)

	Year Ended December 31, 2019	Year Ended December 31, 2018
Cash Flows From Operating Activities		
Net Income	$ 26,075	$ 18,479
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	42,638	35,700
Deferred income taxes	22,078	(7,188)
Uncollectible expense	9,221	6,767
Pension expense	7,776	3,720
Regulatory assets/liabilities amortization	2,374	3,162
Regulatory assets/liabiities carrying cost	66	760
Other non-cash items, net	1,204	37
Changes in:		
Accounts receivable and unbilled revenues, net	(13,272)	(11,020)
Natural gas in storage	810	(4,575)
Accounts payable and accrued liabilities	(5,491)	8,518
Interest accrued	940	383
Taxes accrued/refundable, net	(351)	(1,999)
Accrued pension and other post-retirement	(8,322)	(2,363)
Regulatory assets/liabilities	(3,434)	9,349
Other assets	(4,044)	(412)
Other liabilities	(978)	1,141
Total Adjustments	51,215	41,980
Net Cash provided by Operating Activities	77,290	60,459
Cash Flows from Investing Activities		
Plant expenditures including AFUDC debt	(51,187)	(77,644)
Notes receivable from affiliates	(12,300)	-
Net Cash used in Investing Activities	(63,487)	(77,644)
Cash Flows from Financing Activities		
Issuance of long-term debt	50,000	-
Equity infusion from parent	43,000	-
Payment of common stock dividend	-	(2)
Payment of preferred stock dividend	(27)	(20)
Notes payable to affiliates	(108,432)	19,235
Other	(287)	(175)
Net Cash used (provided by) in Financing Activities	(15,746)	19,038
Cash, Restricted Cash, and Cash Equivalents:		
Net change for the period	(1,943)	1,853
Balance at beginning of period	2,519	666
Balance at end of period	$ 576	$ 2,519
Cash paid during the period for:		
Interest (net of amount capitalized)	$ 7,706	$ 6,830
Non-cash investing activity:		
Plant expenditures included in ending accounts payable	$ 6,933	$ 4,730

The accompanying Notes to Financial Statements
are an integral part of the financial statements.

CONNECTICUT NATURAL GAS CORPORATION
BALANCE SHEETS
ASSETS
(In Thousands)

	December 31, 2019	December 31, 2018
Assets		
Current Assets		
Unrestricted cash and temporary cash investments	$ 513	$ 1,202
Notes receivable from affiliates	12,300	-
Accounts receivable and unbilled revenues, net	85,902	90,671
Accounts receivable from affiliates	9,087	1,017
Regulatory assets	22,079	31,180
Gas in storage	27,144	27,954
Materials and supplies	1,463	2,024
Prepayments and other current assets	5,887	1,290
Total Current Assets	164,375	155,338
Other Investments	1,051	1,090
Net Property, Plant and Equipment	729,061	701,598
Operating lease right of use assets	935	-
Deferred Income Taxes	-	1,979
Regulatory Assets	120,531	113,735
Deferred Charges and Other Assets		
Goodwill	79,341	79,341
Other	323	1,569
Total Deferred Charges and Other Assets	79,664	80,910
Total Assets	$ 1,095,617	$ 1,054,650

The accompanying Notes to Financial Statements
are an integral part of the financial statements.

CONNECTICUT NATURAL GAS CORPORATION
BALANCE SHEETS
LIABILITIES AND CAPITALIZATION
(In Thousands)

	December 31, 2019	December 31, 2018
Liabilities		
Current Liabilities		
Notes payable to affiliates	$ -	$ 108,375
Accounts payable and accrued liabilities	64,873	68,849
Accounts payable to affiliates	12,873	12,749
Other current liabilities	4,482	3,918
Regulatory liabilities	12,408	9,866
Interest accrued	2,585	1,645
Taxes accrued	5,713	6,064
Operating lease liabilities	419	-
Total Current Liabilities	103,353	211,466
Deferred Income Taxes	20,099	-
Regulatory Liabilities	246,850	240,549
Other Noncurrent Liabilities		
Pension and other postretirement	105,491	101,450
Asset retirement obligations	6,576	6,637
Operating lease liabilities	817	-
Other	1,795	2,724
Total Other Noncurrent Liabilities	114,679	110,811
Capitalization		
Long-term debt, net of unamortized premium	159,100	109,336
Preferred Stock, not subject to mandatory redemption	340	340
Common Stock Equity		
Common stock	33,233	33,233
Paid-in capital	358,302	315,302
Retained earnings	59,661	33,613
Net Common Stock Equity	451,196	382,148
Total Capitalization	610,636	491,824
Total Liabilities and Capitalization	$ 1,095,617	$ 1,054,650

The accompanying Notes to Financial Statements
are an integral part of the financial statements.

CONNECTICUT NATURAL GAS CORPORATION
STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
December 31, 2019
(Thousands of Dollars)

	Common Stock Shares	Common Stock Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance as of December 31, 2017	10,634,436	$ 33,233	$ 315,304	$ 15,181	$ (27)	$ 363,691
Net income				18,479		18,479
Adoption of accounting standard				(27)	27	-
Payment of common stock dividend			(2)			(2)
Payment of preferred stock dividend				(20)		(20)
Balance as of December 31, 2018	10,634,436	$ 33,233	$ 315,302	$ 33,613	$ -	$ 382,148
Net income				26,075		26,075
Payment of preferred stock dividend				(27)		(27)
Equity infusion from parent			43,000			43,000
Balance as of December 31, 2019	10,634,436	$ 33,233	$ 358,302	$ 59,661	$ -	$ 451,196

The accompanying Notes to Financial Statements
are an integral part of the financial statements.

CONNECTICUT NATURAL GAS CORPORATION

NOTES TO FINANCIAL STATEMENTS

(A) STATEMENT OF ACCOUNTING POLICIES

Connecticut Natural Gas Corporation (CNG) engages in natural gas transportation, distribution and sales operations in Connecticut serving approximately 182,000 customers in service areas totaling approximately 724 square miles. CNG is regulated by the Connecticut Public Utilities Regulatory Authority (PURA).

CNG is the principal operating utility of CTG Resources, Inc. (CTG), a wholly-owned subsidiary of UIL Holdings Corporation. CTG is a holding company whose sole business is ownership of its operating regulated gas utility. UIL Holdings, whose primary business is ownership of its operating regulated utility businesses, is a wholly owned subsidiary of Avangrid Networks, Inc. (Networks), which is a wholly-owned subsidiary of Avangrid, Inc., which is a 81.5% owned subsidiary of Iberdrola, S.A., a corporation organized under the law of the Kingdom of Spain.

Accounting Records

The accounting records of CNG are maintained in conformity with generally accepted accounting principles in the United States of America (GAAP) and in accordance with the uniform systems of accounts prescribed by the Federal Energy Regulatory Commission (FERC) and PURA.

Basis of Presentation

The preparation of financial statements in conformity with GAAP requires management to use estimates and assumptions that affect (1) the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and (2) the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

CNG's total comprehensive income is equal to net income for the years ended December 31, 2019 and 2018.

CNG has evaluated subsequent events through the date its financial statements were available to be issued, March 30, 2020.

The following policies are considered to be the most critical in understanding the judgments that are involved in preparing CNG's financial statements:

Revenues

On January 1, 2018, CNG adopted Accounting Standards Codification (ASC), Topic 606, "Revenue from Contracts with Customers" (ASC 606) and all related amendments using the modified retrospective method, which was applied only to contracts that were not completed as of January 1, 2018. For reporting periods beginning on January 1, 2018, CNG presents revenue in accordance with ASC 606. For the year ended December 31, 2018, the effect of applying ASC 606 to recognize revenue as compared to applying the legacy accounting standards was not material.

CNG derives its revenue primarily from tariff-based sales of natural gas delivered to customers. For such revenues, CNG recognizes revenues in an amount derived from the commodities delivered to customers. Another major source of revenue is wholesale sales of natural gas.

Tariff-based sales are subject to PURA approval, which determines prices and other terms of service through the ratemaking process. Certain customers have the option to obtain the natural gas directly from CNG or from another supplier. For customers that receive their natural gas from another supplier, CNG acts as an agent and delivers the natural gas for that supplier. Revenue in those cases is only for providing the service of delivery of the natural gas. CNG calculates revenue earned but not yet billed based on the number of days not billed in the month, the estimated amount of energy delivered during those days and the estimated average price per customer class for that month. Differences between actual and estimated unbilled revenue are immaterial.

The performance obligation in all arrangements is satisfied over time because the customer simultaneously receives and consumes the benefits as CNG delivers or sells the natural gas. CNG records revenue for all of those sales based upon the regulatory-approved tariff and the volume delivered, which corresponds to the amount that CNG has a right to invoice. There are no material initial incremental costs of obtaining a contract in any of the arrangements. CNG does not adjust the promised consideration for the effects of a significant financing component if it expects, at contract inception, that the time between the delivery of promised goods or service and customer payment will be one year or less. CNG does not have any material significant payment terms because it receives payment at or shortly after the point of sale.

CNG also records revenue from an Alternative Revenue Program (ARP), which is not ASC 606 revenue. This program, a revenue decoupling mechanism, represents a contract between CNG and their regulators. CNG recognizes and records only the initial recognition of "originating" ARP revenues (when the regulatory-specified conditions for recognition have been met). When CNG subsequently includes those amounts in the price of utility service billed to customers, they record such amounts as a recovery of the associated regulatory asset or liability. When they owe amounts to customers in connection with ARPs, they evaluate those amounts on a quarterly basis and include them in the price of utility service billed to customers and do not reduce ARP revenues.

CNG also has various other sources of revenue including billing, collection, other administrative charges, sundry billings, rent of utility property, and miscellaneous revenue. It classifies such revenues as other ASC 606 revenues to the extent they are not related to revenue generating activities from leasing, or ARPs.

Revenues disaggregated by major source are as follows:

(Thousands)	Year Ended December 31, 2019	Year Ended December 31, 2018
Regulated operations – natural gas	$ 396,653	$ 372,204
Other (a)	2,479	1,844
Revenue from contracts with customers	**399,132**	**374,048**
Leasing revenue	92	101
Alternative revenue programs	4,110	6,522
Total operating revenues	**$ 403,334**	**$ 380,671**

(a) Primarily includes certain intra-month trading activities, billing, collection, and administrative charges, sundry billings, and other miscellaneous revenue.

Regulatory Accounting

Generally accepted accounting principles for regulated entities in the United States of America allow CNG to give accounting recognition to the actions of regulatory authorities in accordance with the provisions of ASC 980 "Regulated Operations." In accordance with ASC 980, CNG has deferred recognition of costs (a regulatory asset) or has recognized obligations (a regulatory liability) if it is probable that such costs will be recovered or obligations refunded in the future through the ratemaking process. CNG is allowed to recover all such deferred costs and is required to refund such obligations to customers through its regulated rates. See

Note (C) “Regulatory Proceedings”, for a discussion of the recovery of certain deferred costs and the refund of certain obligations, as well as a discussion of the regulatory decisions that provide for such recovery and require such refunding.

If CNG, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs would be required in the year in which such criteria are no longer met (if such deferred costs are not recoverable in the portion of the business that continues to meet the criteria for application of ASC 980). CNG expects to continue to meet the criteria for application of ASC 980 for the foreseeable future. If a change in accounting were to occur, it could have a material adverse effect on the CNG’s earnings and retained earnings in that year and could also have a material adverse effect on CNG’s ongoing financial condition.

Unless otherwise stated below, all of CNG’s regulatory assets earn a return. CNG’s regulatory assets and liabilities as of December 31, 2019 and 2018 included the following:

	Remaining Period	December 31, 2019	December 31, 2018
		(In Thousands)	
Regulatory Assets:			
Pension and other post-retirement benefit plans	(a)	$ 115,025	$ 112,031
Hardship programs	(b)	8,868	11,746
Unfunded future income taxes	(c)	3,958	3,958
Deferred purchased gas	(f)	10,074	13,503
Other	(d)	4,685	3,677
Total regulatory assets		142,610	144,915
Less current portion of regulatory assets		22,079	31,180
Regulatory Assets, Net		$ 120,531	$ 113,735
Regulatory Liabilities:			
Pension and other postretirement benefit plans	(a)	$ 6,011	$ 6,105
Asset removal costs	(d)	200,019	187,048
Asset retirement obligation	(e)	9,692	9,058
Rate credits	1 to 8 years	10,000	11,250
Tax reform	1 to 31 years	18,014	21,574
Non-firm margin sharing credits	0 to 2 years	7,509	5,368
Decoupling	(g)	5,745	7,751
Other	(d)	2,268	2,261
Total regulatory liabilities		259,258	250,415
Less current portion of regulatory liabilities		12,408	9,866
Regulatory Liabilities, Net		$ 246,850	$ 240,549

(a) Life is dependent upon timing of final pension plan distribution; balance, which is fully offset by a corresponding asset/liability, is recalculated each year in accordance with ASC 715 "Compensation-Retirement Benefits." See Note (F) Pension and Other Benefits for additional information.
(b) Hardship customer accounts deferred for future recovery to the extent they exceed the amount in rates.
(c) The balance will be extinguished when the asset, which is fully offset by a corresponding liability, or liability has been realized or settled, respectively.

(d) Amortization period and/or balance vary depending on the nature, cost of removal and/or remaining life of the underlying assets/liabilities; asset amount includes certain amounts that are not currently earning a return.
(e) The liability will be extinguished simultaneous with the retirement of the assets and settlement of the corresponding asset retirement obligation.
(f) Deferred purchase gas costs balances at the end of the rate year are normally recorded / returned in the next year.
(g) Decoupling regulatory liability is not currently earning a return. The current portion of $4.1 million will be returned to customers in 2020. The return of the $1.6 million long term portion will be determined in a future proceeding with PURA.

Goodwill

The goodwill for CNG resulted from the purchase of CNG by UIL Holdings in 2010 and amounted to $79.3 million.

Goodwill is not amortized, but is subject to an assessment for impairment at least annually or more frequently if events occur or circumstances change that will more likely than not reduce the fair value of the reporting unit below its carrying amount. A reporting unit is an operating segment or one level below an operating segment and is the level at which goodwill is tested for impairment.

In assessing goodwill for impairment, CNG has the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary, or step zero. If it is determined, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If CNG bypasses step zero or performs the qualitative assessment but determines that it is more likely than not that its fair value is less than its carrying amount, a quantitative two step, fair value based test is performed. Step one compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, step two is performed. Step two requires an allocation of fair value to the individual assets and liabilities using business combination accounting guidance to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than its carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense.

CNG's annual impairment testing takes place as of October 1. CNG's step zero qualitative assessment involves evaluating key events and circumstances that could affect its fair value, as well as other factors. Events and circumstances evaluated include macroeconomic conditions, industry, regulatory and market considerations, cost factors and their effect on earnings and cash flows, overall financial performance as compared with projected results and actual results of relevant prior periods, other relevant entity specific events, and events affecting CNG.

CNG's step one impairment testing includes various assumptions, primarily the discount rate, which is based on an estimate of the marginal, weighted average cost of capital, and forecasted cash flows. CNG tests the reasonableness of the conclusions of the step one impairment testing using a range of discount rates and a range of assumptions for long term cash flows.

CNG had no impairment of goodwill in 2019 and 2018 as a result of its impairment testing.

Property, Plant and Equipment

The cost of additions to property, plant and equipment and the cost of renewals and betterments are capitalized. Costs consist of labor, materials, services and certain indirect construction costs, including allowance for funds used during construction (AFUDC). The costs of current repairs, major maintenance projects and minor replacements are charged to appropriate operating expense accounts as incurred. The original cost of utility property, plant and equipment retired or otherwise disposed of and the cost of removal, less salvage, are charged to the accumulated provision for depreciation.

CNG accrues for estimated costs of removal for certain of their plant-in-service. Such removal costs are included in the approved rates used to depreciate these assets. At the end of the service life of the applicable assets, the accumulated depreciation in excess of the historical cost of the asset provides for the estimated cost of removal. In accordance with ASC 980 "Regulated Operations," the accrued costs of removal have been recorded as a regulatory liability.

CNG's property, plant and equipment as of December 31, 2019 and 2018 were comprised as follows:

	2019	2018
	(In Thousands)	
Gas distribution plant	$ 883,195	$ 842,745
Software	34,259	30,284
Land	1,618	1,618
Building and improvements	34,917	32,475
Other plant	100,832	98,330
Total property, plant & equipment	1,054,821	1,005,452
Less accumulated depreciation	339,601	319,083
	715,219	686,369
Construction work in progress	13,841	15,229
Net property, plant & equipment	$ 729,061	$ 701,598

Allowance for Funds Used During Construction

In accordance with the uniform systems of accounts, CNG capitalizes AFUDC, which represents the approximate cost of debt and equity capital devoted to plant under construction. The portion of the allowance applicable to borrowed funds is presented as interest expense, net and the portion of the allowance applicable to equity funds is presented as other income in the Statement of Income. Although the allowance does not represent current cash income, it has historically been recoverable under the ratemaking process over the service lives of the related properties. Weighted-average AFUDC rates for 2019 and 2018 were 2.66% and 2.13%, respectively. The portion of the allowance applicable to equity funds was immaterial for both 2019 and 2018.

Depreciation

Provisions for depreciation on utility plant for book purposes are computed on a straight-line basis using composite rates based on the estimated service lives of the various classes of assets. For utility plant other than software, service lives are determined by independent depreciation consultants and subject to review and approval by PURA. Software service life is based upon management's estimate of useful life. The aggregate annual provisions for depreciation for both 2019 and 2018 were approximately $42.5 million and $35.6 million, respectively, or 4.13% and 3.8% of the original cost of depreciable property, respectively.

Impairment of Long-Lived Assets and Investments

ASC 360 "Property, Plant, and Equipment" requires the recognition of impairment losses on long-lived assets when the book value of an asset exceeds the sum of the expected future undiscounted cash flows that result from the use of the asset and its eventual disposition. If impairment arises, then the amount of any impairment is measured based on discounted cash flows or estimated fair value.

ASC 360 also requires that rate-regulated companies recognize an impairment loss when a regulator excludes all or part of a cost from rates, even if the regulator allows the company to earn a return on the remaining costs allowed. Under this standard, the probability of recovery and the recognition of regulatory assets under the criteria of ASC 980 must be assessed on an ongoing basis. As discussed in the description of ASC 980 in this Note (A) under "Regulatory Accounting", determination that certain regulatory assets no longer qualify for accounting as such could have a material impact on the financial condition CNG. At December 31, 2019, CNG did not have any assets that were impaired under this standard.

Unrestricted cash and temporary cash investments

CNG considers all of its highly liquid debt instruments with an original maturity of three months or less at the date of purchase to be unrestricted cash and temporary cash investments.

Restricted Cash

CNG's restricted cash primarily relates to gas distribution capital projects which have been withheld by CNG and will remain in place until the verification of fulfillment of contractor obligations. Restricted cash balances are included in other long-term assets on the balance sheet. CNG had $0.1 million and $1.3 million of restricted cash balances at December 31, 2019 and 2018, respectively.

Accounts receivable and unbilled revenues

Accounts receivable at December 31, 2019 and 2018 include unbilled revenues of $29.3 million and $28.2 million, respectively and are shown net of an allowance for doubtful accounts of $1.8 million and $1.0 million for 2019 and 2018, respectively. Accounts receivable do not bear interest, although late fees may be assessed.

Unbilled revenues represent estimates of receivables for products and services provided but not yet billed. The estimates are determined based on various assumptions, such as current month energy load requirements, billing rates by customer classification and weather**.** Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

The allowance for doubtful accounts is management's best estimate of the amount of probable credit losses in the existing accounts receivable, determined based on experience. Each month, CNG reviews the allowance for doubtful accounts and past due accounts by age. When management believes that a receivable will not be recovered, the account balance is charged off against the allowance. Changes in assumptions about input factors and customer receivables, which are inherently uncertain and susceptible to change from period to period, could significantly affect the allowance for doubtful accounts estimates.

Leases

CNG determines if an arrangement is a lease at inception. CNG classifies a lease as a finance lease if it meets any one of specified criteria that in essence transfers ownership of the underlying asset to CNG by the end of the lease term. If a lease does not meet any of those criteria, CNG classifies it as an operating lease. On the balance sheets, CNG includes, for operating leases: "Operating lease right-of-use (ROU) assets", and "Operating lease liabilities (current and non-current)"; and for finance leases: finance lease ROU assets in "Other assets," and liabilities in "Other current liabilities" and "Other liabilities."

ROU assets represent CNG's right to use an underlying asset for the lease term and lease liabilities represent our obligation to make lease payments arising from the lease. CNG recognizes lease ROU assets and liabilities at commencement of an arrangement based on the present value of lease payments over the lease term. Most of CNG's leases do not provide an implicit rate, so CNG uses its incremental borrowing rate based on information available at the lease commencement date to determine the present value of future payments. A lease ROU asset also includes any lease payments made at or before commencement date, minus any lease incentives received, and includes initial direct costs incurred. CNG does not record leases with an initial term of 12 months or less on the balance sheet, for all classes of underlying assets, and CNG recognizes lease expense for those leases on a straight-line basis over the lease term. CNG includes variable lease payments that depend on an index or a rate in the ROU asset and lease liability measurement based on the index or rate at the commencement date, or upon a modification. CNG does not include variable lease payments that do not depend on an index or a rate in the ROU asset and lease liability measurement. A lease term includes options to extend or terminate the lease when it is reasonably certain that we will exercise that option. CNG recognizes lease (rent) expense for operating lease payments on a straight-line basis over the lease term, or the amount eligible for recovery under CNG's rate plan. CNG amortizes finance lease ROU assets on a straight-line basis over the lease term and recognize interest expense based on the outstanding lease liability.

CNG has lease agreements with lease and non-lease components, and account for lease components and associated non-lease components together as a single lease component, for all classes of underlying assets.

Gas in storage

Natural gas in storage is stored in both self-owned and third-party owned underground storage facilities. This gas is recorded as inventory. Injections of inventory into storage are priced at the market purchase cost at the time of injection, and withdrawals of working gas from storage are priced at the weighted-average cost in storage. CNG continuously monitors the weighted-average cost of gas value to ensure it remains at the lower of cost and net realizable value.

Materials and supplies

Materials and supplies inventories are used for construction of new facilities and repairs of existing facilities. The inventories are carried and withdrawn at lower of cost and net realizable value.

Other Investments

The CNG's other investments consist of noncurrent investments available for sale.

Asset removal costs

CNG meets the requirements concerning accounting for regulated operations, and recognizes a regulatory liability, for the difference between removal costs collected in rates and actual costs incurred. CNG classifies those amounts as asset removal costs.

Asset Retirement Obligations

The fair value of the liability for an asset retirement obligation (ARO) and/or a conditional ARO is recorded in the period in which it is incurred and the cost is capitalized by increasing the carrying amount of the related long-lived asset. The liability is adjusted to its present value periodically over time, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement, the obligation is settled either at its recorded amount or a gain or a loss is incurred. Any timing differences between rate recovery and depreciation expense are deferred as either a regulatory asset or a regulatory liability.

The term conditional ARO refers to an entity's legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. If an entity has sufficient information to reasonably estimate the fair value of the liability for a conditional ARO, it must recognize that liability at the time the liability is incurred.

CNG's ARO, including estimated conditional AROs, consist primarily of obligations related to the removal or retirement of asbestos, polychlorinated biphenyl contaminated equipment, gas pipeline and cast iron gas mains. The long-lived assets associated with the AROs are gas storage property, distribution property and other property. CNG's ARO is carried on the balance sheet as other non-current liabilities.

ARO activity for 2019 and 2018 is as follows:

	2019	2018
	(In Thousands)	
Balance as of January 1	$ 6,637	$ 6,683
Liabilities settled during the year	(409)	(397)
Accretion	348	351
Balance as of December 31	$ 6,576	$ 6,637

Pension and Other Postretirement Benefits

CNG accounts for pension plan costs and other postretirement benefits, consisting principally of health care, prescription drugs and life insurance, in accordance with the provisions of ASC 715 "Compensation - Retirement Benefits." See Note (F), "Pension and Other Benefits".

Income Taxes

In accordance with ASC 740 "Income Taxes," CNG has provided deferred taxes for all temporary book-tax differences using the liability method. The liability method requires that deferred tax balances be adjusted to reflect enacted future tax rates that are anticipated to be in effect when the temporary differences reverse. In accordance with generally accepted accounting principles for regulated industries, CNG has established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences. For ratemaking purposes, investment tax credits related to recoverable plant investments are deferred when earned and amortized over the estimated lives of the related assets.

Under ASC 740, CNG may recognize the tax benefit of an uncertain tax position only if management believes it is more likely than not that the tax position will be sustained on examination by the taxing authority based upon the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based upon the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. CNG's policy is to recognize interest accrued and penalties associated with uncertain tax positions as a component of operating expense. See Note (E), "Income Taxes" for additional information.

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Tax Act) was signed into law. The Tax Act contains significant changes to the federal tax structure, including among other things, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017. PURA instituted proceedings in Connecticut to review and address the implications associated with the Tax Act on the utilities providing service in the state and rendered a final decision in Docket No. 18-01-15 on January 23, 2019. The decision approved CNG's method for adjusting rates in a Settlement Agreement to account for the reduced income tax liability as a result of the Tax Act. As part of the Settlement Agreement, dated December 19, 2018, CNG reflected the lower corporate tax rate of 21%, the amortization of a 2018 tax deferral and a credit related to CNG's amortization over 32 years of its excess accumulated deferred federal income tax.

Adoption of New Accounting Pronouncements

Leases

In February 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Codification (ASC) Topic 842, "Leases", with subsequent amendments issued in 2018. The new leases guidance affects all companies and organizations that lease assets, and requires them to record on their balance sheet ROU assets and lease liabilities for the rights and obligations created by those leases. Under ASC 842, a lease is an arrangement that conveys the right to control the use of an identified asset for a period of time in exchange for consideration. The new guidance retains a distinction between finance leases and operating leases, while requiring companies to recognize both types of leases on their balance sheet. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the criteria for distinguishing between capital leases and operating leases in legacy U.S. GAAP - ASC 840. Lessor accounting remains substantially the same as ASC 840, but with some targeted improvements to align lessor accounting with the lessee accounting model and with the revised revenue recognition guidance under ASC 606. The new standard and amendments require new qualitative and quantitative disclosures for both lessees and lessors.

CNG adopted ASC 842 effective January 1, 2019, and elected the optional transition method under which the standard was initially applied on that date without adjusting amounts for prior periods, which CNG continues to present in accordance with ASC 840, including related disclosures. CNG recorded the cumulative effect of applying the new leases guidance as an adjustment to beginning retained earnings. In connection with the adoption, CNG:

• did not elect the package of three practical expedients available under the transition provisions which would have allowed them to not reassess: (i) whether expired or existing contracts were or contained leases, (ii) the lease classification for expired or existing leases, and (iii) whether previously capitalized initial direct costs for existing leases would qualify for capitalization under ASC 842.
• used hindsight for determining the lease term and assessing the likelihood that a lease purchase option will be exercised in applying the new leases guidance.
• did not separate lease and associated non-lease components for transitioned leases, but instead are accounting for them together as a single lease component.

In March 2019, the FASB issued additional amendments to ASC 842 for minor codification improvements, which CNG early applied effective January 1, 2019, with no material effect to its results of operations, financial position and cash flows.

The cumulative effects of the changes to CNG's balance sheet as of January 1, 2019, were as follows:

(In Thousands)	Balance at December 31, 2018	Adjustment Due to Topic 842	Balance at January 1, 2019
Assets			
Operating lease right of use assets	$ -	$ 1,579	$ 1,579
Liabilities			
Operating lease liabilities	$ -	$ 1,579	$ 1,579

CNG's adoption did not change the classification of lease-related expenses in its statements of income, and CNG does not expect significant changes to our pattern of expense recognition. As a result, the adoption will not materially affect CNG's cash flows. Refer to Note (H) "Leases" for further details.

Reclassification of certain tax effects from accumulated other comprehensive income

In February 2018, the FASB issued ASU 2018-02 "Income Statement-Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income" which contains amendments to address a narrow-scope financial reporting issue that arose as a consequence of the Tax Cuts and Jobs Act of 2017 (the Tax Act) enacted on December 22, 2017 by the U.S. federal government. Under current guidance, the adjustment of deferred taxes for the effect of a change in tax laws or rates is required to be included in income from continuing operations, thus the associated tax effects of items within accumulated other comprehensive income (AOCI) (referred to as stranded tax effects) do not reflect the appropriate tax rate. The amendments allow a reclassification from AOCI to retained earnings for stranded tax effects resulting from the Tax Act. As a result, the amendments eliminate the stranded tax effects resulting from the Tax Act and will improve the usefulness of information reported to financial statement users. The amendments only relate to the reclassification of the income tax effects of the Tax Act, and do not affect the underlying guidance that requires the effect of a change in tax laws or rates to be included in income from continuing operations. CNG adopted the amendments effective January 1, 2019, which had no impact on its results of operations, financial position and cash flows.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements issued as indicated, that CNG has evaluated or is evaluating to determine their effect on its financial statements.

<u>Simplifying the test for goodwill impairment</u>

In January 2017, the FASB issued amendments to simplify the test for goodwill impairment, which are required for public entities and certain other entities that have goodwill reported in their financial statements. The amendments simplify the subsequent measurement of goodwill by eliminating Step 2 from the goodwill impairment test, which requires the valuation of assets acquired and liabilities assumed using business combination accounting guidance. Under the new guidance, an entity should perform its annual, or interim, goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; but the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. Also, an entity should consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable. Certain requirements are eliminated for any reporting unit with a zero or negative carrying amount, therefore the same impairment assessment applies to all reporting units. An entity still has the option to perform the qualitative assessment for a reporting unit to determine if the quantitative impairment test is necessary. The amendments are effective for public entities for annual and interim periods in fiscal years beginning after December 15, 2019, with the amendments applied on a prospective basis. Early adoption is allowed. CNG's adoption of the amendments on January 1, 2020, will not materially affect its results of operations, financial position, cash flows, and disclosures.

<u>Changes to the disclosure requirements for fair value measurement and defined benefit plans</u>

In August 2018, the FASB issued amendments related to disclosure requirements for both fair value measurement and defined benefit plans. The amendments concerning fair value measurement remove, modify and add certain disclosure requirements, in order to improve the overall usefulness of the disclosures and reduce unnecessary costs to companies to prepare the disclosures. The amendments to fair value measurement disclosures are effective for all entities for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted as specified. Certain amendments are to be applied prospectively, and all others are to be applied retrospectively. CNG's adoption of the amendments on January 1, 2020, will not materially affect its disclosures.

The amendments concerning disclosure requirements for defined benefit plans are narrow in scope and apply to all employers that sponsor defined benefit pension or other postretirement plans. They remove disclosures that are no longer considered cost beneficial, add certain new relevant disclosures and clarify specific requirements of disclosures concerning information for defined benefit pension plans. The amendments to defined benefit plan disclosures are effective for fiscal years ending after December 15, 2020. Early adoption is permitted and application is to be on a retrospective basis. CNG's adoption of the amendments on January 1, 2020, will not materially affect its disclosures.

<u>Clarifying guidance for certain collaborative arrangements with respect to revenue recognition</u>

The FASB issued amendments in November 2018 to clarify the interaction between the guidance for certain collaborative arrangements and the guidance applicable to ASC 606. A collaborative arrangement is a contractual arrangement under which two or more parties actively participate in a joint operating activity and are exposed to significant risks and rewards that depend on the activity's commercial success. The targeted improvements clarify that certain transactions between collaborative arrangement participants are within the scope of ASC 606 and thus subject to all of its guidance. The amendments are effective for public business entities for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted, including adoption in any interim period for which financial statements have not been issued. Retrospective application to the date of initial application of ASC 606 is required. CNG's adoption of the amendments on January 1, 2020, will not materially affect its results of operations, financial position, cash flows and disclosures.

Simplifying the accounting for income taxes

In December 2019, the FASB issued an accounting standards update that is intended to reduce complexity in accounting for income taxes. The amendments remove specific exceptions to the general principles in ASC 740, Income Taxes, eliminating the need for an entity to analyze whether the following apply in a given period: (1) exception to the incremental approach for intra-period tax allocation, (2) exceptions to accounting for basis differences when there are ownership changes in foreign investments and (3) exception in interim period income tax accounting for year-to-date losses that exceed anticipated losses. The amendments also improve financial statement preparers' application of income-tax related guidance and simplify U. S. GAAP for (1) franchise taxes that are partially based on income, (2) transactions with a government that result in a step up in the tax basis of goodwill, (3) separate financial statements of legal entities that are not subject to tax and (4) enacted changes in tax laws in interim periods. The amendments are effective for public business entities for fiscal years beginning after December 15, 2020, and interim periods within those fiscal years. Early adoption is permitted, including adoption in any interim period for which financial statements have not been issued, with adoption of all amendments in the same period. Application is on a retrospective and/or modified retrospective basis, or a prospective basis, depending on the amendment aspect. CNG expects its adoption will not materially affect its results of operations, financial position, and cash flows.

B) CAPITALIZATION

Common Stock

CNG had 10,634,436 shares of its common stock, $3.125 par value, outstanding as of December 31, 2019 and 2018.

In October 2019, CNG received a $43.0 million equity infusion from CTG in order to maintain its allowed capitalization ratio which was impacted by the long-term debt activity noted below.

Preferred Stock of Subsidiaries, Noncontrolling Interests

CNG has authorized 884,315 shares of its 8.00% non-callable cumulative preferred stock with a par value of $3.125 per share. As of December 31, 2019, there were 108,706 shares issued and outstanding with a value of approximately $0.3 million.

Long-Term Debt

As of December 31,		**2019**		**2018**	
(In Thousands)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
Senior unsecured debt	2028-2049	$ 160,000	4.30%-6.66%	$ 110,000	4.30%-6.66%
Unamortized debt (costs) premium, net		(900)		(664)	
Total Debt		**159,100**		**109,336**	
Less: debt due within one year, included in current liabilities		-		-	
Total Non-current Debt		**$ 159,100**		**$ 109,336**	

The estimated fair value of debt amounted to $202.8 million and $128.2 million as of December 31 2019 and 2018, respectively. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the natural gas industry and the credit ratings of the borrowers in each case. The fair value hierarchy for the fair value of debt is considered as Level 2. The expenses to issue long-term debt are deferred and amortized over the life of the respective debt issue.

On January 15, 2019, CNG issued $50 million of notes with a maturity of 2049 and interest rate of 4.52%.

Information regarding maturities and mandatory redemptions/repayments are set forth below:

	2020	2021	2022	2023	2024 & Thereafter	Total
			(In Thousands)			
Maturities:	$ -	$ -	$ -	$ -	$ 160,000	$ 160,000

Under various debt agreements, CNG is required to maintain a ratio of consolidated debt to consolidated capital of not greater than 65% (debt ratio). As of December 31, 2019, CNG's debt ratio was 26%.

(C) REGULATORY PROCEEDINGS

Rates

Utilities are entitled by Connecticut statute to charge rates that are sufficient to allow them an opportunity to cover their reasonable operating and capital costs, to attract needed capital and to maintain their financial integrity, while also protecting relevant public interests.

In December, 2018, PURA approved new tariffs for CNG effective January 1, 2019 for a three-year rate plan with rate increases of $9.9 million, $4.6 million and $5.2 million in 2019, 2020 and 2021, respectively. The new tariffs, which are based on an ROE of 9.30% and an equity ratio of 54% in 2019, 54.50% in 2020, and 55% in 2021, continued, among other things, two separate ratemaking mechanisms that reconcile actual revenue requirements related to CNG's cast iron and bare steel replacement program and system expansion as well as a revenue decoupling mechanism and CNG's earnings sharing mechanism whereby CNG is required to return to customers 50% of any earnings over the allowed ROE in a calendar year and tariff increases.

Additionally, CNG has a purchased gas adjustment clause, approved by PURA, which enables reasonably incurred cost of gas purchases to be passed through to customers. This clause allows CNG to recover costs associated with changes in the market price of purchased natural gas, substantially eliminating exposure to natural gas price risk.

Gas Supply Arrangements

CNG satisfies its natural gas supply requirements through purchases from various producer/suppliers, withdrawals from natural gas storage capacity contracts and winter peaking supplies and resources. CNG operates diverse portfolios of gas supply, firm transportation capacity, gas storage and peaking resources. Actual reasonable gas costs incurred by CNG are passed through to customers through state regulated purchased gas adjustment mechanisms, subject to regulatory review.

CNG purchases the majority of their natural gas supply at market prices under seasonal, monthly or mid-term supply contracts and the remainder is acquired on the spot market. CNG diversifies its sources of supply by amount purchased and location and primarily acquires gas at various locations in the US Gulf of Mexico region, in the Appalachia region and in Canada.

CNG acquires firm transportation capacity on interstate pipelines under long-term contracts and utilizes that capacity to transport both natural gas supply purchased and natural gas withdrawn from storage to the local distribution system. Tennessee Gas Pipeline, Algonquin Gas Transmission and Iroquois Gas Transmission interconnect with CNG's distribution system and the other pipelines provide indirect services upstream of the city gates. The prices and terms and conditions of the long-term contracts for firm transportation capacity are regulated by the FERC. The actual reasonable cost of such contracts is passed through to customers through state regulated purchased gas adjustment mechanisms.

CNG acquires firm underground natural gas storage capacity using long-term contracts and fills the storage facilities with gas in the summer months for subsequent withdrawal in the winter months. The storage facilities are located in Pennsylvania, New York, West Virginia and Michigan.

CNG owns 100% of the Liquefied Natural Gas (LNG) stored in a LNG facility which is directly attached to its distribution system. CNG uses the LNG capacity as a winter peaking resource.

Tax Cuts and Jobs Act

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Tax Act) was signed into law. The Tax Act significantly changed the federal taxation of business entities including, among other things, implementing a federal corporate tax rate decrease from 35% to 21% for tax years beginning after December 31, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates will result in amounts previously and currently collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates. The PURA and the FERC have instituted proceedings in Connecticut to review and address the implications of the Tax Act on the utilities. CNG included Tax Act savings in its rate case that was filed with PURA in the second quarter of 2018 and such savings are included in new rates effective January 1, 2019.

(D) SHORT-TERM CREDIT ARRANGEMENTS

CNG funds short-term liquidity needs through an agreement among Avangrid's regulated utility subsidiaries (the Virtual Money Pool Agreement), a bi-lateral intercompany credit agreement with Avangrid (the Bi-Lateral Intercompany Facility) and a bank provided credit facility to which CNG is a party (the Avangrid Credit Facility), each of which are described below.

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. CNG has a lending/borrowing limit of $100 million under this agreement. There were no borrowings under this agreement as of December 31, 2019 and $59.8 million outstanding as of December 31, 2018.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $250 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. There were no borrowings under this agreement as of December 31, 2019 and there was $48.6 million outstanding under this agreement as of December 31, 2018.

On June 29, 2018, Avangrid, Inc. and its subsidiaries, including CNG, entered into a new credit facility agreement with a syndicate of banks (Avangrid Credit Facility) that provides for maximum borrowings of up to $2.5 billion in the aggregate. This Avangrid Credit Facility replaces and supersedes the prior revolving credit facility entered into by Avangrid, Inc. and its subsidiaries on April 6, 2016, which provided maximum borrowings of up to $1.5 billion in the aggregate.

Under the Avangrid Credit Facility, CNG has a maximum sublimit of $150 million. Additionally, under the Avangrid Credit Facility, each of the borrowers, including CNG, will pay an annual facility fee that is dependent on their credit rating. The facility fees will range from 12.5 to 17.5 basis points. The maturity date for the Avangrid Credit Facility is June 29, 2024. As of December 31, 2019 and 2018, CNG did not have any outstanding borrowings under the Avangrid Credit Facility.

(E) INCOME TAXES

	Year Ended December 31, 2019	Year Ended December 31, 2018
	(In Thousands)	
Income tax expense consists of:		
Income tax provisions (benefits):		
Current		
Federal	$ (8,799)	$ 9,430
State	(1,115)	2,512
Total current	(9,914)	11,942
Deferred		
Federal	23,625	(4,918)
State	(1,547)	(2,270)
Total deferred	22,078	(7,188)
Total income tax expense	$ 12,164	$ 4,754

Total income taxes differ from the amounts computed by applying the federal statutory tax rate to income before taxes.

The reasons for the differences are as follows:

	Year Ended December 31, 2019	Year Ended December 31, 2018
	(In Thousands)	
Book income before income taxes	$ 38,239	$ 23,233
Computed tax at federal statutory rate	$ 8,030	$ 4,879
Increases (reductions) resulting from:		
Tax Return related adjustments	3,304	806
State income taxes, net of federal income tax	(2,103)	191
Other items, net	2,933	(1,123)
Total income tax expense	$ 12,164	$ 4,754
Effective income tax rates	31.8%	20.5%

The significant portion of CNG's income tax expense, including deferred taxes, is recovered through its regulated utility rates. CNG's annual income tax expense and associated effective tax rate is impacted by differences between the timing of deferred tax temporary difference activity and deferred tax recovery. CNG's effective tax rate is also impacted by permanent differences between the book and tax treatment of certain costs.

CNG is subject to the United States federal income tax statutes administered by the IRS. CNG is a party to Avangrid, Inc.'s tax allocation agreement under which taxable subsidiaries do not pay any more taxes than they would have otherwise paid had they filed a separate company tax return, and subsidiaries generating tax losses, if any, are paid for their losses when utilized. Also pursuant to the tax allocation agreement, CNG settles its current tax liability or benefit each year directly with Avangrid, Inc. The following table summarizes CNG's tax years that remain subject to examination as of December 31, 2019:

Jurisdiction	*Tax years*
Federal	2014 - 2019
Connecticut	2014 - 2019

The following table summarizes CNG's deferred tax assets and liabilities as of December 31, 2019 and 2018:

	2019	2018
	(In Thousands)	
CT credit carryforward	$ 4,438	$ 2,545
Deferred tax liability on 2017 Tax Act remeasurement	4,850	1,732
Property related	(20,760)	(5,167)
Unfunded future income taxes	(1,065)	3,104
Goodwill	(4,320)	(3,851)
Pension (net)	(555)	(881)
Other assets (liabilities)	(2,687)	4,497
	$ (20,099)	$ 1,979

As of December 31, 2019, CNG had a net state credit carry forward of $4.4 million and a state net operating loss carry forward of $1.1 million. As of December 31, 2018, CNG had a net state credit carry forward of $3.3 million and a state net operating loss carry forward of $1.1 million. CNG's state tax credit carry forwards will begin to expire for the 2019 tax year. Each of CNG's state tax credit carry forwards will begin to expire in 2020.

(F) PENSION AND OTHER POSTRETIREMENT BENEFITS

Defined Benefit Plans (the Plans)

<u>Pension Plans</u>

CNG has multiple qualified pension plans covering eligible union and management employees and retirees. CNG also has non-qualified supplemental pension plans for certain retirees. The union plans are all closed to new hires, and the non-union plans were closed as of December 31, 2017. CNG also has non-qualified supplemental pension plans for certain employees and retirees. The qualified pension plans are traditional defined benefit plans or cash balance plans for those hired on or after specified dates. In some cases, neither of these plans is offered to new employees and have been replaced with enhanced 401(k) plans for those hired on or after specified dates. The qualified pension plans provide benefits under a traditional defined benefit formula or cash balance formula depending on date of hire. The plans are closed to new employees hired on or after specified dates.

Employees not participating in a defined benefit plan are eligible to receive an enhanced or core 401(k) Company matching contribution.

Plan Assets

Networks' pension benefits plan assets were consolidated from three legacy master trusts to one new master trust in 2019. A consolidated trust provides for a uniform investment manager lineup and an efficient, cost effective means of allocating expenses and investment performance to each plan. The primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our risk tolerance. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. The primary means for achieving capital preservation is through diversification of the trusts' investments while avoiding significant concentrations of risk in any one area of the securities markets. Further diversification is achieved within each asset group through utilizing multiple asset managers and systematic allocation to various asset classes and providing broad exposure to different segments of the equity, fixed income and alternative investment markets.

The asset allocation policy is the most important consideration in achieving the objective of superior investment returns while minimizing risk. Networks has established target asset allocation policies within allowable ranges for its pension benefits plan assets within broad categories of asset classes made up of Return-Seeking investments and Liability-Hedging investments. Networks currently has target allocations ranging from 35%-70% for Return-Seeking assets and 34%-65% for Liability-Hedging assets. Return-Seeking assets also include investments in real estate, global asset allocation strategies and hedge funds. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

Other Postretirement Benefits Plans

CNG also has plans providing other postretirement benefits for eligible employees and retirees. The plans were closed to newly-hired CNG union employees by end of March 2011. These benefits consist primarily of health care, prescription drug and life insurance benefits for retired employees and their dependents. For Medicare eligible non-union retirees, CNG provides a subsidy through an HRA for retirees to purchase coverage on the individual market. Medicare eligible union retirees have the option of receiving a subsidy through an HRA or paying contributions and participating in company-sponsored retiree health plans.

Plan Assets

Networks' postretirement benefits plan assets are held with trustees in multiple voluntary employees' beneficiary association (VEBA) and 401(h) arrangements and are invested among and within various asset classes to achieve sufficient diversification in accordance with its risk tolerance. This is achieved for Network's postretirement benefits plan assets through the utilization of multiple institutional mutual and money market funds, providing exposure to different segments of the fixed income, equity and short-term cash markets. Approximately 37% of the postretirement benefits plan assets are invested in VEBA and 401(h) arrangements that are not subject to income taxes with the remainder being invested in arrangements subject to income taxes.

Networks has established a target asset allocation policy within allowable ranges for postretirement benefits plan assets of 45%-65% for equity securities, 25%-45% for fixed income and 5%-25% for all other investment types. Equity investments are diversified across U.S. and non-U.S. stocks, investment styles, and market capitalization ranges. Fixed income investments are primarily invested in U.S. bonds and may also include some non-U.S. bonds. Other asset classes, including alternative investments, are used to enhance long-term returns while improving portfolio diversification. Networks primarily minimize the risk of large losses through diversification but also through monitoring and managing other aspects of risk through quarterly investment portfolio reviews. Systematic rebalancing within target ranges increases the probability that the annualized return on investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The following table represents the change in benefit obligation, change in plan assets and the respective funded status of CNG's pension and other postretirement plans as of December 31, 2019 and 2018. Plan assets and obligations have been measured as of December 31, 2019 and 2018.

	Pension Benefits		Other Post-Retirement Benefits	
	Year Ended December 31, 2019	Year Ended December 31, 2018	Year Ended December 31, 2019	Year Ended December 31, 2018
Change in Benefit Obligation:		(In Thousands)		
Benefit obligation at beginning of year	$ 269,499	$ 281,855	$ 19,588	$ 21,006
Service cost	4,594	4,850	152	184
Interest cost	10,774	10,489	768	764
Participant contributions	-	-	-	808
Amendments	-	-	-	225
Actuarial (gain) loss	30,700	(15,263)	293	(611)
Benefits paid (including expenses)	(12,841)	(12,432)	(1,953)	(2,788)
Benefit obligation at end of year	$ 302,726	$ 269,499	$ 18,848	$ 19,588
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 175,020	$ 199,896	$ 11,482	$ 11,009
Actual return on plan assets	35,400	(12,846)	786	507
Employer contributions	5,762	402	1,184	-
Participant contributions	-	-	-	808
Benefits paid (including expenses)	(12,841)	(12,432)	(1,953)	(842)
Fair value of plan assets at end of year	$ 203,341	$ 175,020	$ 11,499	$ 11,482
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ 99,385	$ 94,479	$ 7,349	$ 8,106
Amounts Recognized in the Consolidated Balance Sheet consist of:				
Non-current liabilities	$ 99,385	$ 94,479	$ 7,349	$ 8,106
Amounts Recognized as a Regulatory Asset (Liability)				
Prior service cost	$ -	$ -	$ 597	$ 798
Net (gain) loss	51,401	46,750	(2,293)	(2,625)
Total recognized as a regulatory asset (liability)	$ 51,401	$ 46,750	$ (1,696)	$ (1,827)
Information on Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:				
Projected benefit obligation	$ 302,726	$ 269,499	N/A	N/A
Accumulated benefit obligation	$ 278,829	$ 244,948	N/A	N/A
Fair value of plan assets	$ 203,341	$ 175,020	N/A	N/A
The following weighted average actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate (Qualified Plans)	3.19%	4.09%	N/A	N/A
Discount rate (Non-Qualified Plans)	3.19%	4.09%	N/A	N/A
Discount rate (Other Post-Retirement Benefits)	N/A	N/A	3.19%	4.09%
Average wage increase	3.50%	3.50%	N/A	N/A
Health care trend rate (current year - pre/post-65)	N/A	N/A	6.75%/7.50%	7.00%/7.75%
Health care trend rate (2029/2027 - pre/post-65)	N/A	N/A	4.50%/4.50%	4.50%/4.50%

N/A – not applicable

CNG is allowed to defer as regulatory assets or regulatory liabilities items that would have otherwise been recorded in AOCI pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans. Amounts recognized as regulatory assets or regulatory liabilities for the years ended December 31, 2019 and 2018 are shown above.

The discount rate is the rate at which the benefit obligations could presently be effectively settled. The discount rates were determined by developing yield curves derived from a portfolio of high grade noncallable bonds with yields that closely match the duration of the expected cash flows of our benefit obligations.

The components of net periodic benefit cost are:

	Pension Benefits		Other Post-Retirement	
	Year Ended December 31, 2019	Year Ended December 31, 2018	Year Ended December 31, 2019	Year Ended December 31, 2018
	(In Thousands)			
Components of net periodic benefit cost:				
Service cost	$ 4,594	$ 4,850	$ 152	$ 184
Interest cost	10,774	10,489	768	764
Expected return on plan assets	(12,692)	(14,322)	(562)	(591)
Amortization of prior service costs	-	20	201	239
Amortization of actuarial (gain) loss	3,340	2,318	(262)	(233)
Net periodic benefit cost	$ 6,016	$ 3,355	$ 297	$ 363
Other Changes in Plan Assets and Benefit Obligations Recognized as a Regulatory Asset (Liability):				
Net (gain) loss	$ 7,991	$ 11,907	$ 69	$ (527)
Amortization of current year prior service costs	-	-	-	225
Amortization of prior service costs	-	(20)	(201)	(239)
Amortization of actuarial gain (loss)	(3,340)	(2,318)	262	233
Total recognized as regulatory asset (liability)	$ 4,651	$ 9,569	$ 130	$ (308)
Total recognized in net periodic benefit costs and regulatory asset (liability)	$ 10,667	$ 12,924	$ 427	$ 55
Estimated Amortizations from Regulatory Assets (Liabilities) into Net Periodic Benefit Cost for the next 12 month peri				
Amortization of prior service cost	$ -	$ -	$ 201	$ 201
Amortization of net (gain) loss	3,643	3,340	(229)	(262)
Total estimated amortizations	$ 3,643	$ 3,340	$ (28)	$ (61)
The following actuarial weighted average assumptions were used in calculating net periodic benefit cost:				
Discount rate	4.09%	3.80%	4.09%	3.80%
Average wage increase	3.50%	3.50%	N/A	N/A
Return on plan assets	7.40%	7.40%	4.90%	5.37%
Health care trend rate (current year - pre/post-65)	N/A	N/A	7.00%/7.75%	7.50%/8.50%
Health care trend rate (2029/2027 - pre/post-65)	N/A	N/A	4.50%/4.50%	4.50%/4.50%

N/A – not applicable

CNG utilizes an alternative method to amortize prior service costs and unrecognized gains and losses. Prior service costs for both the pension and other postretirement benefits plans are amortized on a straight-line basis over the average remaining service period of participants expected to receive benefits. Unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans are amortized over the lesser of the average remaining service period or 10 years. For pension benefits, CNG does not recognize gains or losses until there is a variance in an amount equal to at least 5% of the greater of the projected benefit obligation or the market-related value of assets. For other postretirement benefits, there is no such allowance for a variance in capturing the amortization of unrecognized gains and losses.

The expected long-term rate of return on plan assets assumption was developed based on a review of long-term historical returns for the major asset classes, the target asset allocations, and the effect of rebalancing of plan assets. The analysis considered current capital market conditions and projected conditions. CNG amortizes unrecognized actuarial gains and losses over ten years from the time they are incurred as required by the PURA.

A one percentage point change in the assumed health care cost trend rate would have the following effects:

	1% Increase	1% Decrease
	(In Thousands)	
Aggregate service and interest cost components	$ 327	$ (285)
Accumulated post-retirement benefit obligation	$ 6,372	$ (5,305)

Contributions

The funding policy for the Plans is to make annual contributions that satisfy the minimum funding requirements of ERISA but that do not exceed the maximum deductible limits of the Internal Revenue Code. These amounts are determined each year as a result of an actuarial valuation of the Plans. CNG currently expects to make pension contributions of approximately $9.1 million in 2020. Such contribution levels will be adjusted, if necessary, based on actuarial calculations.

Estimated Future Benefit Payments

Expected benefit payments and Medicare Prescription Drug Improvement and Modernization Act of 2003 subsidy receipts reflecting future service as of December 31, 2019 consisted of:

Year	Pension Benefits	Other Post-Retirement Benefits	Medicare Act Subsidy
		(In Thousands)	
2020	$ 12,884	$ 2,039	$ 226
2021	$ 12,946	$ 1,908	$ 219
2022	$ 13,251	$ 1,774	$ 207
2023	$ 13,425	$ 1,664	$ 193
2024	$ 13,853	$ 1,562	$ 179
2025-2029	$ 76,261	$ 6,455	$ 668

The fair values of the Plans' assets as of December 31, 2019, disclosed below, reflect only the assets attributable to CNG's portion of the total assets held in the master trust.

	Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
December 31, 2019		(In Thousands)		
Pension assets				
Cash and cash equivalents	$ -	$ 1,707	$ -	$ 1,707
Registered investment companies	30,330	-	-	30,330
Common collective trusts	-	137,557	-	137,557
	$ 30,330	$ 139,264	$ -	169,594
Other investments measured at net asset value				33,747
TOTAL				$ 203,341
OPEB assets				
Cash and cash equivalents	$ -	$ 1,027	$ -	$ 1,027
Registered investment companies	2,864	-	-	2,864
Other, principally annuity, fixed income	-	7,608	-	7,608
TOTAL	$ 2,864	$ 8,635	$ -	$ 11,499
December 31, 2018				
Pension assets				
Mutual funds	$ -	$ 175,020	$ -	$ 175,020
	-	175,020	-	175,020
OPEB assets				
Mutual funds	3,885	7,597	-	11,482
TOTAL	$ 3,885	$ 182,617	$ -	$ 186,502

As of December 31, 2019, the determination of the fair values of our Plans' Level 2 assets was as follows:

- Cash and cash equivalents - proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- Common collective trusts - primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments measured at net asset value (NAV) – alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.
- Other investments, principally annuity and fixed income - Level 2: based on yields currently available on comparable securities of issuers with similar credit ratings.

As of December 31, 2018, the determination of fair values of the Level 2 co-mingled mutual funds were based on the Net Asset Value (NAV) provided by the managers of the underlying fund investments and the unrealized gains and losses. The NAV provided by the managers typically reflect the fair value of each underlying fund investment.

Defined Contribution Retirement Plans/401(k)

CNG non-union employees are eligible to participate in the UIL Holdings Corporation 401(k) Employee Stock Ownership Plan and union employees are eligible to participate in the Connecticut Natural Gas Corporation Union Employee 401(k) Plan. Employees may defer a portion of the compensation and invest in various investment alternatives. Matching contributions are made in the form of cash which is subsequently invested in various investment alternatives offered to employees. The matching expense for 2019 and 2018 was $1.5 million, and $1.2 million, respectively.

(G) RELATED PARTY TRANSACTIONS

Inter-company Transactions

In October 2019, CNG received an equity infusion from CTG. See Note (B) "Capitalization."

CNG receives various administrative and management services from and enters into certain inter-company transactions with UIL Holdings and its subsidiaries. For the year ended December 31, 2019, CNG recorded inter-company expenses of $13.3 million. Costs of the services that are allocated amongst CNG and other of UIL Holdings' regulated subsidiaries are settled periodically by way of inter-company billings and wire transfers and are included in Accounts receivable from affiliates and Accounts payable to affiliates in the accompanying balance sheets.

Dividends/Capital Contributions

For the year ended December 31, 2019, CNG did not accrue any dividends to CTG. For the year ended December 31, 2018, CNG accrued an immaterial amount of dividends to CTG.

(H) LEASES

CNG has operating leases for land, office buildings, facilities, and certain equipment. CNG does not have any finance leases. Certain of CNG's lease agreements include rental payments adjusted periodically for inflation or are based on other periodic input measures. CNG's leases do not contain any material residual value guarantees or material restrictive covenants. CNG's leases have remaining lease terms of 0.17 years to 4.5 years, some of which may include options to extend the leases, and some of which may include options to terminate. CNG considers extension or termination options in the lease term if it is reasonably certain CNG will exercise the option.

Most of CNG's leases do not provide an implicit rate in the lease; thus CNG uses its incremental borrowing rate based on the information available at the commencement date in determining the present value of lease payments. CNG used the incremental borrowing rate on January 1, 2019, for operating leases that commenced prior to that date.

CONNECTICUT NATURAL GAS CORPORATION

NOTES TO FINANCIAL STATEMENTS

The components of lease cost and other information related to leases were as follows:

(In Thousands)		Year Ended December 31, 2019
Operating lease cost	$	1,859

(In Thousands)		As of December 31, 2019
Operating Leases		
Operating lease right of use assets	$	935
Operating lease liabilities, current	$	419
Operating lease liabilities, long-term		817
Total operating lease liabilities	$	1,236
Weighted-average Remaining Lease Term (years):		
Operating leases		1.86
Weighted-average Discount Rate:		
Operating leases		3.03%

Supplemental cash flow information related to leases was as follows:

(In Thousands)		Year Ended December 31, 2019
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$	428

As of December 31, 2019, maturities of lease liabilities were as follows:

(In Thousands)		Operating Leases
Year ending December 31,		
2020	$	655
2021		574
2022		20
2023		14
2024		7
Thereafter		-
Total lease payments		1,270
Less: imputed interest		34
Total	$	1,236

Comparative 2018 Leases Disclosures

Operating leases, which are charged to operating expense, consist principally of leases for office space and facilities. The future minimum lease payments under these operating leases are estimated to be as follows:

	(In Thousands)	
2019	$	446
2020		640
2021		559
2022		6
2023		-
2024 - after		-
	$	1,651

(I) COMMITMENTS AND CONTINGENCIES

In the ordinary course of business, CNG is involved in various proceedings, including legal, tax, regulatory and environmental matters, which require management's assessment to determine the probability of whether a loss will occur and, if probable, an estimate of probable loss. When assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated, CNG accrues a reserve and discloses the reserve and related matter. CNG discloses material matters when losses are probable but for which an estimate cannot be reasonably estimated or when losses are not probable but are reasonably possible. Subsequent analysis is performed on a periodic basis to assess the impact of any changes in events or circumstances and any resulting need to adjust existing reserves or record additional reserves. However, given the inherent unpredictability of these legal and regulatory proceedings, CNG cannot assure you that its assessment of such proceedings will reflect the ultimate outcome, and an adverse outcome in certain matters could have a material adverse effect on its results of operations or cash flows.

Environmental Matters

In complying with existing environmental statutes and regulations and further developments in areas of environmental concern, including legislation and studies in the fields of water quality, hazardous waste handling and disposal, toxic substances, climate change and electric and magnetic fields, CNG may incur substantial capital expenditures for equipment modifications and additions, monitoring equipment and recording devices, as well as additional operating expenses. The total amount of these expenditures is not now determinable. Significant environmental issues known to CNG at this time are described below.

Site Decontamination, Demolition and Remediation Costs

CNG owns or has previously owned properties where Manufactured Gas Plants (MGPs) had historically operated. MGP operations have led to contamination of soil and groundwater with petroleum hydrocarbons, benzene and metals, among other things, at these properties, the regulation and cleanup of which is regulated by the federal Resource Conservation and Recovery Act as well as other federal and state statutes and regulations. CNG has or had an ownership interest in one or more such properties contaminated as a result of MGP-related activities. Under the existing regulations, the cleanup of such sites requires state and at times, federal, regulators' involvement and approval before cleanup can commence. In certain cases, such contamination has been evaluated, characterized and remediated. In other cases, the sites have been evaluated and characterized, but not yet remediated. Finally, at some of these sites, the scope of the contamination has not yet been fully characterized; no liability was recorded in respect of these sites as of December 31, 2019 and no amount of loss, if any, can be reasonably estimated at this time. In the past, CNG has received approval for the recovery of MGP-related remediation expenses from customers through rates and will seek recovery in rates for ongoing MGP-related remediation expenses for all of their MGP sites.

CNG owns a property located on Columbus Boulevard in Hartford which is a former MGP site. Costs associated with the remediation of the site could be significant and will be subject to a review by PURA as to whether these costs are recoverable in rates. As of December 31, 2019, CNG has determined that remediation of the property in Hartford is not probable and therefore not reserved.

(J) FAIR VALUE MEASUREMENTS

As required by ASC 820, financial assets and liabilities are classified in their entirety, based on the lowest level of input that is significant to the fair value measurement. CNG's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following tables set forth the fair value CNG's financial assets and liabilities, other than pension benefits and OPEB, as of December 31, 2019 and December 31, 2018.

	Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
December 31, 2019		(In Thousands)		
Noncurrent investments	$ 1,051	$ -	$ -	$ 1,051
Total fair value assets, December 31, 2018	$ 1,051	$ -	$ -	$ 1,051
December 31, 2018				
Noncurrent investments	$ 1,090	$ -	$ -	$ 1,090
Total fair value assets, December 31, 2016	$ 1,090	$ -	$ -	$ 1,090

(K) SUBSEQUENT EVENTS

In March 2020 the World Health Organization declared a global pandemic due to the outbreak of COVID-19. CNG is assessing the possible impacts to its business and financial results.

THE SOUTHERN CONNECTICUT GAS COMPANY

AUDITED CONSOLIDATED FINANCIAL STATEMENTS

AS OF AND FOR THE YEARS ENDED

DECEMBER 31, 2019 AND 2018

TABLE OF CONTENTS

KPMG LLP
677 Washington Boulevard
Stamford, CT 06901

Independent Auditors' Report

The Board of Directors
The Southern Connecticut Gas Company:

We have audited the accompanying consolidated financial statements of The Southern Connecticut Gas Company, which comprise the consolidated balance sheets as of December 31, 2019 and 2018, and the related consolidated statements of income, changes in shareholder's equity, and cash flows for the years then ended, and the related notes to the consolidated financial statements.

Management's Responsibility for the Financial Statements

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

Auditors' Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of The Southern Connecticut Gas Company as of December 31, 2019 and 2018, and the results of their operations and their cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

KPMG LLP

Stamford, Connecticut
March 30, 2020

THE SOUTHERN CONNECTICUT GAS COMPANY
CONSOLIDATED STATEMENTS OF INCOME
(In Thousands)

	Year Ended December 31, 2019	Year Ended December 31, 2018
Operating Revenues	$ 390,789	$ 390,498
Operating Expenses		
Natural gas purchased	176,607	183,663
Operation and maintenance	85,164	88,146
Depreciation and amortization	38,149	29,574
Taxes other than income taxes	31,379	28,940
Total Operating Expenses	331,299	330,323
Operating Income	59,490	60,175
Other Income and (Expense), net	(3,943)	(6,402)
Interest Expense, net	15,120	15,835
Income Before Income Tax	40,427	37,938
Income Tax	10,283	10,859
Net Income	$ 30,144	$ 27,079
Less: Net Income Attributable to Noncontrolling Interest	1,921	1,769
Net Income Attributable to The Southern Connecticut Gas Company	$ 28,223	$ 25,310

The accompanying Notes to Consolidated Financial
Statements are an integral part of the financial statements.

THE SOUTHERN CONNECTICUT GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In Thousands)

	Year Ended December 31, 2019	Year Ended December 31, 2018
Cash Flows From Operating Activities		
Net income	$ 30,144	$ 27,079
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	38,463	29,935
Uncollectible expense	8,189	7,235
Deferred income taxes	32,458	493
Pension expense	6,144	2,124
Regulatory assets/liabilities amortization	(1,386)	(1,766)
Regulatory assets/liabilities carrying cost	976	801
Other non-cash items, net	182	1,220
Changes in:		
Accounts receivable and unbilled revenue, net	(13,397)	(6,058)
Gas in storage	332	(1,914)
Accounts payable and accrued liabilities	(6,259)	8,502
Taxes accrued/refundable, net	(1,269)	(901)
Interest accrued	1,439	573
Accrued pension and other post-retirement	(8,350)	(2,191)
Regulatory assets/liabilities	11,390	2,314
Other assets	(7,122)	(589)
Other liabilities	(1,736)	(737)
Total Adjustments	60,054	39,041
Net Cash provided by Operating Activities	90,198	66,120
Cash Flows from Investing Activities		
Plant expenditures including AFUDC debt	(82,751)	(86,998)
Notes receivable from affiliates	(1,138)	(2,063)
Net Cash used in Investing Activities	(83,889)	(89,061)
Cash Flows from Financing Activities		
Issuances of long-term debt	75,000	-
Payment of long-term debt	-	(50,000)
Equity infusion from parent	18,000	-
Payment of common stock dividend	-	(25,000)
Notes payable to affililiates	(100,484)	99,951
Other	(448)	(173)
Net Cash provided by (used in) Financing Activities	(7,932)	24,778
Cash, Restricted Cash, and Cash Equivalents:		
Net change for the period	(1,623)	1,837
Balance at beginning of period	2,459	622
Balance at end of period	$ 836	$ 2,459
Cash paid during the period for:		
Interest (net of amount capitalized)	$ 11,865	$ 13,515
Non-cash investing activity:		
Plant expenditures included in ending accounts payable	$ 11,268	$ 8,968
Notes receivable from affiliates	$ -	$ 6,500
Non-cash financing activity:		
Payment of noncontrolling interest dividend	$ -	$ (6,500)

The accompanying Notes to Consolidated Financial Statements are an integral part of the financial statements.

THE SOUTHERN CONNECTICUT GAS COMPANY
CONSOLIDATED BALANCE SHEETS
ASSETS
(In Thousands)

	December 31, 2019	December 31, 2018
Assets		
Current Assets		
Unrestricted cash and temporary cash investments	$ 324	$ 2,316
Accounts receivable and unbilled revenues, net	82,056	86,097
Accounts receivable from affiliates	11,212	2,913
Notes receivable from affiliates	1,138	-
Regulatory assets	21,050	32,503
Gas in storage	29,275	29,607
Materials and supplies	1,587	1,695
Prepayments and other current assets	9,107	2,109
Total Current Assets	155,749	157,240
Other Investments	9,832	9,141
Net Property, Plant and Equipment	825,711	773,296
Operating lease right of use assets	592	-
Regulatory Assets	137,312	138,522
Deferred Charges and Other Assets		
Goodwill	134,931	134,931
Other	744	143
Total Deferred Charges and Other Assets	135,675	135,074
Total Assets	$ 1,264,871	$ 1,213,273

The accompanying Notes to Consolidated Financial Statements are an integral part of the financial statements.

THE SOUTHERN CONNECTICUT GAS COMPANY
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND CAPITALIZATION
(In Thousands)

	December 31, 2019	December 31, 2018
Liabilities		
Current Liabilities		
Notes payable to affiliates	$ 38,297	$ 138,727
Current portion of long-term debt	911	911
Accounts payable and accrued liabilities	62,058	65,342
Accounts payable to affiliates	13,294	13,975
Regulatory liabilities	10,766	9,080
Other current liabilities	7,338	7,909
Interest accrued	4,213	2,774
Taxes accrued	5,424	6,693
Operating lease liabilities	601	-
Total Current Liabilities	142,902	245,411
Deferred Income Taxes	55,045	23,676
Regulatory Liabilities	210,801	203,690
Other Noncurrent Liabilities		
Pension and other postretirement	62,680	67,424
Asset retirement obligations	12,434	12,264
Operating lease liabilities	335	-
Environmental remediation costs	45,659	46,333
Other	7,230	8,736
Total Other Noncurrent Liabilities	128,338	134,757
Capitalization		
Long-term debt, net of unamortized premium	243,616	169,714
Common Stock Equity		
Common stock	18,761	18,761
Paid-in capital	387,737	369,737
Retained earnings	56,497	28,274
Net Common Stock Equity of The Southern Connecticut Gas Company	462,995	416,772
Noncontrolling interest	21,174	19,253
Total Common Stock Equity	484,169	436,025
Total Capitalization	727,785	605,739
Total Liabilities and Capitalization	$ 1,264,871	$ 1,213,273

The accompanying Notes to Consolidated Financial Statements are an integral part of the financial statements.

THE SOUTHERN CONNECTICUT GAS COMPANY

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

December 31, 2019

(Thousands of Dollars)

	Common Stock Shares	Common Stock Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance as of December 31, 2017	1,407,072	$ 18,761	$ 369,737	$ 27,266	$ 698	$ 23,984	$ 440,446
Net income attributable to The Southern Connecticut Gas Company				25,310			25,310
Net income attributable to Noncontrolling interest						1,769	1,769
Adoption of accounting standard				698	(698)		-
Payment of common stock dividend				(25,000)		(6,500)	(31,500)
Balance as of December 31, 2018	1,407,072	$ 18,761	$ 369,737	$ 28,274	$ -	$ 19,253	$ 436,025
Net income attributable to The Southern Connecticut Gas Company				28,223			28,223
Net income attributable to Noncontrolling interest						1,921	1,921
Equity infusion from parent			18,000				18,000
Balance as of December 31, 2019	16,323,442,272	$ 18,761	$ 387,737	$ 56,497	$ -	$ 21,174	$ 484,169

The accompanying Notes to Consolidated Financial Statements are an integral part of the financial statements.

THE SOUTHERN CONNECTICUT GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(A) STATEMENT OF ACCOUNTING POLICIES

The Southern Connecticut Gas Company (SCG) engages in natural gas transportation, distribution and sales operations in Connecticut serving approximately 203,000 customers in service areas totaling approximately 555 square miles. SCG is regulated by the Connecticut Public Utilities Regulatory Authority (PURA).

SCG is the principal operating utility of Connecticut Energy Corporation (CEC), a wholly owned subsidiary of UIL Holdings Corporation (UIL Holdings). CEC is a holding company whose sole business is ownership of its operating regulated gas utility. UIL Holdings, whose primary business is ownership of its operating regulated utility businesses, is a wholly owned subsidiary of Avangrid Networks, Inc. (Networks), which is a wholly-owned subsidiary of Avangrid, Inc., which is a 81.5% owned subsidiary of Iberdrola, S.A., a corporation organized under the law of the Kingdom of Spain.

Accounting Records

The accounting records of SCG are maintained in conformity with generally accepted accounting principles in the United States of America (GAAP) and in accordance with the uniform systems of accounts prescribed by the Federal Energy Regulatory Commission (FERC) and PURA.

Basis of Presentation

The preparation of consolidated financial statements in conformity with GAAP requires management to use estimates and assumptions that affect (1) the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and (2) the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The Consolidated Financial Statements include the accounts of all variable interest entities (VIEs) where SCG has identified that it is the primary beneficiary. All intercompany transactions and accounts have been eliminated in all periods presented.

SCG has evaluated subsequent events through the date its consolidated financial statements were available to be issued, March 30, 2020.

The following policies are considered to be the most critical in understanding the judgments that are involved in preparing SCG’s financial statements:

Variable Interest Entities

CNE Peaking LLC (CNE) and Total Peaking Services LLC (TPS), both wholly owned subsidiaries of United Resources, Inc. (URI), which is a wholly owned subsidiary of UIL Holdings, own a 14.6 million gallon liquefied natural gas (LNG) storage tank operated by SCG and located on property owned by SCG in Milford, Connecticut, and certain equipment, materials and supplies used in or useful for the operation of the storage tank. The assets earn a rate of return equal to SCG’s allowed rate of return. CNE and TPS have been identified as Variable Interest Entities (VIEs). SCG has been determined to be the primary beneficiary as SCG has the power to direct significant activities at CNE and TPS with SCG operating the storage tank and all of the revenues at CNE and TPS being derived from SCG. As a result, CNE and TPS have been consolidated into the financial statements of SCG, which include total assets of $43.7 million and income of $1.9 million as of and for the year ended December 31, 2019. Intercompany operating revenues and natural gas purchased expenses of $12.0 million and intercompany receivables and payables of $2.8 million have been eliminated upon consolidation. The equity interests in CNE and TPS held by URI are reflected as a noncontrolling interest in the accompanying Consolidated Balance Sheet and Statement of Changes in Shareholder’s Equity.

The liabilities recognized as a result of combining the above VIEs do not necessarily represent additional claims on SCG’s general assets outside of the VIEs; rather they represent claims against the specific assets of the combined VIEs. Conversely, assets recognized as a result of combining these VIEs do not necessarily represent additional assets that could be used to satisfy claims against SCG's general assets. The total combined VIE assets and liabilities reflected on SCG's consolidated balance sheets are as follows:

	December 31, 2019	December 31, 2018
	(In Thousands)	
Assets:		
Current assets	$ 11,607	$ 7,554
Long-term assets	32,068	23,826
Total Assets	$ 43,675	$ 31,380
Liabilities		
Current liabilities	$ 22,501	$ 12,271
Total Liabilities	$ 22,501	$ 12,271

Revenues

On January 1, 2018, SCG adopted Accounting Standards Codification (ASC), Topic 606, "Revenue from Contracts with Customers" (ASC 606) and all related amendments using the modified retrospective method, which was applied only to contracts that were not completed as of January 1, 2018. For reporting periods beginning on January 1, 2018, SCG presents revenue in accordance with ASC 606. For the year ended December 31, 2018, the effect of applying ASC 606 to recognize revenue as compared to applying the legacy accounting standards was not material.

SCG derives its revenue primarily from tariff-based sales of natural gas delivered to customers. For such revenues, SCG recognizes revenues in an amount derived from the commodities delivered to customers. Another major source of revenue is wholesale sales of natural gas.

Tariff-based sales are subject to PURA approval, which determines prices and other terms of service through the ratemaking process. Certain customers have the option to obtain the natural gas directly from SCG or from another supplier. For customers that receive their natural gas from another supplier, SCG acts as an agent and delivers the natural gas for that supplier. Revenue in those cases is only for providing the service of delivery of the natural gas. SCG calculates revenue earned but not yet billed based on the number of days not billed in the month, the estimated amount of energy delivered during those days and the estimated average price per customer class for that month. Differences between actual and estimated unbilled revenue are immaterial.

The performance obligation in all arrangements is satisfied over time because the customer simultaneously receives and consumes the benefits as SCG delivers or sells the natural gas. SCG records revenue for all of those sales based upon the regulatory-approved tariff and the volume delivered, which corresponds to the amount that SCG has a right to invoice. There are no material initial incremental costs of obtaining a contract in any of the arrangements. SCG does not adjust the promised consideration for the effects of a significant financing component if it expects, at contract inception, that the time between the delivery of promised goods or service and customer payment will be one year or less. SCG does not have any material significant payment terms because it receives payment at or shortly after the point of sale.

SCG also records revenue from an Alternative Revenue Program (ARP), which is not ASC 606 revenue. This program, a revenue decoupling mechanism (RDM), represents a contract between SCG and their regulators. SCG recognizes and records only the initial recognition of "originating" ARP revenues (when the regulatory-specified conditions for recognition have been met). When SCG subsequently includes those amounts in the price of utility service billed to customers, they record such amounts as a recovery of the associated regulatory asset or liability. When they owe amounts to customers in connection with ARPs, they evaluate those amounts on a quarterly basis and include them in the price of utility service billed to customers and do not reduce ARP revenues.

SCG also has various other sources of revenue including billing, collection, other administrative charges, sundry billings, rent of utility property, and miscellaneous revenue. It classifies such revenues as other ASC 606 revenues to the extent they are not related to revenue generating activities from leasing, or ARPs.

Revenues disaggregated by major source are as follows:

(Thousands)	Year Ended December 31, 2019		Year Ended December 31, 2018	
Regulated operations – natural gas	$	382,286	$	380,391
Other (a)		2,014		1,466
Revenue from contracts with customers		**384,300**		**381,857**
Leasing revenue		556		632
Alternative revenue programs		5,933		8,009
Total operating revenues	**$**	**390,789**	**$**	**390,498**

(a) Primarily includes certain intra-month trading activities, billing, collection, and administrative charges, sundry billings, and other miscellaneous revenue.

Regulatory Accounting

Generally accepted accounting principles for regulated entities in the United States of America allow SCG to give accounting recognition to the actions of regulatory authorities in accordance with the provisions of ASC 980 "Regulated Operations." In accordance with ASC 980, SCG has deferred recognition of costs (a regulatory asset) or has recognized obligations (a regulatory liability) if it is probable that such costs will be recovered or obligations refunded in the future through the ratemaking process. SCG is allowed to recover all such deferred costs and is required to refund such obligations to customers through its regulated rates. See Note (C) "Regulatory Proceedings", for a discussion of the recovery of certain deferred costs and the refund of certain obligations, as well as a discussion of the regulatory decisions that provide for such recovery and require such refunding.

If SCG, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs would be required in the year in which such criteria are no longer met (if such deferred costs are not recoverable in the portion of the business that continues to meet the criteria for application of ASC 980). SCG expects to continue to meet the criteria for application of ASC 980 for the foreseeable future. If a change in accounting were to occur, it could have a material adverse effect on the SCG's earnings and retained earnings in that year and could also have a material adverse effect on SCG's ongoing financial condition.

Unless otherwise stated below, all of SCG's regulatory assets earn a return. SCG's regulatory assets and liabilities as of December 31, 2019 and 2018 included the following:

	Remaining Period	December 31, 2019	December 31, 2018
		(In Thousands)	
Regulatory Assets:			
Pension and other post-retirement benefit plans	(a)	$ 79,609	$ 84,460
Hardship programs	(b)	6,816	6,981
Deferred purchased gas	(c)	7,908	14,247
Environmental remediation costs	(g)	49,627	49,989
Debt premium	1 to 18 years	8,221	9,131
Other	(e)	6,181	6,217
Total regulatory assets		158,362	171,025
Less current portion of regulatory assets		21,050	32,503
Regulatory Assets, Net		$ 137,312	$ 138,522
Regulatory Liabilities:			
Pension and other post-retirement benefit plans	(a)	4,186	4,067
Asset removal costs	(e)	106,156	102,356
Rate Credits	1 to 8 years	6,000	6,750
Unfunded future income taxes	(d)	21,592	24,263
Tax reform	(h)	38,140	29,574
Low income program	(f)	33,023	38,109
Non-firm margin sharing credits	7 years	7,386	4,656
Other	(e)	5,084	2,995
Total regulatory liabilities		221,567	212,770
Less current portion of regulatory liabilities		10,766	9,080
Regulatory Liabilities, Net		$ 210,801	$ 203,690

(a) Life is dependent upon timing of final pension plan distribution; balance, which is fully offset by a corresponding asset/liability, is recalculated each year in accordance with ASC 715 "Compensation-Retirement Benefits." See Note (F) "Pension and Other Benefits" for additional information.

(b) Hardship customer accounts deferred for future recovery to the extent they exceed the amount in rates.

(c) Deferred purchase gas costs balances at the end of the rate year are normally recorded / returned in the next year.

(d) The balance will be extinguished when the asset, which is fully offset by a corresponding liability, or liability, has been realized or settled, respectively.

(e) Amortization period and/or balance vary depending on the nature, cost of removal and/or remaining life of the underlying assets/liabilities; liability amount as of December 31, 2019 includes decoupling ($0.7 million) that is not currently earning a return.

(f) Various hardship and payment plan programs approved for recovery.

(g) Liability relates to the remediation of the property owned by SCG on Chapel Street in New Haven. See Note (H) "Commitments and Contingencies" for additional information.

(h) Balance includes customer impacts of deferred tax remeasurement as of December 2017, as well as the post 2017 impact of the tax rate decrease related to the passage of the federal Tax Cuts and Jobs Act of 2017 on December 22, 2017. The amount and timing of potential settlement are determined by the regulated utilities' respective rate regulators and IRS Normalization rules.

Goodwill

The goodwill for SCG resulted from the purchase of SCG by UIL Holdings in 2010 and amounted to $134.9 million.

Goodwill is not amortized, but is subject to an assessment for impairment at least annually or more frequently if events occur or circumstances change that will more likely than not reduce the fair value of the reporting unit below its carrying amount. A reporting unit is an operating segment or one level below an operating segment and is the level at which goodwill is tested for impairment.

In assessing goodwill for impairment, SCG has the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary, or step zero. If it is determined, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If SCG bypasses step zero or performs the qualitative assessment but determines that it is more likely than not that its fair value is less than its carrying amount, a quantitative two step, fair value based test is performed. Step one compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, step two is performed. Step two requires an allocation of fair value to the individual assets and liabilities using business combination accounting guidance to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than its carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense.

SCG's annual impairment testing takes place as of October 1. SCG's step zero qualitative assessment involves evaluating key events and circumstances that could affect its fair value, as well as other factors. Events and circumstances evaluated include macroeconomic conditions, industry, regulatory and market considerations, cost factors and their effect on earnings and cash flows, overall financial performance as compared with projected results and actual results of relevant prior periods, other relevant entity specific events, and events affecting SCG.

SCG's step one impairment testing includes various assumptions, primarily the discount rate, which is based on an estimate of the marginal, weighted average cost of capital, and forecasted cash flows. SCG tests the reasonableness of the conclusions of the step one impairment testing using a range of discount rates and a range of assumptions for long term cash flows.

SCG had no impairment of goodwill in 2019 and 2018 as a result of its impairment testing.

Property, Plant and Equipment

The cost of additions to property, plant and equipment and the cost of renewals and betterments are capitalized. Costs consist of labor, materials, services and certain indirect construction costs, including allowance for funds used during construction (AFUDC). The costs of current repairs, major maintenance projects and minor replacements are charged to appropriate operating expense accounts as incurred. The original cost of utility property, plant and equipment retired or otherwise disposed of and the cost of removal, less salvage, are charged to the accumulated provision for depreciation.

SCG accrues for estimated costs of removal for certain of their plant-in-service. Such removal costs are included in the approved rates used to depreciate these assets. At the end of the service life of the applicable assets, the accumulated depreciation in excess of the historical cost of the asset provides for the estimated cost of removal. In accordance with ASC 980 "Regulated Operations," the accrued costs of removal have been recorded as a regulatory liability.

SCG's property, plant and equipment as of December 31, 2019 and 2018 were comprised as follows:

	2019	2018
	(In Thousands)	
Gas distribution plant	$ 950,061	$ 891,318
Software	35,932	32,892
Land	3,748	3,748
Building and improvements	27,385	26,387
VIE	41,225	22,528
Other plant	43,216	39,056
Total property, plant & equipment	1,101,568	1,015,929
Less accumulated depreciation	295,093	267,932
	806,475	747,997
Construction work in progress	19,236	25,299
Net property, plant & equipment	$ 825,711	$ 773,296

Allowance for Funds Used During Construction

In accordance with the uniform systems of accounts, SCG capitalizes AFUDC, which represents the approximate cost of debt and equity capital devoted to plant under construction. The portion of the allowance applicable to borrowed funds is presented as interest expense, net and the portion of the allowance applicable to equity funds are presented as other income in the Statement of Income. Although the allowance does not represent current cash income, it has historically been recoverable under the ratemaking process over the service lives of the related properties. Weighted-average AFUDC rates for 2019 and 2018 were 2.60% and 2.16% respectively. The portion of the allowance applicable to equity funds for 2019 and 2018 was immaterial.

Depreciation

Provisions for depreciation on utility plant for book purposes are computed on a straight-line basis using composite rates based on the estimated service lives of the various classes of assets. For utility plant other than software, service lives are determined by independent depreciation consultants and subject to review and approval by PURA. Software service life is based upon management's estimate of useful life. The aggregate annual provisions for depreciation for each of the years 2019 and 2018 were approximately $38.1 million and $29.6 million, respectively, or approximately 3.6% and 3.1%, respectively, of the original cost of depreciable property.

Impairment of Long-Lived Assets and Investments

ASC 360 "Property, Plant, and Equipment" requires the recognition of impairment losses on long-lived assets when the book value of an asset exceeds the sum of the expected future undiscounted cash flows that result from the use of the asset and its eventual disposition. If impairment arises, then the amount of any impairment is measured based on discounted cash flows or estimated fair value.

ASC 360 also requires that rate-regulated companies recognize an impairment loss when a regulator excludes all or part of a cost from rates, even if the regulator allows the company to earn a return on the remaining costs allowed. Under this standard, the probability of recovery and the recognition of regulatory assets under the criteria of ASC 980 must be assessed on an ongoing basis. As discussed in the description of ASC 980 in this Note (A) under "Regulatory Accounting", determination that certain regulatory assets no longer qualify for accounting as such could have a material impact on the financial condition SCG. At December 31, 2019, SCG did not have any assets that were impaired under this standard.

Unrestricted cash and temporary cash investments

SCG considers all of its highly liquid debt instruments with an original maturity of three months or less at the date of purchase to be unrestricted cash and temporary cash investments.

Restricted Cash

SCG's restricted cash, which primarily relates to its VIE, has been withheld by SCG and will remain in place until the verification of fulfillment of contractor obligations. SCG's restricted cash balances are included in other long-term assets on the balance sheet. SCG's restricted cash at December 31, 2019 and 2018 totaled $0.5 million and $0.1 million, respectively.

Accounts receivable and unbilled revenues

Accounts receivable at December 31, 2019 and 2018 include unbilled revenues of $21.8 million and $22.6 million, respectively and are shown net of an allowance for doubtful accounts of $1.7 million and $0.8 million for 2019 and 2018, respectively. Accounts receivable do not bear interest, although late fees may be assessed.

Unbilled revenues represent estimates of receivables for products and services provided but not yet billed. The estimates are determined based on various assumptions, such as current month energy load requirements, billing rates by customer classification and weather. Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

The allowance for doubtful accounts is management's best estimate of the amount of probable credit losses in the existing accounts receivable, determined based on experience. Each month, SCG reviews the allowance for doubtful accounts and past due accounts by age. When management believes that a receivable will not be recovered, the account balance is charged off against the allowance. Changes in assumptions about input factors and customer receivables, which are inherently uncertain and susceptible to change from period to period, could significantly affect the allowance for doubtful accounts estimates.

Leases

SCG determines if an arrangement is a lease at inception. SCG classifies a lease as a finance lease if it meets any one of specified criteria that in essence transfers ownership of the underlying asset to SCG by the end of the lease term. If a lease does not meet any of those criteria, SCG classifies it as an operating lease. On the balance sheets, SCG includes, for operating leases: "Operating lease right-of-use (ROU) assets", and "Operating lease liabilities (current and non-current)"; and for finance leases: finance lease ROU assets in "Other assets," and liabilities in "Other current liabilities" and "Other liabilities."

ROU assets represent SCG's right to use an underlying asset for the lease term and lease liabilities represent our obligation to make lease payments arising from the lease. SCG recognizes lease ROU assets and liabilities at commencement of an arrangement based on the present value of lease payments over the lease term. Most of SCG's leases do not provide an implicit rate, so SCG uses its incremental borrowing rate based on information available at the lease commencement date to determine the present value of future payments. A lease ROU asset also includes any lease payments made at or before commencement date, minus any lease incentives received, and includes initial direct costs incurred. SCG does not record leases with an initial term of 12 months or less on the balance sheet, for all classes of underlying assets, and SCG recognizes lease expense for those leases on a straight-line basis over the lease term. SCG includes variable lease payments that depend on an index or a rate in the ROU asset and lease liability measurement based on the index or rate at the commencement date, or upon a modification. SCG does not include variable lease payments that do not depend on an index or a rate in the ROU asset and lease liability measurement. A lease term includes options to extend or terminate the lease when it is reasonably certain that we will exercise that option. SCG recognizes lease (rent) expense for operating lease payments on a straight-line basis over the lease term, or the amount eligible for recovery under SCG's rate plan. SCG amortizes finance lease ROU assets on a straight-line basis over the lease term and recognize interest expense based on the outstanding lease liability.

SCG has lease agreements with lease and non-lease components, and account for lease components and associated non-lease components together as a single lease component, for all classes of underlying assets.

Gas in storage

Natural gas in storage is stored in both self-owned and third-party owned underground storage facilities. This gas is recorded as inventory. Injections of inventory into storage are priced at the market purchase cost at the time of injection, and withdrawals of working gas from storage are priced at the weighted-average cost in storage. SCG continuously monitors the weighted-average cost of gas value to ensure it remains at the lower of cost and net realizable value.

Materials and supplies

Materials and supplies inventories are used for construction of new facilities and repairs of existing facilities. The inventories are carried and withdrawn at lower of cost and net realizable value.

Other Investments

The SCG's other investments consist of noncurrent investments available for sale, which primarily consist of money market funds.

Asset Removal Costs

SCG meets the requirements concerning accounting for regulated operations, and recognizes a regulatory liability, for the difference between removal costs collected in rates and actual costs incurred. SCG classifies those amounts as asset removal costs.

Asset Retirement Obligations

The fair value of the liability for an asset retirement obligation (ARO) and/or a conditional ARO is recorded in the period in which it is incurred and the cost is capitalized by increasing the carrying amount of the related long-lived asset. The liability is adjusted to its present value periodically over time, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement, the obligation is settled either at its recorded amount or a gain or a loss is incurred. Any timing differences between rate recovery and depreciation expense are deferred as either a regulatory asset or a regulatory liability.

The term conditional ARO refers to an entity's legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. If an entity has sufficient information to reasonably estimate the fair value of the liability for a conditional ARO, it must recognize that liability at the time the liability is incurred.

SCG's ARO, including estimated conditional AROs, consist primarily of obligations related to the removal or retirement of asbestos, polychlorinated biphenyl contaminated equipment, gas pipeline and cast iron gas mains. The long-lived assets associated with the AROs are gas storage property, distribution property and other property.

ARO activity for 2019 and 2018 is as follows:

	2019	2018
	(In Thousands)	
Balance as of January 1	$ 12,264	$ 12,089
Liabilities settled during the year	(474)	(460)
Accretion	644	635
Balance as of December 31	$ 12,434	$ 12,264

Income Taxes

In accordance with ASC 740 "Income Taxes," SCG has provided deferred taxes for all temporary book-tax differences using the liability method. The liability method requires that deferred tax balances be adjusted to reflect enacted future tax rates that are anticipated to be in effect when the temporary differences reverse. In accordance with generally accepted accounting principles for regulated industries, SCG has established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences.

Under ASC 740, SCG may recognize the tax benefit of an uncertain tax position only if management believes it is more likely than not that the tax position will be sustained on examination by the taxing authority based upon the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based upon the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. SCG's policy is to recognize interest accrued and penalties associated with uncertain tax positions as a component of operating expense. See – Note (E), "Income Taxes" for additional information.

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Tax Act) was signed into law. The Tax Act contains significant changes to the federal tax structure, including among other things, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017. PURA instituted proceedings in Connecticut to review and address the implications associated with the Tax Act on the utilities providing service in the state and rendered a final decision in Docket No. 18-01-15 on January 23, 2019. PURA directed SCG to establish a regulatory liability in the amount of the income tax expense to be returned to customers and propose a method of returning such amount to customers in its next rate case filing.

Pension and Other Postretirement Benefits

SCG accounts for pension plan costs and other postretirement benefits, consisting principally of health care, prescription drug and life insurance, in accordance with the provisions of ASC 715 "Compensation - Retirement Benefits." See Note (F), "Pension and Other Benefits".

Adoption of New Accounting Pronouncements

<u>Leases</u>

In February 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Codification (ASC) Topic 842, "Leases", with subsequent amendments issued in 2018. The new leases guidance affects all companies and organizations that lease assets, and requires them to record on their balance sheet ROU assets and lease liabilities for the rights and obligations created by those leases. Under ASC 842, a lease is an arrangement that conveys the right to control the use of an identified asset for a period of time in exchange for consideration. The new guidance retains a distinction between finance leases and operating leases, while requiring companies to recognize both types of leases on their balance sheet. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the criteria for distinguishing between capital leases and operating leases in legacy U.S. GAAP - ASC 840. Lessor accounting remains substantially the same as ASC 840, but with some targeted improvements to align lessor accounting with the lessee accounting model and with the revised revenue recognition guidance under ASC 606. The new standard and amendments require new qualitative and quantitative disclosures for both lessees and lessors.

SCG adopted ASC 842 effective January 1, 2019, and elected the optional transition method under which the standard was initially applied on that date without adjusting amounts for prior periods, which SCG continues to present in accordance with ASC 840, including related disclosures. SCG recorded the cumulative effect of applying the new leases guidance as an adjustment to beginning retained earnings. In connection with the adoption, SCG:

- did not elect the package of three practical expedients available under the transition provisions which would have allowed them to not reassess: (i) whether expired or existing contracts were or contained leases, (ii) the lease classification for expired or existing leases, and (iii) whether previously capitalized initial direct costs for existing leases would qualify for capitalization under ASC 842.
- used hindsight for determining the lease term and assessing the likelihood that a lease purchase option will be exercised in applying the new leases guidance.
- did not separate lease and associated non-lease components for transitioned leases, but instead are accounting for them together as a single lease component.

In March 2019, the FASB issued additional amendments to ASC 842 for minor codification improvements, which SCG early applied effective January 1, 2019, with no material effect to its consolidated results of operations, financial position and cash flows.
The cumulative effects of the changes to SCG's consolidated balance sheet as of January 1, 2019, were as follows:

	Balance at December 31, 2018	Adjustment Due to Topic 842	Balance at January 1, 2019
(In Thousands)			
Assets			
Operating lease right of use assets	$ -	$ 1,117	$ 1,117
Liabilities			
Operating lease liabilities	$ -	$ 1,117	$ 1,117

SCG's adoption did not change the classification of lease-related expenses in its statements of income, and SCG does not expect significant changes to its pattern of expense recognition. As a result, the adoption is not expected to materially affect SCG's cash flows. Refer to Note (H) "Leases" for further details.

<u>Reclassification of certain tax effects from accumulated other comprehensive income</u>

In February 2018, the FASB issued ASU 2018-02 "Income Statement-Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income" which contains amendments to address a narrow-scope financial reporting issue that arose as a consequence of the Tax Cuts and Jobs Act of 2017 (the Tax Act) enacted on December 22, 2017 by the U.S. federal government. Under current guidance, the adjustment of deferred taxes for the effect of a change in tax laws or rates is required to be included in income from continuing operations, thus the associated tax effects of items within accumulated other comprehensive income (AOCI) (referred to as stranded tax effects) do not reflect the appropriate tax rate. The amendments allow a reclassification from AOCI to retained earnings for stranded tax effects resulting from the Tax Act. As a result, the amendments eliminate the stranded tax effects resulting from the Tax Act and will improve the usefulness of information reported to financial statement users. The amendments only relate to the reclassification of the income tax effects of the Tax Act, and do not affect the underlying guidance that requires the effect of a change in tax laws or rates to be included in income from continuing operations. SCG adopted the amendments effective January 1, 2019, which had no impact on its consolidated results of operations, financial position and cash flows.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements issued as indicated, that SCG has evaluated or is evaluating to determine their effect on its financial statements.

Simplifying the test for goodwill impairment

In January 2017, the FASB issued amendments to simplify the test for goodwill impairment, which are required for public entities and certain other entities that have goodwill reported in their financial statements. The amendments simplify the subsequent measurement of goodwill by eliminating Step 2 from the goodwill impairment test, which requires the valuation of assets acquired and liabilities assumed using business combination accounting guidance. Under the new guidance, an entity should perform its annual, or interim, goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; but the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. Also, an entity should consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable. Certain requirements are eliminated for any reporting unit with a zero or negative carrying amount, therefore the same impairment assessment applies to all reporting units. An entity still has the option to perform the qualitative assessment for a reporting unit to determine if the quantitative impairment test is necessary. The amendments are effective for public entities for annual and interim periods in fiscal years beginning after December 15, 2019, with the amendments applied on a prospective basis. Early adoption is allowed. SCG's adoption of the amendments on January 1, 2020, will not materially affect its consolidated results of operations, financial position, cash flows, and disclosures.

Changes to the disclosure requirements for fair value measurement and defined benefit plans

In August 2018, the FASB issued amendments related to disclosure requirements for both fair value measurement and defined benefit plans. The amendments concerning fair value measurement remove, modify and add certain disclosure requirements, in order to improve the overall usefulness of the disclosures and reduce unnecessary costs to companies to prepare the disclosures. The amendments to fair value measurement disclosures are effective for all entities for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted as specified. Certain amendments are to be applied prospectively, and all others are to be applied retrospectively. SCG's adoption of the amendments on January 1, 2020, will not materially affect its disclosures.

The amendments concerning disclosure requirements for defined benefit plans are narrow in scope and apply to all employers that sponsor defined benefit pension or other postretirement plans. They remove disclosures that are no longer considered cost beneficial, add certain new relevant disclosures and clarify specific requirements of disclosures concerning information for defined benefit pension plans. The amendments to defined benefit plan disclosures are effective for fiscal years ending after December 15, 2020. Early adoption is permitted and application is to be on a retrospective basis. SCG's adoption of the amendments on January 1, 2020, will not materially affect its disclosures.

Clarifying guidance for certain collaborative arrangements with respect to revenue recognition

The FASB issued amendments in November 2018 to clarify the interaction between the guidance for certain collaborative arrangements and the guidance applicable to ASC 606. A collaborative arrangement is a contractual arrangement under which two or more parties actively participate in a joint operating activity and are exposed to significant risks and rewards that depend on the activity's commercial success. The targeted improvements clarify that certain transactions between collaborative arrangement participants are within the scope of ASC 606 and thus subject to all of its guidance. The amendments are effective for public business entities for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted, including adoption in any interim period for which financial statements have not been issued. Retrospective application to the date of initial application of ASC 606 is required. SCG's adoption of the amendments on January 1, 2020, will not materially affect its consolidated results of operations, financial position, cash flows and disclosures.

Simplifying the accounting for income taxes

In December 2019, the FASB issued an accounting standards update that is intended to reduce complexity in accounting for income taxes. The amendments remove specific exceptions to the general principles in ASC 740, Income Taxes, eliminating the need for an entity to analyze whether the following apply in a given period: (1) exception to the incremental approach for intra-period tax allocation, (2) exceptions to accounting for basis differences when there are ownership changes in foreign investments and (3) exception in interim period income tax accounting for year-to-date losses that exceed anticipated losses. The amendments also improve financial statement preparers' application of income-tax related guidance and simplify U. S. GAAP for (1) franchise taxes that are partially based on income, (2) transactions with a government that result in a step up in the tax basis of goodwill, (3) separate financial statements of legal entities that are not subject to tax and (4) enacted changes in tax laws in interim periods. The amendments are effective for public business entities for fiscal years beginning after December 15, 2020, and interim periods within those fiscal years. Early adoption is permitted, including adoption in any interim period for which financial statements have not been issued, with adoption of all amendments in the same period. Application is on a retrospective and/or modified retrospective basis, or a prospective basis, depending on the amendment aspect. SCG expects its adoption will not materially affect its results of operations, financial position, and cash flows.

B) CAPITALIZATION

Common Stock

SCG had 1,407,072 shares of its common stock, $13.33 par value, outstanding as of December 31, 2019 and 2018.

In March 2019, SCG received a $18.0 million equity infusion from CEC in order to maintain its allowed capitalization ratio which was impacted by the long-term debt activity noted below.

Long-Term Debt

As of December 31,		**2019**		**2018**	
(Thousands)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
First mortgage bonds [(a)]	2021-2049	$ 239,000	3.88%-7.95%	$ 164,000	3.88%-7.95%
Unamortized debt (costs) premium, net		5,527		6,625	
Total Debt		**244,527**		**170,625**	
Less: debt due within one year, included in current liabilities		911		911	
Total Long-term Debt		**$ 243,616**		**$ 169,714**	

(a) The first mortgages bonds are secured by a first mortgage lien on substantially all of SCG's properties.

The estimated fair value of debt amounted to $302.5 million and $197.1 million as of December 31 2019 and 2018, respectively. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the natural gas industry and the credit ratings of the borrowers in each case. The fair value hierarchy for the fair value of debt is considered as Level 2. The expenses to issue long-term debt are deferred and amortized over the life of the respective debt issue.

On January 15, 2019, SCG issued $75 million of notes with a maturity of 2049 and interest rate of 4.42%.

Information regarding maturities and mandatory redemptions/repayments are set forth below:

	2020	2021	2022	2023	2024 & Thereafter	Total
	(In Thousands)					
Maturities:	$ -	$ 25,000	$ -	$ -	$ 214,000	$ 239,000

Under various debt agreements, SCG is required to maintain a ratio of consolidated debt to consolidated capital of not greater than 65% (debt ratio). As of December 31, 2019, SCG's debt ratio was 36%.

(C) REGULATORY PROCEEDINGS

Rates

Utilities are entitled by Connecticut statute to charge rates that are sufficient to allow them an opportunity to cover their reasonable operating and capital costs, to attract needed capital and to maintain their financial integrity, while also protecting relevant public interests.

In December 2017, PURA approved new tariffs for SCG effective January 1, 2018 for a three-year rate plan with rate increases of $1.5 million, $4.7 million and $5.0 million in 2018, 2019, and 2020, respectively. The new tariffs also include, among other things, an RDM and Distribution Integrity Management Program, earnings sharing mechanism (ESM), the amortization of certain regulatory liabilities (most notably accumulated hardship deferral balances and certain accumulated deferred income taxes) and tariff increases based on a ROE of 9.25% and approximately 52% equity level. Any dollars due to customers from the ESM will be first applied against any environmental regulatory asset balance as defined in the settlement agreement (if one exists at that time) or refunded to customers through a bill credit if such environmental regulatory asset balance does not exist.

Additionally, SCG has a purchased gas adjustment clause, approved by PURA, which enables reasonably incurred cost of gas purchases to be passed through to customers. This clause allows utilities to recover costs associated with changes in the market price of purchased natural gas, substantially eliminating exposure to natural gas price risk.

Gas Supply Arrangements

SCG satisfies its natural gas supply requirements through purchases from various producer/suppliers, withdrawals from natural gas storage capacity contracts and winter peaking supplies and resources. SCG operates diverse portfolios of gas supply, firm transportation capacity, gas storage and peaking resources. Actual reasonable gas costs incurred by SCG are passed through to customers through state regulated purchased gas adjustment mechanisms subject to regulatory review.

SCG purchases the majority of their natural gas supply at market prices under seasonal, monthly or mid-term supply contracts and the remainder is acquired on the spot market. SCG diversifies its sources of supply by amount purchased and location. SCG primarily acquires gas at various locations in the US Gulf of Mexico region, in the Appalachia region and in Canada.

SCG acquires firm transportation capacity on interstate pipelines under long-term contracts and utilizes that capacity to transport both natural gas supply purchased and natural gas withdrawn from storage to the local distribution system. Tennessee Gas Pipeline, Algonquin Gas Transmission and Iroquois Gas Transmission interconnect with SCG's distribution system and the other pipelines provide indirect services upstream of the city gates. The prices and terms and conditions of the firm transportation capacity long-term contracts for firm transportation capacity are regulated by the FERC. The actual reasonable cost of such contracts is passed through to customers through state regulated purchased gas adjustment mechanisms.

SCG acquires firm underground natural gas storage capacity using long-term contracts and fills the storage facilities with gas in the summer for subsequent withdrawal in the winter months. The storage facilities are located in Pennsylvania, New York, West Virginia and Michigan.

SCG has the rights to 100% of the Liquefied Natural Gas (LNG) stored in a LNG facility which is directly attached to its distribution system. SCG uses the LNG capacity as a winter peaking resource.

Tax Cuts and Jobs Act

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Tax Act) was signed into law. The Tax Act significantly changed the federal taxation of business entities including, among other things, implementing a federal corporate tax rate decrease from 35% to 21% for tax years beginning after December 31, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates will result in amounts previously and currently collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates. During 2018, the PURA and the FERC instituted proceedings in Connecticut to review and address the implications of the Tax Act on utilities. PURA directed SCG to establish a regulatory liability in the amount of the income tax expense to be returned to customers and propose a method of returning such amount to customers in its next rate case filing.

(D) SHORT-TERM CREDIT ARRANGEMENTS

SCG funds short-term liquidity needs through an agreement among Avangrid's regulated utility subsidiaries (the Virtual Money Pool Agreement), a bi-lateral intercompany credit agreement with Avangrid (the Bi-Lateral Intercompany Facility), a bank provided credit facility to which SCG is a party (the Avangrid Credit Facility) and other intercompany agreements with Avangrid.

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. SCG has a lending/borrowing limit of $100 million under this agreement. There was $19.3 million and $55.5 million outstanding as of December 31, 2019 and 2018, respectively, under this agreement.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $250 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. There was $1.5 million and $72.8 million outstanding under this agreement as of December 31, 2019 and 2018, respectively.

On June 29, 2018, Avangrid, Inc. and its subsidiaries, including SCG, entered into a new credit facility agreement with a syndicate of banks (Avangrid Credit Facility) that provides for maximum borrowings of up to $2.5 billion in the aggregate. This Avangrid Credit Facility replaces and supersedes the prior revolving credit facility entered into by Avangrid, Inc. and its subsidiaries on April 6, 2016, which provided maximum borrowings of up to $1.5 billion in the aggregate.

Under the Avangrid Credit Facility, SCG has a maximum sublimit of $150 million. Additionally, under the Avangrid Credit Facility, each of the borrowers, including SCG, will pay an annual facility fee that is dependent on their credit rating. The facility fees will range from 12.5 to 17.5 basis points. The maturity date for the Avangrid Credit Facility is June 29, 2024. As of December 31, 2019 and 2018, SCG did not have any outstanding borrowings under the Avangrid Credit Facility.

CNE and TPS each have a current account agreement with Avangrid whereby they can lend excess cash to Avangrid or borrow from Avangrid when they have cash funding needs to meet their obligations. Interest is charged at a rate equal to three month LIBOR plus an applicable margin and is capitalized annually. As of December 31, 2019 and 2018 TPS had $17.5 million and $10.4 million, respectively, outstanding under its agreement. CNE did not have any amounts outstanding under its agreement as of December 31, 2019 and 2018.

(E) INCOME TAXES

	Year Ended December 31, 2019	Year Ended December 31, 2018
	(In Thousands)	
Income tax expense consists of:		
Income tax provisions (benefits):		
Current		
Federal	$ (19,147)	$ 7,644
State	(3,028)	2,722
Total current	(22,175)	10,366
Deferred		
Federal	24,812	(682)
State	7,646	1,175
Total deferred	32,458	493
Total Income tax expense	$ 10,283	$ 10,859

Total income taxes differ from the amounts computed by applying the federal statutory tax rate to income before taxes. The reasons for the differences are as follows:

	Year Ended December 31, 2019	Year Ended December 31, 2018
	(In Thousands)	
Book income before income taxes	$ 40,427	$ 37,938
Computed tax at federal statutory rate	$ 8,490	$ 7,967
Increases (reductions) resulting from:		
State taxes, net of federal income tax benefits	3,648	3,078
Variable interest entity	(529)	(476)
Other items, net	(1,326)	290
Total income tax expense	$ 10,283	$ 10,859
Effective income tax rates	25.4%	28.6%

The significant portion of SCG's income tax expense, including deferred taxes, is recovered through its regulated utility rates. SCG's annual income tax expense and associated effective tax rate is impacted by differences between the timing of deferred tax temporary difference activity and deferred tax recovery. SCG's effective tax rate is also impacted by permanent differences between the book and tax treatment of certain costs.

SCG is subject to the United States federal income tax statutes administered by the IRS. SCG is a party to Avangrid, Inc.'s tax allocation agreement under which taxable subsidiaries do not pay any more taxes than they would have otherwise paid had they filed a separate company tax return, and subsidiaries generating tax losses, if any, are paid for their losses when utilized. Also pursuant to the tax allocation agreement, SCG settles its current tax liability or benefit each year directly with Avangrid, Inc.

As of December 31, 2019 and 2018, SCG did not have any gross income tax reserves for uncertain tax positions.

The following table summarizes SCG's tax years that remain subject to examination as of December 31, 2019:

Jurisdiction	*Tax years*
Federal	2014 - 2019
Connecticut	2011 - 2019

The following table summarizes SCG's deferred tax assets and liabilities as of December 31, 2019 and 2018:

	2019	**2018**
	(In Thousands)	
Property related	$ (73,411)	$ (39,984)
Unfunded future income taxes	6,533	6,228
Federal and state tax credits	7,844	4,780
Deferred tax asset on 2017 Tax Act remeasurement	10,269	7,179
Federal and state net operating loss	6,517	5,383
Post-retirement benefits, net	(3,342)	(3,260)
Other liabilities	(9,456)	(4,002)
	$ (55,045)	$ (23,676)

As of December 31, 2019, SCG had a net state credit carry forward of $7.8 million, a state net operating loss carry forward of $1.7 million and a federal net operating loss carry forward of $4.8 million. The state credits will begin to expire in 2020. As of December 31, 2018, SCG had a net state credit carry forward of $4.8 million, a state net operating loss carry forward of $0.5 million and a federal net operating loss carry forward of $4.8 million.

(F) PENSION AND OTHER POSTRETIREMENT BENEFITS

Defined Benefit Plans (the Plans)

Pension Plans

SCG has multiple qualified pension plans covering eligible union and management employees and retirees. SCG also has non-qualified supplemental pension plans for certain retirees. The union plans are all closed to new hires, and the non-union plans were closed as of December 31, 2017. SCG also has non-qualified supplemental pension plans for certain employees and retirees. The qualified pension plans are traditional defined benefit plans or cash balance plans for those hired on or after specified dates. In some cases, neither of these plans is offered to new employees and have been replaced with enhanced 401(k) plans for those hired on or after specified dates. The qualified pension plans provide benefits under a traditional defined benefit formula or cash balance formula depending on date of hire. The plans are closed to new employees hired on or after specified dates.

Employees not participating in a defined benefit plan are eligible to receive an enhanced or core 401(k) Company matching contribution.

Plan Assets

Networks' pension benefits plan assets were consolidated from three legacy master trusts to one new master trust in 2019. A consolidated trust provides for a uniform investment manager lineup and an efficient, cost effective means of allocating expenses and investment performance to each plan. The primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our risk tolerance. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. The primary means for achieving capital preservation is through diversification of the trusts' investments while avoiding significant concentrations of risk in any one area of the securities markets. Further diversification is achieved within each asset group through utilizing multiple asset managers and systematic allocation to various asset classes and providing broad exposure to different segments of the equity, fixed income and alternative investment markets.

The asset allocation policy is the most important consideration in achieving the objective of superior investment returns while minimizing risk. Networks has established target asset allocation policies within allowable ranges for its pension benefits plan assets within broad categories of asset classes made up of Return-Seeking investments and Liability-Hedging investments. Networks currently has target allocations ranging from 35%-70% for Return-Seeking assets and 34%-65% for Liability-Hedging assets. Return-Seeking assets also include investments in real estate, global asset allocation strategies and hedge funds. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

Other Postretirement Benefits Plans

SCG has plans providing other postretirement benefits for eligible employees and retirees. The plans were closed to newly-hired non-union employees at the end of 1995 and to newly-hired union employees by the end of March 2010. These benefits consist primarily of health care, prescription drug and life insurance benefits for retired employees and their dependents. For Medicare eligible non-union retirees, SCG provides a subsidy through an HRA for retirees to purchase coverage on the individual market. Medicare eligible union retirees have the option of receiving a subsidy through an HRA or paying contributions and participating in company-sponsored retiree health plans.

Plan Assets

Networks' postretirement benefits plan assets are held with trustees in multiple voluntary employees' beneficiary association (VEBA) and 401(h) arrangements and are invested among and within various asset classes to achieve sufficient diversification in accordance with its risk tolerance. This is achieved for Network's postretirement benefits plan assets through the utilization of multiple institutional mutual and money market funds, providing exposure to different segments of the fixed income, equity and short-term cash markets. Approximately 37% of the postretirement benefits plan assets are invested in VEBA and 401(h) arrangements that are not subject to income taxes with the remainder being invested in arrangements subject to income taxes.

Networks has established a target asset allocation policy within allowable ranges for postretirement benefits plan assets of 45%-65% for equity securities, 25%-45% for fixed income and 5%-25% for all other investment types. Equity investments are diversified across U.S. and non-U.S. stocks, investment styles, and market capitalization ranges. Fixed income investments are primarily invested in U.S.

bonds and may also include some non-U.S. bonds. Other asset classes, including alternative investments, are used to enhance long-term returns while improving portfolio diversification. Networks primarily minimize the risk of large losses through diversification but also through monitoring and managing other aspects of risk through quarterly investment portfolio reviews. Systematic rebalancing within target ranges increases the probability that the annualized return on investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The following table represents the change in benefit obligation, change in plan assets and the respective funded status of SCG's pension and other postretirement plans as of December 31, 2019 and 2018. Plan assets and obligations have been measured as of December 31, 2019 and 2018.

	Pension Benefits		Other Post-Retirement Benefits	
	Year Ended December 31, 2019	Year Ended December 31, 2018	Year Ended December 31, 2019	Year Ended December 31, 2018
Change in Benefit Obligation:	(In Thousands)			
Benefit obligation at beginning of year	$ 171,302	$ 180,032	$ 18,941	$ 19,693
Service cost	1,982	2,199	109	121
Interest cost	6,798	6,658	743	720
Plan participants' contributions	-	-	-	781
Actuarial (gain) loss	14,915	(7,376)	366	147
Benefits paid (including expenses)	(10,365)	(10,211)	(1,520)	(2,521)
Benefit obligation at end of year	$ 184,632	$ 171,302	$ 18,639	$ 18,941
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 110,827	$ 127,044	$ 5,429	$ 6,065
Actual return on plan assets	22,536	(8,302)	823	(312)
Plan participants' contributions	-	-	-	781
Employer contributions	6,486	2,286	419	-
Benefits paid (including expenses)	(10,332)	(10,201)	(1,520)	(1,105)
Fair value of plan assets at end of year	$ 129,517	$ 110,827	$ 5,151	$ 5,429
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ 55,115	$ 60,475	$ 13,488	$ 13,512
Amounts Recognized in the Consolidated Balance Sheet consist of:				
Non-current liabilities	$ 55,115	$ 60,475	$ 13,488	$ 13,512
Amounts Recognized as a Regulatory Asset (Liability) consist of:				
Prior service cost	$ 152	$ 911	$ 306	$ 678
Net (gain) loss	$ 31,766	$ 33,903	(2,735)	(3,030)
Total recognized as a regulatory asset (liability)	$ 31,918	$ 34,814	$ (2,429)	$ (2,352)
Information on Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:				
Projected benefit obligation	$ 184,632	$ 171,302	N/A	N/A
Accumulated benefit obligation	$ 180,190	$ 167,269	N/A	N/A
Fair value of plan assets	$ 129,517	$ 110,827	N/A	N/A
The following weighted average actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate (Qualified Plans)	3.19%	4.09%	N/A	N/A
Discount rate (Non-Qualified Plans)	3.19%	4.09%	N/A	N/A
Discount rate (Other Post-Retirement Benefits)	N/A	N/A	3.19%	4.09%
Average wage increase	3.50%	3.50%	N/A	N/A
Health care trend rate (current year pre/post-65)	N/A	N/A	6.75%/7.50%	7.00%/7.75%
Health care trend rate (2029/2027 - pre/post-65)	N/A	N/A	4.50%/4.50%	4.50%/4.50%

N/A – not applicable

SCG is allowed to defer as regulatory assets or regulatory liabilities items that would have otherwise been recorded in AOCI pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans. Amounts recognized as regulatory assets or regulatory liabilities for the years ended December 31, 2019 and 2018 are shown above.

The discount rate is the rate at which the benefit obligations could presently be effectively settled. The discount rates were determined by developing yield curves derived from a portfolio of high grade noncallable bonds with yields that closely match the duration of the expected cash flows of our benefit obligations.

The components of net periodic benefit cost are:

	Pension Benefits		Other Post-Retirement Benefits	
	Year Ended December 31, 2019	Year Ended December 31, 2018	Year Ended December 31, 2019	Year Ended December 31, 2018
	(In Thousands)			
Components of net periodic benefit cost:				
Service cost	$ 1,982	$ 2,199	$ 109	$ 121
Interest cost	6,798	6,658	743	720
Expected return on plan assets	(8,053)	(9,076)	(373)	(418)
Amortization of prior service cost	759	759	371	477
Amortization of actuarial (gain) loss	2,561	1,671	(379)	(555)
Net periodic benefit cost	$ 4,047	$ 2,211	$ 471	$ 345
Other Changes in Plan Assets and Benefit Obligations Recognized as a Regulatory Asset (Liability):				
Net (gain) loss	$ 433	$ 10,002	$ (84)	$ 878
Amortization of current year prior service (credit)/costs	-	-	-	-
Transition obligation (asset)	-	-	-	-
Amortization of prior service cost	(759)	(759)	(371)	(477)
Amortization of actuarial gain (loss)	(2,562)	(1,671)	379	555
Total recognized as regulatory asset (liability)	$ (2,888)	$ 7,572	$ (76)	$ 956
Total recognized in net periodic benefit costs and regulatory asset (liability)	$ 1,159	$ 9,783	$ 395	$ 1,301
Estimated Amortizations from Regulatory Assets (Liabilities) into Net Periodic Benefit Cost for the next 12 month period:				
Amortization of prior service (cost) credit	$ 152	$ 759	N/A	N/A
Amortization of net (gain) loss	2,274	2,565	N/A	N/A
Total estimated amortizations	$ 2,426	$ 3,324	N/A	N/A
The following actuarial weighted average assumptions were used in calculating net periodic benefit cost:				
Discount rate	4.09%	3.80%	4.09%	3.80%
Average wage increase	3.50%	3.50%	N/A	N/A
Return on plan assets	7.40%	7.40%	7.00%	7.00%
Health care trend rate (current year - pre/post-65)	N/A	N/A	7.00%/7.75%	7.50%/8.50%
Health care trend rate (2029/2027 - pre/post-65)	N/A	N/A	4.50%/4.50%	4.50%/4.50%

N/A – not applicable

SCG utilizes an alternative method to amortize prior service costs and unrecognized gains and losses. Prior service costs for both the pension and other postretirement benefits plans are amortized on a straight-line basis over the average remaining service period of participants expected to receive benefits. Unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans are amortized over the lesser of the average remaining service period or 10 years. For pension benefits, SCG does not recognize gains or losses until there is a variance in an amount equal to at least 5% of the greater of the projected benefit obligation or the market-related value of assets. For other postretirement benefits, there is no such allowance for a variance in capturing the amortization of unrecognized gains and losses.

The expected long-term rate of return on plan assets assumption was developed based on a review of long-term historical returns for the major asset classes, the target asset allocations, and the effect of rebalancing of plan assets. The analysis considered current capital market conditions and projected conditions. SCG amortizes unrecognized actuarial gains and losses over ten years from the time they are incurred as required by the PURA.

A one percentage point change in the assumed health care cost trend rate would have the following effects:

	1% Increase	1% Decrease
	(In Thousands)	
Aggregate service and interest cost components	$ 327	$ (285)
Accumulated post-retirement benefit obligation	$ 6,372	$ (5,305)

Contributions

The funding policy for the Plans is to make annual contributions that satisfy the minimum funding requirements of ERISA but that do not exceed the maximum deductible limits of the Internal Revenue Code. These amounts are determined each year as a result of an actuarial valuation of the Plans. SCG currently expects to make pension contributions of approximately $6.0 million in 2020. Such contribution levels will be adjusted, if necessary, based on actuarial calculations.

Estimated Future Benefit Payments

Expected benefit payments and Medicare Prescription Drug Improvement and Modernization Act of 2003 subsidy receipts reflecting future service as of December 31, 2019 consisted of:

Year	Pension Benefits	Benefits	Subsidy
		(In Thousands)	
2020	$ 10,340	$ 1,623	$ 131
2021	$ 10,325	$ 1,489	$ 108
2022	$ 10,484	$ 1,383	$ 93
2023	$ 10,603	$ 1,308	$ 81
2024	$ 10,847	$ 1,226	$ 74
2025-2029	$ 54,789	$ 5,520	$ 357

The fair values of the Plans' assets as of December 31, 2019, disclosed below, reflect only the assets attributable to SCG's portion of the total assets held in the master trust.

	Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
December 31, 2019		(In Thousands)		
Pension assets				
Cash and cash equivalents	$ -	$ 1,087	$ -	$ 1,087
Registered investment companies	19,318	-	-	19,318
Common collective trusts	-	87,617	-	87,617
	$ 19,318	$ 88,704	$ -	108,022
Other investments measured at net asset value				21,495
TOTAL				$ 129,517
OPEB assets				
Cash and cash equivalents	$ -	$ 150	$ -	$ 150
Registered investment companies	5,001	-	-	5,001
TOTAL	$ 5,001	$ 150	$ -	$ 5,151
December 31, 2018				
Pension assets				
Mutual funds	$ -	$ 110,827	$ -	$ 110,827
OPEB assets				
Mutual funds	5,429	-	-	5,429
Fair value of plan assets, December 31, 2018	$ 5,429	$ 110,827	$ -	$ 116,256

As of December 31, 2019, the determination of the fair values of our Plans' Level 2 assets was as follows:

- Cash and cash equivalents - proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- Common collective trusts - primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market. Other investments measured at net asset value (NAV) – alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

As of December 31, 2018, the determination of fair values of the Level 2 co-mingled mutual funds were based on the Net Asset Value (NAV) provided by the managers of the underlying fund investments and the unrealized gains and losses. The NAV provided by the managers typically reflect the fair value of each underlying fund investment.

Defined Contribution Retirement Plans/401(k)

SCG employees are eligible to participate in the UIL Holdings Corporation 401(k) Employee Stock Ownership Plan. Employees may defer a portion of the compensation and invest in various investment alternatives. Matching contributions are made in the form of cash which is subsequently invested in various investment alternatives offered to employees. The matching expense for 2019 and 2018 was $1.0 million and $0.8 million, respectively.

(G) RELATED PARTY TRANSACTIONS

Inter-company Transactions

In March 2019, SCG received an equity infusion from CEC. See Note (B) "Capitalization."

SCG receives various administrative and management services from and enters into certain inter-company transactions with UIL Holdings and its subsidiaries. For the year ended December 31, 2019, SCG recorded inter-company expenses of $16.1 million. Costs of the services that are allocated amongst SCG and other of UIL Holdings' regulated subsidiaries are settled periodically by way of inter-company billings and wire transfers and are included in Accounts receivable from affiliates and Accounts payable to affiliates in the accompanying balance sheets.

Dividends/Capital Contributions

For the year ended December 31, 2019, SCG did not accrue any dividends to CEC. For the year ended December 31, 2018, SCG accrued $25 million in dividends to CEC. In addition, CNE accrued $6.5 million in dividends to URI for the year ended December 31, 2018 to settle an intercompany loan.

(H) LEASES

SCG has operating leases for land, office buildings, facilities, and certain equipment. SCG does not have any finance leases. Certain of SCG's lease agreements include rental payments adjusted periodically for inflation or are based on other periodic input measures. SCG's leases do not contain any material residual value guarantees or material restrictive covenants. SCG's leases have remaining lease terms 1.67 years, some of which may include options to extend the leases, and some of which may include options to terminate. SCG considers extension or termination options in the lease term if it is reasonably certain SCG will exercise the option.

The components of lease cost and other information related to leases were as follows:

(In Thousands)		Year Ended December 31, 2019
Operating lease cost	$	1,850

(In Thousands)		As of December 31, 2019
Operating Leases		
Operating lease right of use assets	$	592
Operating lease liabilities, current	$	601
Operating lease liabilities, long-term		335
Total operating lease liabilities	$	936
Weighted-average Remaining Lease Term (years):		
Operating leases		1.67
Weighted-average Discount Rate:		
Operating leases		3.06%

Supplemental cash flow information related to leases was as follows:

(In Thousands)		Year Ended December 31, 2019
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$	290

As of December 31, 2019, maturities of lease liabilities were as follows:

(In Thousands)		Operating Leases
Year ending December 31,		
2020	$	85
2021		820
2022		14
2023		14
2024		14
Thereafter		33
Total lease payments		980
Less: imputed interest		44
Total	$	936

Most of SCG's leases do not provide an implicit rate in the lease; thus SCG uses its incremental borrowing rate based on the information available at the commencement date in determining the present value of lease payments. SCG used the incremental borrowing rate on January 1, 2019, for operating leases that commenced prior to that date.

Comparative 2018 Leases Disclosures

Operating leases, which are charged to operating expense, consist principally of leases for office space and facilities. The future minimum lease payments under these operating leases are estimated to be as follows:

	(In Thousands)
2019	1,650
2020	1,650
2021	2,236
2022	1,179
2023	902
2024 - after	3,077
	$ 10,694

(I) COMMITMENTS AND CONTINGENCIES

In the ordinary course of business, SCG is involved in various proceedings, including legal, tax, regulatory and environmental matters, which require management's assessment to determine the probability of whether a loss will occur and, if probable, an estimate of probable loss. When assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated, SCG accrues a reserve and discloses the reserve and related matter. SCG discloses material matters when losses are probable but for which an estimate cannot be reasonably estimated or when losses are not probable but are reasonably possible. Subsequent analysis is performed on a periodic basis to assess the impact of any changes in events or circumstances and any resulting need to adjust existing reserves or record additional reserves. However, given the inherent unpredictability of these legal and regulatory proceedings, SCG cannot assure you that it's assessment of such proceedings will reflect the ultimate outcome, and an adverse outcome in certain matters could have a material adverse effect on its results of operations or cash flows.

Environmental Matters

In complying with existing environmental statutes and regulations and further developments in areas of environmental concern, including legislation and studies in the fields of water quality, hazardous waste handling and disposal, toxic substances, climate change and electric and magnetic fields, we may incur substantial capital expenditures for equipment modifications and additions, monitoring equipment and recording devices, as well as additional operating expenses. The total amount of these expenditures is not now determinable. Significant environmental issues known to SCG at this time are described below.

Site Decontamination, Demolition and Remediation Costs

SCG owns or has previously owned properties where Manufactured Gas Plants (MGPs) had historically operated. MGP operations have led to contamination of soil and groundwater with petroleum hydrocarbons, benzene and metals, among other things, at these properties, the regulation and cleanup of which is regulated by the federal Resource Conservation and Recovery Act as well as other federal and state statutes and regulations. SCG has or had an ownership interest in one or more such properties contaminated as a result of MGP-related activities. Under the existing regulations, the cleanup of such sites requires state and at times, federal, regulators' involvement and approval before cleanup can commence. In certain cases, such contamination has been evaluated, characterized and remediated. In other cases, the sites have been evaluated and characterized, but not yet remediated. Finally, at some of these sites, the scope of the contamination has not yet been fully characterized; no liability was recorded in respect of these sites as of December 31, 2019 and no amount of loss, if any, can be reasonably estimated at this time. In the past, SCG has received approval for the recovery of MGP-related remediation expenses from customers through rates and will seek recovery in rates for ongoing MGP-related remediation expenses for all of their MGP sites.

SCG owns properties on Housatonic Avenue in Bridgeport, and on Chapel Street in New Haven, which are former MGP sites. Costs associated with the remediation of the sites could be significant and will be subject to a review by PURA as to whether these costs are recoverable in rates. As of December 31, 2019, SCG reserved $46.2 million related to the property located in New Haven which was offset by a regulatory asset. Additionally, as of December 31, 2019, SCG has determined that remediation of the property in Bridgeport is not probable and therefore not reserved.

(J) FAIR VALUE MEASUREMENTS

As required by ASC 820, financial assets and liabilities are classified in their entirety, based on the lowest level of input that is significant to the fair value measurement. SCG's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following tables set forth the fair value SCG's financial assets and liabilities, other than pension benefits and OPEB, as of December 31, 2019 and December 31, 2018.

	Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(In Thousands)			
December 31, 2019				
Noncurrent investments	$ 9,832	$ -	$ -	$ 9,832
Total fair value assets, December 31, 2019	$ 9,832	$ -	$ -	$ 9,832
December 31, 2018				
Noncurrent investments	$ 9,141	$ -	$ -	$ 9,141
Total fair value assets, December 31, 2018	$ 9,141	$ -	$ -	$ 9,141

(K) SUBSEQUENT EVENTS

In March 2020 the World Health Organization declared a global pandemic due to the outbreak of COVID-19. SCG is assessing the possible impacts to its business and financial results.

Central Maine Power Company
and Subsidiaries
Consolidated Financial Statements
For the Years Ended December 31, 2019 and 2018

Central Maine Power Company
and Subsidiaries

Index

KPMG LLP
345 Park Avenue
New York, NY 10154-0102

Independent Auditors' Report

The Shareholder and Board of Directors
Central Maine Power Company and Subsidiaries:

We have audited the accompanying consolidated financial statements of Central Maine Power Company and Subsidiaries, which comprise the consolidated balance sheets as of December 31, 2019 and 2018, and the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for the years then ended, and the related notes to the consolidated financial statements.

Management's Responsibility for the Financial Statements

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

Auditors' Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Central Maine Power Company and Subsidiaries as of December 31, 2019 and 2018, and the results of their operations and their cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

KPMG LLP

New York, New York
March 31, 2020

Central Maine Power Company and Subsidiaries
Consolidated Statements of Income

As of December 31,	2019	2018
(Thousands)		
Operating Revenues	$ **819,057**	$ **847,797**
Operating Expenses		
Electricity purchased	17,162	14,543
Operations and maintenance	399,447	415,056
Depreciation and amortization	116,248	107,515
Taxes other than income taxes, net	69,725	64,917
Total Operating Expenses	**602,582**	**602,031**
Operating Income	**216,475**	**245,766**
Other income	12,095	10,318
Other deductions	(15,238)	(17,150)
Interest expense, net of capitalization	(51,433)	(53,188)
Income Before Income Tax	**161,899**	**185,746**
Income tax expense	41,922	53,824
Net Income	**119,977**	**131,922**
Less: net income attributable to noncontrolling interest	1,921	2,205
Net Income Attributable to CMP	$ **118,056**	$ **129,717**

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

Central Maine Power Company and Subsidiaries
Consolidated Statements of Comprehensive Income

As of December 31,	2019	2018
(Thousands)		
Net Income	$ **119,977**	$ **131,922**
Other Comprehensive Income, Net of Tax		
Amortization of pension for nonqualified plans, net of income taxes	—	82
Unrealized gain (loss) during the year on derivatives qualified as cash flow hedges, net of income taxes:		
Unrealized gain (loss) during period on derivatives qualified as hedges	71	(315)
Reclassification adjustment for loss included in net income	211	10
Reclassification adjustment for loss on settled cash flow treasury hedges	714	1,562
Other Comprehensive Income, Net of Tax	**996**	**1,339**
Comprehensive Income	**120,973**	**133,261**
Less:		
Comprehensive income attributable to noncontrolling interests	1,921	2,205
Comprehensive Income Attributable to CMP	$ **119,052**	$ **131,056**

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

Central Maine Power Company and Subsidiaries
Consolidated Balance Sheets

As of December 31,	2019	2018
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$ 15,287	$ 16,126
Accounts receivable and unbilled revenues, net	207,049	198,935
Accounts receivable from affiliates	896	1,776
Notes receivable from affiliates	23,020	12,700
Materials and supplies	18,788	17,103
Prepayments and other current assets	9,822	41,066
Income tax receivable	22,996	—
Regulatory assets	14,818	31,414
Total Current Assets	**312,676**	**319,120**
Utility plant, at original cost	4,469,740	4,300,278
Less accumulated depreciation	(1,151,685)	(1,067,288)
Net Utility Plant in Service	**3,318,055**	**3,232,990**
Construction work in progress	262,119	129,985
Total Utility Plant	**3,580,174**	**3,362,975**
Operating lease right-of-use assets	16,672	—
Other property and investments	856	1,222
Regulatory and Other Assets		
Regulatory assets	429,288	393,225
Goodwill	324,938	324,938
Other	34,531	66,964
Total Regulatory and Other Assets	**788,757**	**785,127**
Total Assets	**$ 4,699,135**	**$ 4,468,444**

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

Central Maine Power Company and Subsidiaries
Consolidated Balance Sheets

As of December 31,	2019	2018
(Thousands)		
Liabilities		
Current Liabilities		
Current portion of debt	$ 513	$ 151,800
Notes payable to affiliates	705	172
Accounts payable and accrued liabilities	177,797	146,065
Accounts payable to affiliates	8,321	38,415
Interest accrued	23,775	17,941
Taxes accrued	2,795	2,953
Operating lease liabilities	753	—
Other current liabilities	56,223	59,417
Regulatory liabilities	26,794	31,067
Total Current Liabilities	**297,676**	**447,830**
Regulatory and Other Liabilities		
Regulatory liabilities	424,604	419,734
Other Non-current liabilities		
Deferred income taxes	533,158	502,943
Pension and other postretirement	191,732	192,283
Operating lease liabilities	16,306	—
Other	35,703	39,245
Total Regulatory and Other Liabilities	**1,201,503**	**1,154,205**
Non-current debt	1,185,635	949,032
Total Liabilities	**2,684,814**	**2,551,067**
Commitments and Contingencies		
Redeemable Preferred Stock	**571**	**571**
CMP Common Stock Equity		
Common stock ($5 par value, 80,000,000 shares authorized and 31,211,471 shares outstanding at December 31, 2019 and 2018)	156,057	156,057
Additional paid-in capital	764,170	764,087
Retained earnings	1,067,514	974,709
Accumulated other comprehensive loss	(3,723)	(3,958)
Total CMP Common Stock Equity	**1,984,018**	**1,890,895**
Noncontrolling interest	29,732	25,911
Total Equity	**2,013,750**	**1,916,806**
Total Liabilities and Equity	**$ 4,699,135**	**$ 4,468,444**

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

Central Maine Power Company and Subsidiaries
Consolidated Statements of Cash Flows

Years Ended December 31,		2019		2018
(Thousands)				
Cash Flow from Operating Activities:				
Net income	$	**119,977**	$	**131,922**
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation and amortization		116,248		107,515
Regulatory assets/liabilities amortization		3,234		(2,109)
Regulatory assets/liabilities carrying cost		1,619		1,082
Amortization of debt issuance costs		(154)		602
Deferred taxes		31,308		32,464
Pension cost		16,220		21,735
Stock-based compensation		83		83
Accretion expenses		47		45
Gain on disposal of assets		(558)		(1,376)
Other non-cash Items		(1,895)		(404)
Changes in operating assets and liabilities:				
Accounts receivable, from affiliates, and unbilled revenues		(7,234)		1,995
Inventories		(1,685)		(1,754)
Accounts payable, to affiliates, and accrued liabilities		(2,751)		(69,904)
Taxes accrued		6,019		29,069
Other assets/liabilities		16,803		(37,854)
Regulatory assets/liabilities		(52,025)		9,232
Net Cash Provided by Operating Activities		**245,256**		**222,343**
Cash Flow from Investing Activities:				
Utility plant additions		(315,000)		(247,616)
Contributions in aid of construction		12,710		13,650
Notes receivable from affiliates		(10,320)		15,636
Proceeds from sale of utility plant		1,700		2,399
Investments, net		396		—
Net Cash Used in Investing Activities		**(310,514)**		**(215,931)**
Cash Flow from Financing Activities:				
Non-current note issuance		239,020		60,000
Repayments of non-current debt		(151,183)		(1,183)
Repayments of other short-term debt, net		—		(454)
Repayments of capital leases		(851)		(662)
Proceeds of short term debt - affiliates		533		(261)
Contributions from noncontrolling interest		1,900		12,178
Dividends paid		(25,000)		(75,000)
Net Cash Provided by (Used in) Financing Activities		**64,419**		**(5,382)**
Net (Decrease) Increase in Cash and Cash Equivalents		**(839)**		**1,030**
Cash and Cash Equivalents, Beginning of Year		**16,126**		**15,096**
Cash and Cash Equivalents, End of Year	$	**15,287**	$	**16,126**

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

Central Maine Power Company and Subsidiaries
Consolidated Statements of Changes in Equity

(Thousands, except per share amounts)	CMP Stockholder: Number of shares (*)	Common stock	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Loss	Total CMP Common Stock Equity	Non-controlling Interest	Total Common Stock Equity
Balances, December 31, 2017	**31,211,471**	**$ 156,057**	**$ 764,004**	**$ 919,992**	**$ (5,297)**	**$ 1,834,756**	**$ 11,528**	**$ 1,846,284**
Net income	—	—	—	129,717	—	129,717	2,205	131,922
Other comprehensive income, net of tax	—	—	—	—	1,339	1,339	—	1,339
Comprehensive income						—	—	133,261
Stock-based compensation	—	—	83	—	—	83	—	83
Capital contribution from parent	—	—	—	—	—	—	12,178	12,178
Common stock dividends	—	—	—	(75,000)	—	(75,000)	—	(75,000)
Balances, December 31, 2018	**31,211,471**	**156,057**	**764,087**	**974,709**	**(3,958)**	**1,890,895**	**25,911**	**1,916,806**
Adoption of accounting standards				(216)	(761)	(977)		(977)
Net income	—	—	—	118,056	—	118,056	1,921	119,977
Other comprehensive income, net of tax	—	—	—	—	996	996	—	996
Comprehensive income								120,973
Stock-based compensation	—	—	83	—	—	83	—	83
Capital contribution from parent	—	—	—	—	—	—	1,900	1,900
Preferred stock dividends	—	—	—	(35)	—	(35)	—	(35)
Common stock dividends	—	—	—	(25,000)	—	(25,000)	—	(25,000)
Balances, December 31, 2019	**31,211,471**	**$ 156,057**	**$ 764,170**	**$1,067,514**	**$ (3,723)**	**$ 1,984,018**	**$ 29,732**	**$ 2,013,750**

(*) Par value of share amounts is $5

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

Note 1. Significant Accounting Policies

Background and nature of operations: Central Maine Power Company and subsidiaries (CMP, the company, we, our, us) conduct regulated electricity transmission and distribution operations in Maine serving approximately 636,300 customers as of December 31, 2019, in a service territory of approximately 11,000 square miles with a population of approximately one million people. The service territory is located in the southern and central areas of Maine and contains most of Maine's industrial and commercial centers, including the city of Portland and the Lewiston-Auburn, Augusta-Waterville, Saco-Biddeford and Bath-Brunswick areas. We operate under the authority of the Maine Public Utilities Commission (MPUC) and are also subject to regulation by the Federal Energy Regulatory Commission (FERC).

CMP consists of the following subsidiaries: Maine Electric Power Company, Inc. (MEPCO) is a 78.3% owned subsidiary of CMP with the remaining 21.7% owned by Emera Maine (EM), which is wholly-owned by Emera, Inc. Chester SVC Partnership (the Partnership or Chester) was organized on October 9, 1990, under the Maine Uniform Partnership Act and is a general partnership between NORVARCO, a wholly-owned subsidiary of CMP, which owns 50% interest in the Partnership and Bangor Var Co., Inc., a wholly-owned subsidiary of EM, which owns the remaining 50% interest.

CMP is the principal operating utility of CMP Group, Inc. (CMP Group), a wholly-owned subsidiary of Avangrid Networks, Inc. (Networks), which is a wholly-owned subsidiary of Avangrid, Inc. (AGR), which is an 81.5% owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain.

Basis of presentation: The accompanying consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States (U.S. GAAP) and are presented on a consolidated basis, and therefore include the accounts of CMP and its consolidated subsidiaries.

All intercompany transactions and accounts have been eliminated in all periods presented.

We consider the following policies to be the most significant in understanding the judgments that are involved in preparing our consolidated financial statements:

Principles of consolidation**:** We consolidate the entities in which we have a controlling financial interest, after the elimination of intercompany transactions. We account for investments in common stock where we have the ability to exercise significant influence, but not control, using the equity method of accounting.

Revenue recognition**:** We recognize revenues when we transfer control of promised goods or services to our customers in an amount that reflects the consideration we expect to be entitled to in exchange for those goods or services. Refer to Note 4 for further details.

Regulatory accounting: We account for our regulated operations in accordance with the authoritative guidance applicable to entities with regulated operations that meet the following criteria: (i) rates are established or approved by a third-party regulator; (ii) rates are designed to recover the entity's cost of providing regulated services or products and; (iii) there is a reasonable expectation that rates are set at levels that will recover the entity's costs and be collected from customers. Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent: (i) the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates; or (ii) billings in advance of expenditures for approved regulatory programs.

Regulatory assets and liabilities are amortized and the related expense or revenue is recognized in the consolidated statements of income with the recovery or refund included in customer rates. We believe it is probable that our currently recorded regulatory assets and liabilities will be recovered or settled in future rates.

Noncontrolling interest: The noncontrolling interest represents the portion of our net income (loss), comprehensive income (loss) and net assets that is not allocable to us and is calculated based on our ownership percentage.

***Goodwill*:** Goodwill is not amortized, but is subject to an assessment for impairment performed in the fourth quarter or more frequently if events occur or circumstances change that will more likely than not reduce the fair value of the reporting unit below its carrying amount. A reporting unit is an operating segment or one level below an operating segment and is the level at which we test goodwill for impairment.

In assessing goodwill for impairment, we have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary, or step zero. If we determine, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If we bypass step zero or perform the qualitative assessment but determine that it is more likely than not that its fair value is less than its carrying amount, we perform a quantitative two step, fair value based test. Step one compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, step two is performed. Step two requires an allocation of fair value to the individual assets and liabilities using business combination accounting guidance to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than its carrying amount, we record an impairment loss as a reduction to goodwill and a charge to operating expense.

Our step zero qualitative assessment involves evaluating key events and circumstances that could affect the fair value of our reporting units, as well as other factors. Events and circumstances evaluated include macroeconomic conditions, industry, regulatory and market considerations, cost factors and their effect on earnings and cash flows, overall financial performance as compared with projected results and actual results of relevant prior periods, other relevant entity specific events, and events affecting a reporting unit.

Our step one impairment testing, and step two if required, includes various assumptions, primarily the discount rate, which is based on an estimate of a market participant's marginal, weighted average cost of capital, and forecasted cash flows. We test the reasonableness of the conclusions of our step one impairment testing using a range of discount rates and a range of assumptions for long term cash flows.

Utility plant: Utility plant is accounted for at historical cost. In cases where we are required to dismantle installations or to recondition the site on which they are located, we record the estimated cost of removal or reconditioning as an asset retirement obligation (ARO) and an equal amount is added to the carrying amount of the asset.

Development and construction of our various facilities are carried out in stages. Project costs are expensed during early stage development activities. Once we achieve certain development milestones and it is probable that we can obtain future economic benefits from a project, we capitalize salaries and wages for persons directly involved in the project, and engineering, permits, licenses, wind measurement and insurance costs. We periodically review development projects in construction for any indications of impairment.

Assets are transferred from “Construction work in progress” to “Utility plant” when they are available for service.

We determine depreciation expense for utility plant in service using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Consistent with FERC accounting requirements, we charge the original cost of utility plant retired or otherwise disposed to accumulated depreciation. Our composite rates for depreciation were 2.5% of average depreciable property for 2019 and 2.6% for 2018. We amortize our capitalized software cost, which is included in other plant, using the straight line method, based on useful lives of 5 to 15 years. Capitalized software costs were approximately $159.4 million as of December 31, 2019, and $154.6 million as of December 31, 2018. Depreciation expense was $106.7 million in 2019 and $99.0 million in 2018. Amortization of capitalized software was $9.6 million in 2019 and $8.5 million in 2018.

We charge repairs and minor replacements to operations and maintenance expense, and capitalize renewals and betterments, including certain indirect costs.

Allowance for funds used during construction (AFUDC) represents the allowed cost of capital, including a return on equity (ROE), used to finance construction projects. We record the portion of AFUDC attributable to borrowed funds as a reduction of interest expense and the portion attributable to equity as other income. AFUDC attributable to equity is a non-cash item.

Our balances of major classes of utility plant and associated useful lives are shown below as of December 31.

Utility Plant	**Estimated useful life range (years)**		**2019**		**2018**
(Thousands)					
Electric					
Transmission	4-70	$	2,500,371	$	2,423,364
Distribution	20-82		1,483,540		1,429,923
Vehicles	4-10		57,864		56,768
Other	2-54		427,965		390,223
Total Utility Plant in Service			**4,469,740**		**4,300,278**
Total accumulated depreciation			(1,151,685)		(1,067,288)
Total Net Utility Plant in Service			**3,318,055**		**3,232,990**
Construction work in progress			262,119		129,985
Total Utility Plant		**$**	**3,580,174**	**$**	**3,362,975**

Electric plant includes capital leases of $7.0 million for 2019 and $45.0 million for 2018. Related accumulated depreciation at December 31 was $2.1 million for 2019 and $38.4 million for 2018.

Leases: We determine if an arrangement is a lease at inception. We classify a lease as a finance lease if it meets any one of specified criteria that in essence transfers ownership of the underlying asset to us by the end of the lease term. If a lease does not meet any of those criteria, we classify it as an operating lease. On our consolidated balance sheets, we include, for operating leases: "Operating lease right-of-use (ROU) assets" and "Operating lease liabilities (current and non-current)"; and for finance leases: finance lease ROU assets in "Other assets" and liabilities in "Other current liabilities" and "Other liabilities."

ROU assets represent our right to use an underlying asset for the lease term and lease liabilities represent our obligation to make lease payments arising from the lease. We recognize lease ROU assets and liabilities at commencement of an arrangement based on the present value of lease payments over the lease term. Most of our leases do not provide an implicit rate, so we use our incremental borrowing rate based on information available at the lease commencement date to determine the present value of future payments. A lease ROU asset also includes any lease payments made at or before commencement date, minus any lease incentives received, and includes initial direct costs incurred. We do not record leases with an initial term of 12 months or less on the balance sheet, for all classes of underlying assets, and we recognize lease expense for those leases on a straight-line basis over the lease term. We include variable lease payments that depend on an index or a rate in the ROU asset and lease liability measurement based on the index or rate at the commencement date, or upon a modification. We do not include variable lease payments that do not depend on an index or a rate in the ROU asset and lease liability measurement. A lease term includes options to extend or terminate the lease when it is reasonably certain that we will exercise that option. We recognize lease (rent) expense for operating lease payments on a straight-line basis over the lease term, or we recognize the amount eligible for recovery under our rate plan, such as actual amounts paid. We amortize finance lease ROU assets on a straight-line basis over the lease term and recognize interest expense based on the outstanding lease liability.

We have lease agreements with lease and non-lease components, and account for lease components and associated nonlease components together as a single lease component, for all classes of underlying assets.

Impairment of long-lived assets: We evaluate utility plant and other long-lived assets for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment evaluation is based on an undiscounted cash flow analysis at the lowest level to which cash flows of the long-lived assets or asset groups are largely independent of the cash flows of other assets and liabilities. An impairment loss is required to be recognized if the carrying amount of the asset exceeds the undiscounted future net cash flows associated with that asset.

The impairment loss to be recognized is the amount by which the carrying value of the long-lived asset exceeds the asset’s fair value, or is the result of a disallowance by the regulator. Depending on the asset, fair value may be determined by use of a discounted cash flow model, with assumptions consistent with a market participant's view of the exit price of the asset.

Fair value measurement: 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 as of the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place in either the principal market for the asset or liability, or, in the absence of a principal market, in the most advantageous market for the asset or liability.

The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest. A fair value measurement of a non-financial asset takes into account a market participant’s ability to generate economic benefits by using the asset according to its highest and best use, or by selling it to another market participant that would use the asset according to its highest and best use.

We use valuation techniques that are appropriate in the circumstances and for which sufficient data is available to measure fair value, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs. All assets and liabilities for which fair value is measured or disclosed in the consolidated financial statements are categorized within the fair value hierarchy based on the transparency of input to the valuation of an asset or liability as of the measurement date.

The three input levels of the fair value hierarchy are as follows:

- Level 1 - inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability either directly or indirectly, for substantially the full term of the contract.
- Level 3 - one or more inputs to the valuation methodology are unobservable or cannot be corroborated with market data.

Categorization within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. Certain investments are not categorized within the fair value hierarchy. These investments are measured based on the fair value of the underlying investments but may not be readily redeemable at that fair value.

Derivatives and hedge accounting: Derivatives are recognized on the consolidated balance sheets at their fair value. To be a derivative under the accounting standards for derivatives and hedging, an agreement would need to have a notional and an underlying, require little or no initial net investment and could be net settled. We recognize changes in the fair value of a derivative contract in earnings unless specific hedge accounting criteria are met.

Derivatives that qualify and are designated for hedge accounting are classified as cash flow hedges. We report the gain or loss on the derivative instrument as a component of Other Comprehensive Income (OCI) and later reclassify amounts into earnings when the underlying transaction occurs. For all designated and qualifying hedges, we maintain formal documentation of the hedge and effectiveness testing in accordance with the accounting standards for derivatives and hedging. If we determine that the derivative is no longer highly effective as a hedge, we will discontinue hedge accounting prospectively. For cash flow hedges of forecasted transactions, we estimate the future cash flows of the forecasted transactions and evaluate the probability of the occurrence and timing of such transactions. If we determine it is probable that the forecasted transaction will not occur, we immediately recognize in earnings hedge gains and losses previously recorded in OCI.

Changes in conditions or the occurrence of unforeseen events could require discontinuance of the hedge accounting or could affect the timing of the reclassification of gains or losses on cash flow hedges from OCI into earnings. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately.

Cash and cash equivalents: Cash and cash equivalents include cash, bank accounts, and other highly liquid short-term investments. We consider all highly liquid investments with a maturity date of three months or less when acquired to be cash equivalents and include those investments in "Cash and cash equivalents." We classify book overdrafts representing outstanding checks in excess of funds on deposit as "Accounts payable and accrued liabilities" on our consolidated balance sheets. Changes in book overdrafts are reported in the operating activities section of the consolidated statements of cash flows.

Consolidated statements of cash flows: Supplemental disclosure of cash flow information is as follows:

		2019		2018
(Thousands)				
Cash paid during the year ended December 31:				
Interest, net of amounts capitalized	$	42,180	$	41,823
Income taxes paid (refunded), net	$	16,961	$	(8,743)

Of the income taxes paid, substantially all was paid to AGR under the tax sharing agreement. Interest capitalized was $5.3 million in 2019 and $9.2 million in 2018. Accrued liabilities for utility plant additions were $20.8 million in 2019 and $23.7 million in 2018.

***Accounts receivable and unbilled revenues, net*:** We record accounts receivable at amounts billed to customers. Accounts receivable at December 31 include unbilled revenues of $29.8 million for 2019 and $31.8 million for 2018, and are shown net of an allowance for doubtful accounts at December 31 of $9.1 million for 2019 and $7.3 million for 2018. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was $9.5 million in 2019 and $7.4 million in 2018.

Unbilled revenues represent estimates of receivables for energy provided but not yet billed. The estimates are determined based on various assumptions, including current month energy load requirements, billing rates by customer class and delivery loss factors. Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

The allowance for doubtful accounts is our best estimate of the amount of probable credit losses in our existing accounts receivable, determined based on experience. Each month we review our allowance for doubtful accounts and past due accounts by age. When we believe that a receivable will not be recovered, we charge off the account balance against the allowance. Changes in assumptions about input factors and customer receivables, which are inherently uncertain and susceptible to change from period to period, could significantly affect the allowance for doubtful accounts estimates.

Our accounts receivable include amounts due under deferred payment arrangements (DPAs). When a residential customer becomes delinquent in making payments, the MPUC requires us to allow the customer to enter into a DPA to settle the account balance. A DPA allows the account balance to be paid in installments without interest over an extended period of time, which generally exceeds one year, by negotiating mutually acceptable payment terms. Generally, we must continue to serve a customer who cannot pay an account balance in full if the customer: (i) pays a reasonable portion of the balance; (ii) agrees to pay the balance in installments; and (iii) agrees to pay future bills within 30 days until the DPA is paid in full or is otherwise considered to be delinquent. We establish provisions for uncollectible accounts by using both historical average loss percentages to project future losses and by establishing specific provisions for known credit issues. Amounts are written off when reasonable collection efforts have been exhausted. The allowance for doubtful accounts for DPAs at December 31 was $5.1 million for 2019 and $4.1 million for 2018. DPA receivable balances at December 31 were $18.6 million for 2019 and $14.8 million for 2018.

Debentures, bonds and bank borrowings: Bonds, debentures and bank borrowings are recorded as a liability equal to the proceeds of the borrowings. The difference between the proceeds and the face amount of the issued liability is treated as discount or premium and is accreted as interest expense or income over the life of the instrument. Incremental costs associated with issuance of the debt instruments are deferred and amortized over the same period as debt discount or premium. Bonds, debentures and bank borrowings are presented net of unamortized discount, premium and debt issuance costs on our consolidated balance sheets.

Inventory: Inventory comprises materials and supplies that are used for construction of new facilities and repairs of existing facilities. These inventories are carried and withdrawn at the lower of cost and net realizable value and reported on the balance sheets within "Materials and supplies."

Government grants**:** We record government grants as a reduction to utility plant to be recovered through rate base, in accordance with the prescribed FERC accounting.

In accounting for government grants related to operating and maintenance costs, we recognize amounts receivable as an offset to expenses in the consolidated statements of income in the period in which the expenses are incurred.

Asset retirement obligations**:** We record the fair value of the liability for an asset retirement obligation (ARO) and a conditional ARO in the period in which it is incurred, capitalizing the cost by increasing the carrying amount of the related long-lived asset. We adjust the liability periodically to reflect revisions to either the timing or amount of the original estimated undiscounted cash flows over time. We accrete the liability to its present value each period and depreciate the capitalized cost over the useful life of the related asset. Upon settlement we will either settle the obligation at its recorded amount or incur a gain or a loss. We defer any timing differences between rate recovery and depreciation expense and accretion as either a regulatory asset or a regulatory liability.

The term conditional ARO refers to an entity's legal obligation to perform an asset retirement activity in which the timing or method of settlement are conditional on a future event that may or may not be within the entity's control. If an entity has sufficient information to reasonably estimate the fair value of the liability for a conditional ARO, it must recognize that liability at the time the liability is incurred.

Our ARO at December 31, including our conditional ARO, was $0.9 million for 2019 and 2018. The ARO is associated with our long-lived assets and primarily consists of obligations related to removal or retirement of asbestos and polychlorinated biphenyl-contaminated equipment.

The following table reconciles the beginning and ending aggregate carrying amount of the ARO, which is recorded in Other Non-current Liabilities for the years ended December 31, 2019 and 2018.

Year Ended December 31,		**2019**		**2018**
(Thousands)				
ARO, beginning of year	$	879	$	834
Accretion expenses		47		45
ARO, end of year	**$**	**926**	**$**	**879**

We have AROs for which we have not recognized a liability because the fair value cannot be reasonably estimated due to indeterminate settlement dates, including the removal of property upon termination of an easement, right-of-way or franchise.

Accrued removal obligations: We meet the requirements concerning accounting for regulated operations and recognize a regulatory liability for the difference between removal costs collected in rates and actual costs incurred. We classify those amounts as accrued removal obligations.

Environmental remediation liability: In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. We record our environmental liabilities on an undiscounted basis. Our environmental liability accruals are expected to be paid through the year 2054.

Post-employment and other employee benefits: We sponsor defined benefit pension plans that cover the majority of our employees. We also provide health care and life insurance benefits through various postretirement plans for eligible retirees.

We evaluate our actuarial assumptions on an annual basis and consider changes based on market conditions and other factors. All of our qualified defined benefit plans are funded in amounts calculated by independent actuaries, based on actuarial assumptions proposed by management.

We account for defined benefit pension or other postretirement plans, recognizing an asset or liability for the overfunded or underfunded plan status. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. We reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in OCI, as management believes it is probable that such items will be recoverable through the ratemaking process. We use a December 31st measurement date for our benefits plans.

We amortize prior service costs for both the pension and other postretirement benefits plans on a straight-line basis over the average remaining service period of participants expected to receive benefits. Unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans are amortized over the average remaining service period or 10 years. Our policy is to calculate the expected return on plan assets using the market-related value of assets. We determine that value by recognizing the difference between actual returns and expected returns over a five-year period.

Income tax: AGR, the parent company of Networks, files a consolidated federal income tax return and various state income tax returns, some of which are unitary as required or permitted, including all of the activities of its subsidiaries. Each subsidiary company is treated as a member of the consolidated group and determines its current and deferred taxes based on the separate return with benefits for loss method. As a member, CMP settles its current tax liability or benefit each year directly with AGR pursuant to a tax allocation agreement between AGR and its members.

The aggregate amount of the related party income tax receivable balance due from AGR at December 31 is $23.0 million for 2019 and $29.1 million for 2018.

We use the asset and liability method of accounting for income taxes. Deferred tax assets and liabilities reflect the expected future tax consequences, based on enacted tax laws, of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts. In accordance with U.S. GAAP for regulated industries, we have established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences. We defer investment tax credits when earned and amortize them over the estimated lives of the related assets. We also recognize the income tax consequences of intra-entity transfers of assets other than inventory when the transfer occurs.

Deferred tax assets and liabilities are measured at the expected tax rate for the period in which the asset or liability will be realized or settled, based on legislation enacted as of the balance sheet date. We charge or credit changes in deferred income tax assets and liabilities that are associated with components of OCI directly to OCI. Significant judgment is required in determining income tax provisions and evaluating tax positions. Our tax positions are evaluated under a more-likely-than-not recognition threshold before they are recognized for financial reporting purposes. We record valuation allowances to reduce deferred tax assets when it is more likely than not that we will not realize all or a portion of a tax benefit. Deferred tax assets and liabilities are classified as non-current on our consolidated balance sheets.

Positions taken or expected to be taken on tax returns, including the decision to exclude certain income or transactions from a return, are recognized in the financial statements when it is more likely than not the tax position can be sustained based solely on the technical merits of the position. The amount of a tax return position that is not recognized in the financial statements is disclosed as an unrecognized tax benefit. Changes in assumptions on tax benefits may also impact interest expense or interest income and may result in the recognition of tax penalties. Interest and penalties related to unrecognized tax benefits are recorded within “Interest expense, net of capitalization” and “Other Income” and “Other Deductions” in our consolidated statements of income.

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. In 2019, we netted our liability for uncertain tax positions against all same jurisdiction deferred tax assets, net operating losses and tax credit carryforwards. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the consolidated statements of income.

Our income tax expense, deferred tax assets and liabilities, and liabilities for unrecognized tax benefits reflect management’s best assessment of estimated current and future taxes to be paid. Significant judgments and estimates are required in determining the consolidated income tax components of the financial statements.

Stock-based compensation: Stock-based compensation represents costs related to AGR stock-based awards granted to CMP employees. We account for stock-based payment transactions based on the estimated fair value of awards reflecting forfeitures when they occur. The recognition period for these costs begins at either the applicable service inception date or grant date and continues throughout the requisite service period, or until the employee becomes retirement eligible, if earlier.

Adoption of New Accounting Pronouncements

Although we are not a public business entity, our parent company is a public business entity; therefore, we adopt new accounting standards based on the effective date for public entities as permitted.

(a) Leases

In February 2016 the Financial Accounting Standards Board (FASB) issued Accounting Standards Codification (ASC) Topic 842, *Leases*, with subsequent amendments issued in 2018. The new leases guidance affects all companies and organizations that lease assets, and requires them to record on their balance sheet ROU assets and lease liabilities for the rights and obligations created by those leases. Under ASC 842, a lease is an arrangement that conveys the right to control the use of an identified asset for a period of time in exchange for consideration. The new guidance retains a distinction between finance leases and operating leases, while requiring companies to recognize both types of leases on their balance sheet. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the criteria for distinguishing between capital leases and operating leases in legacy U.S. GAAP – ASC 840. Lessor accounting remains substantially the same as ASC 840, but with some targeted improvements to align lessor accounting with the lessee accounting model and with the revised revenue recognition guidance under ASC 606. The new standard and amendments require new qualitative and quantitative disclosures for both lessees and lessors.

We adopted ASC 842 effective January 1, 2019, and elected the optional transition method under which we initially applied the standard on that date without adjusting amounts for prior periods, which we continue to present in accordance with ASC 840, including related disclosures. We recorded the cumulative effect of applying the new leases guidance as an adjustment to beginning retained earnings. In connection with our adoption, we:

- did not elect the package of three practical expedients available under the transition provisions which would have allowed us to not reassess: (i) whether expired or existing contracts were or contained leases, (ii) the lease classification for expired or existing leases, and (iii) whether previously capitalized initial direct costs for existing leases would qualify for capitalization under ASC 842.
- elected the land easement practical expedient and did not reassess land easements that did not meet the definition of a lease prior to adoption.
- used hindsight for determining the lease term and assessing the likelihood that a lease purchase option will be exercised in applying the new leases guidance.
- did not separate lease and associated non-lease components for transitioned leases, but instead are accounting for them together as a single lease component.

In March 2019 the FASB issued additional amendments to ASC 842 for minor codification improvements, which we applied effective January 1, 2019, with no material effect to our results of operations, financial position and cash flows.

The cumulative effects of the changes to our condensed balance sheet as of January 1, 2019, were as follows:

(Thousands)	Balance at December 31, 2018	Adjustments Due to ASC 842	Balance at January 1, 2019
Assets			
Total property, plant and equipment	$ 3,362,975	$ (6,802)	$ 3,356,173
Operating lease right-of-use assets	—	16,699	16,699
Other assets	66,964	5,480	72,444
Liabilities			
Current portion of debt	151,800	898	152,698
Operating lease liabilities, current	—	729	729
Other current liabilities	59,417	(1,015)	58,402
Operating lease liabilities, long-term	—	15,934	15,934
Other non-current liabilities	39,245	(1,360)	37,885
Non-current debt	949,032	1,132	950,164
Equity			
Retained earnings	$ 974,709	$ (977)	$ 973,732

Our adoption did not change the classification of lease-related expenses in our consolidated statements of income, and we do not expect significant changes to our pattern of expense recognition. Certain contracts previously classified as lessor leases, consisting mainly of pole rental agreements, no longer meet the definition of a lease under ASC 842. As such, these contracts are accounted for under other U.S. GAAP, but there were no changes to our pattern of revenue recognition. As a result, we expect our adoption will not materially affect our cash flows. Our accounting for finance (formerly capital) leases is substantially unchanged. Refer to Note 10 for further details.

(b) Targeted improvements to accounting for hedging activities

In August 2017 the FASB issued targeted amendments with the objective to better align hedge accounting with an entity's risk management activities in the financial statements, and to simplify the application of hedge accounting. The amendments address concerns of financial statement preparers over difficulties with applying hedge accounting and limitations for hedging both nonfinancial and financial risks and concerns of financial statement users over how hedging activities are reported in financial statements. The amended presentation and disclosure guidance is required only prospectively. Changes to the hedge accounting guidance to address those concerns will: 1) expand hedge accounting for nonfinancial and financial risk components and amend measurement methodologies to more closely align hedge accounting with an entity's risk management activities; 2) eliminate the separate measurement and reporting of hedge ineffectiveness, to reduce the complexity of preparing and understanding hedge results; 3) enhance disclosures and change the presentation of hedge results to align the effects of the hedging instrument and the hedged item in order to enhance transparency, comparability, and understandability of hedge results; and 4) simplify the way assessments of hedge effectiveness may be performed to reduce the cost and complexity of applying hedge accounting. The amendments ease the administrative burden of hedge documentation requirements and assessing hedge effectiveness going forward. We adopted the hedge accounting amendments on January 1, 2019, and had no cumulative-effect adjustment to retained earnings because there were no amounts of ineffectiveness recorded for any existing hedges as of that date. Concurrently with the above targeted improvements, we adopted the additional amendments the FASB issued in October 2018 that permit use of the Overnight Index Swap rate based on the Secured Overnight Financing Rate as a U.S. benchmark interest rate for hedge accounting purposes. Use of that rate is in addition to the already eligible benchmark interest rates, which are: interest rates on direct Treasury obligations of the U.S. government, the London Interbank Offered Rate swap rate, the OIS Rate based on the Fed Funds Effective Rate, and the Securities Industry and Financial Markets Association Municipal Swap Rate.

(c) Reclassification of certain tax effects from accumulated other comprehensive income

In February 2018 the FASB issued amendments to address a financial reporting issue that arose as a consequence of the Tax Cuts and Jobs Act of 2017 (the Tax Act) that the U.S. federal government enacted on December 22, 2017. Under previous guidance, an entity was required to include the adjustment of deferred taxes for the effect of a change in tax laws or rates in income from continuing operations, thus the associated tax effects of items within AOCI (referred to as stranded tax effects) did not reflect the appropriate tax rate. The amendments allow a reclassification from AOCI to retained earnings to eliminate the stranded tax effects resulting from the Tax Act. The amendments only relate to the reclassification of the income tax effects of the Tax Act, and do not affect the underlying guidance that requires the effect of a change in tax laws or rates to be included in income from continuing operations. We adopted the amendments effective January 1, 2019, and elected to reclassify the stranded tax effects of the Tax Act from AOCI to retained earnings at the beginning of the period of adoption. As a result, we reclassified approximately $0.8 million from AOCI to retained earnings within our consolidated statements of changes in equity.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements not yet adopted that we have evaluated or are evaluating to determine their effect on our consolidated financial statements.

(a) Measurement of credit losses on financial instruments, amendments and updates

The FASB issued an accounting standards update in June 2016 that requires more timely recording of credit losses on loans and other financial instruments. The amendments affect entities that hold financial assets and net investment in leases that are not accounted for at fair value through net income (loans, debt securities, trade receivables, net investments in leases, off-balance sheet credit exposures, etc.). They require an entity to present a financial asset (or group of financial assets) that is measured at amortized cost basis at the net amount expected to be collected. 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. The income statement reflects the measurement of credit losses for newly recognized financial assets, as well as the expected increases or decreases of expected credit losses that have taken place during the period. The measurement of expected credit losses is based on relevant information about past events, including historical experience, current conditions, and reasonable and supportable forecasts that affect the collectibility of the reported amount. An entity must use judgment in determining the relevant information and estimation methods appropriate in its circumstances. The FASB subsequently issued various updates to this new guidance to clarify transition and scope requirements, make narrow-scope codification improvements and corrections, and provide targeted transition relief. The new guidance, including the subsequent amendments, is effective for public entities that are SEC filers for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. Entities are to apply the amendments on a modified retrospective basis for most instruments.

Our implementation plan and steps included: evaluating financial assets within scope; documenting related technical accounting issues, policy considerations and financial reporting implications; and identifying changes to processes and controls to ensure all aspects of the new guidance were effectively addressed. Our adoption of the guidance on January 1, 2020, including our transition adjustment, will not materially affect our consolidated results of operations, financial position and cash flows.

(b) Simplifying the test for goodwill impairment

In January 2017 the FASB issued amendments to simplify the test for goodwill impairment, which are required for public entities and certain other entities that have goodwill reported in their financial statements. The amendments simplify the subsequent measurement of goodwill by eliminating Step 2 from the goodwill impairment test, which requires the valuation of assets acquired and liabilities assumed using business combination accounting guidance. Under the new guidance, an entity should perform its annual, or interim, goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; but the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. Also, an entity should consider income tax effects from any tax-deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable. Certain requirements are eliminated for any reporting unit with a zero or negative carrying amount, therefore the same impairment assessment applies to all reporting units. An entity still has the option to perform the qualitative assessment for a reporting unit to determine if the quantitative impairment test is necessary. The amendments are effective for public entities for annual and interim periods in fiscal years beginning after December 15, 2019, with the amendments applied on a prospective basis. Early adoption is allowed. Our adoption of the amendments on January 1, 2020, will not materially affect our results of operations, financial position, cash flows, and disclosures.

(c) Changes to the disclosure requirements for fair value measurement and defined benefit plans

In August 2018, the FASB issued amendments related to disclosure requirements for both fair value measurement and defined benefit plans. The amendments concerning fair value measurement remove, modify and add certain disclosure requirements, in order to improve the overall usefulness of the disclosures and reduce unnecessary costs to companies to prepare the disclosures. The amendments to fair value measurement disclosures are effective for all entities for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted as specified. Certain amendments are to be applied prospectively, and all others are to be applied retrospectively. Our adoption of the amendments on January 1, 2020, will not materially affect our disclosures.

The amendments concerning disclosure requirements for defined benefit plans are narrow in scope and apply to all employers that sponsor defined benefit pension or other postretirement plans. They remove disclosures that are no longer considered cost beneficial, add certain new relevant disclosures and clarify specific requirements of disclosures concerning information for defined benefit pension plans. The amendments to defined benefit plan disclosures are effective for fiscal years ending after December 15, 2020. Early adoption is permitted and application is to be on a retrospective basis. Our adoption of the amendments on January 1, 2020, will not materially affect our disclosures.

(d) Simplifying the accounting for income taxes

In December 2019, the FASB issued an accounting standards update that is intended to reduce complexity in accounting for income taxes. The amendments remove specific exceptions to the general principles in ASC 740, Income Taxes, eliminating the need for an entity to analyze whether the following apply in a given period: (1) exception to the incremental approach for intra-period tax allocation, (2) exceptions to accounting for basis differences when there are ownership changes in foreign investments and (3) exception in interim period income tax accounting for year-to-date losses that exceed anticipated losses. The amendments also improve financial statement preparers' application of income-tax related guidance and simplify U. S. GAAP for (1) franchise taxes that are partially based on income, (2) transactions with a government that result in a step up in the tax basis of goodwill, (3) separate financial statements of legal entities that are not subject to tax and (4) enacted changes in tax laws in interim periods. The amendments are effective for public business entities for fiscal years beginning after December 15, 2020, and interim periods within those fiscal years. Early adoption is permitted, including adoption in any interim period for which financial statements have not been issued, with adoption of all amendments in the same period. Application is on a retrospective and/or modified retrospective basis, or a prospective basis, depending on the amendment aspect. We expect our adoption will not materially affect our consolidated results of operations, financial position, and cash flows.

***Use of estimates and assumptions*: ** The preparation of our consolidated financial statements in conformity with U.S. GAAP requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the reporting periods. Significant estimates and assumptions are used for, but not limited to: (1) allowance for doubtful accounts and unbilled revenues; (2) asset impairments, including goodwill; (3) depreciable lives of assets; (4) income tax valuation allowances; (5) uncertain tax positions; (6) reserves for professional, workers' compensation, and comprehensive general insurance liability risks; (7) contingency and litigation reserves; (8) environmental remediation liabilities; (9) pension and other postretirement employee benefits (OPEB); (10) fair value measurements and (11) AROs. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our consolidated financial statements will change as new events occur, as more experience is acquired, as additional information is obtained, and as our operating environment changes. We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside specialists to assist in our evaluations, as considered necessary. Actual results could differ from those estimates.

Union collective bargaining agreements: Approximately 69% of our employees are covered by a collective bargaining agreement. We have no agreements that will expire within the coming year.

Note 2. Industry Regulation

Our revenues are regulated, being based on tariffs established in accordance with administrative procedures set by the various regulatory bodies. Distribution rates are established by the Maine Public Utilities Commission (MPUC) and transmission rates are established by the Federal Energy Regulatory Commission (FERC). The tariffs are applied based on the cost of providing service.

Electricity Distribution

The Maine distribution rate stipulation, the Federal Energy Regulatory Commission (FERC) Transmission Return on Equity (ROE) case, and the Tax Act are some of the most important specific regulatory processes that currently affect CMP.

The revenues of CMP are regulated, being based on tariffs established in accordance with administrative procedures set by the various regulatory bodies. The tariffs applied to regulated activities in the U.S. are approved by the regulatory commissions and are based on the cost of providing service. The revenues of each regulated utility are set to be sufficient to cover all its operating costs, including finance costs, and the costs of equity, the last of which reflect our capital ratio and a reasonable ROE. Generally, tariff reviews cover various years and provide for a reasonable ROE, protection, and automatic adjustments for exceptional costs incurred.

Energy costs that are set on the New England wholesale markets are passed on to consumers by Competitive Energy Providers, licensed by the MPUC. Under Maine Law, transmission and distribution utilities are prohibited from providing retail energy supply. Default retail supply is provided by Standard Offer Providers periodically selected by the MPUC through a competitive procurement process.

Transmission - FERC ROE and Formula Rate Proceedings

CMP’s transmission rates are determined by a tariff regulated by the FERC and administered by ISO New England, Inc. (ISO-NE). Transmission rates are set annually pursuant to a FERC authorized formula that allows for recovery of direct and allocated transmission operating and maintenance expenses, and for a return of and on investment in assets.

On September 30, 2011, the Massachusetts Attorney General, Massachusetts Department of Public Utilities, Connecticut Public Utilities Regulatory Authority, New Hampshire Public Utilities Commission, Rhode Island Division of Public Utilities and Carriers, Vermont Department of Public Service, numerous New England consumer advocate agencies and transmission tariff customers collectively filed a complaint (Complaint I) with the FERC pursuant to sections 206 and 306 of the Federal Power Act. The filing parties seek an order from the FERC reducing the 11.14% base return on equity used in calculating formula rates for transmission service under the ISO-New England Open Access Transmission Tariff (OATT) to 9.2%. CMP, MEPCO and UI are New England Transmission Owners (NETOs) with assets and service rates that are governed by the OATT and will thereby be affected by any FERC order resulting from the filed complaint.

On June 19, 2014, the FERC issued its decision in Complaint I, establishing a methodology and setting an issue for a paper hearing. On October 16, 2014, FERC issued its final decision in the Complaint I setting the base ROE at 10.57%, and a maximum total ROE of 11.74% (base plus incentive ROE) for the October 2011 - December 2012 period as well as prospectively from October 16, 2014 and ordered the NETOs to file a refund report. On November 17, 2014 the NETOs filed a refund report.

On March 3, 2015, the FERC issued an order on requests for rehearing of its October 16, 2014 decision. The March order upheld the FERC’s June 19, 2014 decision and further clarified that the 11.74% ROE cap will be applied on a project specific basis and not on a transmission owner’s total average transmission return. In June 2015 the NETOs and complainants both filed an appeal in the U.S. Court of Appeals for the District of Columbia of the FERC’s final order. On April 14, 2017, the Court of Appeals (the Court) vacated FERC’s decision on Complaint I and remanded it to FERC. The Court held that FERC, as directed by statute, did not determine first that the existing ROE was unjust and unreasonable before determining a new ROE. The Court ruled that FERC should have first determined that the then existing 11.14% base ROE was unjust and unreasonable before selecting the 10.57% as the new base ROE. The Court also found that FERC did not provide reasoned judgment as to why 10.57%, the point ROE at the midpoint of the upper end of the zone of reasonableness is a just and reasonable ROE. Instead, FERC had only explained in its order that the midpoint of 9.39% was not just and reasonable and a higher base ROE was warranted. On June 5, 2017, the NETOs made a filing with FERC seeking to reinstate transmission rates to the status quo ante (effect of the Court vacating order is to return the parties to the rates in effect prior to FERC Final decision) as of June 8, 2017, the date the Court decision became effective. In that filing, the NETOs stated that they will not begin billing at the higher rates until 60 days after FERC has a quorum of commissioners. On October 6, 2017, FERC issued an order rejecting the NETOs request to collect transmission revenue requirements at the higher ROE of 11.14%, pending FERC order on remand. In reaching this decision, FERC stated that it has broad remedial authority to make whatever ROE it eventually determines to be just and reasonable effective for the Complaint I refund period and prospectively from October 2014, the effective date of the Complaint I Order. Therefore FERC reasoned that the NETOs will not be harmed financially by not immediately returning to their pre-Complaint I ROE. We anticipate FERC to address the Court decision in the context of a final ruling on all outstanding ROE complaint matters, expected sometime during 2020. We cannot predict the outcome of action by FERC.

On December 26, 2012, a second ROE complaint (Complaint II) for a subsequent rate period was filed requesting the then effective ROE of 11.14% be reduced to 8.7%. On June 19, 2014, FERC accepted Complaint II, established a 15-month refund effective date of December 27, 2012, and set the matter for hearing using the methodology established in the Complaint I.

On July 31, 2014, a third ROE complaint (Complaint III) was filed for a subsequent rate period requesting the then effective ROE of 11.14% be reduced to 8.84%. On November 24, 2014, FERC accepted the Complaint III, established a 15-month refund effective date of July 31, 2014, and set this matter consolidated with Complaint II for hearing in June 2015. Hearings relating to the refund periods and going forward period were held in June 2015 on Complaints II and III before a FERC Administrative Law Judge. On July 29, 2015, post-hearing briefs were filed by parties and on August 26, 2015 reply briefs were filed by parties. On July 13, 2015, the NETOs filed a petition for review of FERC’s orders establishing hearing and consolidation procedures for Complaints II and III with the U.S. Court of Appeals. The FERC Administrative Law Judge issued an Initial Decision on March 22, 2016. The Initial Decision determined that: (1) for the 15-month refund period in Complaint II, the base ROE should be 9.59% and that the ROE Cap (base ROE plus incentive ROEs) should be 10.42% and (2) for the 15 month refund period in Complaint III and prospectively, the base ROE should be 10.90% and that the ROE Cap should be 12.19%. The Initial Decision is the Administrative Law Judge’s recommendation to the FERC Commissioners. As noted above, the FERC is expected to make its final decision on all outstanding ROE complaint matters in 2020.

CMP reserved for refunds for Complaints I, II and III consistent with the FERC’s March 3, 2015 final decision in Complaint I. Refunds were provided to customers for Complaint I. The CMP total reserve associated with Complaints II and III is $24.5 million as of December 31, 2019 which has not changed since December 31, 2017, except for the accrual of carrying costs. If adopted as final, the impact of the initial decision would be an additional aggregate reserve for Complaints II and III of $17.1 million, which is based upon currently available information for these proceedings. We cannot predict the outcome of the Complaint II and III proceedings.

On December 28, 2015, the FERC issued an order instituting section 206 proceedings and establishing hearing and settlement judge procedures. Pursuant to section 206 of the Federal Power Act (FPA), the FERC instituted proceedings because it found that ISO-NE Transmission, Markets, and Services Tariff is unjust, unreasonable, and unduly discriminatory or preferential.

The FERC stated that ISO-NE's Tariff lacks adequate transparency and challenge procedures with regard to the formula rates for ISO-NE Participating Transmission Owners, including MEPCO and CMP. The FERC also found that the current Regional Network Service, or RNS, and Local Network Service, or LNS, formula rates appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful as the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates. A settlement judge was appointed and a settlement conference was convened. On August 17, 2018, the ISO-NE Participating Transmission Owners, jointly with utility regulators from the New England states, filed a settlement resolving all matters in the proceeding. On May 22, 2019, the FERC issued an order rejecting the settlement and remanded the matter to the Chief Judge to resume hearing procedures. Settlement negotiations among parties to the proceeding have resumed in an attempt to reach a settlement that will address the issues raised by the FERC's rejection. We are unable to predict the outcome of this proceeding at this time.

On April 29, 2016, a fourth ROE complaint (Complaint IV) was filed for a rate period subsequent to prior complaints requesting the then existing base ROE of 10.57% be reduced to 8.61% and the ROE Cap be set at 11.24%. The NETOs filed a response to the Complaint IV on June 3, 2016. On September 20, 2016, FERC accepted the Complaint IV, established a 15-month refund effective date of April 29, 2016, and set the matter for hearing and settlement judge procedures. In April 2017, the NETOs filed for a stay in the hearings pending FERC on the Court order described above. That request was denied by the Administrative Law Judge. On November 21, 2017, the parties submitted updates to their ROE analyses and recommendations just prior to hearings with the NETOs continuing to advocate that the existing base ROE of 10.57% should remain in effect. Hearings were held in December 2017. The Administrative Law Judge issued his Initial Decision in March 2018 which recommends to the Commission that the base ROE and ROE cap remain at 10.57% and 11.74%, respectively, as the complainants and FERC Trial Staff did not meet the burden of proof in determining that the current ROE is unjust and unreasonable. Parties filed Briefs on Exceptions in April and filed Briefs Opposing Exceptions in May. As noted above, the FERC is expected to make its final decision on all outstanding ROE complaint matters in 2020. A range of possible outcomes is not able to be determined at this time due to the preliminary state of this matter. We cannot predict the outcome of the Complaint IV proceeding.

On October 5, 2017, the NETOs filed a Motion for Dismissal of Pancaked Return on Equity Complaints in light of the decision by the Court in April 2017 that became effective on June 8, 2017. The NETOs assert that all four complaints should be dismissed because the complainants have not shown that the existing ROE of 11.14% is unjust and unreasonable as the Court decision requires. In addition, the NETOs assert that Complaints II, III and IV should also be dismissed because the Court decision implicitly found that FERC's acceptance of Pancaked FPA Section 206 complaints was statutorily improper as Congress intended that the 15-month refund period under Section 206 applies whenever FERC does not complete its review of a complaint within the 15-month period. In the event FERC chooses not to dismiss the complaints, the NETOs request that FERC consolidate the complaints for decision as the evidentiary records are either closed or advanced enough for FERC to address the requirements of the Court decision and expeditiously issue a final order. FERC has not yet ruled on this Motion. We cannot predict the outcome of action by FERC.

On October 16, 2018, the FERC issued an order directing briefs and proposing a new methodology to calculate the NETOs ROE that is contained in NETOs' transmission formula rate on file at FERC (the October 2018 Order). The FERC proposes to use this new methodology to resolve Complaints I, II, III, and IV filed by the New England state consumer advocates.

The new proposed ROE methodology set forth in the October 2018 Order considers more than just the two-step discounted cash flow (DCF) analysis adopted in the FERC order on Complaint I vacated by the Court. The new proposed ROE methodology uses three financial analyses (i.e., DCF, the capital-asset pricing model, and the expected earnings analysis) to produce a range of returns to narrow the zone of reasonableness when assessing whether a complainant has met its initial burden of demonstrating that the utility's existing ROE is unjust and unreasonable. The new proposed ROE methodology establishes a range of just and reasonable ROEs of 9.60% to 10.99% and proposes a just and reasonable base ROE of 10.41% with a new ROE cap of 13.08%. The October 2018 Order directs the NETOs to file briefs with objections and rates consistent with the proposed methodology in all four Complaints by December 17, 2018. The FERC subsequently extended this initial filing deadline to January 11, 2019 with reply briefs due on March 8, 2019. Briefing is now complete but the FERC has taken no action on the matter. We cannot predict the outcome of this proceeding.

CMP Distribution Rate Stipulation and New Renewable Source Generation

On May 1, 2013, CMP submitted its required distribution rate request with the Maine Public Utilities Commission (MPUC). On July 3, 2014, after a fourteen month review process, CMP filed a rate stipulation agreement on the majority of the financial matters with the MPUC. The stipulation agreement was approved by the MPUC on August 25, 2014. The stipulation agreement also noted that certain rate design matters would be litigated, which the MPUC ruled on October 14, 2014.

The rate stipulation agreement provided for an annual CMP distribution tariff increase of 10.7% or $24.3 million. The rate increase was based on a 9.45% ROE and 50% equity capital. CMP was authorized to implement a Rate Decoupling Mechanism (RDM) which protects CMP from variations in sales due to energy efficiency and weather. CMP also adjusted its storm costs recovery mechanism whereby it is allowed to collect in rates a storm allowance and to defer actual storm costs when such storm event costs exceed $3.5 million. CMP and customers share Tier 2 (Large) storm costs that exceed a certain balance on a fifty-fifty basis, with CMP's exposure limited to $3.0 million annually. Tier 2 storms are defined as storms where the incremental restoration costs are between $3.5 million and $15.0 million.

CMP made a separate regulatory filing for a new customer billing system replacement. In accordance with the stipulation agreement, a new billing system is needed and CMP made its filing on February 27, 2015 to request a separate rate recovery mechanism. On October 20, 2015, the MPUC issued an order approving a stipulation agreement authorizing CMP to proceed with the customer billing system investment. The approved stipulation allows CMP to recover the system costs effective July 1, 2017.

The rate stipulation does not have a predetermined rate term. CMP has the option to file for new distribution rates at its own discretion. The rate stipulation does not contain service quality targets or penalties. The rate stipulation also does not contain any earning sharing requirements.

On July 24, 2018, the Maine Public Utilities Commission (MPUC), in response to a Ten Person Complaint, issued an order to initiate an investigation into the Company's rates and revenue requirements, and directed the Company to submit a rate case filing consistent with the requirements as specified in Chapter 120 of the Commission's rules no later than October 15, 2018. On October 15, 2018, CMP filed a general rate case as directed by the MPUC, requesting a ROE of 10% and an equity ratio of 55%. The company proposed to use savings arising out of changes in federal taxation pursuant to the Tax Cuts and Jobs Act of 2017 enacted by the U.S. federal government on December 22, 2017 (the Tax Act) to keep its distribution prices stable while making its electric system more reliable. The MPUC established a ten-month process to review CMP's filing with a decision expected in August of 2019. Based on subsequent MPUC procedural orders, a decision was delayed until January 30, 2020. In an order issued on February 19, 2020, the MPUC authorized an increase in CMP's distribution service rates of $17.4 million or approximately 6.9%. The decision reflects an allowed base ROE of 9.25% and common equity ratio of 50%. However, the order implements a management efficiency adjustment, reducing this ROE by 100 basis points to address concerns with the Company's customer service performance during its implementation of a new customer billing system in 2017 and 2018. The management efficiency adjustment will remain in effect until the Company has demonstrated satisfactory customer service performance on four specified service quality measures for a period of 18 consecutive months. The order provides additional funding for staffing increases, vegetation management programs and storm restoration costs, while retaining the basic tiered structure for storm cost recovery implemented in the 2014 stipulation. The MPUC order also retains the revenue decoupling mechanism implemented in 2014. The order denies the Company's request to increase rates for higher costs associated with services provided by its affiliates, Avangrid Service Company and Avangrid Management Company and will instead initiate a management audit to assess the quality of these services as well as the impacts of the Avangrid management structure on the quality of CMP's customer service.

Under Maine law, the MPUC is authorized to conduct periodic requests for proposals seeking long-term supplies of energy, capacity or Renewable Energy Certificates, or RECs, from qualifying resources. The MPUC is further authorized to order Maine Transmission and Distribution Utilities to enter into contracts with sellers selected from the MPUC's competitive solicitation process. Pursuant to a MPUC Order dated October 8, 2009, CMP entered into a 20-year agreement with Evergreen Wind Power III, LLC, on March 31, 2010, to purchase capacity and energy from Evergreen's 60 MW Rollins wind farm in Penobscot County, Maine. CMP's purchase obligations under the Rollins contract are approximately $7 million per year. Pursuant to a MPUC Order dated December 18, 2017, CMP entered into a 20-year agreement with Dirigo Solar, LLC on September 10, 2018, to purchase capacity and energy from multiple Dirigo solar facilities throughout CMP's service territory. CMP's purchase obligations under the Dirigo contract will increase as additional solar facilities are brought on line, eventually reaching a level of approximately $4 million per year. Pursuant to a MPUC Order dated November 6, 2019, CMP entered into a 20-year agreement with Maine Aqua Ventus I GP LLC on December 9, 2019, to purchase capacity and energy from an off-shore wind farm under development near Monhegan Island, Maine. CMP's purchase obligations under the Maine Aqua Ventus contract will be approximately $12 million per year once the facility begins commercial operation. In accordance with MPUC orders, CMP either sells the purchased energy from these facilities in the ISO New England markets or periodically auctions the purchased output to wholesale buyers in the New England regional market. Under applicable law, CMP is assured recovery of any differences between power purchase costs and achieved market revenues through a reconcilable component of its retail distribution rates. Although the MPUC has conducted multiple requests for proposals under M.R.S.A §3210-C and has tentatively accepted long-term proposals from other sellers, these selections have not yet resulted in additional currently effective contracts with CMP.

MPUC Investigation into the Response by Public Utilities to the October 2017 Storm

On December 19, 2017, the Commission issued a Notice of Investigation regarding utility response to the October 2017 Storm. The wind storm of October 2017 was unprecedented in the number of customers impacted and the magnitude of the damage across the entire Central Maine Power service territory. During the event, thousands of trees were broken or uprooted and many caused damage to the electrical delivery system. The vast majority of tree related damage was from trees that were located outside of the maintenance clearance zone. In an order issued on

October 4, 2018, the MPUC found that CMP's actions in preparation for and response to the October wind storm were reasonable. CMP's total incremental restoration costs for the storm event were approximately $69.3 million, of which approximately $24.7 million are capital costs associated with the replacement of damaged infrastructure, including poles, cross arms, transformers and related equipment. Additionally, approximately $744 thousand of the incremental amount is operations and maintenance expense for repairs to CMP transmission facilities. Accordingly, the net incremental operations and maintenance expenses for restoration of the distribution system were approximately $43.9 million. Recovery of the incremental storm restoration costs in CMP distribution rates has been addressed in the Company's 2018 Annual Compliance Filing proceeding pursuant to the applicable provisions of the stipulation approved by the Commission in Docket No. 2013-00168. Total incremental storm recovery in distribution rates (effective July 1, 2018), after consideration for storm reserve treatment, is $28.4 million.

Tax Cuts and Jobs Act

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Tax Act) was signed into law. The Tax Act contains significant changes to the federal tax structure, including among other things, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017. The MPUC and the FERC approved rate reductions partially reflecting the impacts of the Tax Act effective July 1, 2018. Beginning July 1, 2018, CMP adjusted rates to pass back to customers the Tax Act savings after offsetting for recovery of deferred 2017 storm costs. CMP adjusted its FERC regulated transmission tariffs in June 2018 to reflect the income statement value of Tax Act savings. In its February 19, 2020 order in the Company's distribution rate case proceeding discussed above, the MPUC approved CMP's distribution related accumulated deferred income tax balances associated with the Tax Act as well as the authorized amortization periods for the return of regulatory liabilities and the recovery regulatory assets. The Company expects to address the remaining transmission related impacts associated with deferred income taxes in its 2020 transmission rate adjustment.

Minimum Equity Requirements for Regulated Subsidiaries

CMP is subject to a minimum equity ratio requirement that is tied to the capital structure assumed in establishing revenue requirements. Pursuant to these requirements CMP must maintain a minimum equity ratio equal to the ratio in its currently effective rate plan or decision measured using a trailing 13-month average. On a monthly basis CMP must maintain a minimum equity ratio of no less than 300 basis points below the equity ratio used to set rates. The minimum equity ratio requirement has the effect of limiting the amount of dividends that may be paid and may, under certain circumstances, require that the parent contribute equity capital. CMP is prohibited by regulation from lending to unregulated affiliates. CMP has also agreed to minimum equity ratio requirements in certain short-term borrowing agreements. These requirements are lower than the regulatory requirements. We are in compliance with these requirements.

Note 3. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations we capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric rates. We base our assessment of whether recovery is probable on the existence of regulatory orders that allow for recovery of certain costs over a specific period, or allow for reconciliation or deferral of certain costs. When costs are not treated in a specific order we use regulatory precedent to determine if recovery is probable. We also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs. Of the total regulatory assets net of regulatory liabilities, approximately $214.5 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

Details of other regulatory assets and other regulatory liabilities are shown in the tables below. They result from various regulatory orders that allow for the deferral and/or reconciliation of specific costs. Regulatory assets and regulatory liabilities are classified as current when recovery or refund in the coming year is allowed or required through a specific order or when the rates related to a specific regulatory asset or regulatory liability are subject to automatic annual adjustment.

Current and non-current regulatory assets at December 31, 2019 and 2018 consisted of:

December 31,	**2019**	**2018**
(Thousands)		
Current		
Transmission revenue reconciliation mechanism	$ 5,479	$ 10,865
Deferred meter replacement costs	1,984	2,163
Environmental remediation costs	209	160
Storm - Tier III	—	16,720
Stranded Costs	1,851	1,357
Energy efficiency programs	5,177	—
Other	118	149
Total current regulatory assets	**14,818**	**31,414**
Non-current		
Federal tax depreciation normalization adjustment	14,481	13,137
Storm costs	33,304	14,677
Unamortized losses on reacquired debt	351	444
Pension and other postretirement benefits costs	205,182	201,483
Unfunded future income taxes	143,503	135,120
Deferred meter replacement costs	24,950	26,885
Other	7,517	1,479
Total non-current regulatory assets	**$ 429,288**	**$ 393,225**

Deferred meter replacement costs represent the deferral of the net book value of retired meters which were replaced by advanced metering infrastructure meters. This amount is being amortized at the related existing depreciation amounts.

Energy efficiency programs represent the difference between revenue billed to customers through an energy efficiency charge and the costs of energy efficiency programs as approved by the state authorities.

Environmental remediation costs include spending that has occurred and is eligible for future recovery in customer rates. The amortization period will be established in future proceedings and will depend upon the timing of spending for the remediation costs.

Federal tax depreciation normalization adjustment represents the deferral of the normalization of change impacts in book lives and the pass back of theoretical reserves associated with Powertax deferred income tax.

Pension and other postretirement represent the actuarial losses on the pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future pension expenses. Because no funds have yet been expended for this regulatory asset, it does not accrue carrying costs and is not included within the rate base. Pension and other postretirement benefits cost deferrals include the difference between actual expense for pension and other postretirement benefits and the amount provided for in rates. The recovery of these amounts will be determined in future proceedings.

Storm costs are allowed in rates based on an estimate of the routine costs of service restoration. CMP is also allowed to defer unusually high levels of service restoration costs resulting from major storms when they meet certain criteria for severity and duration. CMP's total deferral, including carrying costs, was $33.3 million at December 31, 2019 and $31.4 million at December 31, 2018.

Stranded cost represents costs that resulted from government-mandated long term Purchased Power Agreement (PPA) contracts between CMP and power producers (at prices above current market rates), which must be resold to the market at the current going rate. These costs and assets became "stranded" as CMP was prohibited from owning power and was therefore forced to sell the power back at the market rate, significantly lower than the PPA price. The monthly stranded cost over/under expense compared to revenue is recorded to be recovered in future years.

Transmission revenue reconciliation mechanism reflects any differences in actual costs in the rate year from those used to set rates. This mechanism contains the Annual Transmission True Up (ATU) which is recovered over the subsequent June to May period. When the ATU is known we record it as a regulatory asset (regulatory liability), with an offset to revenues, and amortize it over the twelve month period as the related revenues are collected (refunded). Transmission Expense Deferral represents the portion of the revenue requirement that will be collected in the subsequent year (January-May); Congestion Costs incurred versus costs recovered in rates from customers in distribution level rates are also deferred.

Unamortized losses on reacquired debt represent deferred losses on debt reacquisitions that will be recovered over the remaining original amortization period of the reacquired debt.

Unfunded future income taxes represent unrecovered federal and state income taxes primarily resulting from regulatory flow through accounting treatment. The income tax benefits or charges for certain plant related timing differences, such as removal costs, are immediately flowed through to, or collected from, customers. This amount is being amortized as the amounts related to temporary differences that give rise to the deferrals are recovered in rates.

Other includes various items subject to reconciliation such as Asset Retirement Obligation, Electric Thermal Storage (ETS), CRM&B (Billing System Costs), Arrears Forgiveness Program, and OPA Consulting Costs.

Current and non-current regulatory liabilities at December 31, 2019 and 2018 consisted of:

December 31,		2019		2018
(Thousands)				
Current				
Accrued removal obligations	$	2,251	$	2,251
Transmission revenue reconciliation mechanism		9,829		7,028
Revenue decoupling mechanism		12,529		7,744
Tax Act - remeasurement		1,145		2,740
Energy Efficiency Programs		—		2,007
Scenario B Storm in rates		—		7,529
Other		1,040		1,768
Total current regulatory liabilities		**26,794**		**31,067**
Non-current				
Environmental remediation costs		1,469		1,335
Rate refund - FERC ROE proceeding		24,542		23,448
Accrued removal obligations		50,075		59,502
Tax Act - remeasurement		346,881		334,340
Other		1,637		1,109
Total non-current regulatory liabilities	**$**	**424,604**	**$**	**419,734**

Accrued removal obligations represent the differences between asset removal costs incurred and amounts collected in rates for those costs. The amortization period is dependent upon the asset removal costs of underlying assets and the life of the utility plant.

Energy efficiency programs represent the difference between revenue billed to customers through an energy efficiency charge and the costs of energy efficiency programs as approved by the state authorities.

Environmental remediation costs include spending that has occurred and is eligible for future recovery in customer rates. The amortization period will be established in future proceedings and will depend upon the timing of spending for the remediation costs.

Rate refund - FERC ROE proceeding: see Note 2.

Revenue Decoupling Mechanism represents the mechanism established to disassociate the utility's profits from its delivery/commodity sales.

Scenario B represents the commission-approved continuation of the December 2013 storm cost amortization for future rate treatment.

Tax Act – re-measurement represents the impact from re-measurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates from 35% to 21% under the provisions of the Tax Act will result in amounts previously collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates.

Transmission revenue reconciliation mechanism (ATU) reflects any differences in actual costs in the rate year from those used to set rates. The ATU is recovered over the subsequent June to May period. When the ATU is known we record it as a regulatory asset (regulatory liability), with an offset to revenues, and amortize it over the twelve month period as the related revenues are collected (refunded).

Other includes various items subject to reconciliation such as Electric Lifeline Program (ELP) and Funded Power Tax.

Note 4. Revenue

We recognize revenue when we have satisfied our obligations under the terms of a contract with a customer, which generally occurs when the control of promised goods or services transfers to the customer. We measure revenue as the amount of consideration we expect to receive in exchange for providing those goods or services. Contracts with customers may include multiple performance obligations. For such contracts, we allocate revenue to each performance obligation based on its relative standalone selling price. We generally determine standalone selling prices based on the prices charged to customers. Certain revenues are not within the scope of ASC 606, such as revenues from leasing, derivatives, other revenues that are not from contracts with customers and other contractual rights or obligations, and we account for such revenues in accordance with the applicable accounting standards. We exclude from revenue amounts collected on behalf of third parties, including any such taxes collected from customers and remitted to governmental authorities. We do not have any material significant payment terms because we receive payment at or shortly after the point of sale.

The following describes the principal activities from which we generate revenue.

CMP derives its revenue primarily from tariff-based sales of electricity service to customers in the Maine area with no defined contractual term. For such revenues, we recognize revenues in an amount derived from the commodities delivered to customers. Other major sources of revenue are electricity transmission and wholesale sales of electricity.

Tariff-based sales are subject to the corresponding state regulatory authorities, which determine prices and other terms of service through the ratemaking process. Maine state law prohibits the utility from providing the electricity commodity to customers. For customers that receive their commodity from another supplier, the utility acts as an agent and delivers the electricity provided by that supplier. Revenue in those cases is only for providing the service of delivery of the commodity.

Transmission revenue results from others’ use of the utility’s transmission system to transmit electricity and is subject to FERC regulation, which establishes the prices and other terms of service. Long-term wholesale sales of electricity are based on individual bilateral contracts.

The performance obligation in all arrangements is satisfied over time because the customer simultaneously receives and consumes the benefits as CMP delivers or sells the electricity or provides the transmission service.

CMP records revenue from Alternative Revenue Programs (ARPs), which is not ASC 606 revenue. Such programs represent contracts between the utilities and their regulators. CMP ARPs include revenue decoupling mechanisms, other ratemaking mechanisms, annual revenue requirement reconciliations, and other demand side management programs.

CMP also has various other sources of revenue including billing, collection, other administrative charges, sundry billings, rent of utility property, and miscellaneous revenue. It classifies such revenues as other ASC 606 revenues to the extent they are not related to revenue generating activities from leasing, ARPs, or other activities.

Revenues disaggregated by major source for the year ended December 31, 2019 and 2018 are as follows:

Year Ended December 31,	2019	2018
(Thousands)		
Regulated operations – electricity	$ 771,013	$ 789,686
Other(a)	21,404	20,752
Revenue from contracts with customers	**792,417**	**810,438**
Leasing revenue	1,540	17,212
Alternative revenue programs	8,569	18,784
Other revenue	16,531	1,363
Total operating revenues	**$ 819,057**	**$ 847,797**

(a) Primarily includes certain intra-month trading activities, billing, collection, and administrative charges, sundry billings, and other miscellaneous revenue.

Refer to Note 1 for details on the adoption of ASC 842 including a discussion regarding the classification of lease revenues.

Note 5. Goodwill

We do not amortize goodwill, but perform a goodwill impairment assessment at least annually as described in Note 1. Our step one impairment testing includes various assumptions, primarily the discount rate, which is based on an estimate of our marginal, weighted-average cost of capital, and forecasted cash flows. We test the reasonableness of the conclusions of our step one impairment testing using a range of discount rates and a range of assumptions for long-term cash flows. Our step zero qualitative assessment involves evaluating key events and circumstances that could affect the fair value of our reporting units, as well as other factors. Events and circumstances evaluated include: macroeconomic conditions, industry, regulatory and market considerations, cost factors and their effect on earnings and cash flows, overall financial performance as compared with projected results and actual results of relevant prior periods, other relevant entity-specific events, and events affecting a reporting unit.

We had no impairment of goodwill in 2019 and in 2018 as a result of our annual impairment assessment, which we performed as of October 1st. For 2019 and 2018 as a result of our step one testing, no impairment was indicated within any of the ranges of assumptions analyzed. There were no events or circumstances subsequent to our annual impairment assessment for 2019 or for 2018 that required us to update the assessment.

The carrying amount of goodwill was $325.0 million at both December 31, 2019 and 2018 with no accumulated impairment losses and no changes during 2019 and 2018.

Note 6. Income Taxes

Upon enactment of the Tax Act, the Company remeasured its existing deferred income tax balances as of December 31, 2017 to reflect the decrease in the corporate income tax rate from 35% to 21%, which results in a material decrease to its net deferred income tax liability balances based on reasonable estimates that could be determined at that time. The Company's operations recorded corresponding regulatory liabilities or assets to the extent that such amounts are probable of settlement or recovery through customer rates. The amount and timing of potential settlements of the established net regulatory liabilities are determined by the MPUC and IRS Normalization rules. As of December 31, 2018, the Company has completed the measurement and accounting of certain effects of the Tax Act which have been reflected in the December 31, 2019 financial statements.

Current and deferred taxes charged to expense for the years ended December 31, 2019 and 2018 consisted of:

Years Ended December 31,	**2019**	**2018**
(Thousands)		
Current		
Federal	$ 13,725	$ 21,762
State	(3,111)	(401)
Current taxes charged to expense	**10,614**	**21,361**
Deferred		
Federal	12,993	29,154
State	18,315	3,309
Deferred taxes charged to expense	**31,308**	**32,463**
Total Income Tax Expense	**$ 41,922**	**$ 53,824**

The differences between tax expense per the statements of income and tax expense at the 21% statutory federal tax rate for the years ended December 31, 2019 and 2018 consisted of:

Years Ended December 31,	**2019**	**2018**
(Thousands)		
Tax expense at federal statutory rate	$ 33,999	$ 39,007
Depreciation and amortization not normalized	(5,005)	(1,711)
State taxes net of federal benefit	12,011	13,104
Other, net	917	3,424
Total Income Tax Expense	**$ 41,922**	**$ 53,824**

Income tax expense for the year ended December 31, 2019 was $7.9 million higher than it would have been at the statutory federal income tax rate of 21% due predominately to state taxes, offset by a benefit in depreciation and amortization not normalized. This resulted in an effective tax rate of 25.9%. Income tax expense for the year ended December 31, 2018 was $14.8 million higher than it would have been at the statutory federal income tax rate of 21% due predominately to state taxes, (net of federal benefit), one-time discrete items offset by a benefit in depreciation and amortization not normalized. This resulted in an effective tax rate of 29.0%.

Deferred tax assets and liabilities as of December 31, 2019 and 2018 consisted of:

December 31,		2019		2018
(Thousands)				
Non-current Deferred Income Tax Liabilities (Assets)				
Property related	$	574,723	$	571,496
Unfunded future income taxes		40,148		39,071
Pension and other postretirement benefits		10,606		7,094
Regulatory liability due to "Tax Cuts and Jobs Act"		(97,233)		(94,567)
Federal and state tax credits		(5,752)		(8,516)
Derivative assets		—		(1,157)
Federal and state NOL's		(214)		(6,799)
Other		10,880		(4,144)
Non-current Deferred Income Tax Liabilities		**533,158**		**502,478**
Add: Valuation allowance		—		465
Total Non-current Deferred Income Tax Liabilities	**$**	**533,158**	**$**	**502,943**
Deferred tax assets	$	103,199	$	115,183
Deferred tax liabilities		636,357		618,126
Net Accumulated Deferred Income Tax Liabilities	**$**	**533,158**	**$**	**502,943**

CMP has gross Maine state net operating losses of $3.0 million and gross Maine tax credits of $7.3 million for the year ended December 31, 2019. CMP had gross federal net operating losses of $31.4 million and gross Maine tax credits of $7.3 million, offset by $0.4 million of valuation allowance for the year ended December 31, 2018.

Uncertain tax positions have been classified as noncurrent unless expected to be paid within one year. In 2019, we netted our liability for uncertain tax positions against all same jurisdiction deferred tax assets, net operating losses and tax credit carryforwards. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the consolidated statements of income.

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2019, and 2018 consisted of:

Years Ended December 31,		2019		2018
(Thousands)				
Beginning Balance	$	25,660	$	29,425
Reduction for tax positions related to prior years		(4,115)		(3,765)
Ending Balance	**$**	**21,545**	**$**	**25,660**

Unrecognized income tax benefits represent income tax positions taken on income tax returns but not yet recognized in the consolidated financial statements. The accounting guidance for uncertainty in income taxes provides that the financial effects of a tax position shall initially be recognized in the financial statements when it is more likely than not based on the technical merits that the position will be sustained upon examination, assuming the position will be audited and the taxing authority has full knowledge of all relevant information.

There were no additional accruals for interest and penalties on tax reserves as of December 31, 2019 or 2018.

Note 7. Non-current Debt

Long-term debt as of December 31, 2019 and 2018 consisted of:

As of December 31,		**2019**		**2018**	
(Thousands)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
First mortgage bonds (a)	2021-2045	$ 1,050,000	3.07%-5.68%	$ 960,000	3.07%-5.70%
Senior unsecured notes	2025-2037	140,000	5.375%-6.40%	140,000	5.375%-6.40%
Chester: Promissory and Senior Notes (b)	2020	993	7.05%-10.48%	2,176	7.05%-10.48%
Obligations under capital leases (c)		—		2,375	
Unamortized debt issuance costs and discount		(4,845)		(3,719)	
Total Debt		**1,186,148**		**1,100,832**	
Less: debt due within one year, included in current liabilities		513		151,800	
Total Non-current Debt		**$ 1,185,635**		**$ 949,032**	

(a) The first mortgages bonds are secured by a first mortgage lien on substantially all of Net Utility Plant In Service.
(b) Chester SVC Partnership notes are secured by the assets of this partnership.
(c) Due to the adoption of ASC 842 in 2019 (see Notes 1 and 10 for more information), capital leases, now known as financing leases, are no longer reported as part of long-term debt.

On December 27, 2018, CMP issued $60 million in aggregate principal amount of First Mortgage Bonds maturing in 2028. Proceeds of the offering were used to reduce short-term debt, to fund capital expenditures and for general corporate purposes.

On June 3, 2019, CMP issued $240 million aggregate principal amount of first mortgage bonds with maturity rates ranging from 2026 to 2034 and interest rates ranging from 3.87% to 4.20%.

Long-term debt, including sinking fund obligations, due during the next five years consist of:

2020	**2021**	**2022**	**2023**	**2024**	**Total**
(Thousands)					
$ 513	$ 150,000	$ 125,000	$ —	$ —	$ 275,513

We have no debt covenant requirements related to the maintenance of financial ratios in our long-term debt agreements at December 31, 2019 and 2018.

Note 8. Bank Loans and Other Borrowings

CMP had $0.7 million of notes payable at December 31, 2019 and $0.2 million at December 31, 2018. CMP funds short-term liquidity needs through an agreement among Avangrid's regulated utility subsidiaries (the "Virtual Money Pool Agreement"), a bi-lateral intercompany credit agreement with Avangrid (the "Bi-Lateral Intercompany Facility") and a bank provided credit facility to which CMP is a party (the "AGR Credit Facility"), each of which are described below.

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. CMP has a lending/borrowing limit of $100 million under this agreement. CMP had no debt outstanding under this agreement at December 31, 2019 and 2018.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $500 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. CMP had $0.7 million outstanding under this agreement at December 31, 2019 and $0.2 million outstanding at December 31, 2018.

On June 29, 2018, AGR and its investment-grade rated utility subsidiaries (New York State Electric & Gas Corporation ("NYSEG"), Rochester Gas and Electric Corporation ("RG&E"), CMP, The United Illuminating Company ("UI"), Connecticut Natural Gas Corporation ("CNG"), The Southern Connecticut Gas Company ("SCG") and The Berkshire Gas Company ("BGC")) increased the maximum borrowing terms of the AGR Credit Facility from $1.5 billion to $2.5 billion (in aggregate) and extended the maturity date from April 5, 2021 to June 29, 2023. The lending commitments under the AGR Credit Facility are comprised of a syndicate of banks. Under the terms of the AGR Credit Facility, each joint borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit established by the banks. AGR's maximum sublimit is $2 billion, NYSEG, RG&E, CMP and UI have maximum sublimits of $400 million, CNG and SCG have maximum sublimits of $150 million and BGC has a maximum sublimit of $40 million. Under the AGR Credit Facility, each of the borrowers will pay an annual facility fee that is dependent on their credit rating. The facility fees range from 10.0 to 17.5 basis points. Effective June 29, 2019, the termination date for the AGR Credit Facility was extended to June 29, 2024. CMP had not borrowed under this agreement as of both December 31, 2019 and 2018.

In the AGR Credit Facility we covenant not to permit, without the consent of the lender, our ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of indebtedness to total capitalization, the facility excludes from net worth the balance of accumulated other comprehensive loss as it appears on the balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness we may maintain. Continued un-remedied failure to comply with those covenants for five business days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity. Our ratio of indebtedness to total capitalization pursuant to the revolving credit facility was 0.37 to 1.00 at December 31, 2019. We are not in default as of December 31, 2019.

Note 9. Redeemable Preferred Stock

We have redeemable preferred stock that contains a feature that could lead to potential redemption-triggering events that are not solely within our control.

At December 31, 2019 and 2018, our redeemable preferred stock was:

				Amount (Thousands)	
Series	**Par Value per Share**	**Redemption Price per Share**	**Shares Authorized and Outstanding(1)**	**2019**	**2018**
CMP, 6% Noncallable	$ 100	$ —	5,713	$ 571	$ 571
Total				**$ 571**	**$ 571**

[(1)] At December 31, 2019 CMP had $2,300,000 shares of $100 par value preferred stock authorized but unissued.

CMP Group owns 3,792 shares of the 5,713 shares outstanding.

Note 10. Leases

We have operating leases for office buildings, facilities, vehicles and certain equipment. Our finance leases are primarily related to electric generation, distribution, transmission and other. Certain of our lease agreements include rental payments adjusted periodically for inflation or are based on other periodic input measures. Our leases do not contain any material residual value guarantees or material restrictive covenants. Our leases have remaining lease terms of 1 year to 64 years, some of which may include options to extend the leases for up to 20 years, and some of which may include options to terminate the leases within one year. We consider extension or termination options in the lease term if it is reasonably certain we will exercise the option.

The components of lease cost and other information related to leases were as follows:

For the Year Ended December 31,		**2019**
(Thousands)		
Lease cost		
Finance lease cost		
Amortization of right-of-use assets	$	540
Interest on lease liabilities		405
Total finance lease cost		945
Operating lease cost		1,749
Short-term lease cost		3,706
Variable lease cost		113
Total lease cost	**$**	**6,513**

Balance sheet and other information for the year ended December 31, 2019 was as follows:

As of December 31,		2019
(Thousands, except lease term and discount rate)		
Operating Leases		
Operating lease right-of-use assets	$	16,672
Operating lease liabilities, current		753
Operating lease liabilities, long-term		16,306
Total operating lease liabilities	$	17,059
Finance Leases		
Other assets	$	4,941
Other current liabilities		890
Other non-current liabilities		290
Total finance lease liabilities	$	1,180
Weighted-average Remaining Lease Term (years)		
Finance leases		1.25
Operating leases		20.20
Weighted-average Discount Rate		
Finance leases		27.44%
Operating leases		3.97%

For the year ended December 31, 2019, supplemental cash flow information related to leases was as follows:

For the Year Ended December 31,		2019
(Thousands)		
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$	1,349
Operating cash flows from finance leases	$	405
Financing cash flows from finance leases	$	851
Right-of-use assets obtained in exchange for lease obligations:		
Finance leases	$	—
Operating leases	$	1,091

Maturities of lease liabilities were as follows:

	Finance Leases	Operating Leases
(Thousands)		
Year ending December 31,		
2020	$ 1,100	$ 1,388
2021	275	1,649
2022	—	1,142
2023	—	1,135
2024	—	1,154
Thereafter	—	19,933
Total lease payments	**1,375**	**26,401**
Less: imputed interest	(195)	(9,342)
Total	**$ 1,180**	**$ 17,059**

Most of our leases do not provide an implicit rate in the lease; thus we use our incremental borrowing rate based on the information available at the commencement date in determining the present value of lease payments. We used the incremental borrowing rate on January 1, 2019, for operating leases that commenced prior to that date.

Comparative 2018 Leases Disclosures

The following are the 2018 annual lease disclosures, presented in accordance with Topic 840.

Operating lease expense relating to operational facilities, office building leases and vehicle and equipment leases was $8.2 million for the year ended December 31, 2018.

Total future minimum lease payments as of December 31, 2018 consisted of:

Year	Operating Leases	Capital Leases	Total
(Thousands)			
2019	$ 1,342	$ 1,271	$ 2,613
2020	1,265	1,115	2,380
2021	1,484	290	1,774
2022	990	15	1,005
2023	977	15	992
Thereafter	20,416	198	20,614
Total	**$ 26,474**	**$ 2,904**	**$ 29,378**

Note 11. Commitments and Contingent Liabilities

Power purchase contracts including nonutility generator

We recognized expense of approximately $17.2 million for NUG power in 2019 and $14.2 million in 2018.

Note 12. Environmental Liability

From time to time environmental laws, regulations and compliance programs may require changes in our operations and facilities and may increase the cost of electric service.

Waste sites

The EPA and various state environmental agencies, as appropriate, have notified us that we are among the potentially responsible parties that may be liable for costs incurred to remediate certain hazardous substances at six waste sites. The six sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the six sites, five sites are included in Maine's Uncontrolled Sites Program, one is included on the Massachusetts Non-Priority Confirmed Disposal Site list and two sites are also included on the National Priorities list. Any liability may be joint and several for certain of those sites. We have recorded an estimated liability of $1.3 million related to the six sites at December 31, 2019.

We have recorded an estimated liability of $2.3 million at December 31, 2019, related to four additional sites where we believe it is probable that we will incur remediation costs and/or monitoring costs, although we have not been notified that we are among the potentially responsible parties or are regulated under State Resource Conservation and Recovery Act (RCRA) program. It is reasonably possible the ultimate cost to remediate the sites may be significantly more than the accrued amount. Our estimate for costs to remediate the 10 total sites ranges from $2.6 million to $8.8 million as of December 31, 2019. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to us. We recorded a corresponding regulatory asset, net of insurance recoveries, because we expect to recover the net costs in rates.

Manufactured gas plants

We have a program to investigate and perform necessary remediation at our three sites where gas was manufactured in the past. All three sites are part of Maine's Voluntary Response Action Program and two are on the Maine's Uncontrolled Sites Program.

Our estimate for all costs related to investigation and remediation of the three sites range from $0.2 million to $1.2 million at December 31, 2019. The estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial action, changes in technology relating to remedial alternatives and changes to current laws and regulations.

The liability to investigate and perform remediation, as necessary, at the known inactive gas manufacturing sites was $0.7 million at December 31, 2019 and 2018. We recorded a corresponding regulatory asset, net of insurance recoveries, because we expect to recover the net costs in rates.

Our environmental liabilities are recorded on an undiscounted basis. We have received insurance settlements during the last two years, which we accounted for as reductions in our related regulatory asset.

Note 13. Accounting for Derivative Instruments and Hedging Activities

We are exposed to certain risks relating to our ongoing business operations. The primary risk we manage by using derivative instruments is commodity price risk. In accordance with the accounting requirements concerning derivative instruments and hedging activities, we recognize all derivative instruments as either assets or liabilities at fair value on our balance sheet. For financial statement presentation, we offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement.

The financial instruments we hold or issue are not for trading or speculative purposes.

Cash flow hedging: Our fleet fuel hedges are designated as cash flow hedging instruments. We record changes in the fair value of the cash flow hedging instruments in other comprehensive income (OCI), to the extent they are considered effective, and reclassify those gains or losses into earnings in the same period or periods during which the hedged transactions affect earnings.

Our derivatives designated as hedging instruments, which are other commodity contracts (fleet fuel), had a fair value of $(0.1) million as of December 31, 2019, and $(0.5) million as of December 31, 2018, and are included in current liabilities.

The effect of hedging instruments on OCI and income was:

Year Ended December 31,		Gain (Loss) Recognized in OCI on Derivatives	Location of Gain (Loss) Reclassified From Accumulated OCI into Income		(Loss) Gain Reclassified From Accumulated OCI into Income		Total Amount per Income Statement
(Thousands)							
2019							
Interest rate contracts	$	—	Interest expense	$	(957)	$	51,433
Commodity contracts: Other		95	Other operating expenses		(283)	$	399,447
Total	**$**	**95**		**$**	**(1,240)**		
2018							
Interest rate contracts	$	—	Interest expense	$	(2,171)	$	53,188
Commodity contracts: Other		(438)	Other operating expenses		(13)	$	415,056
Total	**$**	**(438)**		**$**	**(2,184)**		

The amount in AOCI related to previously settled interest rate hedging contracts at December 31 is a net loss of $2.7 million for 2019 and $3.6 million for 2018. For the year ended December 31, 2019, we recorded $1.0 million in net derivative losses related to discontinued cash flow hedges. We will amortize approximately $0.2 million of discontinued cash flow hedges in 2020.

At December 31, 2019, $0.1 million in losses are reported in OCI because the forecasted transaction is considered to be probable. We expect that those losses in OCI will be reclassified into earnings within the next 12 months, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted energy transactions.

Our derivative volumes by commodity type that are expected to settle each year are:

	Electricity Contracts	Natural Gas Contracts	Other Fuel Contracts
Year to settle	**Mwhs**	**Dths**	**Gallons**
As of December 31, 2019			
2020	—	—	590,800
As of December 31, 2018			
2019	—	—	594,700

Note 14. Fair Value of Financial Instruments and Fair Value Measurements

The estimated fair value of debt amounted to $1,383 million and $1,163 million as of December 31, 2019 and 2018, respectively. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the electricity industry and the credit ratings of the borrowers in each case. The fair value hierarchy for the fair value of debt is considered as Level 2.

Assets and liabilities measured at fair value on a recurring basis

The financial instruments measured at fair value consist of:

		Fair Value Measurements at December 31, Using		
Description	**Total**	**(Level 1)**	**(Level 2)**	**(Level 3)**
(Thousands)				
2019				
Assets				
Noncurrent investments available for sale	$ 63	$ 63	$ —	$ —
Total	**$ 63**	**$ 63**	$ —	$ —
Liabilities				
Derivatives	$ (120)	$ —	$ —	$ (120)
Total	**$ (120)**	**$ —**	**$ —**	**$ (120)**
2018				
Assets				
Noncurrent investments available for sale	$ 535	$ 535	$ —	$ —
Total	**$ 535**	**$ 535**	$ —	$ —
Liabilities				
Derivatives	$ (498)	$ —	$ —	$ (498)
Total	**$ (498)**	**$ —**	**$ —**	**$ (498)**

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2019 and 2018. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

Valuation techniques: We measure the fair value of our noncurrent investments available for sale using quoted market prices in active markets for identical assets and include the measurements in Level 1. The investments primarily consist of money market funds.

We enter into fuel derivative contracts to hedge our unleaded and diesel fuel requirements for our fleet vehicles. Exchange based forward market prices are used but because a basis adjustment is added to the forward prices, we include the fair value measurement for these contracts in Level 3.

The reconciliation of changes in the fair value of financial instruments based on Level 3 inputs for the years ended December 31, 2019 and 2018 consisted of:

Year Ended December 31,		2019		2018
(Thousands)				
Beginning balance	$	(498)	$	(73)
Realized losses included in earnings		283		13
Unrealized gains (losses) included in other comprehensive income		95		(438)
Ending balance	**$**	**(120)**	**$**	**(498)**

The amounts of realized and unrealized gain and loss included in earnings for the period (above) are reported in Operations and maintenance of the consolidated statements of income.

Note 15. Accumulated Other Comprehensive Loss

Accumulated Other Comprehensive Loss for the years ended December 31, 2019 and 2018 consisted of:

(Thousands)	Balance December 31, 2017	2018 Change	Balance December 31, 2018	Balance January 1, 2019	Adoption of new accounting standard	2019 Change	Balance December 31, 2019
Amortization of pension cost for nonqualified plans, net of income tax expense of $32 for 2018	$ (1,873)	$ 82	$ (1,791)	$ (1,791)	$ —	$ —	$ (1,791)
Unrealized (loss) gain on derivatives qualified as hedges:							
Unrealized (loss) gain during period on derivatives qualified as hedges, net of income tax (benefit) expense of $(123) for 2018 and $24 for 2019		(315)				71	
Reclassification adjustment for loss included in net income, net of income tax expense of $3 for 2018 and $72 for 2019		10			(761)	211	
Reclassification adjustment for loss on settled cash flow treasury hedges, net of income tax expense of $609 for 2018 and $243 for 2019		1,562				714	
Net unrealized (loss) gain on derivatives qualified as hedges	(3,424)	1,257	(2,167)	(2,167)	—	996	(1,171)
Accumulated Other Comprehensive Loss	**$ (5,297)**	**$ 1,339**	**$ (3,958)**	**$ (3,958)**	**$ (761)**	**$ 996**	**$ (3,723)**

No Accumulated Other Comprehensive Loss is attributable to the non-controlling interest for the above periods.

Note 16. Post-Retirement and Similar Obligations

We have funded noncontributory defined benefit pension plans that cover the majority of employees. The plans provide defined benefits based on years of service and final average salary for employees hired before 2002. Most employees hired in 2002, or later based upon the plan, are covered under a cash balance plan or formula where their benefit accumulates based on a percentage of annual salary and credited interest. During 2013, the company announced that we would discontinue, effective December 31, 2013, the cash balance accruals for all non-union employees covered under the cash balance plans or formula. At the same time, the plans were closed to newly-hired non-union employees. The plans had been closed to newly-hired union employees in prior years. CMP's unionized employees covered under the cash balance plans ceased to receive accruals as of December 31, 2014. Their earned balances will continue to accrue interest but will no longer be increased by a flat dollar amount or percentage of pay, as defined by the plan. Instead, they will receive a contribution to their account under their respective company's defined contribution plan. There was no change to the defined benefit plans for employees covered under the plans that provide defined benefits based on years of service and final average salary. Employees not participating in a defined benefit plan are eligible to receive an enhanced or core 401(k) Company matching contribution, depending on whether they are union or non-union employees, respectively.

The company maintains a 401(k) Savings and Retirement Plan (the Plan) for all eligible employees as defined in the Plan agreement. Participants in the Plan may contribute a percentage of their compensation and the company may match a predetermined percentage of the participant contributions. Expenses under the Plan for the Company totaled approximately $3.7 million for 2019 and $3.6 million for 2018.

We also have other postretirement health care benefit plans covering the majority of our employees. The plans were closed to newly-hired non-union employees at the end of 2010. The plans had been closed to union employees in prior years. The pre-Medicare-eligible healthcare plans are contributory and participants' contributions are adjusted annually. Networks average contribution to these plans is limited at a level determined in prior periods. Except for a small group of "grandfathered" retirees, all Medicare eligible retirees that choose to participate are provided with a subsidy through a Health Reimbursement Account (HRA) to purchase coverage on the individual market.

Obligations and funded status as of December 31, 2019 and 2018 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2019**	**2018**	**2019**	**2018**
(Thousands)				
Change in benefit obligation				
Benefit obligation as of January 1,	**$ 401,698**	**$ 431,986**	**$ 99,658**	**$ 114,196**
Service cost	7,143	7,654	498	642
Interest cost	15,421	15,339	3,783	4,021
Plan participants' contributions	—	—	—	1,038
Actuarial loss (gain)	43,011	(24,470)	5,243	(12,619)
Benefits paid	(25,740)	(28,811)	(6,529)	(7,620)
Benefit obligation as of December 31,	**$ 441,533**	**$ 401,698**	**$ 102,653**	**$ 99,658**
Change in plan assets				
Fair value of plan assets at January 1,	**$ 277,626**	**$ 301,503**	**$ 31,447**	**$ 36,682**
Actual return (loss) on plan assets	47,281	(15,066)	4,978	(1,640)
Employer contributions	20,000	20,000	3,391	2,987
Plan participants' contributions	—	—	—	1,038
Benefits paid	(25,740)	(28,811)	(6,529)	(7,620)
Fair value of plan assets at December 31,	**$ 319,167**	**$ 277,626**	**$ 33,287**	**$ 31,447**
Funded status at December 31,	**$ (122,366)**	**$ (124,072)**	**$ (69,366)**	**$ (68,211)**

Amounts recognized as of December 31, 2019 and 2018 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	2019	2018	2019	2018
(Thousands)				
Non-current liabilities	$ (122,366)	$ (124,072)	$ (69,366)	$ (68,211)

We have determined that we are allowed to defer as regulatory assets or regulatory liabilities items that would otherwise be recorded in accumulated other comprehensive income pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans.

Amounts recognized as regulatory assets or regulatory liabilities for the years ended December 31, 2019 and 2018 consisted of:

	Pension Benefits		Postretirement Benefits	
Years Ended December 31,	2019	2018	2019	2018
(Thousands)				
Net loss	$ 176,501	$ 174,427	$ 33,344	$ 33,731
Prior service cost (credit)	$ —	$ —	$ (4,663)	$ (6,675)

Our accumulated benefit obligation (ABO) for all defined benefit pension plans was $406.0 million and $373.6 million as of December 31, 2019 and 2018.

Our postretirement benefits were partially funded at December 31, 2019 and 2018.

The projected benefit obligation (PBO) and ABO exceeded the fair value of pension plan assets for our plans as of December 31, 2019 and 2018.

The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets for the relevant periods.

As of December 31,	2019	2018
(Thousands)		
Projected benefit obligation	$441,533	$401,698
Accumulated benefit obligation	$405,994	$373,583
Fair value of plan assets	$319,167	$277,626

Components of net periodic benefit cost and other changes in plan assets and benefit obligations recognized in income and regulatory assets and liabilities for the years ended December 31, 2019 and 2018 consisted of:

For the years ended December 31,	Pension Benefits 2019	Pension Benefits 2018	Postretirement Benefits 2019	Postretirement Benefits 2018
(Thousands)				
Net Periodic Benefit Cost:				
Service cost	$7,143	$7,654	$498	$642
Interest cost	15,421	15,339	3,783	4,021
Expected return on plan assets	(21,875)	(21,503)	(1,868)	(2,177)
Amortization of prior service cost (benefit)	—	—	(2,013)	(2,013)
Amortization of net loss	15,531	20,245	2,520	3,346
Net Periodic Benefit Cost	**$16,220**	**$21,735**	**$2,920**	**$3,819**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities:				
Net loss (gain)	$ 17,604	$ 12,099	$ 2,133	$ (8,802)
Amortization of net loss	(15,531)	(20,245)	(2,520)	(3,346)
Amortization of prior service (cost) benefit	—	—	2,013	2,013
Total Other Changes	**2,073**	**(8,146)**	**1,626**	**(10,135)**
Total Recognized	**$ 18,293**	**$ 13,589**	**$ 4,546**	**$ (6,316)**

We include the net periodic benefit cost in other operating expenses for the service component and other deductions for the non-service component. The net periodic benefit cost for postretirement benefits represents the amount expensed for providing health care benefits to retirees and their eligible dependents.

Amounts expected to be amortized from regulatory assets or liabilities into net periodic benefit cost for the year ending December 31, 2020 consist of:

	Pension Benefits	Postretirement Benefits
(Thousands)		
Estimated net loss	$ 16,843	$ 2,230
Estimated prior service cost (benefit)	$ —	$ (2,013)

We expect that no pension benefit or postretirement benefit plan assets will be returned to us during the year ending December 31, 2020.

The weighted-average assumptions used to determine benefit obligations as of December 31, 2019 and 2018 consisted of:

	Pension Benefits 2019	Pension Benefits 2018	Postretirement Benefits 2019	Postretirement Benefits 2018
Discount rate	2.93%	3.93%	2.93%	3.93%
Rate of compensation increase	Age-Related Rates	3.70%-4.20%	Age-Related Rates	N/A

The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rates by developing yield curves derived from a portfolio of high grade noncallable bonds with yields that closely match the duration of the expected cash flows of our benefit obligations.

The weighted-average assumptions used to determine net periodic benefit cost for the years ended December 31, 2019 and 2018 consisted of:

	Pension Benefits		Postretirement Benefits	
Years Ended December 31,	**2019**	**2018**	**2019**	**2018**
Discount rate	3.93%	3.63%	3.93%	3.63%
Expected long-term return on plan assets	7.30%	7.30%	—	—
Expected long-term return on plan assets - nontaxable trust	—	—	6.40%	6.40%
Expected long-term return on plan assets - taxable trust	—	—	4.20%	4.20%
Rate of compensation increase (Union/Non-Union)	3.70%-4.20%	3.70%-4.20%	Age-Related Rates	N/A

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations, and the effect of rebalancing of plan assets discussed below. Our analysis considered current capital market conditions and projected conditions. Our policy is to calculate the expected return on plan assets using the market related value of assets. We amortize unrecognized actuarial gains and losses using the standard amortization methodology under which amounts in excess of 10% of the greater of the projected benefit obligation or market related value are amortized over the plan participants' average remaining service to retirement.

Assumed health care cost trend rates used to determine benefit obligations as of December 31, 2019 and 2018 consisted of:

As of December 31,	**2019**	**2018**
Health care cost trend rate assumed for next year	6.75%/7.50%	7.50%/8.50%
Rate to which cost trend rate is assumed to decline (ultimate trend rate)	4.50%	4.50%
Year that the rate reaches the ultimate trend rate	2029/2027	2030/2028

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plan. The effects of a one-percent change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
(Thousands)		
Effect on total of service and interest cost	$ 195	$ (160)
Effect on postretirement benefit obligation	$ 6,020	$ (4,126)

Contributions

We make annual contributions in accordance with our funding policy of not less than the minimum amounts as required by applicable regulations. We expect to contribute $20 million to our pension benefit plans during 2020.

Estimated future benefit payments

Expected benefit payments and Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) subsidy receipts reflecting expected future service as of December 31, 2019 consisted of:

(Thousands)	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
2020	$18,707	$6,597	$160
2021	$19,272	$6,406	$173
2022	$20,146	$6,292	$184
2023	$20,982	$6,185	$195
2024	$21,637	$6,135	$203
2024 - 2027	$119,078	$29,481	$1,130

Plan assets

Our pension benefits plan assets were consolidated from three legacy master trusts to one new master trust in 2019. A consolidated trust provides for a uniform investment manager lineup and an efficient, cost-effective means of allocating expenses and investment performance to each plan. Our primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our risk tolerance. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. Our primary means for achieving capital preservation is through diversification of the trust's investments while avoiding significant concentrations of risk in any one area of the securities markets. Further diversification is achieved within each asset group through utilizing multiple asset managers and systematic allocation to various asset classes and providing broad exposure to different segments of the equity, fixed income and alternative investment markets.

The asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established target asset allocation policies within allowable ranges for our pension benefits plan assets within broad categories of asset classes made up of Return-Seeking investments and Liability-Hedging investments. We currently have target allocations ranging from 35%-70% for Return-Seeking assets and 34%-65% for Liability-Hedging assets. Return-Seeking investments generally consist of domestic, international, global, and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking assets also include investments in real estate, global asset allocation strategies and hedge funds. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of pension benefits plan assets, by asset category, as of December 31, 2019, consisted of:

As of December 31, 2019		Fair Value Measurements		
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 5,540	$ 1	$ 5,539	$ —
U.S. government securities	13,469	13,469	—	—
Registered investment companies	50,661	50,661	—	—
Corporate bonds	71,002	—	71,002	—
Preferred stocks	199	199	—	—
Other, principally annuity, fixed income	13,110	—	13,110	
	$ 153,981	**$ 64,330**	**$ 89,651**	**$ —**
Other investments measured at net asset value	165,186			
Total	**$ 319,167**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2018, consisted of:

As of December 31, 2018		Fair Value Measurements		
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 5,714	$ —	$ 5,714	$ —
U.S. government securities	1,674	1,674	—	—
Common stocks	10	10	—	—
Registered investment companies	23,947	23,947	—	—
Corporate bonds	45,646	—	45,646	—
Preferred stocks	389	30	359	—
Equity commingled funds	89,941	19,854	70,087	—
Other, principally annuity, fixed income	7,898	—	7,898	—
	$ 175,219	**$ 45,515**	**$ 129,704**	**$ —**
Other investments measured at net asset value	102,407			
Total	**$ 277,626**			

Valuation Techniques

We value our pension benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities and common stock - at the closing price reported in the active market in which the security is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks - at the closing price reported in the active market in which the individual investment is traded.

- Registered investment companies - at the closing price reported in the active market in which the individual investment is traded.
- Equity commingled funds - the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Other investments measured at net asset value (NAV) - fund shares offered to a limited group of investors and alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

Our postretirement benefits plan assets are held with trustees in multiple voluntary employees' beneficiary association (VEBA) and 401(h) arrangements and are invested among and within various asset classes to achieve sufficient diversification in accordance with our risk tolerance. This is achieved for our postretirement benefits plan assets through the utilization of multiple institutional mutual and money market funds, providing exposure to different segments of the fixed income, equity and short-term cash markets. Approximately 37% of the postretirement benefits plan assets are invested in VEBA and 401(h) arrangements that are not subject to income taxes with the remainder being invested in arrangements subject to income taxes.

We have established a target asset allocation policy within allowable ranges for postretirement benefits plan assets of 45%-65% for equity securities, 25%-45% for fixed income and 5%-25% for all other investment types. The target allocations within allowable ranges are further diversified into 27%-66% large cap domestic equities, 5% small cap domestic equities, 8% international developed market, and 6% emerging market equity securities. Fixed income investment targets and ranges are segregated into core fixed income at 24%-31%, global high yield fixed income at 4%, and international developed market debt at 3%. Other alternative investment targets are 6% for real estate, 6% for tangible assets, and 3%-11% for other funds. Equity investments are diversified across U.S. and non-U.S. stocks, investment styles, and market capitalization ranges. Fixed income investments are primarily invested in U.S. bonds and may also include some non-U.S. bonds. Other asset classes, including alternative investments, are used to enhance long-term returns while improving portfolio diversification. We primarily minimize the risk of large losses through diversification but also through monitoring and managing other aspects of risk through quarterly investment portfolio reviews. Systematic rebalancing within target ranges increases the probability that the annualized return on investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of other postretirement benefits plan assets, by asset category, as of December 31, 2019, consisted of:

As of December 31, 2019		**Fair Value Measurements**		
(Thousands)	**Total**	**Level 1**	**Level 2**	**Level 3**
Asset Category				
Cash and cash equivalents	$ 900	$ —	$ 900	$ —
Common stocks	4,898	4,898	—	—
Registered investment companies	27,026	27,026	—	—
Corporate bonds	463	—	463	—
Total	**$ 33,287**	**$ 31,924**	**$ 1,363**	**$ —**

The fair values of pension benefits plan assets, by asset category, as of December 31, 2018, consisted of:

As of December 31, 2018		Fair Value Measurements		
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Money market funds	$ 1,962	$ 1,025	$ 937	$ —
Registered investment companies	23,274	22,930	344	—
Common collective trusts	4,637	4,637	—	—
Mutual funds, other	1,574	—	1,574	—
Total	**$ 31,447**	**$ 28,592**	**$ 2,855**	**$ —**

Valuation techniques

We value our postretirement benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- Common stocks and registered investment companies - at the closing price reported in the active market in which the individual investment is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Money market funds and mutual funds - based upon quoted market prices in active markets.

Pension and postretirement plan equity securities did not include any AGR and Iberdrola common stock as of both December 31, 2019 and 2018.

Note 17. Other Income and Other Deductions

Other Income and Other Deductions for the years ended December 31, 2019 and 2018 consisted of:

Years Ended December 31,	2019	2018
(Thousands)		
Gain on sale of property	$ 557	$ 1,423
Interest and dividends income	720	31
Allowance for funds used during construction	9,030	6,885
Carrying costs on regulatory assets	975	1,527
Equity earnings	105	43
Miscellaneous	708	409
Total other income	**$ 12,095**	**$ 10,318**
Pension non-service components	$ (10,946)	$ (16,344)
Miscellaneous	(4,292)	(806)
Total other deductions	**$ (15,238)**	**$ (17,150)**

Note 18. Related Party Transactions

Certain Networks subsidiaries, including CMP, borrow from AGR, the parent of Networks, through intercompany revolving credit agreements. For CMP, the intercompany revolving credit agreements provide access to supplemental liquidity. See Note 8 for further detail on the credit facility with AGR.

AGR, through its affiliates, provides administrative and management services to Networks operating utilities, including CMP, pursuant to service agreements. The cost of those services is allocated in accordance with methodologies set forth in the service agreements. The cost allocation methodologies vary depending on the type of service provided. Management believes such allocations are reasonable. The charge for operating and capital services provided to CMP by AGR and its affiliates was $43.1 million and $37.2 million for 2019 and 2018, respectively. Charge for services provided by CMP to AGR and its subsidiaries were approximately $5.7 million for 2019 and $4.0 million for 2018. All charges for services are at cost. The balance in accounts payable to affiliates of $8.3 million at December 31, 2019 is mostly payable to Avangrid Service Company and The United Illuminating Company and the balance of $38.4 million at December 31, 2018 is mostly payable to Avangrid Service Company.

The balance in accounts receivable from affiliates of $0.9 million at December 31, 2019 is from various companies and the balance of $1.8 million as of December 31, 2018 is mostly from Avangrid Service Company.

The balance in notes receivable from affiliates of $23.0 million at December 31, 2019 and the balance of $12.7 million at December 31, 2018 is from the UIL companies. Notes receivable from affiliates relate to the Virtual Money Pool Agreement as discussed in Note 8 of these financial statements.

Note 19. Subsequent Events

The company has performed a review of subsequent events through March 31, 2020, which is the date these financial statements were available to be issued.

In March 2020 the World Health Organization declared a global pandemic due to the outbreak of COVID-19. The company is assessing the possible impacts to our business and financial results.

THE BERKSHIRE GAS COMPANY

AUDITED FINANCIAL STATEMENTS

AS OF AND FOR THE YEARS ENDED

DECEMBER 31, 2019 AND 2018

TABLE OF CONTENTS

KPMG LLP
677 Washington Boulevard
Stamford, CT 06901

Independent Auditors' Report

The Board of Directors
The Berkshire Gas Company:

We have audited the accompanying financial statements of The Berkshire Gas Company, which comprise the balance sheets as of December 31, 2019 and 2018, and the related statements of income, changes in shareholder's equity, and cash flows for the years then ended, 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 U.S. generally accepted accounting principles; 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 auditors' 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 entity'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 entity'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 Berkshire Gas Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

KPMG LLP

Stamford, Connecticut
April 14, 2020

THE BERKSHIRE GAS COMPANY
STATEMENTS OF INCOME
(In Thousands)

	Year Ended December 31, 2019	Year Ended December 31, 2018
Operating Revenues	$ 82,336	$ 79,674
Operating Expenses		
Natural gas purchased	30,545	28,549
Operation and maintenance	26,127	28,738
Depreciation and amortization	8,039	8,452
Taxes other than income taxes	4,963	4,696
Total Operating Expenses	69,674	70,435
Operating Income	12,662	9,239
Other Income and (Expense), net	(400)	(1,319)
Interest Expense, net	3,225	3,502
Income Before Income Tax	9,037	4,418
Income Tax	1,436	1,410
Net Income	$ 7,601	$ 3,008

The accompanying Notes to Financial Statements
are an integral part of the financial statements

THE BERKSHIRE GAS COMPANY
STATEMENTS OF CASH FLOWS
(In Thousands)

	Year Ended December 31, 2019	Year Ended December 31, 2018
Cash Flows From Operating Activities		
Net income	$ 7,601	$ 3,008
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	8,159	8,563
Deferred income taxes	(592)	3,881
Uncollectible expense	569	502
Pension expense	1,932	1,272
Regulatory assets/liabilities amortization	702	1,569
Regulatory assets/liabilities carrying costs	7	54
Other non-cash items, net	106	75
Changes in:		
Accounts receivable and unbilled revenue, net	(2,166)	(1,778)
Natural gas in storage	(26)	(559)
Accounts payable and accrued liabilities	(3,615)	(1,896)
Accrued pension and other post-retirement	(2,062)	(139)
Regulatory assets/liabilities	4,100	(3,955)
Other assets	2,374	(2,686)
Other liabilities	(383)	(537)
Total Adjustments	9,105	4,366
Net Cash provided by Operating Activities	16,706	7,374
Cash Flows from Investing Activities		
Plant expenditures including AFUDC debt	(17,243)	(21,862)
Net Cash used in Investing Activities	(17,243)	(21,862)
Cash Flows from Financing Activities		
Payment of long-term debt	(11,455)	(1,455)
Issuance of long-term debt	20,000	-
Notes payable to affiliates	(7,713)	15,965
Other	(139)	(43)
Net Cash provided by (used in) Financing Activities	693	14,467
Unrestricted Cash and Temporary Cash Investments:		
Net change for the period	156	(21)
Balance at beginning of period	326	347
Balance at end of period	$ 482	$ 326
Cash paid during the period for:		
Interest (net of amount capitalized)	$ 3,144	$ 3,312
Non-cash investing activity:		
Plant expenditures included in ending accounts payable	$ 1,782	$ 1,259

The accompanying Notes to Financial Statements
are an integral part of the financial statements.

THE BERKSHIRE GAS COMPANY
BALANCE SHEETS
ASSETS
(In Thousands)

	December 31, 2019	December 31, 2018
Assets		
Current Assets		
Unrestricted cash and temporary cash investments	$ 482	$ 326
Accounts receivable and unbilled revenues, net	15,978	16,103
Accounts receivable from affiliates	1,773	129
Regulatory assets	9,975	11,531
Gas in storage	2,473	2,447
Materials and supplies	1,116	907
Other current assets	1,967	4,612
Total Current Assets	33,764	36,055
Other Investments	2,185	2,213
Net Property, Plant and Equipment	191,448	180,150
Regulatory Assets	33,316	32,540
Deferred Charges and Other Assets		
Goodwill	51,933	51,933
Other	62	-
Total Deferred Charges and Other Assets	51,995	51,933
Total Assets	$ 312,708	$ 302,891

The accompanying Notes to Financial Statements
are an integral part of the financial statements.

THE BERKSHIRE GAS COMPANY
BALANCE SHEETS
LIABILITIES AND CAPITALIZATION
(In Thousands)

	December 31, 2019	December 31, 2018
Liabilities		
Current Liabilities		
Notes payable to affiliates	$ 23,030	$ 30,730
Current portion of long-term debt	10,062	12,393
Accounts payable and accrued liabilities	12,745	14,204
Accounts payable to affiliates	2,052	3,744
Other current liabilities	1,410	1,351
Interest accrued	789	886
Regulatory liabilities	2,132	61
Total Current Liabilities	52,220	63,369
Deferred Income Taxes	24,693	21,096
Regulatory Liabilities	51,374	52,560
Other Noncurrent Liabilities		
Pension	21,724	20,768
Environmental remediation costs	3,950	3,950
Other	2,064	2,358
Total Other Noncurrent Liabilities	27,738	27,076
Capitalization		
Long-term debt	36,013	25,721
Common Stock Equity		
Paid-in capital	106,095	106,095
Retained earnings	14,575	6,974
Net Common Stock Equity	120,670	113,069
Total Capitalization	156,683	138,790
Total Liabilities and Capitalization	$ 312,708	$ 302,891

The accompanying Notes to Financial Statements
are an integral part of the financial statements.

THE BERKSHIRE GAS COMPANY

STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

December 31, 2019

(Thousands of Dollars)

	Common Stock Shares	Common Stock Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance as of December 31, 2017	100	$ -	$ 106,095	$ 3,964	$ 2	$ 110,061
Net income				3,008		3,008
Adoption of accounting standard				2	(2)	-
Balance as of December 31, 2018	100	$ -	$ 106,095	$ 6,974	$ -	$ 113,069
Net income				7,601		7,601
Balance as of December 31, 2019	100	$ -	$ 106,095	$ 14,575	$ -	$ 120,670

The accompanying Notes to Financial Statements
are an integral part of the financial statements.

NOTES TO FINANCIAL STATEMENTS

(A) STATEMENT OF ACCOUNTING POLICIES

The Berkshire Gas Company (Berkshire) engages in natural gas transportation, distribution and sales operations in Massachusetts serving approximately 41,000 customers in its service area totaling 738 square miles. Berkshire is regulated by the Massachusetts Department of Public Utilities (DPU) as it relates to utility service.

Berkshire is the principal operating utility of Berkshire Energy Resources (BER), a wholly-owned subsidiary of UIL Holdings Corporation (UIL Holdings). BER is a holding company whose sole business is ownership of its operating regulated gas utility. UIL Holdings, whose primary business is ownership of its operating regulated utility businesses, is a wholly owned subsidiary of Avangrid Networks, Inc. (Networks), which is a wholly-owned subsidiary of Avangrid, Inc., which is a 81.5% owned subsidiary of Iberdrola, S.A., a corporation organized under the law of the Kingdom of Spain.

Accounting Records

The accounting records of Berkshire are maintained in conformity with generally accepted accounting principles in the United States of America (GAAP) and also maintained in accordance with the uniform systems of accounts prescribed by the Federal Energy Regulatory Commission (FERC) and the DPU.

Basis of Presentation

The preparation of financial statements in conformity with GAAP requires management to use estimates and assumptions that affect (1) the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and (2) the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Berkshire has evaluated subsequent events through the date its financial statements were available to be issued, April 14, 2020.

The following policies are considered to be the most critical in understanding the judgments that are involved in preparing Berkshire's financial statements:

Revenues

On January 1, 2018, Berkshire adopted Accounting Standards Codification (ASC), Topic 606, "Revenue from Contracts with Customers" (ASC 606) and all related amendments using the modified retrospective method, which was applied only to contracts that were not completed as of January 1, 2018. For reporting periods beginning on January 1, 2018, Berkshire presents revenue in accordance with ASC 606. For the year ended December 31, 2018, the effect of applying ASC 606 to recognize revenue as compared to applying the legacy accounting standards was not material.

Berkshire derives its revenue primarily from tariff-based sales of natural gas delivered to customers. For such revenues, Berkshire recognizes revenues in an amount derived from the commodities delivered to customers. Another major source of revenue is wholesale sales of natural gas.

Tariff-based sales are subject to DPU approval, which determines prices and other terms of service through the ratemaking process. Certain customers have the option to obtain the natural gas directly from Berkshire or from another supplier. For customers that receive their natural gas from another supplier, Berkshire acts as an agent and delivers the natural gas for that supplier. Revenue in those cases is only for providing the service of delivery of the natural gas. Berkshire calculates revenue earned but not yet billed based on the number of days not billed in the month, the estimated amount of energy delivered during those days and the estimated average price per customer class for that month. Differences between actual and estimated unbilled revenue are immaterial.

The performance obligation in all arrangements is satisfied over time because the customer simultaneously receives and consumes the benefits as Berkshire delivers or sells the natural gas. Berkshire records revenue for all of those sales based upon the regulatory-approved tariff and the volume delivered, which corresponds to the amount that Berkshire has a right to invoice. There are no material initial incremental costs of obtaining a contract in any of the arrangements. Berkshire does not adjust the promised consideration for the effects of a significant financing component if it expects, at contract inception, that the time between the delivery of promised goods or service and customer payment will be one year or less. Berkshire does not have any material significant payment terms because it receives payment at or shortly after the point of sale.

Beginning in February 2019, Berkshire began recording revenue from an Alternative Revenue Program (ARP), which is not ASC 606 revenue. This program, a revenue decoupling mechanism, represents a contract between Berkshire and their regulators. Berkshire recognizes and records only the initial recognition of "originating" ARP revenues (when the regulatory-specified conditions for recognition have been met). When Berkshire subsequently includes those amounts in the price of utility service billed to customers, they record such amounts as a recovery of the associated regulatory asset or liability. When they owe amounts to customers in connection with ARPs, they evaluate those amounts on a quarterly basis and include them in the price of utility service billed to customers and do not reduce ARP revenues.

Berkshire also has various other sources of revenue including billing, collection, other administrative charges, sundry billings, rent of utility property, and miscellaneous revenue. It classifies such revenues as other ASC 606 revenues to the extent they are not related to revenue generating activities from leasing, or ARPs.

Revenues disaggregated by major source are as follows:

(Thousands)	Year Ended December 31, 2019	Year Ended December 31, 2018
Regulated operations – natural gas	$ 80,340	$ 78,507
Other (a)	77	31
Revenue from contracts with customers	**80,417**	**78,538**
Leasing revenue	1,135	1,136
Alternative revenue programs	784	-
Total operating revenues	**$ 82,336**	**$ 79,674**

(a) Primarily includes certain intra-month trading activities, billing, collection, and administrative charges, sundry billings, and other miscellaneous revenue.

Regulatory Accounting

Generally accepted accounting principles for regulated entities in the United States of America allows Berkshire to give accounting recognition to the actions of regulatory authorities in accordance with the provisions of ASC 980 "Regulated Operations." In accordance with ASC 980, Berkshire has deferred recognition of costs (a regulatory asset) or have recognized obligations (a regulatory liability) if it is probable that such costs will be recovered or obligations refunded in the future through the ratemaking process. Berkshire is allowed to recover all such deferred costs and is required to refund such obligations to customers through its regulated rates. See Note (C) “Regulatory Proceedings”, for a discussion of the recovery of certain deferred costs and the refund of certain obligations, as well as a discussion of the regulatory decisions that provide for such recovery and require such refunding.

If Berkshire, or a portion of their assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs would be required in the year in which such criteria are no longer met (if such deferred costs are not recoverable in the portion of the business that continues to meet the criteria for application of ASC 980). Berkshire expects to continue to meet the criteria for application of ASC 980 for the foreseeable future. If a change in accounting were to occur, it could have a material adverse effect on the Berkshire’s earnings and retained earnings in that year and could also have a material adverse effect on Berkshire’s ongoing financial condition.

Unless otherwise stated below, all of Berkshire’s regulatory assets earn a return. Berkshire’s regulatory assets and liabilities as of December 31, 2019 and 2018 included the following:

	Remaining Period	December 31, 2019	December 31, 2018
		(In Thousands)	
Regulatory Assets:			
Pension and other post-retirement benefit plan	(a)	$ 24,324	$ 23,312
Environmental remediation costs	7 years	6,135	7,117
Debt premium	0 to 2 years	607	1,159
Deferred purchased gas	(b)	6,516	8,117
Unfunded future income taxes	(c)	724	724
Other	(d)	4,985	3,642
Total regulatory assets		43,291	44,071
Less current portion of regulatory assets		9,975	11,531
Regulatory Assets, Net		$ 33,316	$ 32,540
Regulatory Liabilities:			
Pension and other postretirement benefit plan	(a)	$ 425	$ 128
Asset removal costs	(d)	36,097	35,031
Tax reform	19 years	15,423	16,523
Non-firm margin sharing credits	10 months	634	757
Decoupling	(e)	884	-
Other	(d)	43	182
Total regulatory liabilities		53,506	52,621
Less current portion of regulatory liabilities		2,132	61
Regulatory Liabilities, Net		$ 51,374	$ 52,560

(a) Life is dependent upon timing of final pension plan distribution; balance, which is fully offset by a corresponding asset/liability, is recalculated each year in accordance with ASC 715 "Compensation-Retirement Benefits." See Note (F) Pension and Other Benefits for additional information.
(b) Deferred purchase gas costs balances at the end of the rate year are normally recorded / returned in the next year.
(c) The balance will be extinguished when the asset, which is fully offset by a corresponding liability, or liability has been realized or settled, respectively.
(d) Amortization period and/or balance vary depending on the nature, cost of removal and/or remaining life of the underlying assets/liabilities.

(e) Decoupling regulatory liability is not currently earning a return. The return of the liability to customers will be determined in a future proceeding with the DPU.

Goodwill

The goodwill for Berkshire resulted from the purchase of Berkshire by UIL Holdings in 2010 and amounted to $51.9 million.

Goodwill is not amortized, but is subject to an assessment for impairment at least annually or more frequently if events occur or circumstances change that will more likely than not reduce the fair value of the reporting unit below its carrying amount. A reporting unit is an operating segment or one level below an operating segment and is the level at which goodwill is tested for impairment.

In assessing goodwill for impairment, Berkshire has the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary, or step zero. If it is determined, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If Berkshire bypasses step zero or performs the qualitative assessment but determines that it is more likely than not that its fair value is less than its carrying amount, a quantitative two step, fair value based test is performed. Step one compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, step two is performed. Step two requires an allocation of fair value to the individual assets and liabilities using business combination accounting guidance to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than its carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense.

Berkshire's annual impairment testing takes place as of October 1. Berkshire's step zero qualitative assessment involves evaluating key events and circumstances that could affect its fair value, as well as other factors. Events and circumstances evaluated include macroeconomic conditions, industry, regulatory and market considerations, cost factors and their effect on earnings and cash flows, overall financial performance as compared with projected results and actual results of relevant prior periods, other relevant entity specific events, and events affecting Berkshire.

Berkshire's step one impairment testing includes various assumptions, primarily the discount rate, which is based on an estimate of the marginal, weighted average cost of capital, and forecasted cash flows. Berkshire tests the reasonableness of the conclusions of the step one impairment testing using a range of discount rates and a range of assumptions for long term cash flows.

Berkshire had no impairment of goodwill in 2019 and 2018 as a result of its impairment testing.

Property, Plant and Equipment

The cost of additions to property, plant and equipment and the cost of renewals and betterments are capitalized. Costs consist of labor, materials, services and certain indirect construction costs, including allowance for funds used during construction (AFUDC). The costs of current repairs, major maintenance projects and minor replacements are charged to appropriate operating expense accounts as incurred. The original cost of utility property, plant and equipment retired or otherwise disposed of and the cost of removal, less salvage, are charged to the accumulated provision for depreciation.

Berkshire accrues for estimated costs of removal for certain of their plant-in-service. Such removal costs are included in the approved rates used to depreciate these assets. At the end of the service life of the applicable assets, the accumulated depreciation in excess of the historical cost of the asset provides for the estimated cost of removal. In accordance with ASC 980 "Regulated Operations," the accrued costs of removal have been recorded as a regulatory liability.

Berkshire's property, plant and equipment as of December 31, 2019 and 2018 were comprised as follows:

	2019	2018
	(In Thousands)	
Gas distribution plant	$ 213,079	$ 202,720
Land	2,304	2,304
Buildings and improvements	29,395	28,578
Other plant	31,323	28,451
Total property, plant & equipment	276,101	262,053
Less accumulated depreciation	91,418	86,372
	184,683	175,681
Construction work in progress	6,765	4,469
Net property, plant & equipment	$ 191,448	$ 180,150

Allowance for Funds Used During Construction

In accordance with the uniform systems of accounts, Berkshire capitalizes AFUDC, which represents the approximate cost of debt and equity capital devoted to plant under construction. The portion of the allowance applicable to borrowed funds is presented as interest expense, net and the portion of the allowance applicable to equity funds are presented as other income in the Statement of Income. Although the allowance does not represent current cash income, it has historically been recoverable under the ratemaking process over the service lives of the related properties. The weighted-average AFUDC rate for 2019 and 2018 was 2.57% and 2.15% respectively. The portion of the allowance applicable to equity funds was immaterial for 2019 and 2018.

Depreciation

Provisions for depreciation on utility plant for book purposes are computed on a straight-line basis using composite rates based on the estimated service lives of the various classes of assets. For utility plant other than software, service lives are determined by independent depreciation consultants and subject to review and approval by the DPU. Software service life is based upon management's estimate of useful life. The aggregate annual provisions for depreciation for the years 2019 and 2018 were approximately $8.0 million and $8.5 million, respectively, or 3.0% and 3.4%, respectively, of the original cost of depreciable property.

Impairment of Long-Lived Assets and Investments

ASC 360 "Property, Plant, and Equipment" requires the recognition of impairment losses on long-lived assets when the book value of an asset exceeds the sum of the expected future undiscounted cash flows that result from the use of the asset and its eventual disposition. If impairment arises, then the amount of any impairment is measured based on discounted cash flows or estimated fair value.

ASC 360 also requires that rate-regulated companies recognize an impairment loss when a regulator excludes all or part of a cost from rates, even if the regulator allows the company to earn a return on the remaining costs allowed. Under this standard, the probability of recovery and the recognition of regulatory assets under the criteria of ASC 980 must be assessed on an ongoing basis. As discussed in the description of ASC 980 in this Note (A) under "Regulatory Accounting", determination that certain regulatory assets no longer qualify for accounting as such could have a material impact on the financial condition Berkshire. At December 31, 2019, Berkshire did not have any assets that were impaired under this standard.

Unrestricted cash and temporary cash investments

Berkshire considers all of its highly liquid debt instruments with an original maturity of three months or less at the date of purchase to be unrestricted cash and temporary cash investments.

Accounts receivable and unbilled revenues

Accounts receivable at December 31, 2019 and 2018 include unbilled revenues of $5.9 million and $5.1 million, respectively and are shown net of an allowance for doubtful accounts of $1.4 million for each of the years ended December 31, 2019 and 2018. Accounts receivable do not bear interest, although late fees may be assessed.

Unbilled revenues represent estimates of receivables for products and services provided but not yet billed. The estimates are determined based on various assumptions, such as current month energy load requirements, billing rates by customer classification and weather**.** Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

The allowance for doubtful accounts is management's best estimate of the amount of probable credit losses in the existing accounts receivable, determined based on experience. Each month, Berkshire reviews the allowance for doubtful accounts and past due accounts by age. When management believes that a receivable will not be recovered, the account balance is charged off against the allowance. Changes in assumptions about input factors and customer receivables, which are inherently uncertain and susceptible to change from period to period, could significantly affect the allowance for doubtful accounts estimates.

Gas in storage

Natural gas in storage is stored in both self-owned and third-party owned underground storage facilities. This gas is recorded as inventory. Injections of inventory into storage are priced at the market purchase cost at the time of injection, and withdrawals of working gas from storage are priced at the weighted-average cost in storage. Berkshire continuously monitors the weighted-average cost of gas value to ensure it remains at the lower of cost or net realizable value.

Materials and supplies

Materials and supplies inventories are used for construction of new facilities and repairs of existing facilities. The inventories are carried and withdrawn at lower of cost and net realizable value.

Other Investments

Berkshire's other investments consist of noncurrent investments available for sale and life insurance policies.

Asset removal costs

Berkshire meets the requirements concerning accounting for regulated operations, and recognizes a regulatory liability, for the difference between removal costs collected in rates and actual costs incurred. Berkshire classifies those amounts as asset removal costs.

Pension and Other Postretirement Benefits

Berkshire accounts for pension and other postretirement benefit plan costs in accordance with the provisions of ASC 715 "Compensation - Retirement Benefits." See – Note (F), Pension and Other Benefits.

Income Taxes

In accordance with ASC 740 "Income Taxes," Berkshire has provided deferred taxes for all temporary book-tax differences using the liability method. The liability method requires that deferred tax balances be adjusted to reflect enacted future tax rates that are anticipated to be in effect when the temporary differences reverse. In accordance with generally accepted accounting principles for regulated industries, Berkshire has established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences. For ratemaking purposes, investment tax credits related to recoverable plant investments are deferred when earned and amortized over the estimated lives of the related assets.

Under ASC 740, Berkshire may recognize the tax benefit of an uncertain tax position only if management believes it is more likely than not that the tax position will be sustained on examination by the taxing authority based upon the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based upon the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. Berkshire's policy is to recognize interest accrued and penalties associated with uncertain tax positions as a component of operating expense.

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Tax Act) was signed into law. The Tax Act contained significant changes to the federal tax structure, including among other things, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017. For this material decrease to its net deferred income tax liability balances, Berkshire recorded a corresponding net regulatory liability since such amount was probable of settlement through customer rates. As a result of its 2018 Rate Case Settlement Agreement dated January 18, 2019, Berkshire's revenue requirements reflect a $1.3 million amortization credit of its excess accumulated deferred federal income tax of $11.4 million over a 20 year period.

Adoption of New Accounting Pronouncements

Leases

In February 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Codification (ASC) Topic 842, "Leases", with subsequent amendments issued in 2018. The new leases guidance affects all companies and organizations that lease assets, and requires them to record on their balance sheet ROU assets and lease liabilities for the rights and obligations created by those leases. Under ASC 842, a lease is an arrangement that conveys the right to control the use of an identified asset for a period of time in exchange for consideration. The new guidance retains a distinction between finance leases and operating leases, while requiring companies to recognize both types of leases on their balance sheet. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the criteria for distinguishing between capital leases and operating leases in legacy U.S. GAAP - ASC 840. Lessor accounting remains substantially the same as ASC 840, but with some targeted improvements to align lessor accounting with the lessee accounting model and with the revised revenue recognition guidance under ASC 606. The new standard and amendments require new qualitative and quantitative disclosures for both lessees and lessors.

Berkshire's January 1, 2019 adoption of ASC 842 effective had no material effect on its results of operations, financial position and cash flows. Additionally, in March 2019, the FASB issued additional amendments to ASC 842 for minor codification improvements, which Berkshire early applied effective January 1, 2019, with no material effect to its results of operations, financial position and cash flows.

Reclassification of certain tax effects from accumulated other comprehensive income

In February 2018, the FASB issued ASU 2018-02 "Income Statement-Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income" which contains amendments to address a narrow-scope financial reporting issue that arose as a consequence of the Tax Cuts and Jobs Act of 2017 (the Tax Act) enacted on December 22, 2017 by the U.S. federal government. Under current guidance, the adjustment of deferred taxes for the effect of a change in tax laws or rates is required to be included in income from continuing operations, thus the associated tax effects of items within accumulated other comprehensive income (AOCI) (referred to as stranded tax effects) do not reflect the appropriate tax rate. The amendments allow a reclassification from AOCI to retained earnings for stranded tax effects resulting from the Tax Act. As a result, the amendments eliminate the stranded tax effects resulting from the Tax Act and will improve the usefulness of information reported to financial statement users. The amendments only relate to the reclassification of the income tax effects of the Tax Act, and do not affect the underlying guidance that requires the effect of a change in tax laws or rates to be included in income from continuing operations. Berkshire adopted the amendments effective January 1, 2019, which had no impact on its results of operations, financial position and cash flows.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements issued as indicated, that Berkshire has evaluated or is evaluating to determine their effect on its financial statements.

Simplifying the test for goodwill impairment

In January 2017, the FASB issued amendments to simplify the test for goodwill impairment, which are required for public entities and certain other entities that have goodwill reported in their financial statements. The amendments simplify the subsequent measurement of goodwill by eliminating Step 2 from the goodwill impairment test, which requires the valuation of assets acquired and liabilities assumed using business combination accounting guidance. Under the new guidance, an entity should perform its annual, or interim, goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; but the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. Also, an entity should consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable. Certain requirements are eliminated for any reporting unit with a zero or negative carrying amount, therefore the same impairment assessment applies to all reporting units. An entity still has the option to perform the qualitative assessment for a reporting unit to determine if the quantitative impairment test is necessary. The amendments are effective for public entities for annual and interim periods in fiscal years beginning after December 15, 2019, with the amendments applied on a prospective basis. Early adoption is allowed. Berkshire's adoption of the amendments on January 1, 2020, will not materially affect its results of operations, financial position, cash flows, and disclosures.

Changes to the disclosure requirements for fair value measurement and defined benefit plans

In August 2018, the FASB issued amendments related to disclosure requirements for both fair value measurement and defined benefit plans. The amendments concerning fair value measurement remove, modify and add certain disclosure requirements, in order to improve the overall usefulness of the disclosures and reduce unnecessary costs to companies to prepare the disclosures. The amendments to fair value measurement disclosures are effective for all entities for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted as specified. Certain amendments are to be applied prospectively, and all others are to be applied retrospectively. Berkshire's adoption of the amendments on January 1, 2020, will not materially affect its disclosures.

The amendments concerning disclosure requirements for defined benefit plans are narrow in scope and apply to all employers that sponsor defined benefit pension or other postretirement plans. They remove disclosures that are no longer considered cost beneficial, add certain new relevant disclosures and clarify specific requirements of disclosures concerning information for defined benefit pension plans. The amendments to defined benefit plan disclosures are effective for fiscal years ending after December 15, 2020. Early adoption is permitted and application is to be on a retrospective basis. Berkshire's adoption of the amendments on January 1, 2020, will not materially affect its disclosures.

Clarifying guidance for certain collaborative arrangements with respect to revenue recognition

The FASB issued amendments in November 2018 to clarify the interaction between the guidance for certain collaborative arrangements and the guidance applicable to ASC 606. A collaborative arrangement is a contractual arrangement under which two or more parties actively participate in a joint operating activity and are exposed to significant risks and rewards that depend on the activity's commercial success. The targeted improvements clarify that certain transactions between collaborative arrangement participants are within the scope of ASC 606 and thus subject to all of its guidance. The amendments are effective for public business entities for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted, including adoption in any interim period for which financial statements have not been issued. Retrospective application to the date of initial application of ASC 606 is required. Berkshire's adoption of the amendments on January 1, 2020, will not materially affect its results of operations, financial position, cash flows and disclosures.

Simplifying the accounting for income taxes

In December 2019, the FASB issued an accounting standards update that is intended to reduce complexity in accounting for income taxes. The amendments remove specific exceptions to the general principles in ASC 740, Income Taxes, eliminating the need for an entity to analyze whether the following apply in a given period: (1) exception to the incremental approach for intra-period tax allocation, (2) exceptions to accounting for basis differences when there are ownership changes in foreign investments and (3) exception in interim period income tax accounting for year-to-date losses that exceed anticipated losses. The amendments also improve financial statement preparers' application of income-tax related guidance and simplify U. S. GAAP for (1) franchise taxes that are partially based on income, (2) transactions with a government that result in a step up in the tax basis of goodwill, (3) separate financial statements of legal entities that are not subject to tax and (4) enacted changes in tax laws in interim periods. The amendments are effective for public business entities for fiscal years beginning after December 15, 2020, and interim periods within those fiscal years. Early adoption is permitted, including adoption in any interim period for which financial statements have not been issued, with adoption of all amendments in the same period. Application is on a retrospective and/or modified retrospective basis, or a prospective basis, depending on the amendment aspect. Berkshire expects its adoption will not materially affect its results of operations, financial position, and cash flows.

B) CAPITALIZATION

Common Stock

Berkshire had 100 shares of its common stock, $2.50 par value, outstanding as of December 31, 2019 and 2018.

Long-Term Debt

As of December 31,		**2019**		**2018**	
(Thousands)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
Senior unsecured notes	2020-2043	45,909	4.07%-9.60%	27,364	5.33%-9.60%
First mortgage bonds [(a)]	-	-	-	10,000	10.06%
Unamortized debt (costs) premium, net		166		750	
Total Debt		**46,075**		**38,114**	
Less: debt due within one year, included in current liabilities		10,062		12,393	
Total Non-current Debt		**36,013**		**25,721**	

(a) The first mortgages bonds are secured by a first mortgage lien on substantially all of Berkshire's properties.

The estimated fair value of debt amounted to $53.7 million and $40.8 million as of December 31 2019 and 2018, respectively. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the natural gas industry and the credit ratings of the borrowers in each case. The fair value hierarchy for the fair value of debt is considered as Level 2. The expenses to issue long-term debt are deferred and amortized over the life of the respective debt issue.

Information regarding maturities and mandatory redemptions/repayments are set forth below:

	2020	2021	2022	2023	2024 & Thereafter	Total
			(In Thousands)			
Maturities:	$ 9,454	$ 1,455	$ -	$ -	$ 35,000	$ 45,909

Under various debt agreements, Berkshire is required to maintain the following:

- A ratio of consolidated debt to consolidated capital of not greater than 65% (debt ratio). As of December 31, 2019, such ratio was 36%.
- A ratio of consolidated funded debt to consolidated adjusted capitalization (adjusted capitalization excludes the impact of goodwill) of not greater than 65%. As of December 31, 2019, such ratio was 44.0%.
- A fixed charges coverage ratio of no less than 1.50 to 1.00. As of December 31, 2019, such ratio was 3.78 to 1.00.
- To maintain a tangible net worth greater than $9 million. As of December 31, 2019, Berkshire's tangible net worth was $68.2 million.

(C) REGULATORY PROCEEDINGS

Rates

Utilities are entitled by Massachusetts statute to charge rates that are sufficient to allow them an opportunity to cover their reasonable operating and capital costs, to attract needed capital and to maintain their financial integrity, while also protecting relevant public interests.

Berkshire's rates are established by the DPU. On January 18, 2019, the DPU approved a settlement agreement between Berkshire and the Massachusetts Attorney General's Office providing for new distribution rates for Berkshire. The settlement agreement provides for a $1.6 million distribution base rate increase effective February 1, 2019 (with a make-whole provision back to January 1, 2019), and an additional $0.7 million base distribution increase effective November 1, 2019, if certain investments are made by Berkshire. The distribution rate increase is based on a 9.70% ROE and 54% equity ratio. The settlement agreement provides for the implementation of an revenue decoupling mechanism and pension expense tracker and also provides that Berkshire will not file to change base distribution rates to become effective before November 1, 2021.

Based on existing tracking mechanisms in place for gas and other costs, discussions with the DPU, and precedence set by other utility companies, Berkshire believes that regulatory assets are recoverable and regulatory liabilities are fairly stated. Additionally, Berkshire has a purchased gas adjustment clause approved by the DPU which enables the reasonably incurred cost of gas purchases to be passed through to customers. This clause allows Berkshire to recover changes in the market price of purchased natural gas, substantially eliminating exposure to natural gas price risk.

Gas Supply Arrangements

Berkshire satisfies its natural gas supply requirements through purchases from various producer/suppliers, withdrawals from natural gas storage capacity contracts and winter peaking supplies and resources. Berkshire operates diverse portfolios of gas supply, firm transportation, gas storage and peaking resources. Actual reasonable gas costs incurred by Berkshire are passed through to customers through state regulated purchased gas adjustment mechanisms subject to regulatory review.

Berkshire purchases the majority of the natural gas supply at market prices under seasonal, monthly or mid-term supply contracts and the remainder is acquired on the spot market. Berkshire diversifies its sources of supply by amount purchased and by location while primarily acquiring gas in the Appalachia region. Additionally, as of December 31, 2019, Berkshire was a party to a 90-day contract expiring on February 29, 2020 for a fixed daily quantity of natural gas. Berkshire's remaining commitment as of December 31, 2019 under this contract was approximately $1.2 million.

Berkshire acquires firm transportation capacity on interstate pipelines under long-term contracts and utilizes that capacity to transport both natural gas supply purchased and natural gas withdrawn from storage to the local distribution system. Tennessee Gas Pipeline interconnects with Berkshire's distribution system upstream of the city gates. The prices and terms and conditions of the firm transportation capacity long-term contracts are regulated by the FERC. The actual reasonable cost of such contracts is passed through to customers through state regulated purchased gas adjustment mechanisms.

Berkshire acquires firm underground natural gas storage capacity using long-term contracts and fills the storage facilities with gas in the summer months for subsequent withdrawal in the winter months. The storage facilities are located in Pennsylvania, New York and West Virginia.

Winter peaking resources are primarily attached to the local distribution system and are owned by Berkshire. Berkshire owns or has rights to the natural gas stored in its Liquefied Natural Gas (LNG) facility that is directly attached to its distribution system.

Tax Cuts and Jobs Act

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Tax Act) was signed into law. The Tax Act significantly changed the federal taxation of business entities including, among other things, implementing a federal corporate tax rate decrease from 35% to 21% for tax years beginning after December 31, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates will result in amounts previously and currently collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates. The DPU and the FERC have instituted proceedings in Massachusetts to review and address the implications of the Tax Act on the utilities. Berkshire included Tax Act savings in its rate case that was filed with the DPU in the second quarter of 2018 and such savings are included in new rates effective February 1, 2019.

(D) SHORT-TERM CREDIT ARRANGEMENTS

Berkshire funds short-term liquidity needs through an agreement among Avangrid's regulated utility subsidiaries (the Virtual Money Pool Agreement), a bi-lateral intercompany credit agreement with Avangrid (the Bi-Lateral Intercompany Facility) and a bank provided credit facility to which Berkshire is a party (the Avangrid Credit Facility), each of which are described below.

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. Berkshire has a lending/borrowing limit of $15 million under this agreement. As of December 31, 2019, there was $15.0 million outstanding under this agreement. As of December 31, 2018, there was no balance outstanding under this agreement.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $50 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. There was $8.0 million and $30.7 million outstanding under this agreement as of December 31, 2019 and 2018, respectively.

On June 29, 2018, Avangrid, Inc. and its subsidiaries, including Berkshire, entered into a new credit facility agreement with a syndicate of banks (Avangrid Credit Facility) that provides for maximum borrowings of up to $2.5 billion in the aggregate. This Avangrid Credit Facility replaces and supersedes the prior revolving credit facility entered into by Avangrid, Inc. and its subsidiaries on April 6, 2016, which provided maximum borrowings of up to $1.5 billion in the aggregate.

Under the Avangrid Credit Facility, Berkshire has a maximum sublimit of $40 million. Additionally, under the Avangrid Credit Facility, each of the borrowers, including Berkshire, will pay an annual facility fee that is dependent on their credit rating. The facility fees will range from 12.5 to 17.5 basis points. The maturity date for the Avangrid Credit Facility is June 29, 2024. As of December 31, 2019 and 2018, Berkshire did not have any outstanding borrowings under the Avangrid Credit Facility.

(E) INCOME TAXES

	Year Ended December 31, 2019	Year Ended December 31, 2018
	(In Thousands)	
Income tax expense consists of:		
Income tax provisions:		
Current		
Federal	$ 1,476	$ (1,547)
State	552	(924)
Total current	2,028	(2,471)
Deferred		
Federal	(501)	2,652
State	(91)	1,229
Total deferred	(592)	3,881
Total income tax expense	$ 1,436	$ 1,410

Total income taxes differ from the amounts computed by applying the federal statutory tax rate to income before taxes. The reasons for the differences are as follows:

	Year Ended December 31, 2019	Year Ended December 31, 2018
	(In Thousands)	
Book income before income taxes	$ 9,037	$ 4,418
Computed tax at federal statutory rate	$ 1,898	$ 928
Increases (reductions) resulting from:		
State income taxes, net of federal income tax benefits	364	241
Amortization of excess accumulated deferred income taxes	(1,144)	-
Other items, net	318	241
Total income tax expense	$ 1,436	$ 1,410
Effective income tax rates	15.9%	31.9%

The significant portion of Berkshire's income tax expense, including deferred taxes, is recovered through its regulated utility rates. Berkshire's annual income tax expense and associated effective tax rate is impacted by differences between the timing of deferred tax temporary difference activity and deferred tax recovery. Berkshire's effective tax rate is also impacted by permanent differences between the book and tax treatment of certain costs.

Berkshire is subject to the United States federal income tax statutes administered by the IRS. Berkshire is a party to Avangrid, Inc.'s tax allocation agreement under which taxable subsidiaries do not pay any more taxes than they would have otherwise paid had they filed a separate company tax return, and subsidiaries are paid for their losses and other tax attributes generated when utilized. Also pursuant to the tax allocation agreement, Berkshire settles its current tax liability or benefit each year directly with Avangrid, Inc.

As of December 31, 2019 and 2018, Berkshire did not have any gross income tax reserves for uncertain tax positions.

The following table summarizes Berkshire's tax years that remain subject to examination as of December 31, 2019:

Jurisdiction	*Tax years*
Federal	2014 - 2019
Massachusetts	2014 – 2019

The following table summarizes Berkshire's deferred tax assets and liabilities as of December 31, 2019 and 2018:

	2019	2018
	(In Thousands)	
Property related	$ (27,626)	$ (23,650)
Deferred gas and other deferred charges	(1,628)	(2,904)
Deferred tax liability on 2017 Tax Act remeasurement	4,397	4,290
Federal and State net operating losses and other attributes	985	985
Post-retirement benefits, net	(777)	(804)
Other assets (liabilities)	(44)	987
	$ (24,693)	$ (21,096)

As of each of December 31, 2019 and December 31, 2018, Berkshire had a federal net operating loss carry forward of $1.0 that will begin to expire in 2036.

(F) PENSION AND OTHER POSTRETIREMENT BENEFITS

Defined Benefit Plans (the Plans)

Pension Plans

Berkshire has multiple qualified pension plans covering eligible union and management employees and retirees. The union plans are all closed to new hires, and the non-union plans were closed as of December 31, 2017. The qualified pension plans are traditional defined benefit plans or cash balance plans for those hired on or after specified dates. In some cases, neither of these plans is offered to new employees and have been replaced with enhanced 401(k) plans for those hired on or after specified dates.

Employees not participating in a defined benefit plan are eligible to receive an enhanced or core 401(k) Company matching contribution.

Plan Assets

Networks' pension benefits plan assets were consolidated from three legacy master trusts to one new master trust in 2019. A consolidated trust provides for a uniform investment manager lineup and an efficient, cost effective means of allocating expenses and investment performance to each plan. The primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our risk tolerance. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. The primary means for achieving capital preservation is through diversification of the trusts' investments while avoiding significant concentrations of risk in any one area of the securities markets. Further diversification is achieved within each asset group through utilizing multiple asset managers and systematic allocation to various asset classes and providing broad exposure to different segments of the equity, fixed income and alternative investment markets.

The asset allocation policy is the most important consideration in achieving the objective of superior investment returns while minimizing risk. Networks has established target asset allocation policies within allowable ranges for its pension benefits plan assets within broad categories of asset classes made up of Return-Seeking investments and Liability-Hedging investments. Networks currently has target allocations ranging from 35%-70% for Return-Seeking assets and 34%-65% for Liability-Hedging assets. Return-Seeking assets also include investments in real estate, global asset allocation strategies and hedge funds. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

Other Postretirement Plans

Berkshire also has plans providing other postretirement benefits for eligible employees and retirees. The plans were closed to newly-hired Berkshire union employees by end of March 2011. These benefits consist primarily of health care, prescription drug and life insurance benefits for retired employees and their dependents. For Medicare eligible non-union retirees, Berkshire provides a subsidy through an HRA for retirees to purchase coverage on the individual market. Medicare eligible union retirees have the option of receiving a subsidy through an HRA or paying contributions and participating in company-sponsored retiree health plans.

Plan Assets

Networks' postretirement benefits plan assets are held with trustees in multiple voluntary employees' beneficiary association (VEBA) and 401(h) arrangements and are invested among and within various asset classes to achieve sufficient diversification in accordance with its risk tolerance. This is achieved for Network's postretirement benefits plan assets through the utilization of multiple institutional mutual and money market funds, providing exposure to different segments of the fixed income, equity and short-term cash markets. Approximately 37% of the postretirement benefits plan assets are invested in VEBA and 401(h) arrangements that are not subject to income taxes with the remainder being invested in arrangements subject to income taxes.

Networks has established a target asset allocation policy within allowable ranges for postretirement benefits plan assets of 45%-65% for equity securities, 25%-45% for fixed income and 5%-25% for all other investment types. Equity investments are diversified across U.S. and non-U.S. stocks, investment styles, and market capitalization ranges. Fixed income investments are primarily invested in U.S. bonds and may also include some non-U.S. bonds. Other asset classes, including alternative investments, are used to enhance long-term returns while improving portfolio diversification. Networks primarily minimize the risk of large losses through diversification but also through monitoring and managing other aspects of risk through quarterly investment portfolio reviews. Systematic rebalancing within target ranges increases the probability that the annualized return on investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

THE BERKSHIRE GAS COMPANY

NOTES TO FINANCIAL STATEMENTS

The following table represents the change in benefit obligation, change in plan assets and the respective funded status of Berkshire's pension plans as of December 31, 2019 and 2018. Plan assets and obligations have been measured as of December 31, 2019 and 2018.

	Pension Benefits		Other Post-Retirement Benefits	
	Year Ended December 31, 2019	Year Ended December 31, 2018	Year Ended December 31, 2019	Year Ended December 31, 2018
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation at beginning of year	$ 51,114	$ 52,591	$ 3,194	$ 3,700
Service cost	853	884	46	61
Interest cost	1,988	1,902	125	136
Participant contributions	-	-	-	88
Actuarial (gain) loss	6,087	(1,918)	(256)	(602)
Benefits paid (including expenses)	(2,747)	(2,345)	(59)	(189)
Benefit obligation at end of year	$ 57,295	$ 51,114	$ 3,050	$ 3,194
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 32,148	$ 36,512	$ -	$ -
Actual return on plan assets	6,172	(2,266)	-	-
Participant contributions	-	-	-	88
Employer contributions	1,657	145	59	101
Benefits paid (including expenses)	(2,721)	(2,243)	(59)	(189)
Fair value of plan assets at end of year	$ 37,256	$ 32,148	$ -	$ -
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ 20,039	$ 18,966	$ 3,050	$ 3,194
Amounts Recognized in the Consolidated Balance Sheet consist of:				
Non-current liabilities	$ 20,039	$ 18,966	$ 3,050	$ 3,194
Amounts Recognized as a Regulatory Asset (Liability) consist of:				
Prior service cost	$ 1	$ 44	$ -	$ -
Net (gain) loss	$ 11,718	$ 10,291	(120)	152
Total recognized as a regulatory asset (liability)	$ 11,719	$ 10,335	$ (120)	$ 152
Information on Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:				
Projected benefit obligation	$ 57,295	$ 51,114	N/A	N/A
Accumulated benefit obligation	$ 50,491	$ 45,033	N/A	N/A
Fair value of plan assets	$ 37,256	$ 32,148	N/A	N/A
The following weighted average actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate (Pension Benefits)	3.19%	4.09%	N/A	N/A
Discount rate (Other Post-Retirement Benefits)	N/A	N/A	3.19%	4.09%
Average wage increase	3.50%	3.50%	N/A	N/A
Health care trend rate (current year - pre/post-65)	N/A	N/A	6.75%/7.50%	7.00%/7.75%
Health care trend rate (2029/2027 - pre/post-65)	N/A	N/A	4.50%/4.50%	4.50%/4.50%

N/A – Not applicable

Berkshire is allowed to defer as regulatory assets or regulatory liabilities items that would have otherwise been recorded in AOCI pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans. Amounts recognized as regulatory assets or regulatory liabilities for the years ended December 31, 2019 and 2018 are shown above.

The discount rate is the rate at which the benefit obligations could presently be effectively settled. The discount rates were determined by developing yield curves derived from a portfolio of high grade noncallable bonds with yields that closely match the duration of the expected cash flows of our benefit obligations.

The components of net periodic benefit cost are:

	Pension Benefits		Other Post-Retirement Benefits	
	Year Ended December 31, 2019	Year Ended December 31, 2018	Year Ended December 31, 2019	Year Ended December 31, 2018
	(In Thousands)			
Components of net periodic benefit cost:				
Service cost	$ 853	$ 884	$ 46	$ 61
Interest cost	1,988	1,902	125	136
Expected return on plan assets	(2,354)	(2,538)	-	-
Amortization of actuarial (gain) loss	844	580	16	84
Amortization of prior service cost	43	168	-	-
Net periodic benefit cost	$ 1,374	$ 996	$ 187	$ 281
Other Changes in Plan Assets and Benefit Obligations Recognized as a Regulatory Asset (Liability):				
Net (gain) loss	$ 2,269	$ 2,885	$ (256)	$ (602)
Amortization of prior service cost	(43)	(168)	-	-
Amortization of Actuarial gain (loss)	(844)	(580)	(16)	(84)
Total recognized as regulatory asset (liability)	$ 1,382	$ 2,137	$ (272)	$ (686)
Total recognized in Net Periodic Benefit Costs and Regulatory Asset (Liability):				
	$ 2,756	$ 3,133	$ (85)	$ (405)
Estimated Amortizations from Regulatory Assets (Liabilities) into Net Periodic Benefit Cost for the next 12 month period:				
Amortization of transition obligation	$ -	$ -	$ -	$ -
Amortization of prior service cost	-	43	-	-
Amortization of net (gain) loss	936	844	12	16
Total estimated amortizations	$ 936	$ 887	$ 12	$ 16
The following actuarial weighted average assumptions were used in calculating net periodic benefit cost:				
Discount rate	4.09%	3.80%	4.09%	3.80%
Average wage increase	3.50%	3.50%	N/A	N/A
Return on plan assets	7.00% - 7.40%	7.00%	N/A	N/A
Health care trend rate (current year - pre/post-65)	N/A	N/A	7.00%/7.75%	7.50%/8.50%
Health care trend rate (2029/2027 - pre/post-65)	N/A	N/A	4.50%/4.50%	4.50%/4.50%

N/A – Not applicable

Berkshire utilizes an alternative method to amortize prior service costs and unrecognized gains and losses. Prior service costs for the Plans are amortized on a straight-line basis over the average remaining service period of participants expected to receive benefits. Unrecognized actuarial gains and losses related to the Plans are amortized over 10 years as required by the DPU. Berkshire does not recognize gains or losses until there is a variance in an amount equal to at least 5% of the greater of the projected benefit obligation or the market-related value of assets.

The expected long-term rate of return on plan assets assumption was developed based on a review of long-term historical returns for the major asset classes, the target asset allocations, and the effect of rebalancing of plan assets. The analysis considered current capital market conditions and projected conditions.

A one percentage point change in the assumed health care cost trend rate would have the following effects:

	1% Increase	1% Decrease
	(In Thousands)	
Aggregate service and interest cost components	$ 327	$ (285)
Accumulated post-retirement benefit obligation	$ 6,372	$ (5,305)

Contributions

The funding policy for the Plans is to make annual contributions that satisfy the minimum funding requirements of ERISA but that do not exceed the maximum deductible limits of the Internal Revenue Code. These amounts are determined each year as a result of an actuarial valuation of the Plans. Berkshire expects to make a pension contribution of approximately $1.8 million in 2020. Such contribution levels will be adjusted, if necessary, based on actuarial calculations.

Estimated Future Benefit Payments

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Year	Pension Benefits	Other Post-Retirement Benefits
	(In Thousands)	
2020	$ 2,474	$ 306
2021	$ 2,565	$ 270
2022	$ 2,722	$ 273
2023	$ 2,734	$ 239
2024	$ 2,802	$ 223
2025-2028	$ 15,008	$ 1,118

The fair values of the Plans’ assets as of December 31, 2019, disclosed below, reflect only the assets attributable to Berkshire’s portion of the total assets held in the master trust.

	Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
December 31, 2019		(In Thousands)		
Pension assets				
Cash and cash equivalents	$ -	$ 523	$ -	$ 523
Registered investment companies	2,874			2,874
Common collective trusts	-	30,662	-	30,662
	$ 2,874	$ 31,185	$ -	34,059
Other investments measured at net asset value				3,197
TOTAL				$ 37,256
December 31, 2018				
Pension assets				
Mutual funds	$ -	$ 32,148	$ -	$ 32,148
TOTAL	$ -	$ 32,148	$ -	$ 32,148

As of December 31, 2019, the determination of the fair values of our Plans' Level 2 assets was as follows:

- Cash and cash equivalents - proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- Common collective trusts - primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments measured at net asset value (NAV) – alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

As of December 31, 2018, the determination of fair values of the Level 2 co-mingled mutual funds were based on the Net Asset Value (NAV) provided by the managers of the underlying fund investments and the unrealized gains and losses. The NAV provided by the managers typically reflect the fair value of each underlying fund investment.

Defined Contribution Retirement Plans/401(k)

Berkshire non-union employees are eligible to participate in UIL Holdings Corporation 401(k) Employee Stock Ownership Plan and union employees are eligible to participate in the Berkshire Gas Company Union 401(k) Plan. Employees may defer a portion of their compensation and invest in various investment alternatives. Matching contributions are made in the form of cash which is subsequently invested in various investment alternatives offered to employees. The matching expense for each of the years ending December 31, 2019 and 2018 was $0.5 million.

(G) RELATED PARTY TRANSACTIONS

Inter-company Transactions

Berkshire receives various administrative and management services from and enters into certain inter-company transactions with UIL Holdings and its subsidiaries. For the year ended December 31, 2019, Berkshire recorded inter-company expenses of $2.9 million. Costs of the services that are allocated amongst Berkshire and other of UIL Holdings' regulated subsidiaries are settled periodically by way of inter-company billings and wire transfers and are included in Accounts receivable from affiliates and Accounts payable to affiliates in the accompanying balance sheets.

Dividends/Capital Contributions

For the years ended December 31, 2019 and 2018, Berkshire did not accrue any dividends to BER.

(H) COMMITMENTS AND CONTINGENCIES

In the ordinary course of business, Berkshire is involved in various proceedings, including legal, tax, regulatory and environmental matters, which require management's assessment to determine the probability of whether a loss will occur and, if probable, an estimate of probable loss. When assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated, Berkshire accrues a reserve and discloses the reserve and related matter. Berkshire discloses material matters when losses are probable but for which an estimate cannot be reasonably estimated or when losses are not probable but are reasonably possible. Subsequent analysis is performed on a periodic basis to assess the impact of any changes in events or circumstances and any resulting need to adjust existing reserves or record additional reserves. However, given the inherent unpredictability of these legal and regulatory proceedings, Berkshire cannot assure you that its assessment of such proceedings will reflect the ultimate outcome, and an adverse outcome in certain matters could have a material adverse effect on its results of operations or cash flows.

Environmental Matters

Site Decontamination, Demolition and Remediation Costs

Berkshire owns or has previously owned properties where Manufactured Gas Plants (MGPs) had historically operated. MGP operations have led to contamination of soil and groundwater with petroleum hydrocarbons, benzene and metals, among other things, at these properties, the regulation and cleanup of which is regulated by the federal Resource Conservation and Recovery Act as well as other federal and state statutes and regulations. Berkshire has or had an ownership interest in one of such properties contaminated as a result of MGP-related activities. Under the existing regulations, the cleanup of such sites requires state and at times, federal, regulators' involvement and approval before cleanup can commence. In certain cases, such contamination has been evaluated, characterized and remediated. In other cases, the sites have been evaluated and characterized, but not yet remediated. Finally, at some of these sites, the scope of the contamination has not yet been fully characterized; no liability was recorded in respect of these sites as of December 31, 2019 and no amount of loss, if any, can be reasonably estimated at this time. In the past, Berkshire has received approval for the recovery of MGP-related remediation expenses from customers through rates and will seek recovery in rates for ongoing MGP-related remediation expenses for all of their MGP sites.

Berkshire owns property on Mill Street in Greenfield, Massachusetts, a former MGP site. Management estimates that expenses associated with the remaining remedial activities, as well as the required ongoing monitoring and reporting to the Massachusetts Department of Environmental Protection will likely amount to approximately $0.5 million and has recorded a liability and offsetting regulatory asset for such expenses as of December 31, 2019. Historically, Berkshire has received approval from the DPU for recovery of environmental expenses in its customer rates.

Berkshire formerly owned a site on East Street (the East Street Site) in Pittsfield, Massachusetts, a former MGP site. The East Street Site is part of a larger site known as the GE–Pittsfield/Housatonic River Site. Berkshire sold the East Street Site to the General Electric Company (GE) in the 1970s and was named a potentially responsible party for the site by the EPA in 1990.

In December 2002, Berkshire reached a settlement with GE which provides, among other things, a framework for Berkshire and GE to allocate various monitoring and remediation costs at the East Street Site. As of December 31, 2019, Berkshire had accrued approximately $3.8 million and established a regulatory asset for these and future costs incurred by GE in responding to releases of hazardous substances at the East Street Site. Historically, Berkshire has received approval from the DPU for recovery of remediation expenses in its customer rates.

(I) FAIR VALUE MEASUREMENTS

As required by ASC 820, financial assets and liabilities are classified in their entirety, based on the lowest level of input that is significant to the fair value measurement. Berkshire's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following tables set forth the fair value Berkshire's financial assets and liabilities, other than pension benefits and OPEB, as of December 31, 2019 and December 31, 2018.

	Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
December 31, 2019		(In Thousands)		
Noncurrent investments	$ 246	$ -	$ -	$ 246
Total fair value assets, December 31, 2019	$ 246	$ -	$ -	$ 246
December 31, 2018				
Noncurrent investments	$ 386	$ -	$ -	$ 386
Total fair value assets, December 31, 2018	$ 386	$ -	$ -	$ 386

(K) SUBSEQUENT EVENTS

In March 2020 the World Health Organization declared a global pandemic due to the outbreak of COVID-19. Berkshire is assessing the possible impacts to its business and financial results.

New York State Electric & Gas Corporation
Financial Statements
For the Years Ended December 31, 2019 and 2018

New York State Electric & Gas Corporation

Index

KPMG LLP
345 Park Avenue
New York, NY 10154-0102

Independent Auditors' Report

Shareholders and The Board of Directors
New York State Electric & Gas Corporation:

We have audited the accompanying financial statements of New York State Electric & Gas Corporation, which comprise the balance sheets as of December 31, 2019 and 2018, and the related statements of income, comprehensive income, changes in common stock equity, and cash flows for the years then ended, 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 U.S. generally accepted accounting principles; 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 auditors' 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 entity'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 entity'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 New York State Electric & Gas Corporation as of December 31, 2019 and 2018, and the results of its operations and its cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

KPMG LLP

New York, New York
March 31, 2020

New York State Electric & Gas Corporation
Statements of Income

Years Ended December 31,	2019	2018
(Thousands)		
Operating Revenues	$ 1,548,367	$ 1,694,292
Operating Expenses		
Electricity purchased	303,190	434,752
Natural gas purchased	110,833	116,227
Operations and maintenance	648,039	614,744
Depreciation and amortization	145,316	133,531
Taxes other than income taxes, net	150,466	147,595
Total Operating Expenses	**1,357,844**	**1,446,849**
Operating Income	**190,523**	**247,443**
Other Income	28,197	13,401
Other Deductions	(42,157)	(53,215)
Interest expense, net of capitalization	(73,246)	(62,840)
Income Before Income Tax	**103,317**	**144,789**
Income tax expense	36,015	37,883
Net Income	**$ 67,302**	**$ 106,906**

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

New York State Electric & Gas Corporation
Statements of Comprehensive Income

Years Ended December 31,	2019	2018
(Thousands)		
Net Income	**$ 67,302**	**$ 106,906**
Other Comprehensive Income (Loss), Net of Tax		
Amortization of pension cost for nonqualified plans, net of income taxes	(124)	131
Unrealized (loss) gain during the year on derivatives qualifying as cash flow hedges, net of income taxes:		
Unrealized (loss) gain during the year on derivatives qualifying as hedges	139	(535)
Reclassification adjustment for loss included in net income	306	(34)
Reclassification adjustment for loss on settled cash flow treasury hedges	77	76
Total Other Comprehensive Income (Loss), Net of Tax	**398**	**(362)**
Comprehensive Income	**$ 67,700**	**$ 106,544**

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

New York State Electric & Gas Corporation
Balance Sheets

As of December 31,	2019	2018
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$ 1	$ 4,943
Accounts receivable and unbilled revenues, net	265,499	289,751
Accounts receivable from affiliates	1,148	2,505
Fuel and natural gas in storage, at average cost	14,363	16,820
Materials and supplies	18,145	16,759
Derivative assets	—	3,248
Broker margin accounts	6,773	5,301
Income tax receivable	21,939	20,896
Prepaid property taxes	37,214	36,400
Other current assets	5,014	5,872
Regulatory assets	138,162	113,210
Total Current Assets	**508,258**	**515,705**
Utility plant, at original cost	6,375,471	5,950,914
Less accumulated depreciation	(2,228,040)	(2,173,629)
Net Utility Plant in Service	**4,147,431**	**3,777,285**
Construction work in progress	385,134	353,440
Total Utility Plant	**4,532,565**	**4,130,725**
Operating lease right-of-use assets	9,341	—
Other Property and Investments	8,207	8,081
Regulatory and Other Assets		
Regulatory assets	822,285	897,938
Other	51,743	6,469
Total Regulatory and Other Assets	**874,028**	**904,407**
Total Assets	**$ 5,932,399**	**$ 5,558,918**

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

New York State Electric & Gas Corporation
Balance Sheets

As of December 31,		2019		2018
(Thousands, except share information)				
Liabilities				
Current Liabilities				
Current portion of long-term debt	$	198,439	$	20,305
Notes payable to affiliates		71,255		40,375
Accounts payable and accrued liabilities		413,367		374,591
Accounts payable to affiliates		29,840		82,366
Interest accrued		10,572		7,382
Taxes accrued		2,617		1,563
Operating lease liabilities		1,339		—
Derivative liabilities		222		824
Environmental remediation costs		27,760		38,910
Customer deposits		15,048		12,744
Regulatory liabilities		106,709		91,674
Other		77,476		70,322
Total Current Liabilities		**954,644**		**741,056**
Regulatory and Other Liabilities				
Regulatory liabilities		1,192,343		1,197,227
Other non-current liabilities				
Deferred income taxes		553,434		479,633
Pension and other postretirement		281,952		270,984
Operating lease liabilities		8,385		—
Asset retirement obligation		12,928		13,506
Environmental remediation costs		90,713		102,168
Other		41,220		82,484
Total Regulatory and Other liabilities		**2,180,975**		**2,146,002**
Non-current debt		1,325,181		1,217,990
Total Liabilities		**4,460,800**		**4,105,048**
Commitments and Contingencies				
Common Stock Equity				
Common stock ($6.66 2/3 par value, 90,000,000 shares authorized and 64,508,477 shares outstanding at December 31, 2019 and 2018)		430,057		430,057
Additional paid-in capital		468,459		418,430
Retained earnings		574,153		606,650
Accumulated other comprehensive loss		(1,070)		(1,267)
Total Common Stock Equity		**1,471,599**		**1,453,870**
Total Liabilities and Equity	**$**	**5,932,399**	**$**	**5,558,918**

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

New York State Electric & Gas Corporation
Statements of Cash Flows

Years Ended December 31,	2019	2018
(Thousands)		
Cash Flow from Operating Activities:		
Net income	**$ 67,302**	**$ 106,906**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	145,316	133,531
Regulatory assets/liabilities amortization	43,448	45,790
Regulatory assets/liabilities carrying cost	4,114	1,831
Amortization of debt issuance costs	3,491	1,352
Deferred taxes	28,401	39,125
Pension cost	51,434	70,190
Stock-based compensation	28	144
Accretion expenses	718	748
Gain on disposal of assets	(752)	(717)
Other non-cash items	(24,316)	(17,844)
Changes in assets and liabilities		
Accounts receivable, from affiliates, and unbilled revenues	25,609	(12,575)
Inventories	1,071	(2,535)
Accounts payable, to affiliates, and accrued liabilities	(25,157)	93,727
Taxes accrued	(172)	20,958
Other assets/liabilities	(49,314)	3,078
Regulatory assets/liabilities	5,427	(67,932)
Net Cash Provided by Operating Activities	**276,648**	**415,777**
Cash Flow from Investing Activities:		
Capital expenditures	(593,577)	(529,875)
Contributions in aid of construction	42,968	26,505
Proceeds from sale of utility plant	2,189	3,004
Net Cash Used in Investing Activities	**(548,420)**	**(500,366)**
Cash Flow from Financing Activities:		
Non-current debt issuance	307,485	172,566
Repayments of capital leases	(21,535)	(1,708)
Notes payable	—	(150,454)
Notes payable to affiliates	30,880	(84,268)
Capital contribution	50,000	150,000
Dividends paid	(100,000)	—
Net Cash Provided by Financing Activities	**266,830**	**86,136**
Net (Decrease) Increase in Cash and Cash Equivalents	**(4,942)**	**1,547**
Cash and Cash Equivalents, Beginning of Year	**4,943**	**3,396**
Cash and Cash Equivalents, End of Year	**$ 1**	**$ 4,943**

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

New York State Electric & Gas Corporation
Statements of Changes in Common Stock Equity

(Thousands, except per share amounts)	Number of shares (*)	Common stock	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stock Equity
Balance, December 31, 2017	**64,508,477**	**$430,057**	**$268,403**	**$499,744**	**$(905)**	**$1,197,299**
Net income		—	—	106,906	—	106,906
Other comprehensive income, net of tax		—	—	—	(362)	(362)
Comprehensive income						106,544
Stock-based compensation	—	—	27	—	—	27
Capital contribution	—	—	150,000	—	—	150,000
Balance, December 31, 2018	**64,508,477**	**430,057**	**418,430**	**606,650**	**(1,267)**	**1,453,870**
Adoption of accounting standards		—	—	201	(201)	—
Net income		—	—	67,302	—	67,302
Other comprehensive income, net of tax		—	—	—	398	398
Comprehensive income						67,700
Stock-based compensation	—	—	29	—	—	29
Common stock dividends	—	—	—	(100,000)	—	(100,000)
Capital contribution	—	—	50,000	—	—	50,000
Balance, December 31, 2019	**64,508,477**	**$430,057**	**$468,459**	**$574,153**	**$(1,070)**	**$1,471,599**

(*) Par value of share amounts is 6.66 2/3

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

Notes to Financial Statements

Note 1. Significant Accounting Policies

Background and nature of operations: New York State Electric & Gas Corporation (NYSEG, the company, we, our, us) conducts regulated electricity transmission and distribution operations and regulated natural gas transportation, storage and distribution operations in upstate New York. It also generates electricity, primarily from its several hydroelectric stations. NYSEG serves approximately 903,000 electricity and 269,000 natural gas customers as of December 31, 2019, in its service territory of approximately 20,000 square miles, which is located in the central, eastern and western parts of the state of New York and has a population of approximately 2.5 million. The larger cities in which NYSEG serves electricity and natural gas customers are Binghamton, Elmira, Auburn, Geneva, Ithaca and Lockport. We operate under the authority of the New York State Public Service Commission (NYPSC) and are also subject to regulation by the Federal Energy Regulatory Commission (FERC).

NYSEG is a subsidiary of Avangrid Networks, Inc. (Networks), which is a wholly-owned subsidiary of Avangrid, Inc. (AGR), which is an 81.5% owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain.

***Basis of presentation*:** The accompanying financial statements have been prepared in accordance with generally accepted accounting principles in the United States (U.S. GAAP).

We consider the following policies to be the most significant in understanding the judgments that are involved in preparing our financial statements:

***Revenue recognition*:** We recognize revenues when we transfer control of promised goods or services to our customers in an amount that reflects the consideration we expect to be entitled to in exchange for those goods or services. Refer to Note 4 for further details.

***Regulatory accounting*:** We account for our regulated operations in accordance with the authoritative guidance applicable to entities with regulated operations that meet the following criteria: (i) rates are established or approved by a third-party regulator; (ii) rates are designed to recover the entity's cost of providing regulated services or products and; (iii) there is a reasonable expectation that rates are set at levels that will recover the entity's costs and be collected from customers. Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent: (i) the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates; or (ii) billings in advance of expenditures for approved regulatory programs.

Regulatory assets and liabilities are amortized and the related expense or revenue is recognized in the statements of income consistent with the recovery or refund included in customer rates. We believe it is probable that our currently recorded regulatory assets and liabilities will be recovered or settled in future rates.

***Utility plant*:** Utility plant is accounted for at historical cost. In cases where we are required to dismantle installations or to recondition the site on which they are located, we record the estimated cost of removal or reconditioning as an asset retirement obligation (ARO) and an equal amount is added to the carrying amount of the asset.

Development and construction of our various facilities are carried out in stages. Project costs are expensed during early stage development activities. Once we achieve certain development milestones and it is probable that we can obtain future economic benefits from a project, we capitalize salaries and wages for persons directly involved in the project, and engineering, permits, licenses, wind measurement and insurance costs. We periodically review development projects in construction for any indications of impairment.

Assets are transferred from “Construction work in progress” to “Utility plant” when they are available for service.

We determine depreciation expense for utility plant in service using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Consistent with FERC accounting requirements, we charge the original cost of utility plant retired or otherwise disposed to accumulated depreciation. Our composite rates for depreciation were 2.2% of average depreciable property for 2019 and 2018. We amortize our capitalized software cost which is included in common plant, using the straight line method, based on useful lives of 7 to 17 years. Capitalized software costs were approximately $209.9 million as of December 31, 2019 and $201.1 million as of December 31, 2018. Depreciation expense was $136.7 million in 2019 and $126.5 million in 2018. Amortization of capitalized software was $8.6 million in 2019 and $7.1 million in 2018.

We charge repairs and minor replacements to operation and maintenance expense, and capitalize renewals and betterments, including certain indirect costs.

Allowance for funds used during construction (AFUDC) represents the allowed cost of capital, including a return on equity (ROE), used to finance construction projects. We record the portion of AFUDC attributable to borrowed funds as a reduction of interest expense and the portion attributable to equity as other income. AFUDC attributable to equity is a non-cash item.

Our balances of major classes of utility plant and associated useful lives are shown below as of December 31:

Utility Plant	**Estimated useful life range (years)**	**2019**	**2018**
(Thousands)			
Electric	29-75	$4,577,776	$4,250,399
Natural Gas	25-75	1,118,425	1,041,984
Common	7-75	679,270	658,531
Total Utility Plant in Service		**6,375,471**	**5,950,914**
Total accumulated depreciation		(2,228,040)	(2,173,629)
Total Net Utility Plant in Service		**4,147,431**	**3,777,285**
Construction work in progress		385,134	353,440
Total Utility Plant		**$4,532,565**	**$4,130,725**

Electric plant includes capital leases of $50.7 million for 2019 and $45 million for 2018. Related accumulated depreciation at December 31 was $11.1 million for 2019 and $7.8 million for 2018.

Leases: We determine if an arrangement is a lease at inception. We classify a lease as a finance lease if it meets any one of specified criteria that in essence transfers ownership of the underlying asset to us by the end of the lease term. If a lease does not meet any of those criteria, we classify it as an operating lease. On our balance sheets, we include, for operating leases: "Operating lease right-of-use (ROU) assets" and "Operating lease liabilities (current and non-current)"; and for finance leases: finance lease ROU assets in "Other assets" and liabilities in "Other current liabilities" and "Other liabilities."

ROU assets represent our right to use an underlying asset for the lease term and lease liabilities represent our obligation to make lease payments arising from the lease. We recognize lease ROU assets and liabilities at commencement of an arrangement based on the present value of lease payments over the lease term. Most of our leases do not provide an implicit rate, so we use our incremental borrowing rate based on information available at the lease commencement date to determine the present value of future payments. A lease ROU asset also includes any lease payments made at or before commencement date, minus any lease incentives received, and includes initial direct costs incurred. We do not record leases with an initial term of 12 months or less on the balance sheet, for all classes of underlying assets, and we recognize lease expense for those leases on a straight-line basis over the lease term. We include variable lease payments that depend on an index or a rate in the ROU asset and lease liability measurement based on the index or rate at the commencement date, or upon a modification. We do not include variable lease payments that do not depend on an index or a rate in the ROU asset and lease liability measurement. A lease term includes options to extend or terminate the lease when it is reasonably certain that we will exercise that option. We recognize lease (rent) expense for operating lease payments on a straight-line basis over the lease term, or we recognize the amount eligible for recovery under our rate plan, such as actual amounts paid. We amortize finance lease ROU assets on a straight-line basis over the lease term and recognize interest expense based on the outstanding lease liability.

We have lease agreements with lease and non-lease components, and account for lease components and associated nonlease components together as a single lease component, for all classes of underlying assets.

Impairment of long-lived assets: We evaluate utility plant and other long-lived assets for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment evaluation is based on an undiscounted cash flow analysis at the lowest level to which cash flows of the long-lived assets or asset groups are largely independent of the cash flows of other assets and liabilities.
An impairment loss is required to be recognized if the carrying amount of the asset exceeds the undiscounted future net cash flows associated with that asset.

The impairment loss to be recognized is the amount by which the carrying value of the long-lived asset exceeds the asset's fair value, or is the result of a disallowance by the regulator. Depending on the asset, fair value may be determined by use of a discounted cash flow model, with assumptions consistent with a market participant's view of the exit price of the asset.

***Fair value measurement*:** 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 as of the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place in either the principal market for the asset or liability, or, in the absence of a principal market, in the most advantageous market for the asset or liability.

The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest. A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset according to its highest and best use, or by selling it to another market participant that would use the asset according to its highest and best use.

We use valuation techniques that are appropriate in the circumstances and for which sufficient data is available to measure fair value, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs. All assets and liabilities for which fair value is measured or disclosed in the financial statements are categorized within the fair value hierarchy based on the transparency of input to the valuation of an asset or liability as of the measurement date.

The three input levels of the fair value hierarchy are as follows:

- Level 1 - inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability either directly or indirectly, for substantially the full term of the contract.
- Level 3 - one or more inputs to the valuation methodology are unobservable or cannot be corroborated with market data.

Categorization within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. Certain investments are not categorized within the fair value hierarchy. These investments are measured based on the fair value of the underlying investments but may not be readily redeemable at that fair value.

***Derivatives and hedge accounting*:** Derivatives are recognized on the balance sheets at their fair value, except for certain electricity commodity purchases and sales contracts for both capacity and energy (physical contracts) that qualify for, and are elected under, the normal purchases and normal sales exception. To be a derivative under the accounting standards for derivatives and hedging, an agreement would need to have a notional and an underlying, require little or no initial net investment and could be net settled. We recognize changes in the fair value of a derivative contract in earnings unless specific hedge accounting criteria are met.

Derivatives that qualify and are designated for hedge accounting are classified as cash flow hedges. We report the gain or loss on the derivative instrument as a component of Other Comprehensive Income (OCI) and later reclassify into earnings when the underlying transaction occurs. For all designated and qualifying hedges, we maintain formal documentation of the hedge and effectiveness testing in accordance with the accounting standards for derivatives and hedging. If we determine that the derivative is no longer highly effective as a hedge, we will discontinue hedge accounting prospectively. For cash flow hedges of forecasted transactions, we estimate the future cash flows of the forecasted transactions and evaluate the probability of the occurrence and timing of such transactions. If we determine it is probable that the forecasted transaction will not occur, we immediately recognize in earnings hedge gains and losses previously recorded in OCI.

Changes in conditions or the occurrence of unforeseen events could require discontinuance of the hedge accounting or could affect the timing of the reclassification of gains or losses on cash flow hedges from OCI into earnings. We record changes in the fair value of electric and natural gas hedge contracts to derivative assets or liabilities with an offset to regulatory assets or regulatory liabilities.

We offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement.

Cash and cash equivalents**:** Cash and cash equivalents include cash, bank accounts, and other highly liquid short-term investments. We consider all highly liquid investments with a maturity date of three months or less when acquired to be cash equivalents and include those investments in "Cash and cash equivalents." We classify book overdrafts representing outstanding checks in excess of funds on deposit as "Accounts payable and accrued liabilities" on our balance sheets. Changes in book overdrafts are reported in the operating activities section of the statements of cash flows.

Statements of cash flows: Supplemental disclosure of cash flow information is as follows:

	2019	2018
(Thousands)		
Cash paid during the year ended December 31:		
Interest, net of amounts capitalized	$37,869	$32,986
Income taxes paid, net	$9,656	$21,662

Of the income taxes paid, substantially all was paid to AGR under the tax sharing agreement. Interest capitalized was $6.1 million in 2019 and in $7.6 million in 2018. Accrued liabilities for utility plant additions were $50.3 million in 2019 and $35.4 million in 2018.

Broker margin accounts: We maintain accounts with clearing firms that require initial margin deposits upon the establishment of new positions, primarily related to natural gas and electricity derivatives, as well as maintenance margin deposits in the event of unfavorable movements in market valuation for those positions. We show the amount reflecting those activities as broker margin accounts on our balance sheets.

Accounts receivable and unbilled revenues, net**:** We record accounts receivable at amounts billed to customers. Accounts receivable at December 31 include unbilled revenues of $88.1 million for 2019 and $90.3 million for 2018, and are shown net of an allowance for doubtful accounts at December 31 of $23.8 million for 2019 and $24 million for 2018. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was $17.2 million in 2019 and $17.3 million in 2018.

Unbilled revenues represent estimates of receivables for energy provided but not yet billed. The estimates are determined based on various assumptions, including current month energy load requirements, billing rates by customer class and delivery loss factors. Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

The allowance for doubtful accounts is our best estimate of the amount of probable credit losses in our existing accounts receivable, determined based on experience for each service region. Each month we review our allowance for doubtful accounts and past due accounts by age. When we believe that a receivable will not be recovered, we charge off the account balance against the allowance. Changes in assumptions about input factors and customer receivables, which are inherently uncertain and susceptible to change from period to period, could significantly affect the allowance for doubtful accounts estimates.

Our accounts receivable include amounts due under deferred payment arrangements (DPAs). When a residential customer becomes delinquent in making payments, the NYPSC requires us to allow the customer to enter into a DPA to settle the account balance. A DPA allows the account balance to be paid in installments without interest over an extended period of time, which generally exceeds one year, by negotiating mutually acceptable payment terms. Generally, we must continue to serve a customer who cannot pay an account balance in full if the customer: (i) pays a reasonable portion of the balance; (ii) agrees to pay the balance in installments; and (iii) agrees to pay future bills within 30 days until the DPA is paid in full or is otherwise considered to be delinquent. We establish provisions for uncollectible accounts by using both historical average loss percentages to project future losses, and by establishing specific provisions for known credit issues. Amounts are written off when reasonable collection efforts have been exhausted. The allowance for doubtful accounts for DPAs at December 31 was $13 million for 2019 and $13.6 million for 2018. DPA receivable balances at December 31 were $23.7 million for 2019 and $24.3 million for 2018.

Debentures, bonds and bank borrowings: Bonds, debentures and bank borrowings are recorded as a liability equal to the proceeds of the borrowings. The difference between the proceeds and the face amount of the issued liability is treated as discount or premium and is accreted as interest expense or income over the life of the instrument. Incremental costs associated with issuance of the debt instruments are deferred and amortized over the same period as debt discount or premium. Bonds, debentures and bank borrowings are presented net of unamortized discount, premium and debt issuance costs on our balance sheets.

Inventory*:* Inventory comprises fuel and natural gas in storage and materials and supplies. We own natural gas that is stored in third-party owned underground storage facilities. This gas is recorded as inventory. Injections of inventory into storage are priced at the market purchase cost at the time of injection, and withdrawals of working gas from storage are priced at the weighted-average cost in storage. We continuously monitor the weighted-average cost of gas value to ensure it remains at the lower of cost and net realizable value. Inventories to support gas operations are reported on our balance sheet within “Fuel and natural gas in storage.”

We also have materials and supplies inventories that are used for construction of new facilities and repairs of existing facilities. These inventories are carried and withdrawn at the lower of cost and net realizable value and reported on the balance sheets within “Materials and supplies.” Inventory items are combined for the statement of cash flows presentation purposes.

Government grants: We record government grants as a reduction to utility plant to be recovered through rate base, in accordance with the prescribed FERC accounting.

In accounting for government grants related to operating and maintenance costs, we recognize amounts receivable as an offset to expenses in the statements of income in the period in which the expenses are incurred.

Deferred income: Apart from government grants, we occasionally receive revenues from transactions in advance of the resulting performance obligations arising from the transaction. It is our policy to defer such revenues on our balance sheets and amortize them into earnings when revenue recognition criteria are met.

Asset retirement obligations**:** We record the fair value of the liability for an asset retirement obligation (ARO) and a conditional ARO in the period in which it is incurred, capitalizing the cost by increasing the carrying amount of the related long-lived asset. We adjust the liability periodically to reflect revisions to either the timing or amount of the original estimated undiscounted cash flows over time. We accrete the liability to its present value each period and depreciate the capitalized cost over the useful life of the related asset. Upon settlement we will either settle the obligation at its recorded amount or incur a gain or a loss. We defer any timing differences between rate recovery and depreciation expense and accretion as either a regulatory asset or a regulatory liability.

The term conditional ARO refers to an entity's legal obligation to perform an asset retirement activity in which the timing or method of settlement are conditional on a future event that may or may not be within the entity's control. If an entity has sufficient information to reasonably estimate the fair value of the liability for a conditional ARO, it must recognize that liability at the time the liability is incurred.

Our ARO at December 31, including our conditional ARO, was $12.9 million for 2019 and $13.5 million for 2018. The ARO is associated with our long-lived assets and primarily consists of obligations related to removal or retirement of: asbestos, polychlorinated biphenyl contaminated equipment, gas pipeline and cast iron gas mains.

The following table reconciles the beginning and ending aggregate carrying amount of the ARO for the years ended December 31, 2019 and 2018.

Years ended December 31,	**2019**	**2018**
(Thousands)		
ARO, beginning of year	$13,506	$14,021
Liabilities settled during the year	(1,296)	(1,263)
Accretion expense	718	748
ARO, end of year	**$12,928**	**$13,506**

We have AROs for which we have not recognized a liability because the fair value cannot be reasonably estimated due to indeterminate settlement dates, including: the removal of hydroelectric dams due to structural inadequacy or for decommissioning; the removal of property upon termination of an easement, right-of-way or franchise; and costs for abandonment of certain types of gas mains.

Accrued removal obligations**:** We meet the requirements concerning accounting for regulated operations and recognize a regulatory liability for the difference between removal costs collected in rates and actual costs incurred. We classify those amounts as accrued removal obligations.

Environmental remediation liability**:** In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. We record our environmental liabilities on an undiscounted basis. Our environmental liability accruals are expected to be paid through the year 2052.

Post-employment and other employee benefits: We sponsor defined benefit pension plans that cover the majority of our employees. We also provide health care and life insurance benefits through various postretirement plans for eligible retirees.

We evaluate our actuarial assumptions on an annual basis and consider changes based on market conditions and other factors. All of our qualified defined benefit plans are funded in amounts calculated by independent actuaries, based on actuarial assumptions proposed by management.

We account for defined benefit pension or other postretirement plans, recognizing an asset or liability for the overfunded or underfunded plan status. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. We reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in OCI, as management believes it is probable that such items will be recoverable through the ratemaking process. We use a December 31st measurement date for our benefits plans.

We amortize prior service costs for both the pension and other postretirement benefits plans on a straight-line basis over the average remaining service period of participants expected to receive benefits. We amortize unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans over 10 years from the time they are incurred as required by the NYPSC. Our policy for the pension plans is to calculate the expected return on plan assets using the market-related value of assets. Our policy for the postretirement health care benefit plans is to calculate the expected return on plan assets using the market-related value of assets. We determine that value by recognizing the difference between actual returns and expected returns over a five year period.

Income tax**:** AGR, the parent company of Networks, files a consolidated federal income tax return and various state income tax returns, some of which are unitary as required or permitted, including all of the activities of its subsidiaries. Each subsidiary company is treated as a member of the consolidated group and determines its current and deferred taxes based on the separate return with benefits for loss method. As a member, NYSEG settles its current tax liability or benefit each year directly with AGR pursuant to a tax allocation agreement between AGR and its members.

The aggregate amount of the related party income tax receivable balance due from AGR at December 31 is $21.9 million for 2019 and $20.9 million for 2018.

We use the asset and liability method of accounting for income taxes. Deferred tax assets and liabilities reflect the expected future tax consequences, based on enacted tax laws, of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts. In accordance with U.S. GAAP for regulated industries, we have established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences. We defer investment tax credits when earned and amortize them over the estimated lives of the related assets. We also recognize the income tax consequences of intra-entity transfers of assets other than inventory when the transfer occurs.

Deferred tax assets and liabilities are measured at the expected tax rate for the period in which the asset or liability will be realized or settled, based on legislation enacted as of the balance sheet date. We charge or credit changes in deferred income tax assets and liabilities that are associated with components of OCI directly to OCI. Significant judgment is required in determining income tax provisions and evaluating tax positions. Our tax positions are evaluated under a more-likely-than-not recognition threshold before they are recognized for financial reporting purposes. We record valuation allowances to reduce deferred tax assets when it is more likely than not that we will not realize all or a portion of a tax benefit. Deferred tax assets and liabilities are classified as non-current on our balance sheets.

Positions taken or expected to be taken on tax returns, including the decision to exclude certain income or transactions from a return, are recognized in the financial statements when it is more likely than not the tax position can be sustained based solely on the technical merits of the position. The amount of a tax return position that is not recognized in the financial statements is disclosed as an unrecognized tax benefit. Changes in assumptions on tax benefits may also impact interest expense or interest income and may result in the recognition of tax penalties. Interest and penalties related to unrecognized tax benefits are recorded within “Interest expense, net of capitalization” and “Other Income” and “Other Deductions” in our statements of income.

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. In 2019, we netted our liability for uncertain tax positions against all same jurisdiction deferred tax assets, net operating losses and tax credit carryforwards. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the statements of income.

Our income tax expense, deferred tax assets and liabilities, and liabilities for unrecognized tax benefits reflect management’s best assessment of estimated current and future taxes to be paid. Significant judgments and estimates are required in determining the consolidated income tax components of the financial statements.

Limited voting junior preferred stock: We have a class of preferred stock having one share and a par value of $1, which is issued and outstanding and has voting authority only with respect to whether NYSEG may file a voluntary bankruptcy petition.

Stock-based compensation: Stock-based compensation represents costs related to AGR stock-based awards granted to NYSEG employees. We account for stock-based payment transactions based on the estimated fair value of awards reflecting forfeitures when they occur. The recognition period for these costs begins at either the applicable service inception date or grant date and continues throughout the requisite service period, or until the employee becomes retirement eligible, if earlier.

Adoption of New Accounting Pronouncements

Although we are not a public business entity, our parent company is a public business entity; therefore, we adopt new accounting standards based on the effective date for public entities as permitted.

(a) Leases

In February 2016 the Financial Accounting Standards Board (FASB) issued Accounting Standards Codification (ASC) Topic 842, *Leases*, with subsequent amendments issued in 2018. The new leases guidance affects all companies and organizations that lease assets, and requires them to record on their balance sheet ROU assets and lease liabilities for the rights and obligations created by those leases. Under ASC 842, a lease is an arrangement that conveys the right to control the use of an identified asset for a period of time in exchange for consideration. The new guidance retains a distinction between finance leases and operating leases, while requiring companies to recognize both types of leases on their balance sheet. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the criteria for distinguishing between capital leases and operating leases in legacy U.S. GAAP – ASC 840. Lessor accounting remains substantially the same as ASC 840, but with some targeted improvements to align lessor accounting with the lessee accounting model and with the revised revenue recognition guidance under ASC 606. The new standard and amendments require new qualitative and quantitative disclosures for both lessees and lessors.

We adopted ASC 842 effective January 1, 2019, and elected the optional transition method under which we initially applied the standard on that date without adjusting amounts for prior periods, which we continue to present in accordance with ASC 840, including related disclosures. We recorded the cumulative effect of applying the new leases guidance as an adjustment to beginning retained earnings. In connection with our adoption, we:

- did not elect the package of three practical expedients available under the transition provisions which would have allowed us to not reassess: (i) whether expired or existing contracts were or contained leases, (ii) the lease classification for expired or existing leases, and (iii) whether previously capitalized initial direct costs for existing leases would qualify for capitalization under ASC 842.
- elected the land easement practical expedient and did not reassess land easements that did not meet the definition of a lease prior to adoption.
- used hindsight for determining the lease term and assessing the likelihood that a lease purchase option will be exercised in applying the new leases guidance.
- did not separate lease and associated non-lease components for transitioned leases, but instead are accounting for them together as a single lease component.

In March 2019 the FASB issued additional amendments to ASC 842 for minor codification improvements, which we applied effective January 1, 2019, with no material effect to our results of operations, financial position and cash flows.

The cumulative effects of the changes to our balance sheet as of January 1, 2019, were as follows:

(Thousands)	Balance at December 31, 2018	Adjustments Due to ASC 842	Balance at January 1, 2019
Assets			
Total Property, Plant and Equipment	$ 4,130,725	$ (45,000)	$ 4,085,725
Operating lease right-of-use assets	—	10,394	10,394
Other assets	6,469	45,000	51,469
Liabilities			
Current portion of debt	$ 20,305	$ (21,617)	$ (1,312)
Operating lease liabilities, current	—	1,523	1,523
Other current liabilities	70,322	21,617	91,939
Operating lease liabilities, long-term	—	8,871	8,871
Other non-current liabilities	82,484	4,042	86,526
Non-current debt	1,217,990	(4,042)	1,213,948
Equity			
Retained earnings	$ 606,650		$ 606,650

Our adoption did not change the classification of lease-related expenses in our statements of income, and we do not expect significant changes to our pattern of expense recognition. Certain contracts previously classified as lessor leases, consisting mainly of pole rental agreements, no longer meet the definition of a lease under ASC 842. As such, these contracts are accounted for under other U.S. GAAP, but there were no changes to our pattern of revenue recognition. As a result, we expect our adoption will not materially affect our cash flows. Our accounting for finance (formerly capital) leases is substantially unchanged. Refer to Note 9 for further details.

(b) Targeted improvements to accounting for hedging activities

In August 2017 the FASB issued targeted amendments with the objective to better align hedge accounting with an entity's risk management activities in the financial statements, and to simplify the application of hedge accounting. The amendments address concerns of financial statement preparers over difficulties with applying hedge accounting and limitations for hedging both nonfinancial and financial risks and concerns of financial statement users over how hedging activities are reported in financial statements. The amended presentation and disclosure guidance is required only prospectively. Changes to the hedge accounting guidance to address those concerns will: 1) expand hedge accounting for nonfinancial and financial risk components and amend measurement methodologies to more closely align hedge accounting with an entity's risk management activities; 2) eliminate the separate measurement and reporting of hedge ineffectiveness, to reduce the complexity of preparing and understanding hedge results; 3) enhance disclosures and change the presentation of hedge results to align the effects of the hedging instrument and the hedged item in order to enhance transparency, comparability, and understandability of hedge results; and 4) simplify the way assessments of hedge effectiveness may be performed to reduce the cost and complexity of applying hedge accounting. The amendments ease the administrative burden of hedge documentation requirements and assessing hedge effectiveness going forward. We adopted the hedge accounting amendments on January 1, 2019, and had no cumulative-effect adjustment to retained earnings because there were no amounts of ineffectiveness recorded for any existing hedges as of that date. Concurrently with the above targeted improvements, we adopted the additional amendments the FASB issued in October 2018 that permit use of the Overnight Index Swap rate based on the Secured Overnight Financing Rate as a U.S. benchmark interest rate for hedge accounting purposes. Use of that rate is in addition to the already eligible benchmark interest rates, which are: interest rates on direct Treasury obligations of the U.S. government, the London Interbank Offered Rate swap rate, the OIS Rate based on the Fed Funds Effective Rate, and the Securities Industry and Financial Markets Association Municipal Swap Rate.

(c) Reclassification of certain tax effects from accumulated other comprehensive income

In February 2018 the FASB issued amendments to address a financial reporting issue that arose as a consequence of the Tax Cuts and Jobs Act of 2017 (the Tax Act) that the U.S. federal government enacted on December 22, 2017. Under previous guidance, an entity was required to include the adjustment of deferred taxes for the effect of a change in tax laws or rates in income from continuing operations, thus the associated tax effects of items within AOCI (referred to as stranded tax effects) did not reflect the appropriate tax rate. The amendments allow a reclassification from AOCI to retained earnings to eliminate the stranded tax effects resulting from the Tax Act. The amendments only relate to the reclassification of the income tax effects of the Tax Act, and do not affect the underlying guidance that requires the effect of a change in tax laws or rates to be included in income from continuing operations. We adopted the amendments effective January 1, 2019, and elected to reclassify the stranded tax effects of the Tax Act from AOCI to retained earnings at the beginning of the period of adoption. As a result, we reclassified approximately $0.2 million from AOCI to retained earnings within our statements of changes in equity.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements not yet adopted that we have evaluated or are evaluating to determine their effect on our financial statements.

(a) Measurement of credit losses on financial instruments, amendments and updates

The FASB issued an accounting standards update in June 2016 that requires more timely recording of credit losses on loans and other financial instruments. The amendments affect entities that hold financial assets and net investment in leases that are not accounted for at fair value through net income (loans, debt securities, trade receivables, net investments in leases, off-balance sheet credit exposures, etc.). They require an entity to present a financial asset (or group of financial assets) that is measured at amortized cost basis at the net amount expected to be collected. 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. The income statement reflects the measurement of credit losses for newly recognized financial assets, as well as the expected increases or decreases of expected credit losses that have taken place during the period. The measurement of expected credit losses is based on relevant information about past events, including historical experience, current conditions, and reasonable and supportable forecasts that affect the collectibility of the reported amount. An entity must use judgment in determining the relevant information and estimation methods appropriate in its circumstances. The FASB subsequently issued various updates to this new guidance to clarify transition and scope requirements, make narrow-scope codification improvements and corrections, and provide targeted transition relief. The new guidance, including the subsequent amendments, is effective for public entities that are SEC filers for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. Entities are to apply the amendments on a modified retrospective basis for most instruments.

Our implementation plan and steps included: evaluating financial assets within scope; documenting related technical accounting issues, policy considerations and financial reporting implications; and identifying changes to processes and controls to ensure all aspects of the new guidance were effectively addressed. Our adoption of the guidance on January 1, 2020, including our transition adjustment, will not materially affect our results of operations, financial position and cash flows.

(b) Changes to the disclosure requirements for fair value measurement and defined benefit plans

In August 2018, the FASB issued amendments related to disclosure requirements for both fair value measurement and defined benefit plans. The amendments concerning fair value measurement remove, modify and add certain disclosure requirements, in order to improve the overall usefulness of the disclosures and reduce unnecessary costs to companies to prepare the disclosures. The amendments to fair value measurement disclosures are effective for all entities for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted as specified. Certain amendments are to be applied prospectively, and all others are to be applied retrospectively. Our adoption of the amendments on January 1, 2020, will not materially affect our disclosures.

The amendments concerning disclosure requirements for defined benefit plans are narrow in scope and apply to all employers that sponsor defined benefit pension or other postretirement plans. They remove disclosures that are no longer considered cost beneficial, add certain new relevant disclosures and clarify specific requirements of disclosures concerning information for defined benefit pension plans. The amendments to defined benefit plan disclosures are effective for fiscal years ending after December 15, 2020. Early adoption is permitted and application is to be on a retrospective basis. Our adoption of the amendments on January 1, 2020, will not materially affect our disclosures.

(c) Simplifying the accounting for income taxes

In December 2019, the FASB issued an accounting standards update that is intended to reduce complexity in accounting for income taxes. The amendments remove specific exceptions to the general principles in ASC 740, Income Taxes, eliminating the need for an entity to analyze whether the following apply in a given period: (1) exception to the incremental approach for intra-period tax allocation, (2) exceptions to accounting for basis differences when there are ownership changes in foreign investments and (3) exception in interim period income tax accounting for year-to-date losses that exceed anticipated losses. The amendments also improve financial statement preparers' application of income-tax related guidance and simplify U. S. GAAP for (1) franchise taxes that are partially based on income, (2) transactions with a government that result in a step up in the tax basis of goodwill, (3) separate financial statements of legal entities that are not subject to tax and (4) enacted changes in tax laws in interim periods. The amendments are effective for public business entities for fiscal years beginning after December 15, 2020, and interim periods within those fiscal years. Early adoption is permitted, including adoption in any interim period for which financial statements have not been issued, with adoption of all amendments in the same period. Application is on a retrospective and/or modified retrospective basis, or a prospective basis, depending on the amendment aspect. We expect our adoption will not materially affect our results of operations, financial position, and cash flows.

Use of estimates and assumptions: The preparation of our financial statements in conformity with U.S. GAAP requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Significant estimates and assumptions are used for, but not limited to: (1) allowance for doubtful accounts and unbilled revenues; (2) asset impairments; (3) depreciable lives of assets; (4) income tax valuation allowances; (5) uncertain tax positions; (6) reserves for professional, workers' compensation, and comprehensive general insurance liability risks; (7) contingency and litigation reserves; (8) earnings sharing mechanism (ESM); (9) environmental remediation liabilities; (10) pension and other postretirement employee benefits (OPEB); (11) fair value measurements and (12) AROs. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our financial statements will change as new events occur, as more experience is acquired, as additional information is obtained, and as our operating environment changes. We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside specialists to assist in our evaluations, as considered necessary. Actual results could differ from those estimates.

Union collective bargaining agreements: Approximately 76% of our employees are covered by a collective bargaining agreement. We have no agreements that will expire within the coming year.

Note 2. Industry Regulation

Electricity and Natural Gas Distribution

Our revenues are regulated, being based on tariffs established in accordance with administrative procedures set by the NYPSC. The tariffs applied to regulated activities are approved by the NYPSC and are based on the cost of providing service. Our revenues are set to be sufficient to cover all of our operating costs, including energy costs, finance costs, and the costs of equity, the last of which reflect our capital ratio and a reasonable return on equity (ROE).

Energy costs that are set on the New York wholesale markets are passed on to consumers. The difference between energy costs that are budgeted and those that are actually incurred is offset by applying reconciliation procedures that result in either immediate or deferred tariff adjustments. Reconciliation procedures apply to other costs, which are in many cases exceptional, such as the effects of extreme weather conditions, environmental factors, regulatory and accounting changes, and treatment of vulnerable customers. Any revenues that allow us to exceed target returns, usually the result of better than expected cost efficiency, are generally shared with customers, resulting in future tariff reductions.

NYSEG Rate Plans

On May 20, 2015, NYSEG and Rochester Gas and Electric Corporation (“RG&E”) (together, “the companies”) filed electric and gas rate cases with the NYPSC. We requested rate increases for NYSEG Electric and NYSEG Gas.

On February 19, 2016, NYSEG and the other signatory parties filed a Joint Proposal (Proposal) with the NYPSC for a three-year rate plan for electric and gas service at NYSEG commencing May 1, 2016. The Proposal, which was approved on June 15, 2016, balanced the varied interests of the signatory parties including but not limited to maintaining the company’s credit quality and mitigating the rate impacts to customers. The Proposal reflects many customer benefits including: acceleration of the company’s natural gas leak prone main replacement programs and enhanced electric vegetation management to provide continued safe and reliable service. The delivery rate increase in the Proposal can be summarized as follows:

	May 1, 2016		May 1, 2017		May 1, 2018	
	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %
Electric	$29.6	4.10%	$29.9	4.10%	$30.3	4.10%
Gas	$13.1	7.30%	$13.9	7.30%	$14.8	7.30%

The allowed rate of return on common equity for NYSEG Electric and NYSEG Gas is 9.00%. The equity ratio for each company is 48%; however, the equity ratio is set at the actual up to 50% for earnings sharing calculation purposes. The customer share of any earnings above allowed levels increases as the ROE increases, with customers receiving 50%, 75% and 90% of earnings over 9.5%, 10.0% and 10.5% ROE, respectively, in the first rate year covering the period May 1, 2016 - April 30, 2017. The earnings sharing levels increased in rate year two (May 1, 2017 - April 30, 2018) to 9.65%, 10.15% and 10.65% ROE, respectively. The earnings sharing levels have further increased in rate year three (May 1, 2018 - April 30, 2019) to 9.75%, 10.25% and 10.75% ROE, respectively. The rate plans also include the implementation of a rate adjustment mechanism (“RAM”) designed to return or collect certain defined reconciled revenues and costs, implementation of new depreciation rates, and continuation of the existing Revenue Decoupling Mechanism (“RDM”) for each business.

The Proposal reflects the recovery of deferred NYSEG Electric storm costs of approximately $262 million, of which $123 million will be amortized over ten years and the remaining $139 million will be amortized over five years. The Proposal also continues reserve accounting for qualifying Major Storms ($21.4 million annually). Incremental maintenance costs incurred to restore service in qualifying divisions will be chargeable to the Major Storm Reserve provided they meet certain thresholds for each storm event.

The Proposal maintains current electric reliability performance measures (and associated potential negative revenue adjustments for failing to meet established performance levels) which include the system average interruption frequency index (SAIFI) and the customer average interruption duration index (CAIDI). The Proposal also modifies certain gas safety performance measures at the company, including those relating to the replacement of leak prone main, leak backlog management, emergency response, and damage prevention. The Proposal establishes threshold performance levels for designated aspects of customer service quality and continues and expands bill reduction and arrears forgiveness Low Income Programs with increased funding levels. The Proposal provided for the implementation of NYSEG's Energy Smart Community ("ESC") Project in the Ithaca region which would serve as a test-bed for implementation and deployment of Reforming the Energy Vision (REV) initiatives. The ESC Project is supported by NYSEG's Distribution Automation upgrades and Advanced Metering Infrastructure (AMI) implementation for customers on circuits in the Ithaca region. Other REV-related incremental costs and fees will be included in the RAM to the extent cost recovery is not provided for elsewhere. Under the Proposal, we will implement the RAM, which will be applicable to all customers, to return or collect RAM Eligible Deferrals and Costs, including: (1) property taxes; (2) Major Storm deferral balances; (3) gas leak prone pipe replacement; (4) REV costs and fees which are not covered by other recovery mechanisms; and (5) Electric Pole Attachment revenues.

The Proposal provides for partial or full reconciliation of certain expenses including, but not limited to: pension and other postretirement benefits; property taxes; variable rate debt and new fixed rate debt; gas research and development; environmental remediation costs; Major Storms; nuclear electric insurance limited credits; economic development; and Low Income Programs. The Proposal also includes a downward-only Net Plant reconciliation. In addition, the Proposal includes downward-only reconciliations for the costs of: electric distribution and gas vegetation management; pipeline integrity; and other incremental maintenance programs. The Proposal provides that we continue the electric RDMs on a total revenue per class basis and the gas RDMs on a revenue per customer basis.

On May 20, 2019, NYSEG filed rate cases requesting increases in delivery revenues for both its electric and gas businesses. Other parties to the rate cases filed direct testimony on September 20, 2019, and NYSEG filed rebuttal testimony on October 15, 2019. The Administrative Law Judges in the cases agreed to an extension of the litigation schedule to allow the Company, the Department of Public Service Staff ("DPS Staff"), and other parties to enter into settlement discussions, which are ongoing. The Company expects a Commission order in these rate cases in the second quarter of 2020.

Reforming the Energy Vision (REV)

In April 2014, the NYPSC commenced a proceeding entitled REV, which is a wide ranging initiative to reform New York State's energy industry and regulatory practices. REV has been divided into two tracks, Track 1 for Market Design and Technology, and Track 2 for Regulatory Reform. REV and its related proceedings have and will continue to propose regulatory changes that are intended to promote more efficient use of energy, deeper penetration of renewable energy resources such as wind and solar and wider deployment of distributed energy resources, such as micro grids, on-site power supplies and storage.

REV is also intended to promote greater use of advanced energy management products to enhance demand elasticity and efficiencies. Track 1 of this initiative involves a collaborative process to examine the role of distribution utilities in enabling market based deployment of distributed energy resources to promote load management and greater system efficiency, including peak load reductions. NYSEG is participating in the initiative with other New York utilities and are providing their unique perspective. The NYPSC issued a 2015 order in Track 1, which acknowledges the utilities' role as a Distribution System Platform (DSP) provider, and required the utilities to file an initial Distribution System Implementation Plan (DSIP) by June 30, 2016, followed by bi-annual updates. The companies filed the initial DSIP, which also included information regarding the potential deployment of AMI across its entire service territory. The companies, in December 2016, filed a petition to the NYPSC requesting approval for cost recovery associated with the full deployment of AMI, and a collaborative associated with this petition began in the first quarter of 2017, was suspended in the second quarter of 2017, was resumed in the first quarter of 2018, and has been included in the companies' May 20, 2019 rate filing. The companies also filed their first bi-annual update of the DSIP on July 31, 2018.

Other various proceedings have also been initiated by the NYPSC which are REV related, and each proceeding has its own schedule. These proceedings include the Clean Energy Standard, Value of Distributed Energy Resources (VDER) and Net Energy Metering, Demand Response Tariffs, and Community Choice Aggregation. As part of the Clean Energy Standard proceeding, all electric utilities were ordered to begin payments to New York State Energy Research and Development Authority (NYSERDA) for Renewable Energy Credits ("RECs") and Zero Emissions Credits beginning in 2017. A separate Offshore Wind proceeding was ordered by the NYPSC in July 2018.

Track 2 of the REV initiative is also underway, and through a DPS Staff Whitepaper review process, is examining potential changes in current regulatory, tariff, market design and incentive structures which could better align utility interests with achieving New York state and NYPSC's policy objectives. New York utilities will also be addressing related regulatory issues in their individual rate cases. A Track 2 order was issued in May 2016, and includes guidance related to the potential for Earnings Adjustment Mechanisms (EAMs), Platform Service Revenues, innovative rate designs, and data utilization and security. The companies, in December 2016, filed a proposal for the implementation of EAMs in the areas of System Efficiency, Energy Efficiency, Interconnections, and Clean Air. A collaborative process to review the companies' petition began in the first quarter of 2017 and was suspended in the third quarter of 2017. A proposal for EAMs has been included in the companies' May 20, 2019 rate filing.

In March, 2017, the NYPSC issued three separate REV-related orders. These orders created a series of filing requirements for NYSEG beginning in March 2017 and extending through the end of 2018. The three orders involve: 1) modifications to the electric utilities' proposed interconnection earnings adjustment mechanism framework; 2) further DSIP requirements, including confirmation of the filing of an updated DSIP plan by mid-2018 and implementing two energy storage projects at NYSEG by the end of 2018; and 3) Net Energy Metering Transition including implementation of Phase One of VDER. In September 2017, the NYPSC issued another order related to VDER, requiring tariff filings, changes to Standard Interconnection Requirements, and planning for the implementation of automated consolidated billing. NYSEG has participated with the other NY state electric utilities in jointly filing updates to the interconnection earnings adjustment mechanism, has implemented two energy storage projects, and has participated with the other NY state electric utilities in the VDER transition effort, including tariff updates and application of VDER principles.

The March 2017 Order in the VDER proceeding approved a transition from traditional Net Energy Metering (NEM) towards a more values-based approach (Value Stack) for compensating Distributed Energy Resources (DER). The March 2017 Order approved an interim methodology for more precise DER valuation and compensation for NEM-eligible technologies. The interim methodology approved by the NYPSC provides for a market transition consistent with the principles of gradualism and predictability, and established a tranche system to manage impacts on non-participants.

The March 2017 Order also directed a Phase Two of the VDER proceeding. Phase Two would encompass improvements to the interim methodology established in Phase One, seek to expand Value Stack eligibility to technologies not included in Phase One, and review rate designs for mass market (i.e., residential and small non-residential) on-site DERs whose project would be interconnected after January 1, 2020. Working groups were established for further discussions regarding Value Stack, Rate Design and Low Income. The working groups met toward the latter half of 2017 and all of 2018 to discuss, review and analyze several issues regarding each subject. The working groups culminated with a series of whitepapers developed by DPS Staff a) Standby and Buyback Service Rate Design, b) Future Value Stack Compensation, and c) Capacity Value Compensation. The whitepapers were submitted between December 12 and December 14, 2018 in the VDER proceeding. Public comments on the whitepapers were submitted by February 25, 2019.

On April 18, 2019, the Commission adopted the DPS Staff recommendations in the Future Value Stack Compensation and Capacity Value Compensation whitepapers, with modifications. The decisions in the Order impact the compensation provided to DERs with respect to distribution system value and installed capacity value. In addition, the Order establishes a new Community Credit in place of the Market Transition Credit for certain CDG projects in NYSEG's and RG&E's service territories, and expands eligibility for Phase One Net Metering for certain projects that have a rated capacity of 750 kW AC or lower, The decisions in the Order regarding changes to Value Stack compensation for DERs became effective on June 1, 2019. The April 18, 2019 Order also initiated a new proceeding to examine utilities' marginal cost of service studies. An initial meeting in that proceeding was held on June 28, 2019, during which the utilities explained their various marginal cost methodologies. DPS Staff will develop a whitepaper addressing the utilities' marginal cost studies with recommendations on how such studies shall be subsequently performed. To aid in the development of the whitepaper, Staff is requesting preliminary comments from stakeholders by November 25, 2019. At this time it is not known when the DPS Staff whitepaper on marginal cost methodologies will be issued.

An additional DPS Staff whitepaper on Rate Design for Mass Market On-Site DER projects interconnected after January 1, 2020 was scheduled to be submitted in the first quarter of 2019 but has been delayed and has not yet been filed with the NYPSC. On April 15, 2019, DPS Staff hosted a meeting and indicated that further analysis will be needed regarding rate design for mass market on-site DER projects. A subsequent meeting was held on May 31, 2019. At this time it is not known when the DPS Staff's further analysis will be completed, nor when the DPS Staff white paper on rate design will be submitted. The March 2017 Order stated that should a new compensation methodology not be in place by January 1, 2020, projects put into service after that date would receive NEM compensation only until the new compensation methodology is developed and implemented and would then be transferred to the new compensation methodology.

On May 16, 2019, the Commission issued an *Order on Standby and Buyback Service and Establishing Optional Demand Rates*. The Order expands the availability of demand rates based on standby service rate design principles by requiring utilities to file tariffs to provide opt-in eligibility for all customers, including mass market (i.e., residential), to a demand-based rate option, irrespective of whether customers have on-site DERs. The availability of existing standby rates was expanded to all current demand-billed customers on an optional basis beginning July 1, 2019. Optional standby rates for mass market customers will be made available in the near future. Utilities filed draft tariffs on September 23, 2019 as required, with further analysis and discussion regarding approval and implementation of the optional rates to occur in the Rate Design Working Group of the VDER proceeding. The NYPSC issued an order on Value Stack Compensation for High-Capacity-Factor Resources on December 12, 2019.

New York State Department of Public Service Investigation of the Preparation for and Response to the March 2017 Windstorm

On March 11, 2017, the New York State Department of Public Service (the Department) commenced an investigation of NYSEG's preparation for and response to the March 2017 windstorm, which affected more than 219,000 customers at NYSEG and RG&E. The Department investigation included a comprehensive review of NYSEG's preparation for and response to the windstorm, including all aspects of the company's filed and approved emergency plan. The Department held public hearings on April 12 and 13, 2017.

On November 16, 2017, the NYPSC announced that the Department Staff had completed their investigation into the March 2017 Windstorm and the NYPSC issued an Order Instituting Proceeding and to Show Cause. The DPS Staff's investigation found that NYSEG had allegedly violated certain parts of its emergency response plan, which makes the Company subject to possible financial penalties. NYSEG responded to the order in a timely manner and has conducted settlement discussions with the DPS Staff and other parties. These settlement discussions culminated with the filing of two Joint Proposals for settling the issues raised by the Department in June 2018, with several parties signing on to the Joint Proposals. These Joint Proposals have NYSEG and RG&E implementing a combined $3.9 million of storm resiliency and restoration projects which will not be paid for by ratepayers. The Joint Proposals were approved by the Commission in April 2019.

New York State Department of Public Service Investigation of the Preparation for and Response to the March 2018 Winter Storms

In March 2018, following two severe winter storms that impacted more than one million electric utility customers in New York, including 520,000 NYSEG and RG&E customers, the New York State Department of Public Service (NYDPS) commenced a comprehensive investigation of the preparation and response to those events by New York's major electric utility companies. The investigation was expanded in the Spring of 2018 to include other 2018 New York Spring storm events.

On April 18, 2019, the NYDPS staff issued a report (the 2018 Staff Report) of the findings from their investigation. The 2018 Staff Report identifies 94 recommendations for corrective actions to be implemented in the utilities Emergency Response Plans (ERP). The report also identified potential violations by several of the utilities, including NYSEG and RG&E.

Also on April 18, 2019, the NYPSC issued an Order Instituting Proceeding and to Show Cause directed to all major electric utilities in New York, including NYSEG and RG&E. The order directs the utilities, including NYSEG and RG&E, to show cause why the NYPSC should not pursue civil penalties, and/or administrative penalties for the apparent failure to follow their respective ERPs as approved and mandated by the NYPSC. The NYPSC also directs the utilities, within 30 days, to address whether the NYPSC should mandate, reject or modify in whole or in part, the 94 recommendations contained in the 2018 Staff Report. On May 20, 2019, NYSEG and RG&E responded to the portion of the Order to Show Cause with respect to the recommendations contained in the 2018 Staff Report. The Commission granted the companies a series of extensions to respond to the portion of the Order to Show Cause with respect to why the Commission should not pursue a penalty action. A Petition requesting New York State Public Service Commission (NYPSC) approval of a joint settlement agreement was filed with the NYPSC on December 17, 2019. The joint settlement agreement allows the Companies to avoid litigation and provides for payment by the companies of penalty of $10.5 million ($9.0 million NYSEG and $1.5 million RG&E). We cannot predict the final outcome of this matter.

NYPSC Directs Counsel to Commence Judicial Enforcement Proceeding Against NYSEG

On April 18, 2019, the NYPSC issued an Order Directing Counsel to the Commission to commence a special proceeding or an action in New York State Supreme Court to stop and prevent ongoing future violations by NYSEG of NYPSC regulations and orders. On December 24, 2019, the Commission filed a Verified Petition to commence the action against NYSEG. At the same time, NYSEG and the Commission settled the causes of action asserted in the Verified Petition and entered into a Consent and Stipulation and also submitted a joint motion to the Court requesting that the Court approve and enter a Consent Order and Judgment reflecting the settlement. We cannot predict the final outcome of this matter.

Tax Cuts and Jobs Act

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Tax Act) was signed into law. The Tax Act contains significant changes to the federal tax structure, including among other things, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017. The NYPSC has instituted proceedings in New York to review and address the implications associated with the Tax Act on the utilities providing service in state of New York. The Department of Public Service (DPS) Staff, on March 29, 2018, submitted a proposal to the NYPSC indicating that any companies which have not included the impacts from the Tax Act in a recent rate proceeding should submit a filing to initiate a surcredit beginning October 1, 2018 to pass back benefits to customers. The proposal invited all companies to comment on the proposal prior to June 29, 2018, and to include comments about alternative mechanisms to return the benefits to customers. NYSEG has submitted comments in response to the DPS Staff proposal, identifying that it would be premature to begin a surcredit which could cause rate volatility when major expenditures may be forthcoming. On August 9, 2018, the NYPSC issued an order in case 17-M-0815 and as part of that order instituted surcredits for NYSEG customers beginning October 1, 2018. The surcredits include the annual 2018 tax expense savings for both electric and gas businesses and include an amortization of previously deferred tax savings through September 30, 2018 for NYSEG Gas business. The annual amounts of the surcredits beginning October 1, 2018 for NYSEG are approximately $31 million. The full effect of the Tax Cut Act is reflected in the rate case filings of May 20, 2019.

Minimum Equity Requirements for Regulated Subsidiaries

NYSEG is subject to a minimum equity ratio requirement that is tied to the capital structure assumed in establishing revenue requirements. Pursuant to these requirements, NYSEG must maintain a minimum equity ratio equal to the ratio in its currently effective rate plan or decision measured using a trailing 13-month average. On a monthly basis, NYSEG must maintain a minimum equity ratio of no less than 300 basis points below the equity ratio used to set rates. The minimum equity ratio requirement has the effect of limiting the amount of dividends that may be paid and may, under certain circumstances, require that the parent contribute equity capital. NYSEG is prohibited by regulation from lending to unregulated affiliates. NYSEG has also agreed to minimum equity ratio requirements in certain borrowing agreements. These requirements are lower than the regulatory requirements.

Note 3. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations we capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric and natural gas rates. We base our assessment of whether recovery is probable on the existence of regulatory orders that allow for recovery of certain costs over a specific period, or allow for reconciliation or deferral of certain costs. When costs are not treated in a specific order we use regulatory precedent to determine if recovery is probable.

We also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs. Of the total regulatory assets net of regulatory liabilities, approximately $501.2 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

Details of other regulatory assets and other regulatory liabilities are shown in the tables below. They result from various regulatory orders that allow for the deferral and/or reconciliation of specific costs. Regulatory assets and regulatory liabilities are classified as current when recovery or refund in the coming year is allowed or required through a specific order or when the rates related to a specific regulatory asset or regulatory liability are subject to automatic annual adjustment.

On June 15, 2016, the NYPSC approved the Proposal in connection with a three-year rate plan for electric and gas service at NYSEG effective May 1, 2016. Following the approval of the proposal most of these items related to NYSEG are amortized over a five-year period, except the portion of storm costs to be recovered over ten years, and plant related tax items which are amortized over the life of associated plant. Annual amortization expense for NYSEG is approximately $16.5 million per rate year.

Current and non-current regulatory assets at December 31, 2019 and 2018 consisted of:

December 31,	2019	2018
(Thousands)		
Current		
Electric supply reconciliation	$4,667	$1,744
Environmental remediation costs	5,705	5,705
Hedge losses	15,720	—
Low income programs	1,826	1,826
Pension and other post-retirement benefits cost deferrals	23,886	23,886
Property tax deferrals	9,766	—
Rate adjustment mechanism	17,395	—
Rate change levelization	—	4,657
Revenue decoupling mechanism	10,227	5,919
Storm costs	40,128	58,226
Unamortized loss on re-acquired debt	1,496	1,968
Other	7,346	9,279
Total current regulatory assets	**138,162**	**113,210**
Non-current		
Asset retirement obligation	13,037	13,577
Environmental remediation costs	84,693	85,014
Federal tax depreciation normalization adjustment	87,823	90,405
Low income programs	3,321	5,547
Merger capital expenditure	246	983
Pension and other post-retirement benefits	347,735	393,787
Pension and other post-retirement benefits cost deferrals	52,503	71,108
Property tax deferrals	8,276	2,135
Rate adjustment mechanism	26,350	—
Storm costs	171,096	209,085
Unamortized loss on re-acquired debt	14,996	14,499
Other	12,209	11,798
Total non-current regulatory assets	**$822,285**	**$897,938**

Asset retirement obligations represent the differences in timing of the recognition of costs associated with our AROs and the collection of such amounts through rates. This amount is being amortized at the related depreciation and accretion amounts of the underlying liability.

Deferred property taxes represent the customer portion of the difference between actual expense for property taxes and the amount provided for in rates. The New York (NY) amount is being amortized over a five year period following the approval of the proposal by the NYPSC.

Environmental remediation costs include spending that has occurred and is eligible for future return/recovery in customer rates. Environmental costs are currently recovered through a reserve mechanism whereby projected spending is included in rates with any variance recorded as a regulatory asset or a regulatory liability. The amortization period will be established in future proceedings and will depend upon the timing of spending for the remediation costs. It also includes the anticipated future rate recovery of costs that are recorded as environmental liabilities since these will be recovered when incurred. Because no funds have yet been expended for the regulatory asset related to future spending, it does not accrue carrying costs and is not included within rate base.

Federal tax depreciation normalization adjustment represents the deferral of the normalization of change impacts in book lives and the pass back of theoretical reserves associated with deferred income tax.

Hedge losses regulatory asset represents the deferred fair value losses on electric and gas hedge contracts.

Low income programs represent deferrals related to over/under spending on Low-Income customer assistance programs.

Merger capital expense target customer credit account was created as a result of NYSEG not meeting certain capital expenditure requirements established in the order approving the purchase of Energy East by Iberdrola. The amortization period is five years following the approval of the proposal by the NYPSC.

Pension and other postretirement benefits represent the actuarial losses on the pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future pension expenses. Because no funds have yet been expended for this regulatory asset, it does not accrue carrying costs and is not included within the rate base. Pension and other postretirement benefits cost deferrals include the difference between actual expense for pension and other postretirement benefits and the amount provided for in rates. The recovery of these amounts will be determined in future proceedings.

Rate Adjustment Mechanism (RAM) represents a mechanism each business implements to return or collect the net balance of RAM eligible deferrals and costs. The primary driver of RAM collections is storm costs but it also includes property taxes and REV costs and fees not covered in other recovery mechanisms.

Rate change levelization represents NY delivery rate levelization to smooth the rate increase across the three year plan to avoid unnecessary spikes and offsetting dips in customer rates.

Storm costs for NYSEG are allowed in rates based on an estimate of the routine costs of service restoration. NYSEG is also allowed to defer unusually high levels of service restoration costs resulting from major storms when they meet certain criteria for severity and duration. Since the approval of the 2010 rate plan in New York (see Note 2), we have experienced unusually high levels of restoration costs resulting from various storms including Hurricane Sandy, Hurricane Irene and tropical storm Lee. NYSEG's total storm balance was $211.2 million at December 31, 2019 and $267.3 million at December 31, 2018. Pursuant to the most recent Joint Proposal approved by the Commission, which began May 1, 2016, NYSEG will recover $139 million of the balance over five years for non-super-storms and the super-storm balance of $123 million over ten years.

Unamortized losses on reacquired debt represent deferred losses on debt reacquisitions that will be recovered over the remaining original amortization period of the reacquired debt.

Other includes items such as post-term amortization and Reforming the Energy Vision (REV).

Current and non-current regulatory liabilities at December 31, 2019 and 2018 consisted of:

Notes to Financial Statements

December 31,		2019		2018
(Thousands)				
Current				
Carrying costs on deferred income tax depreciation	$	12,934	$	12,934
Carrying costs on mixed use 263(a)		5,173		5,173
Debt rate reconciliation		2,825		2,825
Economic development		3,487		3,487
Energy efficiency programs		36,189		25,315
Gas supply charge and deferred natural gas cost		5,174		2,751
Hedge gains		—		3,248
Non by-passable charges		7,301		3,456
NYS excess DIT – in rates		2,676		2,676
Pension and other postretirement benefits cost deferral		13,601		13,601
Positive benefit adjustment		2,685		2,685
Property tax		—		905
Theoretical reserve flow through impact		5,367		5,367
Other		9,297		7,251
Total current regulatory liabilities		**106,709**		**91,674**
Non-current				
Accrued removal obligation		525,035		521,175
Carrying costs on deferred income tax depreciation		314		13,248
Debt rate reconciliation		37,923		25,987
Economic development		4,309		5,596
Pension and other postretirement benefits		14,958		29,841
Pension and other postretirement benefits cost deferral		14,153		21,520
Positive benefit adjustment		895		3,579
Tax Act-remeasurement		504,359		496,381
Unfunded future income taxes		16,980		23,424
Other		73,417		56,476
Total non-current regulatory liabilities	**$**	**1,192,343**	**$**	**1,197,227**

Accrued removal obligations represent the differences between asset removal costs recorded and amounts collected in rates for those costs. The amortization period is dependent upon the asset removal costs of underlying assets and the life of the utility plant.

Carrying costs on deferred income tax bonus depreciation represent the carrying costs benefit of increased accumulated deferred income taxes created by the change in tax law allowing bonus depreciation. The amortization period is five years following the approval of the proposal by the NYPSC.

Debt rate reconciliation represents the over/under collection of costs related to fixed and variable rate debt instruments identified in the rate case. Costs include interest, commissions and fees versus amounts included in rates.

Economic development represents the economic development program which enables NYSEG to foster economic development through attraction, expansion, and retention of businesses within its service territory. If the level of actual expenditures for economic development allocated to NYSEG varies in any rate year from the level provided for in rates, the difference is refunded to ratepayers. The amortization period is five years following the approval of the proposal by the NYPSC.

Energy efficiency portfolio standard represents the difference between revenue billed to customers through an energy efficiency charge and the costs of our energy efficiency programs as approved by the state authorities. This may be refunded to customers within the next year.

Hedge gains regulatory liability represents deferred fair value gains on electric and gas hedge contracts.

Non by-passable charges represent the non by-passable charge paid by all customers. An asset or liability is recognized resulting from differences between actual revenues and the underlying cost being recovered. This liability will be refunded to customers within the next year.

NYS excess DIT – in rates represents changes in accumulated deferred income tax balances due to the reduction in the NY State corporate income tax rate of 0.6%, from 7.1% to 6.5% percent. Amounts previously collected from utility customers for these deferred taxes are refundable to such customers, generally through reductions in rates.

Pension and other postretirement benefits represent the actuarial gains on pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future expenses. Because no funds have yet been received for this a regulatory liability is not reflected within rate base. They also represent the difference between actual expense for pension and other postretirement benefits and the amount provided for in rates. Recovery of these amounts will be determined in future proceedings.

Positive benefit adjustment resulted from Iberdrola's 2008 acquisition of Energy East. This is being used to moderate increases in rates. The amortization period is five years following the approval of the proposal by the NYPSC and included in the Ginna RSSA settlement.

Tax Act - remeasurement represents the impact from remeasurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates from 35% to 21% under the provisions of the Tax Act will result in amounts previously collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates. The NYPSC has instituted separate proceedings to review and address the implications associated with the Tax Act on the utilities providing service in state of New York.

Theoretical reserve flow through impact represents the differences from the rate allowance for applicable federal and state flow through impacts related to the excess depreciation reserve amortization. It also represents the carrying cost on the differences. The amortization period is five years following the approval of the proposal by the NYPSC.

Unfunded future income taxes represent unrecovered federal and state income taxes primarily resulting from regulatory flow through accounting treatment. The income tax benefits or charges for certain plant related timing differences, such as removal costs, are immediately flowed through to, or collected from, customers. This amount is being amortized as the amounts related to temporary differences that give rise to the deferrals are recovered in rates.

Other includes various items subject to reconciliation including low income, earnings sharing provision and asset retirement obligations.

Note 4. Revenue

We recognize revenue when we have satisfied our obligations under the terms of a contract with a customer, which generally occurs when the control of promised goods or services transfers to the customer. We measure revenue as the amount of consideration we expect to receive in exchange for providing those goods or services. Contracts with customers may include multiple performance obligations. For such contracts, we allocate revenue to each performance obligation based on its relative standalone selling price. We generally determine standalone selling prices based on the prices charged to customers. Certain revenues are not within the scope of ASC 606, such as revenues from leasing, derivatives, other revenues that are not from contracts with customers and other contractual rights or obligations, and we account for such revenues in accordance with the applicable accounting standards. We exclude from revenue amounts collected on behalf of third parties, including any such taxes collected from customers and remitted to governmental authorities. We do not have any material significant payment terms because we receive payment at or shortly after the point of sale.

The following describes the principal activities from which we generate revenue.

NYSEG derives its revenue primarily from tariff-based sales of electricity and natural gas service to customers in New York with no defined contractual term. For such revenues, we recognize revenues in an amount derived from the commodities delivered to customers. Other major sources of revenue are electricity transmission and wholesale sales of electricity and natural gas.

Tariff-based sales are subject to the corresponding state regulatory authorities, which determine prices and other terms of service through the ratemaking process. In New York, customers have the option to obtain the electricity or natural gas commodity directly from the utility or from another supplier. For customers that receive their commodity from another supplier, the utility acts as an agent and delivers the electricity or natural gas provided by that supplier. Revenue in those cases is only for providing the service of delivery of the commodity.

Transmission revenue results from others’ use of the utility’s transmission system to transmit electricity and is subject to FERC regulation, which establishes the prices and other terms of service. Long-term wholesale sales of electricity are based on individual bilateral contracts. Short-term wholesale sales of electricity are generally on a daily basis based on market prices and are administered by the New York Independent System Operator (NYISO) or PJM Interconnection, LLC (PJM), as applicable. Wholesale sales of natural gas are generally short-term based on market prices through contracts with the specific customer.

The performance obligation in all arrangements is satisfied over time because the customer simultaneously receives and consumes the benefits as NYSEG delivers or sells the electricity or natural gas or provides the transmission service.

NYSEG records revenue from Alternative Revenue Programs (ARPs), which is not ASC 606 revenue. Such programs represent contracts between the utilities and their regulators. The NYSEG ARPs include revenue decoupling mechanisms, other ratemaking mechanisms, annual revenue requirement reconciliations, and other demand side management programs.

NYSEG also has various other sources of revenue including billing, collection, other administrative charges, sundry billings, rent of utility property, and miscellaneous revenue. It classifies such revenues as other ASC 606 revenues to the extent they are not related to revenue generating activities from leasing, ARPs, or other activities.

Notes to Financial Statements

We have contract liabilities for revenue from transmission congestion contract (TCC) auctions, for which we receive payment at the beginning of an auction period, and amortize ratably each month into revenue over the applicable auction period. The auction periods range from six months to two years. TCC contract liabilities totaled $9.4 million at December 31, 2019, and $8.8 million at December 31, 2018, and are presented in "Other current liabilities" on our condensed balance sheets. We recognized $19.6 million and $16.5 million as revenue during the year ended December 31, 2019 and 2018, respectively.

We apply a practical expedient to expense as incurred costs to obtain a contract when the amortization period is one year or less. We record costs incurred to obtain a contract within operating expenses, including amortization of capitalized costs.

Revenues disaggregated by major source for the years ended December 31, 2019 and 2018 are as follows:

Years Ended December 31,	**2019**	**2018**
(Thousands)		
Regulated operations – electricity	$1,203,096	$1,323,626
Regulated operations – natural gas	305,286	318,344
Other(a)	26,202	29,589
Revenue from contracts with customers	**1,534,584**	**1,671,559**
Leasing revenue	1,078	12,335
Alternative revenue programs	10,003	10,647
Other revenue	2,702	(249)
Total operating revenues	**$1,548,367**	**$1,694,292**

(a) Primarily includes certain intra-month trading activities, billing, collection, and administrative charges, sundry billings, and other miscellaneous revenue.

Refer to Note 1 for details on the adoption of ASC 842 including a discussion regarding the classification of lease revenues.

Note 5. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2019 and 2018 consisted of:

Years Ended December 31,	**2019**	**2018**
(Thousands)		
Current		
Federal	$ 44	$ 5,707
State	7,570	(6,440)
Current taxes charged to expense (benefit)	**7,614**	**(733)**
Deferred		
Federal	29,043	23,762
State	(132)	15,364
Deferred taxes charged to expense (benefit)	**28,911**	**39,126**
Investment tax credit adjustments	(510)	(510)
Total Income Tax Expense	**$ 36,015**	**$ 37,883**

Notes to Financial Statements

The differences between tax expense per the statements of income and tax expense at the 21% statutory federal tax rate for the years ended December 31, 2019 and 2018, respectively, consisted of:

Years Ended December 31,	2019	2018
(Thousands)		
Tax expense at statutory rate	$ 21,697	$ 31,492
Equity AFUDC tax effects not normalized	(5,082)	—
Investment tax credit	13,638	—
Investment tax credit amortization	(510)	(510)
State tax expense, net of federal benefit	5,876	7,701
Other, net	396	(800)
Total Income Tax Expense	**$ 36,015**	**$ 37,883**

Income tax expense for the year ended December 31, 2019 was $14.3 million higher than it would have been at the statutory federal income tax rate of 21% due predominately to investment tax credit deferral adjustment and state taxes, partially offset by AFUDC Equity not normalized. This resulted in an effective tax rate of 34.9%. Income tax expense for the year ended December 31, 2018 was $6.4 million higher than it would have been at the statutory federal income tax rate of 21% due predominately to state taxes. This resulted in an effective tax rate of 26.2%.

Deferred tax assets and liabilities as of December 31, 2019 and 2018 consisted of:

December 31,	2019	2018
(Thousands)		
Non-current Deferred Income Tax Liabilities (Assets)		
Property related	$ 605,817	$ 573,148
Storm costs	72,115	69,938
Pension and other post-retirement benefits	29,173	55,570
Power tax DIT	23,656	24,329
Accumulated deferred investment tax credits	9,560	(1,020)
Federal and state tax credits	—	(49,148)
Unfunded future income taxes	(6,509)	4,640
Regulatory liability due to "Tax Cuts and Jobs Act"	(132,470)	(130,399)
Environmental	(30,999)	(36,911)
Federal and state NOL’s	(1,295)	(738)
Other	(15,614)	(29,776)
Total Non-current Deferred Income Tax Liabilities	**$ 553,434**	**$ 479,633**
Deferred tax assets	$ 186,887	$ 243,352
Deferred tax liabilities	740,321	722,985
Net Accumulated Deferred Income Tax Liabilities	**$ 553,434**	**$ 479,633**

NYSEG has gross NY state net operating losses of $25.2 million for the year ended December 31, 2019. NYSEG had gross federal net operating losses of $3.5 million, federal research and development credits of $2.7 million, and claims for NY state tax credits of $46.5 million for the year ended December 31, 2018.

Uncertain tax positions have been classified as noncurrent unless expected to be paid within one year. In 2019, we netted our liability for uncertain tax positions against all same jurisdiction tax credit carryforwards. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the statements of income.

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2019 and 2018 consisted of:

Years Ended December 31,	2019	2018
(Thousands)		
Balance as of January 1	$ 45,269	$ 17,861
Increases for tax positions related to prior years	—	46,484
Reduction for tax positions related to prior years	(72)	(19,076)
Balance as of December 31	**$ 45,197**	**$ 45,269**

Unrecognized income tax benefits represent income tax positions taken on income tax returns but not yet recognized in the financial statements. The accounting guidance for uncertainty in income taxes provides that the financial effects of a tax position shall initially be recognized in the financial statements when it is more likely than not based on the technical merits that the position will be sustained upon examination, assuming the position will be audited and the taxing authority has full knowledge of all relevant information.

There were no additional accruals for interest and penalties on tax reserves as of December 31, 2019 and 2018.

Note 6. Long-term Debt

Long-term debt as of December 31, 2019 and 2018 consisted of:

As of December 31,		2019		2018	
(Thousands)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
Senior unsecured debt	2022-2049	$ 1,150,000	3.24%-5.75%	$ 850,000	3.24%-5.75%
Unsecured pollution control notes – fixed	2020-2029	386,000	2.00%-3.50%	374,000	2.00%-3.50%
Obligations under capital leases (a)				25,659	
Unamortized debt issuance costs and discount		(12,380)		(11,364)	
Total Debt		**$ 1,523,620**		**$ 1,238,295**	
Less: debt due within one year, included in current liabilities		198,439		20,305	
Total Non-current Debt		**$ 1,325,181**		**$ 1,217,990**	

(a) Due to the adoption of ASC 842 in 2019 (see Notes 1 and 9 for more information), capital leases, now known as financing leases, are no longer reported as part of long-term debt.

On June 29, 2018, NYSEG remarketed $174 million in aggregate principal amount of Pollution Control Revenue Bonds, issued through the New York State Energy Research and Development Authority, with mandatory tender dates ranging from 2023 to 2029 and interest rates ranging from 2.625% to 3.50%.

On April 1, 2019, NYSEG issued $12 million of Indiana County Industrial Development Authority Pollution Control Revenue Bonds in a private placement maturing in 2024 at an interest rate of 2.65%.

On September 5, 2019, NYSEG issued $300 million aggregate principal amount of senior unsecured notes maturing in 2049 at an interest rate of 3.30%.

Long-term debt, including sinking fund obligations, due over the next five years consist of:

2020	2021	2022	2023	2024	Total
(Thousands)					
$198,439	$—	$75,000	$300,000	$12,000	$585,439

Note 7. Bank Loans and Other Borrowings

NYSEG had $71.3 million and $40.4 million of notes payable at December 31, 2019 and 2018, respectively. NYSEG funds short-term liquidity needs through an agreement among Avangrid's regulated utility subsidiaries (the Virtual Money Pool Agreement), a bi-lateral intercompany credit agreement with Avangrid (the Bi-Lateral Intercompany Facility) and a bank provided credit facility to which NYSEG is a party (the AGR Credit Facility), each of which are described below.

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. NYSEG has a lending/borrowing limit of $100 million under this agreement. NYSEG had $20.3 million and $14.6 million outstanding under this agreement at December 31, 2019 and 2018, respectively.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $500 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. NYSEG had $51 million and $25.8 million outstanding under this agreement at December 31, 2019 and 2018, respectively.

On June 29, 2018, AGR and its investment-grade rate utility subsidiaries (NYSEG, RG&E, Central Maine Power Company ("CMP"), The United Illuminating Company ("UI"), Connecticut Natural Gas Corporation ("CNG"), The Southern Connecticut Gas Company ("SCG") and The Berkshire Gas Company ("BGC")) executed a new credit facility with an aggregate limit of $2.5 billion and a termination date of June 29, 2023. The revolving credit facility is provided by a syndicate of banks. Under the terms of the AGR Credit Facility, each joint borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum sublimit established by the lenders. AGR's maximum sublimit is $2 billion, NYSEG, RG&E, CMP and UI have maximum sublimits of $400 million, CNG and SCG have maximum sublimits of $150 million and BGC has a maximum sublimit of $40 million. Under the AGR Credit Facility, each of the borrowers will pay an annual facility fee that is dependent on their credit rating. The facility fees will range from 10.0 to 17.5 basis points. Effective on June 29, 2019, the termination date for the AGR Credit Facility was extended to June 29, 2024. NYSEG had no outstanding balance as of December 31, 2019 and December 31, 2018.

In the AGR Credit Facility we covenant not to permit, without the consent of the lenders, our ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of indebtedness to total capitalization, the facility excludes from net worth the balance of accumulated other comprehensive loss as it appears on the balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness we may maintain. Continued un-remedied failure to comply with those covenants beyond any applicable cure period, constitutes an event of default, and events of default could result in termination or reduction of lenders' commitments or acceleration of amounts owed under the facility. Our ratio of indebtedness to total capitalization pursuant to the revolving credit facility was 0.52 to 1.00 at December 31, 2019. We are not in default as of December 31, 2019.

Note 8. Preferred Stock Redeemable Solely at the Option of the Company

At December 31, 2019, NYSEG had 2,455,000 shares of $100 par value preferred stock, 10,800,000 shares of $25 par value preferred stock and 1,000,000 shares of $100 par value preference stock authorized but unissued.

Note 9. Leases

We have operating leases for office buildings, facilities, vehicles and certain equipment. Our finance leases are primarily related to electric generation, distribution, transmission and other. Certain of our lease agreements include rental payments adjusted periodically for inflation or are based on other periodic input measures. Our leases do not contain any material residual value guarantees or material restrictive covenants. Our leases have remaining lease terms of 1 to 18 years, some of which may include options to extend the leases for up to 20 years, and some of which may include options to terminate the leases within one year. We consider extension or termination options in the lease term if it is reasonably certain we will exercise the option.

The components of lease cost and other information related to leases were as follows:

Year Ended December 31,		**2019**
(Thousands)		
Lease cost		
Finance lease cost		
Amortization of right-of-use assets	$	4,911
Interest on lease liabilities		367
Total finance lease cost		5,278
Operating lease cost		2,039
Short-term lease cost		787
Variable lease cost		477
Intercompany		(48)
Total lease cost	**$**	**8,533**

Notes to Financial Statements

As of December 31,		2019
(Thousands, except lease term and discount rate)		
Operating Leases		
Operating lease right of use assets	$	9,341
Operating lease liabilities, current		1,339
Operating lease liabilities, long-term		8,385
Total operating lease liabilities	$	9,724
Finance Leases		
Other assets	$	39,620
Other current liabilities		1,218
Other non-current liabilities		2,952
Total finance lease liabilities	$	4,170
Weighted-average Remaining Lease Term (years):		
Finance leases		7.55
Operating leases		9.72
Weighted-average Discount Rate:		
Finance leases		7.78%
Operating leases		3.73%

Supplemental cash flows information related to leases was as follows:

Year Ended December 31,		2019
(Thousands)		
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$	1,604
Operating cash flows from finance leases	$	365
Financing cash flows from finance leases	$	21,535
Right-of-use assets obtained in exchange for lease obligations:		
Finance leases	$	122
Operating leases	$	619

Maturities of lease liabilities were as follows:

	Finance	Operating
(Thousands)		
Year Ended December 31,		
2020	$ 1,404	$ 1,642
2021	391	1,057
2022	320	928
2023	320	942
2024	320	903
Thereafter	2,441	6,445
Total lease payments	**5,196**	**11,917**
Less: imputed interest	(1,026)	(2,193)
Total	**$ 4,170**	**$ 9,724**

Most of our leases do not provide an implicit rate in the lease, thus we use our incremental borrowing rate based on the information available at the commencement date in determining the present value of lease payments. We used the incremental borrowing rate on January 1, 2019, for operating leases that commenced prior to that date.

Comparative 2018 Leases Disclosures

The following are the 2018 annual lease disclosures, presented in accordance with Topic 840.

Operating lease expense relating to operational facilities, office building leases and vehicle and equipment leases was $2.3 million for the year ended December 31, 2018.

Total future minimum lease payments as of December 31, 2018 consisted of:

Year	Operating Leases	Capital Leases	Total
(Thousands)			
2019	$1,696	$21,951	$23,647
2020	1,520	1,437	2,957
2021	998	397	1,395
2022	894	332	1,226
2023	930	332	1,262
Thereafter	6,688	2,614	9,302
Total	**$12,726**	**$27,063**	**$39,789**

Note 10. Commitments and Contingencies

Purchase power and natural gas contracts, including nonutility generators

NYSEG is the provider of last resort for customers. As a result, the company buys physical energy and capacity from the NYISO. In accordance with the NYPSC's February 26, 2008 Order, NYSEG is required to hedge on behalf of non-demand billed customers. The physical electric capacity purchases we make from parties other than the NYISO are to comply with the hedge requirement for electric capacity. The company enters into financial swaps to comply with the hedge requirement for physical electric energy purchases. NYSEG also makes purchases from other independent power producers and New York Power Authority (NYPA) under existing contracts or long-term supply agreements in order to comply with the company's Public Utility Regulatory Policies Act (PURPA) purchase obligation.

NYSEG satisfies its natural gas supply requirements through purchases from various producers and suppliers, withdrawals from natural gas storage, capacity contracts and winter peaking supplies and resources. The company operates diverse portfolios of gas supply, firm transportation capacity, gas storage and peaking resources. Actual gas costs incurred by the company are passed through to customers through state regulated purchased gas adjustment mechanisms, subject to regulatory review.

The company purchases the majority of its natural gas supply at market prices under seasonal, monthly or mid-term supply contracts and the remainder is acquired on the spot market. The company acquires firm transportation capacity on interstate pipelines under long-term contracts and utilizes that capacity to transport both natural gas supply purchased and natural gas withdrawn from storage to the local distribution system. The company acquires firm underground natural gas storage capacity using long-term contracts and fills the storage facilities with gas in the summer months for subsequent withdrawal in the winter months.

We recognized expenses of approximately $68.4 million for Normal Purchase Normal Sale (NPNS) purchase power and natural gas contracts including non-utility generators in 2019 and $80.6 million in 2018.

Note 11. Environmental Liability

From time to time environmental laws, regulations and compliance programs may require changes in our operations and facilities and may increase the cost of electric and natural gas service.

Waste sites

The Environmental Protection Agency (EPA) and the New York State Department of Environmental Conservation (NYSDEC), as appropriate, have notified us that we are among the potentially responsible parties that may be liable for costs incurred to remediate certain hazardous substances at twelve waste sites. The twelve sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the twelve sites, ten sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites and three sites are also included on the National Priorities list. Any liability may be joint and several for certain of those sites.

We have a liability recorded of $4.9 million as of December 31, 2019, related to the twelve sites. We have paid remediation costs related to the twelve sites. We have recorded an estimated liability of $0.5 million related to other two sites where we believe it is probable that we will incur remediation costs and/or monitoring costs, although we have not been notified that we are among the potentially responsible parties. It is possible that the ultimate cost to remediate the sites may be significantly more than the accrued amount. Our estimate for costs to remediate these sites ranges from $5.4 million to $6 million as of December 31, 2019. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to us. Any cost will be flowed through to NYSEG ratepayers.

Manufactured gas plants

We have a program to investigate and perform necessary remediation at our 39 sites where gas was manufactured in the past. In 1994 and 1996 we entered into orders on consent with the NYSDEC. Those orders require us to investigate and, where necessary, remediate 38 of our 39 sites. Eight sites are included in the New York State Registry.

Our estimate for all costs related to investigation and remediation of the 39 sites ranges from $85 million to $234.3 million at December 31, 2019. The estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial action, changes in technology relating to remedial alternatives and changes to current laws and regulations.

The liability to investigate and perform remediation, as necessary, at the known inactive gas manufacturing sites was $113 million at December 31, 2019 and $135.7 million at December 31, 2018. We recorded a corresponding regulatory asset, net of insurance recoveries and the amount collected from FirstEnergy described below, because we expect to recover the net costs in rates.

Our environmental liability accruals are recorded on an undiscounted basis and are expected to be paid through the year 2052.

FirstEnergy

NYSEG sued FirstEnergy under the Comprehensive Environmental Response, Compensation, and Liability Act to recover environmental cleanup costs at sixteen former manufactured gas sites, which are included in the discussion above. In July 2011, the District Court issued a decision and order in NYSEG's favor. Based on past and future clean-up costs at the sixteen sites in dispute, FirstEnergy would be required to pay NYSEG approximately $60 million if the decision were upheld on appeal. On September 9, 2011, FirstEnergy paid NYSEG $30 million, representing their share of past costs of $27 million and pre-judgment interest of $3 million.

FirstEnergy appealed the decision to the Second Circuit Court of Appeals. On September 11, 2014, the Second Circuit Court of Appeals affirmed the District Court's decision in NYSEG's favor, but modified the decision for nine sites, reducing NYSEG's damages for incurred costs from $27 million to $22 million, excluding interest, and reducing FirstEnergy's allocable share of future costs at these sites. NYSEG refunded FirstEnergy the excess $5 million in November 2014.

FirstEnergy remains liable for a substantial share of clean up expenses at nine manufactured gas plant (MGP) sites. Based on current projections, FirstEnergy's share is estimated at approximately $21 million. This amount is being treated as a contingent asset and has not been recorded as either a receivable or a decrease to the environmental provision. Any recovery will be flowed through to NYSEG ratepayers.

Century Indemnity and OneBeacon

On August 14, 2013, NYSEG filed suit in federal court against two excess insurers, Century Indemnity and OneBeacon, who provided excess liability coverage to NYSEG. NYSEG seeks payment for clean-up costs associated with contamination at twenty-two former manufactured gas plants. Based on estimated clean-up costs of $282 million, the carriers' allocable share is approximately $89 million, excluding pre-judgment interest, although this amount may change substantially depending upon the determination of various factual matters and legal issues during the case.

Century Indemnity and OneBeacon have answered admitting issuance of the excess policies, but contesting coverage and providing documentation proving they received notice of the claims in the 1990s. On March 31, 2017, the District Court granted motions filed by Century Indemnity and One Beacon dismissing all of NYSEG's claims against both defendants on the grounds of late notice. NYSEG filed a motion with the District Court on April 14, 2017 seeking reconsideration of the Court's decision. On March 27, 2018, the District Court denied NYSEG's request for reconsideration; NYSEG filed a notice of appeal on April 9, 2018. On April 25, 2019, the Second Circuit Court of Appeals affirmed the lower court's dismissal of NYSEG's claims. NYSEG filed a motion seeking en banc review on May 2, 2019, which was denied by the Second Circuit Court of Appeals on May 20, 2019.

Note 12. Accounting for Derivative Instruments and Hedging Activities

We are exposed to certain risks relating to our ongoing business operations. The primary risk we manage by using derivative instruments is commodity price risk. In accordance with the accounting requirements concerning derivative instruments and hedging activities, we recognize all derivative instruments as either assets or liabilities at fair value on our balance sheet.

The financial instruments we hold or issue are not for trading or speculative purposes.

Commodity price risk: Commodity price risk, due to volatility experienced in the wholesale energy markets, is a significant issue for the electric and natural gas utility industries. We manage this risk through a combination of regulatory mechanisms, such as the pass-through of the market price of electricity and natural gas to customers, and through comprehensive risk management processes. Those measures mitigate our commodity price exposure, but do not completely eliminate it. Owned electric generation and long-term supply contracts reduce our exposure to market fluctuations.

We have electricity commodity purchases and sales contracts for both capacity and energy (physical contracts) that have been designated and qualify for the normal purchases and normal sales exception in accordance with the accounting requirements concerning derivative instruments and hedging activities.

We currently have a non by-passable wires charge adjustment that allows us to pass through rates any changes in the market price of electricity. We use electricity contracts, both physical and financial, to manage fluctuations in electricity commodity prices in order to provide price stability to customers. We include the cost or benefit of those contracts in the amount expensed for electricity purchased when the related electricity is sold. We record changes in the fair value of electric hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations.

We have a purchased gas adjustment clause that allows us to recover through rates any changes in the market price of purchased natural gas, substantially eliminating our exposure to natural gas price risk. We use natural gas futures and forwards to manage fluctuations in natural gas commodity prices in order to provide price stability to customers. We include the cost or benefit of natural gas futures and forwards in the commodity cost that is passed on to customers when the related sales commitments are fulfilled. We record changes in the fair value of natural gas hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations.

The amounts for electricity hedge contracts and natural gas hedge contracts recognized in regulatory liabilities and assets as of December 31, 2019 and 2018, respectively, and amounts reclassified from regulatory assets and liabilities into income for the year ended December 31, 2019 and 2018, respectively, are as follows:

	Loss or Gain Recognized in Regulatory Assets/ Liabilities		Location of Loss (Gain) Reclassified from Regulatory Assets/ Liabilities into Income	Loss (Gain) Reclassified From Regulatory Assets/ Liabilities Into Income	
(Thousands)					
As of			Years Ended December 31,		
December 31, 2019	Electricity	Natural Gas	2019	Electricity	Natural Gas
Regulatory assets	$ 15,631	$ 1,047	Purchased power, natural gas and fuel used	$ 16,401	$ 195
Regulatory liabilities	$ —	$ —			
December 31, 2018			2018		
Regulatory assets	$ —	$ —	Purchased power, natural gas and fuel used	$ (5,101)	$ (321)
Regulatory liabilities	$ 3,369	$ 79			

Our derivative volumes by commodity type that are expected to settle each year are:

	Electricity Contracts	Natural Gas Contracts	Other Fuel Contracts
Year to settle	Mwhs	Dths	Gallons
As of December 31, 2019			
2020	2,432,700	2,430,000	1,201,200
2021	773,600	260,000	—
As of December 31, 2018			
2019	2,597,550	2,120,000	1,061,900
2020	761,600	350,000	—

The offsetting of derivatives, location in the balance sheet and amounts of derivatives as of December 31, 2019 and 2018, respectively, consisted of:

December 31, 2019	Derivative Assets-current	Derivative Assets-Non-current	Derivative Liabilities-current	Derivative Liabilities-Non-current
(Thousands)				
Not designated as hedging instruments				
Derivative assets	$ 733	$ 1,644	$ 733	$ 1,644
Derivative liabilities	(733)	(1,644)	(16,453)	(2,602)
	—	—	(15,720)	(958)
Designated as hedging instruments				
Derivative assets	2	—	2	—
Derivative liabilities	(2)	—	(224)	—
	—	—	(222)	—
Total derivatives before offset of cash collateral	—	—	(15,942)	(958)
Cash collateral receivable	—	—	15,720	958
Total derivatives as presented in the balance sheet	**$ —**	**$ —**	**$ (222)**	**$ —**

December 31, 2018	Derivative Assets-current	Derivative Assets-Non-current	Derivative Liabilities-current	Derivative Liabilities-Non-current
(Thousands)				
Not designated as hedging instruments				
Derivative assets	$ 9,991	$ 2,467	$ 6,743	$ 2,267
Derivative liabilities	(6,743)	(2,267)	(6,743)	(2,267)
	3,248	200	—	—
Designated as hedging instruments				
Derivative assets	—	—	—	—
Derivative liabilities	—	—	(824)	—
	—	—	(824)	—
Total derivatives before offset of cash collateral	3,248	200	(824)	—
Cash collateral receivable	—	—	—	—
Total derivatives as presented in the balance sheet	**$ 3,248**	**$ 200**	**$ (824)**	**$ —**

As of both December 31, 2019 and 2018, the derivative assets – noncurrent are presented within other non-current assets of the balance sheet. The derivative liabilities – noncurrent are presented within other non-current liabilities of the balance sheet.

Derivatives designated as hedging instruments

The effect of derivatives in cash flow hedging instruments on OCI and income for the year ended December 31, 2019 and 2018, respectively, consisted of:

Year Ended December 31,		(Loss) Gain Recognized in OCI on Derivatives	Location of (Loss) Gain Reclassified From Accumulated OCI into Income		(Loss) Gain Reclassified From Accumulated OCI into Income		Total Amount per Income Statement
(Thousands)							
2019							
Interest rate contracts	$	—	Interest expense	$	(105)	$	73,246
Commodity contracts: Other		188	Other operating expenses		(414)	$	648,039
Total	**$**	**188**		**$**	**(519)**		
2018							
Interest rate contracts	$	—	Interest expense	$	(105)	$	62,840
Commodity contracts: Other		(738)	Other operating expenses		47	$	614,744
Total	**$**	**(738)**		**$**	**(58)**		

The amounts in AOCI related to previously settled forward starting swaps, and accumulated amortization, as of December 31, 2019, is a net loss of $0.4 million as compared to a net loss of $0.5 million for 2018. For the year ended December 31, 2019, we recorded $0.1 million in net derivative losses related to discontinued cash flow hedges. We will amortize approximately $0.1 million of discontinued cash flow hedges in 2020.

As of December 31, 2019, $0.2 million in losses are reported in AOCI because the forecasted transaction is considered to be probable. We expect that those losses will be reclassified into earnings within the next 12 months, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted energy transactions. There was no ineffective portion of hedge recognized during the year ended December 31, 2019.

We face risks related to counterparty performance on hedging contracts due to counterparty credit default. We have developed a matrix of unsecured credit thresholds that are dependent on a counterparty's or the counterparty guarantor's applicable credit rating (normally Moody's or Standard & Poor's). When our exposure to risk for counterparty exceeds the unsecured credit threshold, the counterparty is required to post additional collateral or we will no longer transact with the counterparty until the exposure drops below the unsecured credit threshold.

We have various master netting arrangements in the form of multiple contracts with various single counterparties that are subject to contractual agreements that provide for the net settlement of all contracts through a single payment. Those arrangements reduce our exposure to a counterparty in the event of default on or termination of any one contract. For financial statement presentation, we offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement.

Certain of our derivative instruments contain provisions that require us to maintain an investment grade credit rating on our debt from each of the major credit rating agencies. If our debt were to fall below investment grade, it would be in violation of those provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position on December 31, 2019 is $16.7 million for which we have posted collateral.

Note 13. Fair Value of Financial Instruments and Fair Value Measurements

The estimated fair value of debt amounted to $1,598 million and $1,249 million as of December 31, 2019 and 2018, respectively. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the electricity industry and the credit ratings of the borrowers in each case. The fair value hierarchy for the fair value of debt is considered as Level 2.

Assets and liabilities measured at fair value on a recurring basis

The financial instruments measured at fair value as of December 31, 2019 and 2018, consisted of:

Notes to Financial Statements

Description	(Level 1)	(Level 2)	(Level 3)	Netting	Total
(Thousands)					
As of December 31, 2019					
Assets					
Noncurrent investments available for sale, primarily money market funds	$ 8,207	$ —	$ —	$ —	$ 8,207
Derivatives					
Commodity contracts:					
Electricity	2,354	—	—	(2,354)	—
Natural Gas	23	—	—	(23)	—
Other	—	—	2	(2)	—
Total	**$ 10,584**	**$ —**	**$ 2**	**$ (2,379)**	**$ 8,207**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	$ (17,985)	$ —	$ —	$ 17,985	$ —
Natural gas	(1,070)	—	—	1,070	—
Other	—	—	(224)	2	(222)
Total	**$ (19,055)**	**$ —**	**$ (224)**	**$ 19,057**	**$ (222)**
As of December 31, 2018					
Assets					
Noncurrent investments available for sale, primarily money market funds	$ 8,081	$ —	$ —	$ —	$ 8,081
Derivatives					
Commodity contracts:					
Electricity	12,045	—	—	(8,676)	3,369
Natural Gas	413	—	—	(334)	79
Other	—	—	—	—	—
Total	**$ 20,539**	**$ —**	**$ 0**	**$ (9,010)**	**$ 11,529**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	$ (8,676)	$ —	$ —	$ 8,676	$ —
Natural gas	(334)	—	—	334	—
Other	—	—	(824)	—	(824)
Total	**$ (9,010)**	**$ —**	**$ (824)**	**$ 9,010**	**$ (824)**

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2019 and 2018. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

Valuation techniques: We measure the fair value of our noncurrent investments available for sale using quoted market prices in active markets for identical assets and include the measurements in Level 1. The investments which are Rabbi Trusts for deferred compensation plans primarily consist of money market funds.

We determine the fair value of our derivative assets and liabilities utilizing market approach valuation techniques:

- We enter into electric energy derivative contracts to hedge the forecasted purchases required to serve their electric load obligations. We hedge our electric load obligations using derivative contracts that are settled based upon Locational Based Marginal Pricing published by the NYISO. We hedge approximately 70% of their electric load obligations using contracts for a NYISO location where an active market exists. The forward market prices used to value the companies' open electric energy derivative contracts are based on quoted prices in active markets for identical assets or liabilities with no adjustment required and therefore we include the fair value in Level 1.
- We enter into natural gas derivative contracts to hedge the forecasted purchases required to serve our natural gas load obligations. The forward market prices used to value our open natural gas derivative contracts are exchange-based prices for the identical derivative contracts traded actively on the New York Mercantile Exchange. Because we use prices quoted in an active market, we include those fair value measurements in Level 1.
- We enter into fuel derivative contracts to hedge our unleaded and diesel fuel requirements for our fleet vehicles. Exchange based forward market prices are used but because a basis adjustment is added to the forward prices, we include the fair value measurement for these contracts in Level 3.

The reconciliation of changes in the fair value of financial instruments based on Level 3 inputs for the years ended December 31, 2019 and 2018 consisted of:

	(Level 3) Derivatives, Net	
Year Ended December 31,	**2019**	**2018**
(Thousands)		
Beginning balance	$ (824)	$ (39)
Realized (gains) losses included in earnings	414	(47)
Unrealized gains (losses) included in other comprehensive income	188	(738)
Ending balance	**$ (222)**	**$ (824)**

The gains and losses included in earnings for the periods above are reported in Operations and maintenance of the statements of income.

Note 14. Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss for the years ended December 31, 2019 and 2018, consisted of:

(Thousands)	Balance, December 31, 2017	Change 2018	Balance, December 31, 2018	Adoption of new accounting standard	Change 2019	Balance, December 31, 2019
Amortization of pension cost for nonqualified plans, net of income tax expense (benefit) of $50 for 2018 and ($44) for 2019	$ (545)	$ 131	$ (414)	$ —	$ (124)	$ (538)
Unrealized gain (loss) on derivatives qualified as hedges:						
Unrealized gain (loss) during period on derivatives qualified as hedges, net of income tax (benefit) expense of ($203) for 2018 and $49 for 2019		(535)			139	
Reclassification adjustment for loss included in net income, net of income tax (benefit) expense of ($13) for 2018 and $108 for 2019		(34)		(201)	306	
Reclassification adjustment for loss on settled cash flow treasury hedges, net of income tax expense of $29 for 2018 and $28 for 2019		76			77	
Net unrealized gain (loss) on derivatives qualified as hedges	(360)	(493)	(853)	(201)	522	(532)
Accumulated Other Comprehensive Loss	**$ (905)**	**$ (362)**	**$ (1,267)**	**$ (201)**	**$ 398**	**$ (1,070)**

Note 15. Post-retirement and Similar Obligations

We have funded noncontributory defined benefit pension plans that cover all eligible employees. For employees hired before 2002, the plans provide defined benefits based on years of service and final average salary. Employees hired in 2002 or later are covered under a cash balance plan or formula where their benefit accumulates based on a percentage of annual salary and credited interest. During 2013, we announced that we would stop the cash balance accruals for all non-union employees covered under the cash balance plans effective December 31, 2013. NYSEG's unionized employees covered under the cash balance plans ceased to receive accruals as of December 31, 2015. Their earned balances would continue to accrue interest, but would no longer be increased by a percentage of earnings. In place of the pension benefit for those employees, they will receive a minimum contribution to their account under their respective company's defined contribution plan. There was no change to the defined benefit plans for employees covered under the plans that provide defined benefits based on years of service and final average salary.

Notes to Financial Statements

The company maintains a 401(k) Savings and Retirement Plan (the Plan) for all eligible employees as defined in the Plan agreement. Participants in the Plan may contribute a percentage of their compensation and the company may match a predetermined percentage of the participant contributions. Expenses under the Plan for the Company totaled approximately $6.9 million for 2019 and $6.3 million for 2018.

We also have other postretirement health care benefit plans covering substantially all of our employees. The health care plans are contributory with participants' contributions adjusted annually.

Obligations and funded status as of December 31, 2019 and 2018 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2019**	**2018**	**2019**	**2018**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	$ 1,508,082	$ 1,601,569	$ 151,159	$ 181,111
Service cost	14,915	16,516	994	1,836
Interest cost	57,524	56,498	5,706	6,354
Plan participants' contributions	—	—	—	3,993
Actuarial loss/(gain)	161,924	(69,054)	15,851	(26,404)
Benefits paid	(93,199)	(97,447)	(13,328)	(15,732)
Benefit obligation at December 31	**$ 1,649,246**	**$ 1,508,082**	**$ 160,382**	**$ 151,158**
Change in plan assets				
Fair value of plan assets at January 1	$ 1,314,984	$ 1,474,106	$ 73,273	$ 83,838
Actual return on plan assets	228,980	(61,675)	10,438	(3,287)
Employer & plan participants' contributions	—	—	6,528	8,453
Benefits paid	(93,199)	(97,447)	(13,328)	(15,732)
Fair value of plan assets at December 31	**$ 1,450,765**	**$ 1,314,984**	**$ 76,911**	**$ 73,272**
Funded status	**$ (198,481)**	**$ (193,098)**	**$ (83,471)**	**$ (77,886)**

Amounts recognized in the balance sheet as of December 31, 2019 and 2018 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2019**	**2018**	**2019**	**2018**
(Thousands)				
Noncurrent liabilities	$ (198,481)	$ (193,098)	$ (83,471)	$ (77,886)

We have determined that we are allowed to defer as regulatory assets or regulatory liabilities items that would otherwise be recorded in accumulated other comprehensive income pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans. Amounts recognized as regulatory assets or regulatory liabilities consist of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2019**	**2018**	**2019**	**2018**
(Thousands)				
Net loss	$ 344,163	$ 389,296	$ (6,785)	$ (16,071)
Prior service cost (credit)	$ 3,572	$ 4,491	$ (8,173)	$ (13,770)

Our accumulated benefit obligation for all defined benefit pension plans was $1,578 million and $1,445 million as of December 31, 2019 and 2018. NYSEG's postretirement benefits were partially funded as of December 31, 2019 and 2018.

The projected benefit obligation and the accumulated benefit obligation exceeded the fair value of pension plan assets for our plans as of both December 31, 2019 and 2018. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets as of December 31, 2019 and 2018.

As of December 31,	2019	2018
(Thousands)		
Projected benefit obligation	$ 1,649,246	$ 1,508,082
Accumulated benefit obligation	$ 1,578,437	$ 1,445,266
Fair value of plan assets	$ 1,450,765	$ 1,314,984

Components of net periodic benefit cost and other amounts recognized in regulatory assets and regulatory liabilities for the years ended December 31, 2019 and 2018 consisted of:

	Pension Benefits		Postretirement Benefits	
Year Ended December 31,	**2019**	**2018**	**2019**	**2018**
(Thousands)				
Net periodic benefit cost				
Service cost	$ 14,915	$ 16,516	$ 994	$ 1,836
Interest cost	57,524	56,498	5,706	6,354
Expected return on plan assets	(100,694)	(103,271)	(3,077)	(3,521)
Amortization of prior service cost (credit)	919	1,077	(5,597)	(5,597)
Amortization of net loss	78,770	99,370	(796)	3,661
Net periodic benefit cost	**$ 51,434**	**$ 70,190**	**$ (2,770)**	**$ 2,733**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net loss (gain)	$ 33,636	$ 95,892	$ 8,490	$ (19,596)
Amortization of net (loss)	(78,769)	(99,370)	796	(3,661)
Amortization of prior service (cost) credit	(919)	(1,077)	5,597	5,597
Total recognized in regulatory assets and regulatory liabilities	**$ (46,052)**	**$ (4,555)**	**$ 14,883**	**$ (17,660)**
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$ 5,382**	**$ 65,635**	**$ 12,113**	**$ (14,927)**

We include the net periodic benefit cost in other operating expenses for the service component and other deductions for the non-service component. The net periodic benefit cost for postretirement benefits represents the amount expensed for providing health care benefits to retirees and their eligible dependents.

Amounts expected to be amortized from regulatory assets or regulatory liabilities into net periodic benefit cost for the year ending December 31, 2020 consist of:

(Thousands)	Pension Benefits	Postretirement Benefits
Estimated net loss	$ 83,880	$ 1,252
Estimated prior service cost (credit)	$ 791	$ (5,495)

We expect that no pension benefit or postretirement benefit plan assets will be returned to us during the year ending December 31, 2020.

The weighted-average assumptions used to determine benefit obligations as of December 31, 2019 and 2018 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	2019	2018	2019	2018
Discount rate	2.93%	3.93%	2.93%	3.93%
Rate of compensation increase	Age-Related Rates	3.80%	Age-Related Rates	N/A

The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rate developing a yield curve derived from a portfolio of high grade non-callable bonds with above median yields that closely matches the duration of the expected cash flows of our benefit obligations.

The weighted-average assumptions used to determine net periodic benefit cost for the years ended December 31, 2019 and 2018 consisted of:

	Pension Benefits		Postretirement Benefits	
Years Ended December 31,	2019	2018	2019	2018
Discount rate	3.93%	3.63%	3.93%	3.63%
Expected long-term return on plan assets	7.30%	7.30%	—%	—%
Expected long-term return on plan assets - nontaxable trust	—%	—%	6.40%	6.40%
Expected long-term return on plan assets - taxable trust	—%	—%	4.20%	4.20%
Rate of compensation increase	3.80%	3.90%	Age-Related Rates	N/A

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations and the effect of rebalancing of plan assets discussed below. That analysis considered current capital market conditions and projected conditions. Our policy is to calculate the expected return on plan assets using the market related value of assets. We amortize unrecognized actuarial gains and losses over 10 years from the time they are incurred.

Assumed health care cost trend rates to determine benefit obligations as of December 31, 2019 and 2018 consisted of:

As of December 31,	2019	2018
Health care cost trend rate (pre 65/post 65)	6.75% / 7.50%	7.00%/7.75%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	4.50%	4.50%
Year that the rate reaches the ultimate trend rate	2029 / 2027	2029/2027

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1% Increase		1% Decrease	
(Thousands)				
Effect on total of service and interest cost	$	195	$	(165)
Effect on postretirement benefit obligation	$	6,020	$	(5,171)

Contributions: In accordance with our funding policy, we make annual contributions of not less than the minimum required by applicable regulations. We do not expect to contribute to our pension benefit plan in 2020. We expect to contribute $6,069 million to our postretirement benefits plan in 2020.

Estimated future benefit payments: Our expected benefit payments and expected Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) subsidy receipts, which reflect expected future service, as appropriate, are:

	Pension Benefits		Postretirement Benefits		Medicare Act Subsidy Receipts	
(Thousands)						
2020	$	90,105	$	12,137	$	—
2021	$	92,348	$	11,903	$	—
2022	$	94,541	$	11,580	$	—
2023	$	96,299	$	11,277	$	—
2024	$	97,671	$	10,963	$	—
2025-2029	$	493,275	$	49,567	$	—

***Plan assets*:** Our pension benefits plan assets are held in a master trust providing for a single trustee/ custodian, a uniform investment manager lineup, and an efficient, cost-effective means of allocating expenses and investment performance to each plan under the master trust. Our primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our tolerance for risk. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. Our primary means for achieving capital preservation is through diversification of the trust's investments while avoiding significant concentrations of risk in any one area of the securities markets. Within each asset group, further diversification is achieved through utilizing multiple asset managers and systematic allocation to various asset classes and providing broad exposure to different segments of the equity, fixed-income and alternative investment markets.

The asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets within broad categories of asset classes made up of Return-Seeking and Liability-Hedging investments. We have targets of 35%-70% for Return-Seeking assets and 34%-65% for Liability-Hedging assets. Return-Seeking investments generally consist of domestic, international, global, and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking assets also include investments in real estate, global asset allocation strategies and hedge funds. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS, and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of pension benefits plan assets as of December 31, 2019, by asset category, consisted of:

		Fair Value Measurements		
Asset Category	**Total**	**(Level 1)**	**(Level 2)**	**(Level 3)**
(Thousands)				
As of December 31, 2019				
Cash and cash equivalents	$ 25,182	$ 3	$ 25,179	$ —
U.S. government securities	61,222	61,222	—	—
Registered investment companies	230,280	230,280	—	—
Corporate bonds	322,739	—	322,739	—
Preferred stocks	903	903	—	—
Other, principally annuity, fixed income	59,590	—	59,590	—
	$ 699,916	**$ 292,408**	**$ 407,508**	**$ —**
Other investments measured at net asset value	750,849			
Total	**$ 1,450,765**			

The fair values of pension benefits plan assets as of December 31, 2018, by asset category, consisted of:

		Fair Value Measurements		
Asset Category	**Total**	**(Level 1)**	**(Level 2)**	**(Level 3)**
(Thousands)				
As of December 31, 2018				
Cash and cash equivalents	$ 27,064	$ —	$ 27,064	$ —
U.S. government securities	7,930	7,930	—	—
Common stocks	47	47	—	—
Registered investment companies	113,424	113,424	—	—
Corporate bonds	216,206	—	216,206	—
Preferred stocks	1,839	141	1,698	—
Equity commingled funds	426,010	94,041	331,969	—
Other, principally annuity, fixed income	37,412	—	37,412	—
	$ 829,932	**$ 215,583**	**$ 614,349**	**$ —**
Other investments measured at net asset value	485,052			
Total	**$ 1,314,984**			

Valuation Techniques

We value our pension benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.

- U.S. government securities and common stock - at the closing price reported in the active market in which the security is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks - at the closing price reported in the active market in which the individual investment is traded.
- Registered investment companies - at the closing price reported in the active market in which the individual investment is traded.
- Equity commingled funds – the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Other investments measured at net asset value (NAV) – fund shares offered to a limited group of investors and alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

Our postretirement benefits plan assets are held with trustees in multiple voluntary employees' beneficiary association (VEBA) and 401(h) arrangements and are invested among and within various asset classes to achieve sufficient diversification in accordance with our risk tolerance. This is achieved for our postretirement benefits plan assets through the utilization of multiple institutional mutual and money market funds, providing exposure to different segments of the fixed income, equity and short-term cash markets. Approximately 37% of the postretirement benefits plan assets are invested in VEBA and 401(h) arrangements that are not subject to income taxes with the remainder being invested in arrangements subject to income taxes.

We have established a target asset allocation policy within allowable ranges for postretirement benefits plan assets of 45% - 65% for equity securities, 25% - 45% for fixed income, and 5% - 25% for all other investment types. Equity investments are diversified across U.S. and non-U.S. stocks, investment styles, and market capitalization ranges. Fixed income investments are primarily invested in U.S. bonds and may also include some non-U.S. bonds. Other asset classes, including alternative investments, are used to enhance long-term returns while improving portfolio diversification. We primarily minimize the risk of large losses through diversification but also through monitoring and managing other aspects of risk through quarterly investment portfolio reviews. Systematic rebalancing within target ranges increases the probability that the annualized return on investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair value of other postretirement benefits plan assets, by asset category, as of December 31, 2019 consisted of:

		Fair Value Measurements		
Asset Category	**Total**	**(Level 1)**	**(Level 2)**	**(Level 3)**
(Thousands)				
As of December 31, 2019				
Cash and cash equivalents	$ 2,078	$ —	$ 2,078	$ —
Common stocks	11,317	11,317	—	—
Registered investment companies	62,445	62,445	—	—
Corporate bonds	1,071	—	1,071	—
Total assets measured at fair value	**$ 76,911**	**$ 73,762**	**$ 3,149**	**$ —**

The fair value of other postretirement benefits plan assets, by asset category, as of December 31, 2018 consisted of:

Asset Category	Total	Fair Value Measurements (Level 1)	(Level 2)	(Level 3)
(Thousands)				
As of December 31, 2018				
Money market funds	$ 4,570	$ 2,387	$ 2,183	$ —
Registered investment companies	54,231	53,428	803	—
Common collective trusts	10,804	10,804	—	—
Mutual funds, other	3,667	—	3,667	—
Total assets measured at fair value	**$ 73,272**	**$ 66,619**	**$ 6,653**	**$ —**

Valuation Techniques

We value our postretirement benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Common stock and registered investment companies - at the closing price reported in the active market in which the individual investment is traded.
- Money market funds and mutual funds - based upon quoted market prices in active markets.

Pension and postretirement benefit plan equity securities did not include any AGR and Iberdrola common stock as of both December 31, 2019 and 2018.

Note 16. Other Income and Other Deductions

Other income and deductions for the years ended December 31, 2019 and 2018, consisted of:

Years Ended December 31,	2019	2018
(Thousands)		
Interest and dividend income	$ 265	$ 67
Carrying costs on regulatory assets	11,845	9,316
Allowance for funds used during construction	14,428	3,006
Gain on sale of property	1,433	899
Miscellaneous	226	113
Total other income	**$ 28,197**	**$ 13,401**
Pension non-service components	$ (30,343)	$ (52,058)
Miscellaneous	(11,814)	(1,157)
Total other deductions	**$ (42,157)**	**$ (53,215)**

Note 17. Related Party Transactions

Certain Networks subsidiaries, including NYSEG, borrow from AGR, the parent of Networks, through intercompany revolving credit agreements. For NYSEG, the intercompany revolving credit agreements provide access to supplemental liquidity. See Note 7 for further detail on the credit facility with AGR.

Avangrid Service Company provides administrative and management services to Networks operating utilities, including NYSEG, pursuant to service agreements. The cost of those services is allocated in accordance with methodologies set forth in the service agreements. The cost allocation methodologies vary depending on the type of service provided. Management believes such allocations are reasonable. The charge for operating and capital services provided to NYSEG by AGR and its affiliates was approximately $98 million for 2019 and $102.4 million for 2018 and charge for services provided by NYSEG to AGR and its subsidiaries were approximately $12.4 million for 2019 and $11 million for 2018. All charges for services are at cost. The balance in accounts payable to affiliates of $81.8 million at December 31, 2019 and $82.4 million at December 31, 2018 is mostly payable to Avangrid Service Company. The balance in accounts receivable from affiliates of $53.1 million at December 31, 2019 is from various companies and the balance of $2.5 million at December 31, 2018 is mostly receivable from Avangrid Service Company.

Networks holds an approximate 20% ownership interest in the regulated New York TransCo. Through New York TransCo, Networks has formed a partnership with Central Hudson Gas and Electric Corporation, Consolidated Edison, Inc., National Grid, plc and Orange and Rockland Utilities, Inc. to develop a portfolio of interconnected transmission lines and substations to fulfill the objectives of the New York energy highway initiative, which is a proposal to install up to 3,200 MW of new electric generation and transmission capacity in order to deliver more power generated from upstate New York power plants to downstate New York. In 2016 NYSEG received approximately $67 million from New York TransCo in the form of $43 million for assets constructed and transferred to the New York TransCo, $22 million in contributions in aid of construction and approximately $2 million in advanced lease payments for a 99 year lease of land and attachment rights. As of December 31, 2019 we had no outstanding receivable balance from New York TransCo. As of December 31, 2018 we had $1 million outstanding receivable from New York TransCo.

Note 18. Subsequent Events

The company has performed a review of subsequent events through March 31, 2020, which is the date these financial statements were available to be issued.

In March 2020 the World Health Organization declared a global pandemic due to the outbreak of COVID-19. The company is assessing the possible impacts to our business and financial results.

Rochester Gas and Electric Corporation

Financial Statements

As of and For the Years Ended December 31, 2019 and 2018

Rochester Gas and Electric Corporation

Index

Page(s)

Financial Statements As of and for the Years Ended December 31, 2019 and 2018

KPMG LLP
345 Park Avenue
New York, NY 10154-0102

Independent Auditors' Report

Shareholders and The Board of Directors
Rochester Gas and Electric Corporation:

We have audited the accompanying financial statements of Rochester Gas and Electric Corporation, which comprise the balance sheets as of December 31, 2019 and 2018, and the related statements of income, comprehensive income, changes in common stock equity, and cash flows for the years then ended, 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 U.S. generally accepted accounting principles; 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 auditors' 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 entity'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 entity'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 Rochester Gas and Electric Corporation as of December 31, 2019 and 2018, and the results of its operations and its cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

KPMG LLP

New York, New York
March 31, 2020

Rochester Gas and Electric Corporation
Statements of Income

Years Ended December 31,		2019		2018
(Thousands)				
Operating Revenues	$	**893,042**	$	**923,768**
Operating Expenses				
Electricity purchased and fuel used in generation		94,958		128,817
Natural gas purchased		108,138		116,169
Operations and maintenance		282,270		271,177
Depreciation and amortization		94,619		84,744
Taxes other than income taxes, net		125,842		122,920
Total Operating Expenses		**705,827**		**723,827**
Operating Income		**187,215**		**199,941**
Other income		24,121		20,638
Other deductions		(12,343)		(24,406)
Interest expense, net of capitalization		(70,784)		(71,322)
Income Before Tax		**128,209**		**124,851**
Income tax expense		33,354		30,722
Net Income	$	**94,855**	$	**94,129**

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

Rochester Gas and Electric Corporation
Statements of Comprehensive Income

Years Ended December 31,		2019		2018
(Thousands)				
Net Income	$	**94,855**	$	**94,129**
Other Comprehensive Income, Net of Tax				
Amortization of pension for nonqualified plans, net of income taxes		(283)		323
Unrealized gain (loss) during the year on derivatives qualifying as cash flow hedges, net of income taxes:				
Unrealized gain (loss) during period on derivatives qualifying as hedges		66		(212)
Reclassification adjustment for loss included in net income		123		1
Reclassification adjustment for loss on settled cash flow treasury hedges		3,488		4,260
Other Comprehensive Income, Net of Tax		**3,394**		**4,372**
Comprehensive Income	$	**98,249**	$	**98,501**

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

Rochester Gas and Electric Corporation
Balance Sheets

As of December 31,	2019	2018
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$ 579	$ 170
Accounts receivable and unbilled revenues, net	149,647	175,409
Accounts receivable from affiliates	2,656	2,674
Notes receivable from affiliates	—	106,350
Fuel and gas in storage	9,728	10,927
Materials and supplies	12,214	11,824
Derivative assets	—	1,717
Broker margin accounts	4,424	2,661
Income tax receivable	30,215	1,591
Prepaid property taxes	37,182	36,708
Regulatory assets	52,328	51,876
Other current assets	2,887	2,622
Total Current Assets	**301,860**	**404,529**
Utility plant, at original cost	3,956,748	3,711,126
Less accumulated depreciation	(1,060,419)	(1,008,290)
Net Utility Plant in Service	**2,896,329**	**2,702,836**
Construction work in progress	406,367	312,111
Total Utility Plant	**3,302,696**	**3,014,947**
Operating lease right-of-use assets	9,469	—
Other property and investments	184	2,662
Regulatory and Other Assets		
Regulatory assets	433,733	446,997
Other	12,784	2,032
Total Regulatory and Other Assets	**446,517**	**449,029**
Total Assets	**$ 4,060,726**	**$ 3,871,167**

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

Rochester Gas and Electric Corporation
Balance Sheets

As of December 31,	2019	2018
(Thousands)		
Liabilities		
Current Liabilities		
Current portion of debt	$ —	$ 150,532
Notes payable to affiliates	33,201	—
Accounts payable and accrued liabilities	208,708	203,480
Accounts payable to affiliates	12,307	42,739
Interest accrued	9,713	13,379
Taxes accrued	1,355	1,449
Operating lease liabilities	1,344	—
Environmental remediation costs	1,327	3,633
Regulatory liabilities	67,676	55,531
Other	44,250	43,885
Total Current Liabilities	**379,881**	**514,628**
Regulatory and Other Liabilities		
Regulatory liabilities	749,053	712,258
Other Non-current Liabilities		
Deferred income taxes	331,111	244,260
Nuclear plant obligations	128,749	125,930
Pension and other postretirement	152,393	169,888
Operating lease liabilities	9,026	—
Asset retirement obligations	2,713	2,846
Environmental remediation costs	131,336	127,943
Other	26,836	68,610
Total Regulatory and Other Liabilities	**1,531,217**	**1,451,735**
Non-current debt	1,045,203	898,652
Total Liabilities	**2,956,301**	**2,865,015**
Commitments and Contingencies		
Common Stock Equity		
Common stock ($5 par value, 50,000,000 shares authorized, 38,885,813 shares outstanding at December 31, 2019 and 2018)	194,429	194,429
Additional paid-in capital	605,022	604,998
Retained earnings	462,501	359,003
Accumulated other comprehensive loss	(40,289)	(35,040)
Treasury stock, at cost (4,379,300 shares at December 31, 2019 and 2018)	(117,238)	(117,238)
Total Common Stock Equity	**1,104,425**	**1,006,152**
Total Liabilities and Equity	**$ 4,060,726**	**$ 3,871,167**

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

Rochester Gas and Electric Corporation
Statements of Cash Flows

Years Ended December 31,	2019	2018
(Thousands)		
Cash Flow From Operating Activities:		
Net income	**$ 94,855**	**$ 94,129**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	94,619	84,744
Regulatory assets/liabilities amortization	2,398	11,165
Regulatory assets/liabilities carrying cost	7,394	5,932
Amortization of debt issuance costs	440	1,572
Deferred taxes	34,468	(12,944)
Pension cost	13,127	25,794
Stock-based compensation	24	(154)
Accretion expenses	150	155
Gain on disposal of assets	(144)	(60)
Other non-cash items	(10,588)	(7,822)
Changes in operating assets and liabilities:		
Accounts receivable, from affiliates, and unbilled revenues	25,780	(13,462)
Inventories	809	(2,444)
Accounts payable, to affiliates, and accrued liabilities	(29,117)	34,756
Taxes accrued	(28,717)	14,754
Other assets/liabilities	(37,196)	35,167
Regulatory assets/liabilities	47,685	17,446
Net Cash Provided by Operating Activities	**215,987**	**288,728**
Cash Flow From Investing Activities:		
Capital expenditures	(374,472)	(278,650)
Contributions in aid of construction	14,234	8,265
Proceeds from sale of utility plant	1,441	826
Notes receivable from affiliates	106,350	(66,623)
Investments	2,473	—
Net Cash Used in Investing Activities	**(249,974)**	**(336,182)**
Cash Flow From Financing Activities:		
Non-current note issuance	153,454	151,031
Repayments of non-current debt	(150,000)	(62,150)
Repayments of other short-term debt, net	—	(454)
Repayments of capital leases	(2,259)	(1,434)
Notes payable to affiliates	33,201	—
Dividends paid	—	(40,000)
Net Cash Provided by Financing Activities	**34,396**	**46,993**
Net Increase (Decrease) in Cash and Cash Equivalents	**409**	**(461)**
Cash and Cash Equivalents, Beginning of Period	**170**	**631**
Cash and Cash Equivalents, End of Period	**$ 579**	**$ 170**

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

Rochester Gas and Electric Corporation
Statements of Changes in Common Stock Equity

(Thousands, except per share amounts)	Number of shares (*)		Common stock		Capital in Excess of Par Value		Retained Earnings		Accumulated Other Comprehensive Loss		Treasury Stock		Total Common Stock Equity
Balance, December 31, 2017	**38,885,813**	**$**	**194,429**	**$**	**604,975**	**$**	**304,820**	**$**	**(39,358)**	**$**	**(117,238)**	**$**	**947,628**
Net income	—		—		—		94,129		—		—		94,129
Other comprehensive income, net of tax	—		—		—		—		4,372		—		4,372
Comprehensive income													98,501
Stock-based compensation	—		—		23		—		—		—		23
Common stock dividends	—		—		—		(40,000)		—		—		(40,000)
Adoption of accounting standards	—		—		—		54		(54)		—		—
Balance, December 31, 2018	**38,885,813**		**194,429**		**604,998**		**359,003**		**(35,040)**		**(117,238)**		**1,006,152**
Net income	—		—		—		94,855		—		—		94,855
Other comprehensive income, net of tax	—		—		—		—		3,394		—		3,394
Comprehensive income													98,249
Stock-based compensation	—		—		24		—		—		—		24
Common stock dividends	—		—		—		—		—		—		—
Adoption of accounting standards	—		—		—		8,643		(8,643)		—		—
Balance, December 31, 2019	**38,885,813**	**$**	**194,429**	**$**	**605,022**	**$**	**462,501**	**$**	**(40,289)**	**$**	**(117,238)**	**$**	**1,104,425**

(*) Par value of share amounts is $5

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

Note 1. Significant Accounting Policies

Background and nature of operations: Rochester Gas and Electric Corporation's (RG&E, the company, we, our, us), conducts regulated electricity transmission, distribution, and generation operations and regulated natural gas transportation and distribution operations in western New York. RG&E generates electricity from hydroelectric stations. RG&E serves approximately 383,600 electricity and 317,700 natural gas customers as of December 31, 2019, in its service territory of approximately 2,700 square miles. The service territory contains a substantial suburban area and a large agricultural area in parts of nine counties including and surrounding the city of Rochester, New York with a population of approximately one million people. We operate under the authority of the New York State Public Service Commission (NYPSC) and are also subject to regulation by the Federal Energy Regulatory Commission (FERC).

RG&E is a subsidiary of Avangrid Networks, Inc. (Networks), which is a wholly-owned subsidiary of Avangrid, Inc. (AGR), which is an 81.5% owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain.

Basis of presentation: The accompanying financial statements have been prepared in accordance with generally accepted accounting principles in the United States (U.S. GAAP).

We consider the following policies to be the most significant in understanding the judgments that are involved in preparing our financial statements:

Revenue recognition**:** We recognize revenues when we transfer control of promised goods or services to our customers in an amount that reflects the consideration we expect to be entitled to in exchange for those goods or services. Refer to Note 4 for further details.

Regulatory accounting**:** We account for our regulated operations in accordance with the authoritative guidance applicable to entities with regulated operations that meet the following criteria: (i) rates are established or approved by a third-party regulator; (ii) rates are designed to recover the entity's cost of providing regulated services or products and; (iii) there is a reasonable expectation that rates are set at levels that will recover the entity's costs and be collected from customers. Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent: (i) the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates; or (ii) billings in advance of expenditures for approved regulatory programs.

Regulatory assets and liabilities are amortized and the related expense or revenue is recognized in the statements of income consistent with the recovery or refund included in customer rates. We believe it is probable that our currently recorded regulatory assets and liabilities will be recovered or settled in future rates.

Utility plant**:** Utility plant is accounted for at historical cost. In cases where we are required to dismantle installations or to recondition the site on which they are located, we record the estimated cost of removal or reconditioning as an asset retirement obligation (ARO) and an equal amount is added to the carrying amount of the asset.

Development and construction of our various facilities are carried out in stages. Project costs are expensed during early stage development activities. Once we achieve certain development milestones and it is probable that we can obtain future economic benefits from a project, we capitalize salaries and wages for persons directly involved in the project, and engineering, permits, licenses, wind measurement and insurance costs. We periodically review development projects in construction for any indications of impairment.

Assets are transferred from “Construction work in progress” to “Utility plant” when they are available for service.

We determine depreciation expense for utility plant in service using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Consistent with FERC accounting requirements, we charge the original cost of utility plant retired or otherwise disposed to accumulated depreciation.

Our composite rate for depreciation was 2.4% of average depreciable property for 2019 and 2018. We amortize our capitalized software cost which is included in common plant, using the straight line method, based on useful lives of 7 to 25 years. Capitalized software costs were approximately $128.6 million as of December 31, 2019 and $123.9 million as of December 31, 2018. Depreciation expense was $91.0 million in 2019 and $81.8 million in 2018. Amortization of capitalized software was $3.7 million in 2019 and $3.0 million in 2018.

We charge repairs and minor replacements to operation and maintenance expense, and capitalize renewals and betterments, including certain indirect costs.

Allowance for funds used during construction (AFUDC) represents the allowed cost of capital, including a return on equity (ROE), used to finance construction projects. We record the portion of AFUDC attributable to borrowed funds as a reduction of interest expense and the portion attributable to equity as other income. AFUDC attributable to equity is a non-cash item.

Our balances of major classes of utility plant and associated useful lives are shown below as of December 31.

Utility Plant	Estimated useful life range (years)	2019	2018
(Thousands)			
Electric	29-75	$ 2,587,615	$ 2,441,300
Natural Gas	30-80	993,590	911,350
Common	6-50	375,543	358,476
Utility plant at original cost		**3,956,748**	**3,711,126**
Less accumulated depreciation		(1,060,419)	(1,008,290)
Net Utility Plant in Service		**2,896,329**	**2,702,836**
Construction work in progress		406,367	312,111
Total Utility Plant		**$ 3,302,696**	**$ 3,014,947**

Electric plant includes capital leases of $14.9 million in 2019 and $13.7 million in 2018. Accumulated depreciation related to these leases was $5.6 million in 2019 and $3.3 million in 2018.

Leases: We determine if an arrangement is a lease at inception. We classify a lease as a finance lease if it meets any one of specified criteria that in essence transfers ownership of the underlying asset to us by the end of the lease term. If a lease does not meet any of those criteria, we classify it as an operating lease. On our balance sheets, we include, for operating leases: "Operating lease right-of-use assets" and "Operating lease liabilities (current and non-current)"; and for finance leases: finance lease ROU assets in "Other assets" and liabilities in "Other current liabilities" and "Other liabilities."

ROU assets represent our right to use an underlying asset for the lease term and lease liabilities represent our obligation to make lease payments arising from the lease. We recognize lease ROU assets and liabilities at commencement of an arrangement based on the present value of lease payments over the lease term. Most of our leases do not provide an implicit rate, so we use our incremental borrowing rate based on information available at the lease commencement date to determine the present value of future payments. A lease ROU asset also includes any lease payments made at or before commencement date, minus any lease incentives received, and includes initial direct costs incurred. We do not record leases with an initial term of 12 months or less on the balance sheet, for all classes of underlying assets, and we recognize lease expense for those leases on a straight-line basis over the lease term. We include variable lease payments that depend on an index or a rate in the ROU asset and lease liability measurement based on the index or rate at the commencement date, or upon a modification. We do not include variable lease payments that do not depend on an index or a rate in the ROU asset and lease liability measurement. A lease term includes options to extend or terminate the lease when it is reasonably certain that we will exercise that option. We recognize lease (rent) expense for operating lease payments on a straight-line basis over the lease term, or we recognize the amount eligible for recovery under our rate plan, such as actual amounts paid. We amortize finance lease ROU assets on a straight-line basis over the lease term and recognize interest expense based on the outstanding lease liability.

We have lease agreements with lease and non-lease components, and account for lease components and associated nonlease components together as a single lease component, for all classes of underlying assets.

Impairment of long-lived assets: We evaluate utility plant and other long-lived assets for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment evaluation is based on an undiscounted cash flow analysis at the lowest level to which cash flows of the long-lived assets or asset groups are largely independent of the cash flows of other assets and liabilities. An impairment loss is required to be recognized if the carrying amount of the asset exceeds the undiscounted future net cash flows associated with that asset.

The impairment loss to be recognized is the amount by which the carrying value of the long-lived asset exceeds the asset's fair value, or is the result of a disallowance by the regulator. Depending on the asset, fair value may be determined by use of a discounted cash flow model, with assumptions consistent with a market participant's view of the exit price of the asset.

***Fair value measurement*:** 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 as of the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place in either the principal market for the asset or liability, or, in the absence of a principal market, in the most advantageous market for the asset or liability.

The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest. A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset according to its highest and best use, or by selling it to another market participant that would use the asset according to its highest and best use.

We use valuation techniques that are appropriate in the circumstances and for which sufficient data is available to measure fair value, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs. All assets and liabilities for which fair value is measured or disclosed in the financial statements are categorized within the fair value hierarchy based on the transparency of input to the valuation of an asset or liability as of the measurement date.

The three input levels of the fair value hierarchy are as follows:

- Level 1 - inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability either directly or indirectly, for substantially the full term of the contract.
- Level 3 - one or more inputs to the valuation methodology are unobservable or cannot be corroborated with market data.

Categorization within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. Certain investments are not categorized within the fair value hierarchy. These investments are measured based on the fair value of the underlying investments but may not be readily redeemable at that fair value.

Equity investments with readily determinable fair values: We measure equity investments with readily determinable fair values at fair value, with changes in fair value reported in net income.

***Derivatives and hedge accounting*:** Derivatives are recognized on the balance sheets at their fair value, except for certain electricity commodity purchases and sales contracts for both capacity and energy (physical contracts) that qualify for, and are elected under, the normal purchases and normal sales exception. To be a derivative under the accounting standards for derivatives and hedging, an agreement would need to have a notional and an underlying, require little or no initial net investment and could be net settled. We recognize changes in the fair value of a derivative contract in earnings unless specific hedge accounting criteria are met.

Derivatives that qualify and are designated for hedge accounting are classified as cash flow hedges. We report the gain or loss on the derivative instrument as a component of Other Comprehensive Income (OCI) and later reclassify amounts into earnings when the underlying transaction occurs. For all designated and qualifying hedges, we maintain formal documentation of the hedge and effectiveness testing in accordance with the accounting standards for derivatives and hedging. If we determine that the derivative is no longer highly effective as a hedge, we will discontinue hedge accounting prospectively. For cash flow hedges of forecasted transactions, we estimate the future cash flows of the forecasted transactions and evaluate the probability of the occurrence and timing of such transactions. If we determine it is probable that the forecasted transaction will not occur, we immediately recognize in earnings hedge gains and losses previously recorded in OCI.

Changes in conditions or the occurrence of unforeseen events could require discontinuance of the hedge accounting or could affect the timing of the reclassification of gains or losses on cash flow hedges from OCI into earnings. We record changes in the fair value of electric and natural gas hedge contracts to derivative assets or liabilities with an offset to regulatory assets or regulatory liabilities.

We offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement.

***Cash and cash equivalents*:** Cash and cash equivalents include cash, bank accounts, and other highly liquid short-term investments. We consider all highly liquid investments with a maturity date of three months or less when acquired to be cash equivalents and include those investments in “Cash and cash equivalents.” We classify book overdrafts representing outstanding checks in excess of funds on deposit as “Accounts payable and accrued liabilities” on our balance sheets. Changes in book overdrafts are reported in the operating activities section of our statements of cash flows.

Statements of cash flows: Supplemental disclosure of cash flow information is as follows:

		2019		2018
(Thousands)				
Cash paid during the year ended December 31:				
Interest, net of amounts capitalized	$	46,111	$	35,763
Income taxes paid, net	$	27,509	$	28,669

Of the income taxes paid, substantially all was paid to AGR under the tax sharing agreement. Interest capitalized was $11.6 million in 2019 and $20.1 million in 2018. Accrued liabilities for utility plant additions were $33.9 million in 2019 and $27.0 million in 2018.

Broker margin accounts: We maintain accounts with clearing firms that require initial margin deposits upon the establishment of new positions, primarily related to natural gas and electricity derivatives, as well as maintenance margin deposits in the event of unfavorable movements in market valuation for those positions. We show the amount reflecting those activities as broker margin accounts on our balance sheets.

Accounts receivable and unbilled revenues, net: We record accounts receivable at amounts billed to customers. Accounts receivable at December 31 include unbilled revenues of $53.8 million for 2019 and $62.3 million for 2018, and are shown net of an allowance for doubtful accounts at December 31 of $25.0 million for 2019 and $24.0 million for 2018. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was $15.0 million in 2019 and $14.7 million in 2018.

Unbilled revenues represent estimates of receivables for energy provided but not yet billed. The estimates are determined based on various assumptions, including current month energy load requirements, billing rates by customer class and delivery loss factors. Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

The allowance for doubtful accounts is our best estimate of the amount of probable credit losses in our existing accounts receivable, determined based on experience for each service region. Each month we review our allowance for doubtful accounts and past due accounts by age. When we believe that a receivable will not be recovered, we charge off the account balance against the allowance. Changes in assumptions about input factors and customer receivables, which are inherently uncertain and susceptible to change from period to period, could significantly affect the allowance for doubtful accounts estimates.

Our accounts receivable include amounts due under deferred payment arrangements (DPAs). When a residential customer becomes delinquent in making payments, the NYPSC requires us to allow the customer to enter into a DPA to settle the account balance. A DPA allows the account balance to be paid in installments without interest over an extended period of time, which generally exceeds one year, by negotiating mutually acceptable payment terms. Generally, we must continue to serve a customer who cannot pay an account balance in full if the customer: (i) pays a reasonable portion of the balance; (ii) agrees to pay the balance in installments; and (iii) agrees to pay future bills within 30 days until the DPA is paid in full or is otherwise considered to be delinquent. We establish provisions for uncollectible accounts by using both historical average loss percentages to project future losses, and by establishing specific provisions for known credit issues. Amounts are written off when reasonable collection efforts have been exhausted. The allowance for doubtful accounts for DPAs at December 31 was $15.0 million in 2019 and $14.4 million in 2018. DPA receivable balances at December 31 were $23.0 million in 2019 and $23.3 million in 2018.

Debentures, bonds and bank borrowings: Bonds, debentures and bank borrowings are recorded as a liability equal to the proceeds of the borrowings. The difference between the proceeds and the face amount of the issued liability is treated as discount or premium and is accreted as interest expense or income over the life of the instrument. Incremental costs associated with issuance of the debt instruments are deferred and amortized over the same period as debt discount or premium. Bonds, debentures and bank borrowings are presented net of unamortized discount, premium and debt issuance costs on our balance sheets.

Inventory: Inventory comprises fuel and natural gas in storage and materials and supplies. We own natural gas that is stored in third-party owned underground storage facilities. This gas is recorded as inventory. Injections of inventory into storage are priced at the market purchase cost at the time of injection, and withdrawals of working gas from storage are priced at the weighted-average cost in storage. We continuously monitor the weighted-average cost of gas value to ensure it remains at the lower of cost and net realizable value. Inventories to support gas operations are reported on our balance sheet within “Fuel and gas in storage.”

We also have materials and supplies inventories that are used for construction of new facilities and repairs of existing facilities. These inventories are carried and withdrawn at the lower of cost and net realizable value and reported on our balance sheets within “Materials and supplies.” Inventory items are combined for the statement of cash flow presentation purposes.

Government grants: We record government grants as a reduction to utility plant to be recovered through rate base, in accordance with the prescribed FERC accounting.

In accounting for government grants related to operating and maintenance costs, we recognize amounts receivable as an offset to expenses in the statements of income in the period in which the expenses are incurred.

Deferred income: Apart from government grants, we occasionally receive revenues from transactions in advance of the resulting performance obligations arising from the transaction. It is our policy to defer such revenues on our balance sheets and amortize them to earnings when revenue recognition criteria are met.

Asset retirement obligations: We record the fair value of the liability for an asset retirement obligation (ARO) and a conditional ARO in the period in which it is incurred, capitalizing the cost by increasing the carrying amount of the related long-lived asset. We adjust the liability periodically to reflect revisions to either the timing or amount of the original estimated undiscounted cash flows over time. We accrete the liability to its present value each period and depreciate the capitalized cost over the useful life of the related asset. Upon settlement we will either settle the obligation at its recorded amount or incur a gain or a loss. We defer any timing differences between rate recovery and depreciation expense and accretion as either a regulatory asset or a regulatory liability.

The term conditional ARO refers to an entity's legal obligation to perform an asset retirement activity in which the timing or method of settlement are conditional on a future event that may or may not be within the entity's control. If an entity has sufficient information to reasonably estimate the fair value of the liability for a conditional ARO, it must recognize that liability at the time the liability is incurred.

Our ARO at December 31, including our conditional ARO, was $2.7 million for 2019 and $2.8 million for 2018. The ARO is associated with our long-lived assets and primarily consists of obligations related to removal or retirement of: asbestos, polychlorinated biphenyl contaminated equipment, gas pipeline and cast iron gas mains.

The following table reconciles the beginning and ending aggregate carrying amount of the ARO for the years ended December 31, 2019 and 2018.

Years Ended December 31,		**2019**		**2018**
(Thousands)				
ARO, beginning of year	$	2,846	$	3,214
Liabilities settled during the year		(283)		(244)
(Decrease) increase to provision		—		(279)
Accretion expense		150		155
ARO, end of year	**$**	**2,713**	**$**	**2,846**

We have AROs for which we have not recognized a liability because the fair value cannot be reasonably estimated due to indeterminate settlement dates, including: the removal of hydroelectric dams due to structural inadequacy or for decommissioning; the removal of property upon termination of an easement, right-of-way or franchise; and costs for abandonment of certain types of gas mains.

Accrued removal obligations: We meet the requirements concerning accounting for regulated operations and recognize a regulatory liability for the difference between removal costs collected in rates and actual costs incurred. We classify those amounts as accrued removal obligations.

Environmental remediation liability: In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. We record our environmental liabilities on an undiscounted basis. Our environmental liability accruals are expected to be paid through the year 2057.

Post-employment and other employee benefits: We sponsor defined benefit pension plans that cover the majority of our employees. We also provide health care and life insurance benefits through various postretirement plans for eligible retirees.

We evaluate our actuarial assumptions on an annual basis and consider changes based on market conditions and other factors. All of our qualified defined benefit plans are funded in amounts calculated by independent actuaries, based on actuarial assumptions proposed by management.

We account for defined benefit pension or other postretirement plans, recognizing an asset or liability for the overfunded or underfunded plan status. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. We reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in OCI, as management believes it is probable that such items will be recoverable through the ratemaking process. We use a December 31st measurement date for our benefits plans.

We amortize prior service costs for both the pension and other postretirement benefits plans on a straight-line basis over the average remaining service period of participants expected to receive benefits. We amortize unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans over 10 years from the time they are incurred as required by the NYPSC. Our policy for the pension plans is to calculate the expected return on plan assets using the market-related value of assets. Our policy for the postretirement health care benefit plans is to calculate the expected return on plan assets using the market-related value of assets. We determine that value by recognizing the difference between actual returns and expected returns over a five year period.

Income tax: AGR, the parent company of Networks, files consolidated federal and state income tax returns including all of the activities of its subsidiaries. Each subsidiary company is treated as a member of the consolidated group and determines its current and deferred taxes based on the separate return with benefits for loss method. As a member, RG&E settles its current tax liability or benefit each year directly with AGR pursuant to a tax allocation agreement between AGR and its members.

The aggregate amount of the related party income tax receivable balance due from AGR at December 31 is $30.2 million for 2019 and $1.6 million for 2018.

We use the asset and liability method of accounting for income taxes. Deferred tax assets and liabilities reflect the expected future tax consequences, based on enacted tax laws, of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts. In accordance with generally accepted accounting principles for regulated industries, we have established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences. We defer the investment tax credits when earned and amortize them over the estimated lives of the related assets. We also recognize the income tax consequences of intra-entity transfers of assets other than inventory when the transfer occurs.

Deferred tax assets and liabilities are measured at the expected tax rate for the period in which the asset or liability will be realized or settled, based on legislation enacted as of the balance sheet date. We charge or credit changes in deferred income tax assets and liabilities that are associated with components of OCI directly to OCI. Significant judgment is required in determining income tax provisions and evaluating tax positions. Our tax positions are evaluated under a more-likely-than-not recognition threshold before they are recognized for financial reporting purposes. Valuation allowances are recorded to reduce deferred tax assets when it is not more likely than not that we will realize all or a portion of a tax benefit. Deferred tax assets and liabilities are classified as non-current in the balance sheets.

Positions taken or expected to be taken on tax returns, including the decision to exclude certain income or transactions from a return, are recognized in the financial statements when it is more likely than not the tax position can be sustained based solely on the technical merits of the position. The amount of a tax return position that is not recognized in the financial statements is disclosed as an unrecognized tax benefit. Changes in assumptions on tax benefits may also impact interest expense or interest income and may result in the recognition of tax penalties. Interest and penalties related to unrecognized tax benefits are recorded within “Interest expense, net of capitalization” and “Other Income” and “Other Deductions” in the statements of income.

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the statements of income.

Our income tax expense, deferred tax assets and liabilities, and liabilities for unrecognized tax benefits reflect management’s best assessment of estimated current and future taxes to be paid. Significant judgments and estimates are required in determining the consolidated income tax components of the financial statements.

Limited voting junior preferred stock: We have a class of preferred stock having one share and a par value of $1, which is issued and outstanding and has voting authority only with respect to whether RG&E may file a voluntary bankruptcy petition.

Stock-based compensation: Stock-based compensation represents costs related to AGR stock-based awards granted to RG&E employees. We account for stock-based payment transactions based on the estimated fair value of awards reflecting forfeitures when they occur. The recognition period for these costs begins at either the applicable service inception date or grant date and continues throughout the requisite service period, or until the employee becomes retirement eligible, if earlier.

Adoption of New Accounting Pronouncements

Although we are not a public business entity, our parent company is a public business entity; therefore, we adopt new accounting standards based on the effective date for public entities as permitted.

(a) Leases

In February 2016 the Financial Accounting Standards Board (FASB) issued Accounting Standards Codification (ASC) Topic 842, Leases, with subsequent amendments issued in 2018. The new leases guidance affects all companies and organizations that lease assets, and requires them to record on their balance sheet ROU assets and lease liabilities for the rights and obligations created by those leases. Under ASC 842, a lease is an arrangement that conveys the right to control the use of an identified asset for a period of time in exchange for consideration. The new guidance retains a distinction between finance leases and operating leases, while requiring companies to recognize both types of leases on their balance sheet. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the criteria for distinguishing between capital leases and operating leases in legacy U.S. GAAP – ASC 840. Lessor accounting remains substantially the same as ASC 840, but with some targeted improvements to align lessor accounting with the lessee accounting model and with the revised revenue recognition guidance under ASC 606. The new standard and amendments require new qualitative and quantitative disclosures for both lessees and lessors.

We adopted ASC 842 effective January 1, 2019, and elected the optional transition method under which we initially applied the standard on that date without adjusting amounts for prior periods, which we continue to present in accordance with ASC 840, including related disclosures. We recorded the cumulative effect of applying the new leases guidance as an adjustment to beginning retained earnings. In connection with our adoption, we:

- did not elect the package of three practical expedients available under the transition provisions which would have allowed us to not reassess: (i) whether expired or existing contracts were or contained leases, (ii) the lease classification for expired or existing leases, and (iii) whether previously capitalized initial direct costs for existing leases would qualify for capitalization under ASC 842.
- elected the land easement practical expedient and did not reassess land easements that did not meet the definition of a lease prior to adoption.
- used hindsight for determining the lease term and assessing the likelihood that a lease purchase option will be exercised in applying the new leases guidance.
- did not separate lease and associated non-lease components for transitioned leases, but instead are accounting for them together as a single lease component.

In March 2019 the FASB issued additional amendments to ASC 842 for minor codification improvements, which we applied effective January 1, 2019, with no material effect to our results of operations, financial position and cash flows.

The cumulative effects of the changes to our condensed balance sheet as of January 1, 2019, were as follows:

	Balance at December 31, 2018	Adjustments Due to ASC 842	Balance at January 1, 2019
(Thousands)			
Assets			
Total Property, Plant and Equipment	3,014,947	(10,721)	3,004,226
Operating lease right-of-use assets	—	11,085	11,085
Other assets	2,032	10,721	12,753
Liabilities			
Current portion of debt	150,532	(1,914)	148,618
Operating lease liabilities, current	—	1,291	1,291
Other current liabilities	43,885	1,914	45,799
Operating lease liabilities, long-term	—	9,790	9,790
Other non-current liabilities	68,610	6,864	75,474
Non-current debt	898,652	(6,864)	891,788
Equity			
Retained earnings	359,003	—	359,003

Our adoption did not change the classification of lease-related expenses in our statements of income, and we do not expect significant changes to our pattern of expense recognition. Certain contracts previously classified as lessor leases, consisting mainly of pole rental agreements, no longer meet the definition of a lease under ASC 842. As such, these contracts are accounted for under other U.S. GAAP, but there were no changes to our pattern of revenue recognition. As a result, we expect our adoption will not materially affect our cash flows. Our accounting for finance (formerly capital) leases is substantially unchanged. Refer to Note 8 for further details.

(b) Targeted improvements to accounting for hedging activities

In August 2017 the FASB issued targeted amendments with the objective to better align hedge accounting with an entity's risk management activities in the financial statements, and to simplify the application of hedge accounting. The amendments address concerns of financial statement preparers over difficulties with applying hedge accounting and limitations for hedging both nonfinancial and financial risks and concerns of financial statement users over how hedging activities are reported in financial statements. The amended presentation and disclosure guidance is required only prospectively. Changes to the hedge accounting guidance to address those concerns will: 1) expand hedge accounting for nonfinancial and financial risk components and amend measurement methodologies to more closely align hedge accounting with an entity's risk management activities; 2) eliminate the separate measurement and reporting of hedge ineffectiveness, to reduce the complexity of preparing and understanding hedge results; 3) enhance disclosures and change the presentation of hedge results to align the effects of the hedging instrument and the hedged item in order to enhance transparency, comparability and understandability of hedge results; and 4) simplify the way assessments of hedge effectiveness may be performed to reduce the cost and complexity of applying hedge accounting. The amendments ease the administrative burden of hedge documentation requirements and assessing hedge effectiveness going forward. We adopted the hedge accounting amendments on January 1, 2019, and had no cumulative-effect adjustment to retained earnings because there were no amounts of ineffectiveness recorded for any existing hedges as of that date. Concurrently with the above targeted improvements, we adopted the additional amendments the FASB issued in October 2018 that permit use of the Overnight Index Swap rate based on the Secured Overnight Financing Rate as a U.S. benchmark interest rate for hedge accounting purposes. Use of that rate is in addition to the already eligible benchmark interest rates, which are: interest rates on direct Treasury obligations of the U.S. government, the London Interbank Offered Rate swap rate, the OIS Rate based on the Fed Funds Effective Rate and the Securities Industry and Financial Markets Association Municipal Swap Rate.

(c) Reclassification of certain tax effects from accumulated other comprehensive income

In February 2018 the FASB issued amendments to address a financial reporting issue that arose as a consequence of the Tax Cuts and Jobs Act of 2017 (the Tax Act) that the U.S. federal government enacted on December 22, 2017. Under previous guidance, an entity was required to include the adjustment of deferred taxes for the effect of a change in tax laws or rates in income from continuing operations, thus the associated tax effects of items within AOCI (referred to as stranded tax effects) did not reflect the appropriate tax rate. The amendments allow a reclassification from AOCI to retained earnings to eliminate the stranded tax effects resulting from the Tax Act. The amendments only relate to the reclassification of the income tax effects of the Tax Act, and do not affect the underlying guidance that requires the effect of a change in tax laws or rates to be included in income from continuing operations. We adopted the amendments effective January 1, 2019, and elected to reclassify the stranded tax effects of the Tax Act from AOCI to retained earnings at the beginning of the period of adoption. As a result, we reclassified approximately $8.6 million from AOCI to retained earnings within our statements of changes in equity.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements not yet adopted that we have evaluated or are evaluating to determine their effect on our financial statements.

(a) Measurement of credit losses on financial instruments, amendments and updates

The FASB issued an accounting standards update in June 2016 that requires more timely recording of credit losses on loans and other financial instruments. The amendments affect entities that hold financial assets and net investment in leases that are not accounted for at fair value through net income (loans, debt securities, trade receivables, net investments in leases, off-balance sheet credit exposures, etc.). They require an entity to present a financial asset (or group of financial assets) that is measured at amortized cost basis at the net amount expected to be collected. 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. The income statement reflects the measurement of credit losses for newly recognized financial assets, as well as the expected increases or decreases of expected credit losses that have taken place during the period. The measurement of expected credit losses is based on relevant information about past events, including historical experience, current conditions, and reasonable and supportable forecasts that affect the collectibility of the reported amount. An entity must use judgment in determining the relevant information and estimation methods appropriate in its circumstances. The FASB subsequently issued various updates to this new guidance to clarify transition and scope requirements, make narrow-scope codification improvements and corrections, and provide targeted transition relief. The new guidance, including the subsequent amendments, is effective for public entities that are SEC filers for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. Entities are to apply the amendments on a modified retrospective basis for most instruments.

Our implementation plan and steps included: evaluating financial assets within scope; documenting related technical accounting issues, policy considerations and financial reporting implications; and identifying changes to processes and controls to ensure all aspects of the new guidance were effectively addressed. Our adoption of the guidance on January 1, 2020, including our transition adjustment, will not materially affect our results of operations, financial position and cash flows.

(b) Changes to the disclosure requirements for fair value measurement and defined benefit plans

In August 2018, the FASB issued amendments related to disclosure requirements for both fair value measurement and defined benefit plans. The amendments concerning fair value measurement remove, modify and add certain disclosure requirements, in order to improve the overall usefulness of the disclosures and reduce unnecessary costs to companies to prepare the disclosures. The amendments to fair value measurement disclosures are effective for all entities for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted as specified. Certain amendments are to be applied prospectively, and all others are to be applied retrospectively. Our adoption of the amendments on January 1, 2020, will not materially affect our disclosures.

The amendments concerning disclosure requirements for defined benefit plans are narrow in scope and apply to all employers that sponsor defined benefit pension or other postretirement plans. They remove disclosures that are no longer considered cost beneficial, add certain new relevant disclosures and clarify specific requirements of disclosures concerning information for defined benefit pension plans. The amendments to defined benefit plan disclosures are effective for fiscal years ending after December 15, 2020. Early adoption is permitted and application is to be on a retrospective basis. Our adoption of the amendments on January 1, 2020, will not materially affect our disclosures.

(c) Simplifying the accounting for income taxes

In December 2019, the FASB issued an accounting standards update that is intended to reduce complexity in accounting for income taxes. The amendments remove specific exceptions to the general principles in ASC 740, Income Taxes, eliminating the need for an entity to analyze whether the following apply in a given period: (1) exception to the incremental approach for intra-period tax allocation, (2) exceptions to accounting for basis differences when there are ownership changes in foreign investments and (3) exception in interim period income tax accounting for year-to-date losses that exceed anticipated losses. The amendments also improve financial statement preparers' application of income-tax related guidance and simplify U. S. GAAP for (1) franchise taxes that are partially based on income, (2) transactions with a government that result in a step up in the tax basis of goodwill, (3) separate financial statements of legal entities that are not subject to tax and (4) enacted changes in tax laws in interim periods. The amendments are effective for public business entities for fiscal years beginning after December 15, 2020, and interim periods within those fiscal years. Early adoption is permitted, including adoption in any interim period for which financial statements have not been issued, with adoption of all amendments in the same period. Application is on a retrospective and/or modified retrospective basis, or a prospective basis, depending on the amendment aspect. We expect our adoption will not materially affect our consolidated results of operations, financial position, and cash flows.

Use of estimates and assumptions: The preparation of our financial statements in conformity with U.S. GAAP requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Significant estimates and assumptions are used for, but not limited to: (1) allowance for doubtful accounts and unbilled revenues; (2) asset impairments; (3) depreciable lives of assets; (4) income tax valuation allowances; (5) uncertain tax positions; (6) reserves for professional, workers' compensation, and comprehensive general insurance liability risks; (7) contingency and litigation reserves; (8) earnings sharing mechanism (ESM); (9) environmental remediation liabilities; (10) pension and other postretirement employee benefits (OPEB); (11) fair value measurements and (12) AROs. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our financial statements will change as new events occur, as more experience is acquired, as additional information is obtained, and as our operating environment changes. We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside specialists to assist in our evaluations, as considered necessary. Actual results could differ from those estimates.

Union collective bargaining agreements: Approximately 50% of our employees are covered by a collective bargaining agreement. We have no agreements that will expire within the coming year.

Note 2. Industry Regulation

Electricity and Natural Gas Distribution

Our revenues are regulated, being based on tariffs established in accordance with administrative procedures set by the New York State Public Service commission (NYPSC). The tariffs are applied to regulated activities and are approved by the NYPSC and are based on the cost of providing service. Our revenues are set to be sufficient to cover all operating costs, including energy costs, finance costs, and the costs of equity, the last of which reflects our capital ratio and a reasonable return on equity (ROE).

Energy costs that are set on the New York wholesale markets are passed on to consumers. The difference between energy costs that are budgeted and those that are actually incurred by the utilities is offset by applying reconciliation procedures that result in either immediate or deferred tariff adjustments. Reconciliation procedures apply to other costs, which are in many cases exceptional, such as the effects of extreme weather conditions, environmental factors, regulatory and accounting changes, and treatment of vulnerable customers. Revenues that allow us to exceed target returns, usually the result of better than expected cost efficiency, are generally shared with our customers, resulting in future tariff reductions.

RG&E Rate Plan

On May 20, 2015, RG&E filed electric and gas rate cases with the NYPSC. We requested a rate increase for RG&E gas. RG&E electric proposed a rate decrease.

On February 19, 2016, RG&E and New York State Electric & Gas Corporation (NYSEG) (together, “the companies”) and other signatory parties filed a Joint Proposal (Proposal) with the NYPSC for a three-year rate plan for electric and gas service at RG&E commencing May 1, 2016. The Proposal, which was approved by the NYPSC on June 15, 2016, balanced the varied interests of the signatory parties including but not limited to maintaining the companies’ credit quality and mitigating the rate impacts to customers. The Proposal reflects many customer benefits including: acceleration of the companies’ natural gas leak prone main replacement programs and increased funding for electric vegetation management to provide continued safe and reliable service. The delivery rate increase in the Proposal can be summarized as follows:

	May 1, 2016		May 1, 2017		May 1, 2018	
	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %
Electric	$3.0	0.7%	$21.6	5.0%	$25.9	5.7%
Gas	$8.8	5.2%	$7.7	4.4%	$9.5	5.2%

The allowed rate of return on common equity for RG&E Electric and RG&E Gas is 9.00%. The equity ratio for each company is 48%; however, the equity ratio is set at the actual up to 50% for earnings sharing calculation purposes. The customer share of any earnings above allowed levels increases as the ROE increases, with customers receiving 50%, 75% and 90% of earnings over 9.5%, 10.0% and 10.5% of ROE, respectively, in the first rate year covering the period May 1, 2016 – April 30, 2017. The earnings sharing levels increase in rate year two (May 1, 2017 – April 30, 2018) to 9.65%, 10.15% and 10.65% ROE, respectively. The earnings sharing levels further increase in rate year three (May 1, 2018 – April 30, 2019) to 9.75%, 10.25% and 10.75% ROE, respectively. The rate plans also include the implementation of a rate adjustment mechanism (“RAM”) designed to return or collect certain defined reconciled revenues and costs, implementation of new depreciation rates, and continuation of the existing Revenue Decoupling Mechanism (“RDM”) for each business.

The Proposal continues reserve accounting for qualifying Major Storms ($2.5 million annually for RG&E Electric). Incremental maintenance costs incurred to restore service in qualifying divisions will be chargeable to the Major Storm Reserve provided they meet certain thresholds for each storm event.

The Proposal maintains current electric reliability performance measures (and associated potential negative revenue adjustments for failing to meet established performance levels) which include the system average interruption frequency index (SAIFI) and the customer average interruption duration index (CAIDI). The Proposal also modifies certain gas safety performance measures at the companies, including those relating to the replacement of leak prone main, leak backlog management, emergency response, and damage prevention. The Proposal establishes threshold performance levels for designated aspects of customer service quality and continues and expands RG&E's bill reduction and arrears forgiveness Low Income Programs with increased funding levels included in the Proposal. Reforming the Energy Vision (REV) related incremental costs and fees will be included in the RAM to the extent cost recovery is not provided for elsewhere. Under the Proposal, the Company will implement the RAM, which will be applicable to all customers, to return or collect RAM Eligible Deferrals and Costs, including: (1) property taxes; (2) Major Storm deferral balances; (3) gas leak prone pipe replacement; and (4) REV costs and fees which are not covered by other recovery mechanisms.

The Proposal provides for partial or full reconciliation of certain expenses including, but not limited to: pensions, pension and other postretirement benefits; property taxes; variable rate debt and new fixed rate debt; gas research and development; environmental remediation costs; Major Storms; nuclear electric insurance limited credits; economic development; and Low Income Programs. The Proposal also includes a downward-only Net Plant reconciliation. In addition, the Proposal includes downward-only reconciliations for the costs of: electric distribution and gas vegetation management; pipeline integrity; and other incremental maintenance programs. The Proposal provides that we continue the electric RDMs on a total revenue per class basis and the gas RDMs on a revenue per customer basis.

On May 20, 2019, RG&E filed rate cases requesting increases in delivery revenues for both its electric and gas businesses. Other parties to the rate cases filed direct testimony on September 20, 2019, and RG&E filed rebuttal testimony on October 15. The Administrative Law Judges in the cases agreed to an extension of the litigation schedule to allow the Company, the Department of Public Service Staff ("DPS Staff"), and other parties to enter into settlement discussions, which are ongoing. The Company expects a Commission order in these rate cases in the second quarter of 2020.

Reforming the Energy Vision (REV)

In April 2014, the NYPSC commenced a proceeding entitled REV, which is a wide ranging initiative to reform New York State's energy industry and regulatory practices. REV has been divided into two tracks, Track 1 for Market Design and Technology, and Track 2 for Regulatory Reform. REV and its related proceedings have and will continue to propose regulatory changes that are intended to promote more efficient use of energy, deeper penetration of renewable energy resources such as wind and solar and wider deployment of distributed energy resources, such as micro grids, on-site power supplies and storage.

REV is also intended to promote greater use of advanced energy management products to enhance demand elasticity and efficiencies. Track 1 of this initiative involves a collaborative process to examine the role of distribution utilities in enabling market based deployment of distributed energy resources to promote load management and greater system efficiency, including peak load reductions. RG&E is participating in the initiative with other New York utilities and are providing their unique perspective. The NYPSC issued a 2015 order in Track 1, which acknowledges the utilities' role as a Distribution System Platform (DSP) provider, and required the utilities to file an initial Distribution System Implementation Plan (DSIP) by June 30, 2016, followed by bi-annual updates. The companies filed the initial DSIP, which also included information regarding the potential deployment of Automated Metering Infrastructure (AMI) across its entire service territory. The companies, in December 2016, filed a petition to the NYPSC requesting approval for cost recovery associated with the full deployment of AMI, and a collaborative associated with this petition began in the first quarter of 2017, was suspended in the second quarter of 2017, was resumed in the first quarter of 2018 and has been included in the companies' next rate filing. The companies also filed their first bi-annual update of the DSIP on July 31, 2018.

Other various proceedings have also been initiated by the NYPSC which are REV related, and each proceeding has its own schedule. These proceedings include the Clean Energy Standard, Value of Distributed Energy Resources (VDER) and Net Energy Metering, Demand Response Tariffs, and Community Choice Aggregation. As part of the Clean Energy Standard proceeding, all electric utilities were ordered to begin payments to New York State Energy Research and Development Authority (NYSERDA) for Renewable Energy Credits ("RECs") and Zero Emissions Credits beginning in 2017. A separate Offshore Wind was ordered by the NYPSC in July 2018.

Track 2 of the REV initiative is also underway, and through a DPS Staff whitepaper review process, is examining potential changes in current regulatory, tariff, market design and incentive structures which could better align utility interests with achieving New York state and NYPSC's policy objectives. New York utilities will also be addressing related regulatory issues in their individual rate cases. A Track 2 order was issued in May, 2016, and includes guidance related to the potential for Earnings Adjustment Mechanisms (EAMs), Platform Service Revenues, innovative rate designs, and data utilization and security. The companies, in December 2016, filed a proposal for the implementation of EAMs in the areas of System Efficiency, Energy Efficiency, Interconnections, and Clean Air. A collaborative process to review the companies' petition began in the first quarter of 2017 and was suspended in the third quarter of 2017. A proposal for EAMs has been included in the companies' May 20, 2019 rate filing.

In March, 2017, the NYPSC issued three separate REV-related orders. These orders created a series of filing requirements for NYSEG beginning in March 2017 and extending through the end of 2018. The three orders involve: 1) modifications to the electric utilities' proposed interconnection earnings adjustment mechanism framework; 2) further DSIP requirements, including confirmation of the filing of an updated DSIP plan by mid-2018 and implementing two energy storage projects at RG&E by the end of 2018; and 3) Net Energy Metering Transition including implementation of Phase One of the VDER. In September 2017, the NYPSC issued another order related to the VDER, requiring tariff filings, changes to Standard Interconnection Requirements, and planning for the implementation of automated consolidated billing. RG&E has participated with the other NY state electric utilities in jointly filing updates to the interconnection earnings adjustment mechanism, has implemented two energy storage projects, and has participated with the other NY state electric utilities in the VDER transition effort, including tariff updates and application of VDER principles.

The March 2017 Order in the VDER proceeding approved a transition from traditional Net Energy Metering (NEM) towards a more values-based approach (Value Stack) for compensating Distributed Energy Resources (DER). The March 2017 Order approved an interim methodology for more precise DER valuation and compensation for NEM-eligible technologies. The interim methodology approved by the NYPSC provides for a market transition consistent with the principles of gradualism and predictability, and established a tranche system to manage impacts on non-participants.

The March 2017 Order also directed a Phase Two of the VDER proceeding. Phase Two would encompass improvements to the interim methodology established in Phase One, seek to expand Value Stack eligibility to technologies not included in Phase One, and review rate designs for mass market (i.e., residential and small non-residential) on-site DERs whose project would be interconnected after January 1, 2020. Working groups were established for further discussions regarding Value Stack, Rate Design and Low Income. The working groups met toward the latter half of 2017 and all of 2018 to discuss, review and analyze several issues regarding each subject. The working groups culminated with a series of whitepapers developed by DPS Staff a) Standby and Buyback Service Rate Design, b) Future Value Stack Compensation, and c) Capacity Value Compensation. The whitepapers were submitted between December 12 and December 14, 2018 in the VDER proceeding. Public comments on the whitepapers were submitted by February 25, 2019.

On April 18, 2019, the Commission adopted the DPS Staff recommendations in the Future Value Stack Compensation and Capacity Value Compensation whitepapers, with modifications. The decisions in the Order impact the compensation provided to DERs with respect to distribution system value and installed capacity value. In addition, the Order establishes a new Community Credit in place of the Market Transition Credit for certain CDG projects in NYSEG's and RG&E's service territories, and expands eligibility for Phase One Net Metering for certain projects that have a rated capacity of 750 kW AC or lower. The decisions in the Order regarding changes to Value Stack compensation for DERs became effective on June 1, 2019. The April 18, 2019 Order also initiated a new proceeding to examine utilities' marginal cost of service studies. An initial meeting in that proceeding was held on June 28, 2019, during which the utilities explained their various marginal cost methodologies. DPS Staff will develop a whitepaper addressing the utilities' marginal cost studies with recommendations on how such studies shall be subsequently performed. To aid in the development of the whitepaper, Staff is requesting preliminary comments from stakeholders by November 25, 2019. At this time it is not known when the DPS Staff whitepaper on marginal cost methodologies will be issued.

An additional DPS Staff whitepaper on Rate Design for Mass Market On-Site DER projects interconnected after January 1, 2020 was scheduled to be submitted in the first quarter of 2019 but has been delayed and not yet been filed with the NYPSC. On April 15, 2019, DPS Staff hosted a meeting and indicated that further analysis will be needed regarding rate design for mass market on-site DER projects. A subsequent meeting was held on May 31, 2019. At this time it is not known when DPS Staff's further analysis will be completed, nor when the DPS Staff whitepaper on rate design will be submitted. The March 2017 Order stated that should a new compensation methodology not be in place by January 1, 2020, projects put into service after that date would receive NEM compensation only until the new compensation methodology is developed and implemented and would then be transferred to the new compensation methodology.

On May 16, 2019, the Commission issued an Order on Standby and Buyback Service and Establishing Optional Demand Rates. The Order expands the availability of demand rates based on standby service rate design principles by requiring utilities to file tariffs to provide opt-in eligibility for all customers, including mass market (i.e., residential), to a demand-based rate option, irrespective of whether customers have on-site DERs. The availability of existing standby rates was expanded to all current demand-billed customers on an optional basis beginning July 1, 2019. Optional standby rates for mass market customers will be made available in the near future. Utilities filed draft tariffs on September 23, 2019 as required, with further analysis and discussion regarding approval and implementation of the optional rates to occur in the Rate Design Working Group of the VDER proceeding. The NYPSC issued an order on Value Stack Compensation for High-Capacity-Factor Resources on December 12, 2019.

New York State Department of Public Service Investigation of the Preparation for and Response to the March 2017 Windstorm

On March 11, 2017, the New York State Department of Public Service (the Department) commenced an investigation of RG&E's preparation for and response to the March 2017 windstorm, which affected more than 219,000 customers at NYSEG and RG&E. The Department investigation included a comprehensive review of RG&E's preparation for and response to the windstorm, including all aspects of the companies' filed and approved emergency plan. The Department held public hearings on April 12 and 13, 2017.

On November 16, 2017, the NYPSC announced that the DPS Staff had completed their investigation into the March 2017 Windstorm and the NYPSC issued an Order Instituting Proceeding and to Show Cause. The DPS Staff's investigation found that RG&E had allegedly violated certain parts of its emergency response plan, which makes the Company subject to possible financial penalties. RG&E responded to the order in a timely manner and has conducted settlement discussions with the DPS Staff and other parties. These settlement discussions culminated with the filing of two Joint Proposals for settling the issues raised by the Department in May 2018, with several parties signing on to the Joint Proposals. These Joint Proposals have NYSEG and RG&E implementing a combined $3.9 million of storm resiliency and restoration projects which will not be paid for by ratepayers. The Joint Proposals were approved by the Commission in April 2019.

New York State Department of Public Service Investigation of the Preparation for and Response to the March 2018 Winter Storms

In March 2018, following two severe winter storms that impacted more than one million electric utility customers in New York, including 520,000 NYSEG and RG&E customers, the New York Department of Public Service (NYDPS) commenced a comprehensive investigation of the preparation and response to those events by New York's major electric utility companies. The investigation was expanded in the Spring of 2018 to include other 2018 New York Spring storm events.

On April 18, 2019, the NYDPS staff issued a report (the 2018 Staff Report) of the findings from their investigation. The 2018 Staff Report identifies 94 recommendations for corrective actions to be implemented in the utilities Emergency Response Plans (ERP). The report also identified potential violations by several of the utilities, including NYSEG and RG&E.

Also on April 18, 2019, the NYPSC issued an Order Instituting Proceeding and to Show Cause directed to all major electric utilities in New York, including NYSEG and RG&E. The order directs the utilities, including NYSEG and RG&E, to show cause why the NYPSC should not pursue civil penalties, and/or administrative penalties for the apparent failure to follow their respective ERPs as approved and mandated by the NYPSC. The NYPSC also directs the utilities, within 30 days, to address whether the NYPSC should mandate, reject or modify in whole or in part, the 94 recommendations contained in the 2018 Staff Report. On May 20, 2019, NYSEG and RG&E responded to the portion of the Order to Show Cause with respect to the recommendations contained in the 2018 Staff Report. The Commission granted the companies a series of extensions to respond to the portion of the Order to Show Cause with respect to why the Commission should not pursue a penalty action. A Petition requesting New York State Public Service Commission (NYPSC) approval of a joint settlement agreement was filed with the NYPSC on December 17, 2019. The joint settlement agreement allows the Companies to avoid litigation and provides for payment by the companies of penalty of $10.5 million ($9.0 million NYSEG and $1.5 million RG&E). We cannot predict the final outcome of this matter.

Tax Cuts and Jobs Act

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Tax Act) was signed into law. The Tax Act contains significant changes to the federal tax structure, including among other things, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017. The NYPSC has instituted proceedings in New York to review and address the implications associated with the Tax Act on the utilities providing service in state of New York. The Department of Public Service (DPS) Staff, on March 29, 2018, submitted a proposal to the NYPSC indicating that any companies which have not included the impacts from the Tax Act in a recent rate proceeding should submit a filing to initiate a surcredit beginning October 1, 2018 to pass back benefits to customers. The proposal invited all companies to comment on the proposal prior to June 29, 2018, and to include comments about alternative mechanisms to return the benefits to customers. RG&E has submitted comments in response to the DPS Staff proposal, identifying that it would be premature to begin a surcredit which could cause rate volatility when major expenditures may be forthcoming.

On August 9, 2018, the NYPSC issued an order in case 17-M-0815 and as part of that order instituted surcredits for RG&E customers beginning October 1, 2018. The surcredits include the annual 2018 tax expense savings for both electric and gas businesses, and include an amortization of previously deferred tax savings through September 30, 2018 for both businesses. The annual amount of the surcredits beginning October 1, 2018 for RG&E is approximately $29 million. The full effect of the Tax Cut Act is reflected in the rate case filings of May 20, 2019.

Ginna Reliability Support Service Agreement

Ginna Nuclear Power Plant, LLC (GNPP), which is a subsidiary of Constellation Energy Nuclear Group, LLC (CENG), owns and operates the R.E. Ginna Nuclear Power Plant (Ginna Facility and together with GNPP, Ginna), a 581 MW single-unit pressurized water reactor located in Ontario, New York. In May 2014, the New York Independent System Operator (NYISO) produced a Reliability Study, confirming that the Ginna Facility needs to remain in operation to avoid bulk transmission and non-bulk local distribution system reliability violations in 2015 and 2018. In July, 2014, GNPP filed a petition requesting that the NYPSC initiate a proceeding to examine a proposal for the continued operation of the Ginna Facility.

In November 2014, the NYPSC ruled that GNPP had demonstrated that the Ginna Facility is required to maintain system reliability and that its actions with respect to meeting the relevant retirement notice requirements were satisfactory. The NYPSC also accepted the findings of the 2014 Reliability Study and stated that it established “the reliability need for continued operation of the Ginna Facility that is the essential prerequisite to negotiating a Reliability Support Services Agreement (RSSA).” As such, the NYPSC ordered RG&E and GNPP to negotiate an RSSA.

On February 13, 2015, RG&E submitted to the NYPSC an executed RSSA between RG&E and GNPP. RG&E requested that the NYPSC accept the RSSA and approve cost recovery by RG&E

from its customers of all amounts payable to GNPP under the RSSA utilizing the cost recovery surcharge mechanism.

On October 21, 2015, RG&E, GNPP, New York Department of Public Service, Utility Intervention Unit and Multiple Intervenors filed a Joint Proposal with the NYPSC for approval of the RSSA, as modified. On February 23, 2016, the NYPSC unanimously adopted the joint proposal, which provides for a term of the RSSA from April 1, 2015 through March 31, 2017 and RG&E monthly payments to Ginna in the amount of $15.4 million. In addition, RG&E is entitled to 70% of revenues from Ginna's sales into the NYISO energy and capacity markets, while Ginna is entitled to 30% of such revenues. The NYPSC also authorized RG&E to implement a rate surcharge effective January 1, 2016, to recover amounts paid to Ginna pursuant to the RSSA. The FERC issued an order authorizing the FERC Settlement agreement in the Settlement Docket on March 1, 2016, at which point the rate surcharge went into effect. RG&E used deferred rate credit amounts (regulatory liabilities) to offset the full amount of the Deferred Collection Amount (including carrying costs), plus credit amounts to offset all RSSA costs that exceed $2.3 million per month, not to exceed a total use of credits in the amount of $110 million, applicable through June 30, 2017. The available credits were insufficient to satisfy the final payment amount from RG&E to Ginna, and consistent with the agreement with the NYPSC, the RSSA surcharge continues past March 31, 2017, to recover up to $2.3 million per month until the final payment has been recovered by RG&E from customers. RG&E has met all payment obligations associated with the RSSA. Accordingly, the surcharge is no longer in effect beginning August 1, 2019.

Minimum Equity Requirements for Regulated Subsidiaries

RG&E is subject to a minimum equity ratio requirement that is tied to the capital structure assumed in establishing revenue requirements. Pursuant to these requirements, RG&E must maintain a minimum equity ratio equal to the ratio in its currently effective rate plan or decision measured using a trailing 13-month average. On a monthly basis, RG&E must maintain a minimum equity ratio of no less than 300 basis points below the equity ratio used to set rates. The minimum equity ratio requirement has the effect of limiting the amount of dividends that may be paid and may, under certain circumstances, require that the parent contribute equity capital. RG&E is prohibited by regulation from lending to unregulated affiliates. RG&E has also agreed to minimum equity ratio requirements in certain short-term borrowing agreements. These requirements are lower than the regulatory requirements.

Note 3. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations we capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric and natural gas rates. We base our assessment of whether recovery is probable on the existence of regulatory orders that allow for recovery of certain costs over a specific period, or allow for reconciliation or deferral of certain costs. When costs are not treated in a specific order we use regulatory precedent to determine if recovery is probable. We also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs. Of the total regulatory assets net of regulatory liabilities, approximately $183.6 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

Details of regulatory assets and regulatory liabilities are shown in the tables below. They result from various regulatory orders that allow for the deferral and/or reconciliation of specific costs. Regulatory assets and regulatory liabilities are classified as current when recovery or refund in the coming year is allowed or required through a specific order or when the rates related a specific regulatory asset or regulatory liability are subject to automatic annual adjustment.

On June 15, 2016, the NYPSC approved the proposal in connection with a three-year rate plan for electric and gas service at RG&E effective May 1, 2016. Following the approval of the Proposal RG&E's plant related tax items are amortized over the life of associated plant, and unfunded deferred taxes being amortized over a period of fifty years. A majority of the other items related to RG&E, which net to a regulatory liability, remains deferred and will not be amortized until future proceedings or will be used to recover costs of the Ginna RSSA. Following the approval of the proposal by the NYPSC, unfunded future income taxes were adjusted for the amount of $123 million to reflect the change from a flow through to normalization method, which has been recorded as an increase to income tax expense and an offsetting increase to revenue, during the year ended December 31, 2016. The amounts will be collected over a period of fifty years.

Current and non-current regulatory assets at December 31, 2019 and 2018 consisted of:

December 31,	2019	2018
(Thousands)		
Current		
Decommissioning	$ 4,856	$ 6,471
Environmental remediation costs	6,363	6,363
Hedge losses	10,945	—
Rate Adjustment Mechanism (RAM)	14,907	18,436
Reliability support services	—	12,775
Revenue decoupling mechanism	8,554	1,320
Unfunded future income taxes	2,738	2,738
Other	3,965	3,773
Total current regulatory assets	**52,328**	**51,876**
Non-current		
Asset retirement obligation	3,201	3,181
Decommissioning	—	4,827
Environmental remediation costs	73,569	77,794
Federal tax depreciation normalization adjustment	45,940	48,076
Pension and other postretirement benefits	71,320	78,955
Pension and other postretirement benefits cost deferrals	42,335	46,018
Rate Adjustment Mechanism (RAM)	20,180	5,700
Storm costs	27,064	47,136
Unamortized losses on re-acquired debt	5,008	5,605
Unfunded future income taxes	125,378	119,588
Other	19,738	10,117
Total long-term regulatory assets	**$ 433,733**	**$ 446,997**

Asset retirement obligations represent the differences in timing of the recognition of costs associated with our AROs and the collection of such amounts through rates. This amount is being amortized at the related depreciation and accretion amounts of the underlying liability.

Decommissioning represents amounts to be collected in rates for the decommissioning of shut down plants.

Environmental remediation costs include spending that has occurred and is eligible for future recovery in customer rates. Environmental costs are currently recovered through a reserve mechanism whereby projected spending is included in rates with any variance recorded as a regulatory asset or a regulatory liability. The amortization period will be established in future proceedings and will depend upon the timing of spending for the remediation costs. It also includes the anticipated future rate recovery of costs that are recorded as environmental liabilities since these will be recovered when incurred. Because no funds have yet been expended for the regulatory asset related to future spending, it does not accrue carrying costs and is not included within rate base.

Federal tax depreciation normalization adjustment represents the deferral of the normalization of change impacts in book lives and the pass back of theoretical reserves associated with Powertax deferred income tax.

Hedge losses represents deferred fair value losses on electric and gas hedge contracts.

Pension and other postretirement benefits represent the actuarial losses on the pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future pension expenses. Because no funds have yet been expended for this regulatory asset, it does not accrue carrying costs and is not included within the rate base.

Pension and other postretirement benefits cost deferrals include the difference between actual expense for pension and other postretirement benefits and the amount provided for in rates. The recovery of these amounts will be determined in future proceedings.

Rate adjustment mechanism (“RAM”) represents a mechanism each business implements to return or collect the net balance of RAM eligible deferrals and costs. The primary driver of RAM collections is storm costs but this also includes property taxes and REV costs and fees not covered in other recovery mechanisms.

Reliability support services represent the deferral of costs associated with keeping units available and capable of being committed for reliability purposes as requested by the utility or the NYISO.

Revenue decoupling mechanism represents the mechanism established to disassociate the utility's profits from its delivery/commodity sales.

Storm costs are allowed in rates based on an estimate of the routine costs of service restoration. RG&E is also allowed to defer unusually high levels of service restoration costs resulting from major storms when they meet certain criteria for severity and duration.

Unamortized losses on reacquired debt represent deferred losses on debt reacquisitions that will be recovered over the remaining original amortization period of the reacquired debt.

Unfunded future income taxes represent unrecovered federal and state income taxes primarily resulting from regulatory flow through accounting treatment. The income tax benefits or charges for certain plant related timing differences, such as removal costs, are immediately flowed through to, or collected from, customers. This amount is being amortized as the amounts related to temporary differences that give rise to the deferrals are recovered in rates.

Deferred income taxes regulatory: see Note 1.

Current and non-current regulatory liabilities at December 31, 2019 and 2018 consisted of:

December 31,	2019	2018
(Thousands)		
Current		
Carrying costs on deferred income tax bonus depreciation	$ 10,000	$ 10,000
Electric Supply Reconciliation (ESR)	860	154
Energy efficiency programs	35,739	28,466
Gas Supply Charge (GSC)	5,461	1,469
Merchant Function Charge (MFC)	127	647
Rate Adjustment Mechanism (RAM)	5,280	5,976
Tax Act – remeasurement	6,439	6,439
Other	3,770	2,380
Total current regulatory liabilities	**67,676**	**55,531**
Non-current		
Accrued removal obligations	187,927	180,224
Asset gain sale account	10,851	10,851
Carrying costs on deferred income tax bonus depreciation	25,769	35,769
Debt rate reconciliations	26,124	20,356
Deferred property taxes	15,225	24,800
Deferred transmission congestion contracts	23,293	21,339
Earnings sharing	12,326	10,294
Economic development	19,936	19,330
Merger capital expense	5,953	5,953
NEIL (Nuclear Electric Insurance Limited) credits	7,147	4,420
Net plant reconciliation	22,656	18,657
Pension and other postretirement benefits	8,246	—
Pension and other postretirement benefits cost deferrals	4,260	3,076
Positive benefit adjustment	32,639	32,639
Rate Adjustment Mechanism (RAM)	5,280	—
Tax Act – remeasurement	297,409	290,051
Theoretical reserve flow through impact	6,279	6,279
Other	37,733	28,220
Total non-current regulatory liabilities	**$ 749,053**	**$ 712,258**

Accrued removal obligations represent the differences between asset removal costs recorded and amounts collected in rates for those costs. The amortization period is dependent upon the asset removal costs of underlying assets and the life of the utility plant.

Carrying costs on deferred income tax bonus depreciation represent the carrying costs benefit of increased accumulated deferred income taxes created by the change in tax law allowing bonus depreciation. The amortization period is five years following the approval of the proposal by the NYPSC.

Debt rate reconciliations represent the over/under collection of costs related to fixed and variable rate debt instruments identified in the rate case. Costs would include interest, commissions and fees versus amounts included in rates.

Deferred property taxes represent the customer portion of the difference between actual expense for property taxes and the amount provided for in rates. The amount is being amortized over a five year period following the approval of the proposal by the NYPSC.

Deferred transmission congestion contracts represent the deferral of the right to collect day-ahead market congestions rents going forward in time.

Economic development represents the economic development program which enables RG&E to foster economic development through attraction, expansion, and retention of businesses within its service territory. If the level of actual expenditures for economic development allocated to RG&E varies in any rate year from the level provided for in rates, the difference is refunded to ratepayers. The amortization period is five years following the approval of the proposal by the NYPSC.

Energy efficiency programs standard represents the difference between revenue billed to customers through an energy efficiency charge and the costs of our energy efficiency programs as approved by the state authorities.

Merger capital expense target customer credit account was created as a result of RG&E not meeting certain capital expenditure requirements established in the order approving the purchase of Energy East by Iberdrola. The amortization period is five years following the approval of the proposal by the NYPSC.

Rate Adjustment Mechanism (“RAM”) represents a mechanism each business implements to return or collect the net balance of RAM eligible deferrals and costs. The primary driver of RAM collections is storm costs but this also includes property taxes and REV costs and fees not covered in other recovery mechanisms.

Tax Act - remeasurement represents the impact from remeasurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates from 35% to 21% under the provisions of the Tax Act will result in amounts previously collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates. The NYPSC has instituted separate proceedings to review and address the implications associated with the Tax Act on the utilities providing service in state of New York. The NYPSC has required RG&E to institute surcredits to customers as of October 1, 2018. The surcredits include the annual tax expense savings as well as an amortization of previously deferred tax savings through September 30, 2019.

Other includes items such as asset retirement obligations and New York State tax rate change.

Note 4. Revenue

We recognize revenue when we have satisfied our obligations under the terms of a contract with a customer, which generally occurs when the control of promised goods or services transfers to the customer. We measure revenue as the amount of consideration we expect to receive in exchange for providing those goods or services. Contracts with customers may include multiple performance obligations. For such contracts, we allocate revenue to each performance obligation based on its relative standalone selling price. We generally determine standalone selling prices based on the prices charged to customers. Certain revenues are not within the scope of ASC 606, such as revenues from leasing, derivatives, other revenues that are not from contracts with customers and other contractual rights or obligations, and we account for such revenues in accordance with the applicable accounting standards. We exclude from revenue amounts collected on behalf of third parties, including any such taxes collected from customers and remitted to governmental authorities. We do not have any material significant payment terms because we receive payment at or shortly after the point of sale.

The following describes the principal activities from which we generate revenue.

RG&E derives its revenue primarily from tariff-based sales of electricity and natural gas service to customers in New York with no defined contractual term. For such revenues, we recognize revenues in an amount derived from the commodities delivered to customers. Other major sources of revenue are electricity transmission and wholesale sales of electricity and natural gas.

Tariff-based sales are subject to the corresponding state regulatory authorities, which determine prices and other terms of service through the ratemaking process. In New York, customers have the option to obtain the electricity or natural gas commodity directly from the utility or from another supplier. For customers that receive their commodity from another supplier, the utility acts as an agent and delivers the electricity or natural gas provided by that supplier. Revenue in those cases is only for providing the service of delivery of the commodity.

Transmission revenue results from others' use of the utility's transmission system to transmit electricity and is subject to FERC regulation, which establishes the prices and other terms of service. Long-term wholesale sales of electricity are based on individual bilateral contracts. Short-term wholesale sales of electricity are generally on a daily basis based on market prices and are administered by the NYISO or PJM Interconnection, LLC (PJM), as applicable. Wholesale sales of natural gas are generally short-term based on market prices through contracts with the specific customer.

The performance obligation in all arrangements is satisfied over time because the customer simultaneously receives and consumes the benefits as RG&E delivers or sells the electricity or natural gas or provides the transmission service.

RG&E records revenue from Alternative Revenue Programs (ARPs), which is not ASC 606 revenue. Such programs represent contracts between the utilities and their regulators. The RG&E ARPs include revenue decoupling mechanisms, other ratemaking mechanisms, annual revenue requirement reconciliations, and other demand side management programs.

RG&E also has various other sources of revenue including billing, collection, other administrative charges, sundry billings, rent of utility property, and miscellaneous revenue. It classifies such revenues as other ASC 606 revenues to the extent they are not related to revenue generating activities from leasing, ARPs, or other activities.

We have contract liabilities for revenue from transmission congestion contract (TCC) auctions, for which we receive payment at the beginning of an auction period, and amortize ratably each month into revenue over the applicable auction period. The auction periods range from six months to two years. TCC contract liabilities totaled \$0.4 million at December 31, 2019, and \$0.5 million at December 31, 2018, and are presented in "Other current liabilities" on our balance sheets. We recognized $1.1 million and $0.6 million as revenue during 2019 and 2018, respectively.

We apply a practical expedient to expense as incurred costs to obtain a contract when the amortization period is one year or less. We record costs incurred to obtain a contract within operating expenses, including amortization of capitalized costs.

Revenues disaggregated by major source for the years ended December 31, 2019 and 2018 are as follows:

Years Ended December 31,		**2019**		**2018**
(Thousands)				
Regulated operations – electricity	$	580,043	$	603,219
Regulated operations – natural gas		285,256		296,873
Other (a)		12,699		13,131
Revenue from contracts with customers		**877,998**		**913,223**
Leasing revenue		140		1,452
Alternative revenue programs		13,575		6,950
Other revenue		1,329		2,143
Total operating revenues	**$**	**893,042**	**$**	**923,768**

(a) Primarily includes certain intra-month trading activities, billing, collection, and administrative charges, sundry billings, and other miscellaneous revenue.

Note 5. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2019 and 2018 consisted of:

Years Ended December 31,		**2019**		**2018**
(Thousands)				
Current				
Federal	$	(6,079)	$	42,017
State		4,965		1,649
Current taxes charged to (benefit) expense		**(1,114)**		**43,666**
Deferred				
Federal		31,850		(17,467)
State		2,618		4,523
Deferred taxes charged to expense (benefit)		**34,468**		**(12,944)**
Total Income Tax Expense	**$**	**33,354**	**$**	**30,722**

The differences between tax expense per the statements of income and tax expense at the 21% statutory federal tax rate for the years ended December 31, 2019 and 2018, respectively, consisted of:

Years Ended December 31,		2019		2018
(Thousands)				
Tax expense at statutory rate	$	26,924	$	26,219
Equity AFUDC tax impacts not normalized		(10,026)		—
State tax expense (benefit), net of federal benefit		5,990		6,411
Other, net		10,466		(1,908)
Total Income Tax Expense	**$**	**33,354**	**$**	**30,722**

Income tax expense for the year ended December 31, 2019 was $6.4 million higher than it would have been at the statutory federal income tax rate of 21% due predominately to state tax expense; partially offset by Equity AFUDC tax effects. This resulted in an effective tax rate of 26.0%. Income tax expense for the year ended December 31, 2018 was $4.5 million higher than it would have been at the statutory federal income tax rate of 21% due predominately to state taxes. This resulted in an effective tax rate of 24.6%.

Deferred tax assets and liabilities as of December 31, 2019 and 2018 consisted of:

December 31,		2019		2018
(Thousands)				
Non-current Deferred Income Tax Liabilities (Assets)				
Property related	$	459,299	$	426,645
Unfunded future income taxes		29,068		31,970
Storms		16,916		12,319
Regulatory liability due to "Tax Cuts and Jobs Act"		(79,410)		(77,488)
Pension and other postretirement benefits		(16,241)		(12,441)
Derivative assets		(14,903)		(15,824)
Environmental		(13,781)		(12,393)
Non-cash return – bonus depreciation		(9,348)		(11,962)
Positive benefits adjustment merger order		(8,530)		(8,530)
Federal and state tax credits		—		(48,622)
Federal and state NOLs		(1,564)		(17,610)
Other		(30,395)		(21,804)
Total Non-current Deferred Income Tax Liabilities	**$**	**331,111**	**$**	**244,260**
Deferred tax assets	$	174,172	$	226,674
Deferred tax liabilities		505,283		470,934
Net Accumulated Deferred Income Tax Liabilities	**$**	**331,111**	**$**	**244,260**

RG&E has gross New York state net operating losses of $30.5 million for the year ended December 31, 2019. RG&E had gross federal net operating losses of $76.4 million, federal research and development credits of $1.4 million, gross New York state net operating losses of $30.5 million, and claims for New York state tax credits of $47.2 million for the year ended December 31, 2018.

Uncertain tax positions have been classified as noncurrent unless expected to be paid within one year. In 2019, we netted our liability for uncertain tax positions against all same jurisdiction tax credit carryforwards. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the consolidated statements of income.

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2019 and 2018 consisted of:

Years Ended December 31,	2019	2018
(Thousands)		
Balance as of January 1	$ 49,961	$ 2,526
Increases for tax positions related to prior years	—	47,737
Reduction for tax positions related to prior years	(287)	(302)
Balance as of December 31	**$ 49,674**	**$ 49,961**

Unrecognized income tax benefits represent income tax positions taken on income tax returns but not yet recognized in the financial statements. The accounting guidance for uncertainty in income taxes provides that the financial effects of a tax position shall initially be recognized in the financial statements when it is more likely than not based on the technical merits that the position will be sustained upon examination, assuming the position will be audited and the taxing authority has full knowledge of all relevant information.

There were no additional accruals for interest and penalties on tax reserves as of December 31, 2019 and December 31, 2018.

Note 6. Long-term Debt

Long-term debt as of December 31, 2019 and 2018 consisted of:

As of December 31,		2019		2018	
(Thousands)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
First mortgage bonds (a)	2021-2033	$ 900,000	3.10%-8.00%	$ 900,000	3.10%-8.00%
Unsecured pollution control notes - fixed	2025	152,400	2.875%-3.00%	152,400	2.875%-3.00%
Obligations under capital leases (b)		—		8,778	
Unamortized debt issuance cost and discount		(7,197)		(11,994)	
Total Debt		**$ 1,045,203**		**$ 1,049,184**	
Less: debt due within one year, included in current liabilities		—		150,532	
Total Non-current Debt		**$ 1,045,203**		**$ 898,652**	

(a) The first mortgage bonds are secured by a first mortgage lien on substantially all of Net Utility Plant In Service. We have no other secured indebtedness. None of our other debt obligations are guaranteed or secured by any of our affiliates.

(b) Due to the adoption of ASC 842 in 2019 (see Notes 1 and 8 for more information), capital leases, now known as financing leases, are no longer reported as part of long-term debt.

On June 29, 2018, RG&E remarketed $152 million in aggregate principal amount of Pollution Control Revenue Bonds, issued through the New York State Energy Research and Development Authority, with mandatory tender and maturity date of 2025 and interest rates ranging 2.875% - 3.00%.

On August 27, 2019, RG&E issued $150 million aggregate principal amount of first mortgage bonds maturing in 2027 at an interest rate of 3.10% .

Long-term debt, including sinking fund obligations, due over the next five years consist of:

2020	2021	2022	2023	2024	Total
(Thousands)					
$ —	$ 125,000	$ —	$ —	$ —	$ 125,000

We have no financial debt covenant requirements related to our long-term debt at December 31, 2019 and 2018.

Note 7. Bank Loans and Other Borrowings

RG&E had a total of $33.2 million of notes payable as of December 31, 2019 and none as of December 31, 2018. RG&E funds short-term liquidity needs through an agreement among Avangrid's regulated utility subsidiaries (the Virtual Money Pool Agreement), a bi-lateral intercompany credit agreement with Avangrid (the Bi-Lateral Intercompany Facility) and a bank provided credit facility to which RG&E is a party (the AGR Credit Facility), each of which are described below.

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. RG&E has a lending/borrowing limit of $100 million under this agreement. On June 29, 2018, the RG&E Board approved the amendment to RG&E's borrowing and lending limit, increasing it temporarily from $100 million to $200 million. The amendment shall terminate on December 31, 2018, and all terms and conditions of the amendment shall revert back to the original terms and conditions provided for in the Agreement. There was no debt outstanding as of December 31, 2019 and December 31, 2018 under this agreement.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $500 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. RG&E had $33.2 million outstanding under this agreement as of December 31, 2019 and no debt outstanding under this agreement as of December 31, 2018.

On June 29, 2018, AGR and its investment-grade rate utility subsidiaries (New York State Electric & Gas Corporation (NYSEG), RG&E, Central Maine Power Company (CMP), The United Illuminating Company (UI), Connecticut Natural Gas Corporation (CNG), The Southern Connecticut Gas Company (SCG) and The Berkshire Gas Company (BGC)) increased the maximum borrowing terms of the facility from $1.5 billion to $2.5 billion (in aggregate) and extended the maturity date from April 5, 2021 to June 29, 2023. The revolving credit facility is comprised of a syndicate of banks. Under the terms of the AGR Credit Facility, each joint borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit established by the banks. AGR's maximum sublimit is $2 billion, NYSEG, RG&E, CMP and UI have maximum sublimits of $400 million, CNG and SCG have maximum sublimits of $150 million and BGC has a maximum sublimit of $40 million. Under the AGR Credit Facility, each of the borrowers will pay an annual facility fee that is dependent on their credit rating. The facility fees will range from 10.0 to 17.5 basis points. Effective on June 29, 2019, the termination date for the AGR Credit Facility was extended to June 29, 2024. RG&E had not borrowed under this agreement as of both December 31, 2019 and December 31, 2018.

In the AGR Credit Facility we covenant not to permit, without the consent of the lender, our ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of indebtedness to total capitalization, the facility excludes from net worth the balance of accumulated other comprehensive loss as it appears on the balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness we may maintain. Continued un-remedied failure to comply with those covenants for five business days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity. Our ratio of indebtedness to total capitalization pursuant to the revolving credit facility was 0.50 to 1.00 at December 31, 2019. We are not in default as of December 31, 2019.

Note 8. Leases

We have operating leases for office buildings, facilities, vehicles and certain equipment. Our finance leases are primarily related to electric generation, distribution, transmission and other. Certain of our lease agreements include rental payments adjusted periodically for inflation or are based on other periodic input measures. Our leases do not contain any material residual value guarantees or material restrictive covenants. Our leases have remaining lease terms of 1 year to 16 years, some of which may include options to extend the leases for up to 30 years, and some of which may include options to terminate the leases within one year. We consider extension or termination options in the lease term if it is reasonably certain we will exercise the option.

The components of lease cost and other information related to leases were as follows:

Year Ended December 31,		**2019**
(Thousands)		
Lease cost		
Finance lease cost		
Amortization of right-of-use assets	$	2,264
Interest on lease liabilities		528
Total finance lease cost		2,792
Operating lease cost		2,337
Short-term lease cost		102
Variable lease cost		332
Intercompany		48
Total lease cost	**$**	**5,611**

		As of December 31, 2019
(Thousands, except lease term and discount rate)		
Operating Leases		
Operating lease right-of-use assets	$	9,469
Operating lease liabilities, current		1,344
Operating lease liabilities, long-term		9,026
Total operating lease liabilities	$	10,370
Finance Leases		
Other assets	$	9,307
Other current liabilities		1,757
Other non-current liabilities		5,611
Total finance lease liabilities	$	7,368
Weighted-average Remaining Lease Term (years):		
Finance leases		3.92
Operating leases		5.19
Weighted-average Discount Rate:		
Finance leases		6.53%
Operating leases		3.31%

Supplemental cash flows information related to leases was as follows:

Year Ended December 31,		2019
(Thousands)		
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$	1,503
Operating cash flows from finance leases	$	528
Financing cash flows from finance leases	$	2,259
Right-of-use assets obtained in exchange for lease obligations:		
Finance leases	$	850
Operating leases	$	365

Maturities of lease liabilities were as follows:

	Finance Leases	Operating Leases
(Thousands)		
Year ending December 31,		
2020	$ 2,201	$ 1,563
2021	2,201	1,453
2022	2,201	1,448
2023	1,756	3,547
2024	—	2,842
Thereafter	—	663
Total lease payments	**8,359**	**11,516**
Less: imputed interest	(991)	(1,146)
Total	**$ 7,368**	**$ 10,370**

Most of our leases do not provide an implicit rate in the lease, thus we use our incremental borrowing rate based on the information available at the commencement date in determining the present value of lease payments. We used the incremental borrowing rate on January 1, 2019, for operating leases that commenced prior to that date.

Comparative 2018 Leases Disclosures

The following are the 2018 annual lease disclosures, presented in accordance with Topic 840.

Operating lease expense relating to operational facilities, office building leases and vehicle and equipment leases was $1.9 million for the year ended December 31, 2018.

Total future minimum lease payments as of December 31, 2018 consisted of:

Year	Operating Leases	Capital Leases	Total
(Thousands)			
2019	$ 1,524	$ 2,397	$ 3,921
2020	1,638	1,961	3,599
2021	1,417	1,961	3,378
2022	1,402	1,961	3,363
2023	3,510	1,798	5,308
Thereafter	2,915	-	2,915
Total	**$ 12,406**	**$ 10,078**	**$ 22,484**

Note 9. Commitments and Contingencies

Purchase power and natural gas contracts, including nonutility generators

RG&E is the provider of last resort for customers. As a result, the company buys physical energy and capacity from the NYISO. In accordance with the NYPSC's February 26, 2008 Order, RG&E is required to hedge on behalf of non-demand billed customers. The physical electric capacity purchases we make from parties other than the NYISO are to comply with the hedge requirement for electric capacity. The company enters into financial swaps to comply with the hedge requirement for physical electric energy purchases. RG&E also makes purchases from other independent power producers and New York Power Authority (NYPA) under existing contracts or long-term supply agreements in order to comply with the company's Public Utility Regulatory Policies Act (PURPA) purchase obligation.

RG&E satisfies its natural gas supply requirements through purchases from various producers and suppliers, withdrawals from natural gas storage, capacity contracts and winter peaking supplies and resources. The company operates diverse portfolios of gas supply, firm transportation capacity, gas storage and peaking resources. Actual gas costs incurred by each of the companies are passed through to customers through state regulated purchased gas adjustment mechanisms, subject to regulatory review.

The company purchases the majority of its natural gas supply at market prices under seasonal, monthly or mid-term supply contracts and the remainder is acquired on the spot market. The company acquires firm transportation capacity on interstate pipelines under long-term contracts and utilizes that capacity to transport both natural gas supply purchased and natural gas withdrawn from storage to the local distribution system. The company acquires firm underground natural gas storage capacity using long-term contracts and fills the storage facilities with gas in the summer months for subsequent withdrawal in the winter months.

We recognized expenses of approximately $43.9 million for Normal Purchase Normal Sale (NPNS) purchase power and natural gas contracts including nonutility generators in 2019 and $47.7 million in 2018.

Note 10. Environmental Liability

From time to time environmental laws, regulations and compliance programs may require changes in our operations and facilities and may increase the cost of electric and natural gas service.

Waste sites

The Environmental Protection Agency (EPA) and the New York State Department of Environmental Conservation (NYSDEC), as appropriate, have notified us that we are among the potentially responsible parties that may be liable for costs incurred to remediate certain hazardous substances at nine waste sites. The nine sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the nine sites, seven sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites and two sites are also included on the National Priorities list.

Any liability may be joint and several for certain of those sites. We have recorded an estimated liability of $0.2 million at December 31, 2019, related to the nine sites. We have recorded an estimated liability of $4.2 million related to another seven sites where we believe it is probable that we will incur remediation costs and/or monitoring costs, although we have not been notified that we are among the potentially responsible parties. It is possible the ultimate cost to remediate the sites may be significantly more than the accrued amount. Our estimate for costs to remediate these sites ranges from $3.9 million to $6.6 million as of December 31, 2019. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to us. Any cost will be flowed through to RG&E ratepayers.

Manufactured gas plants

We have a program to investigate and perform necessary remediation at our twelve sites where gas was manufactured in the past. In 1994 and 1996 we entered into orders on consent with the NYSDEC. Those orders require us to investigate and, where necessary, remediate all of our eleven sites. All eleven sites are included in the New York Voluntary Clean-up Program.

Our estimate for all costs related to investigation and remediation of the twelve sites ranges from $79.0 million to $194.2 million at December 31, 2019. The estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial action, changes in technology relating to remedial alternatives and changes to current laws and regulations.

The liability to investigate and perform remediation, as necessary, at the known inactive gas manufacturing sites was $128.3 million at December 31, 2019, and $127.3 million at December 31, 2018. We recorded a corresponding regulatory asset, net of insurance recoveries, because we expect to recover the net costs in rates.

Our environmental liabilities are recorded on an undiscounted basis and are expected to be paid through the year 2057.

Note 11. Accounting for Derivative Instruments and Hedging Activities

We are exposed to certain risks relating to our ongoing business operations. The primary risk we manage by using derivative instruments is commodity price risk. In accordance with the accounting requirements concerning derivative instruments and hedging activities, we recognize all derivative instruments as either assets or liabilities at fair value on our balance sheet.

The financial instruments we hold or issue are not for trading or speculative purposes.

***Commodity price risk**:* Commodity price risk, due to volatility experienced in the wholesale energy markets, is a significant issue for the electric and natural gas utility industries. We manage this risk through a combination of regulatory mechanisms, such as the pass-through of the market price of electricity and natural gas to customers, and through comprehensive risk management processes. Those measures mitigate our commodity price exposure, but do not completely eliminate it. Owned electric generation and long-term supply contracts reduce our exposure to market fluctuations.

We have electricity commodity purchases and sales contracts for both capacity and energy (physical contracts) that have been designated and qualify for the normal purchases and normal sales exception in accordance with the accounting requirements concerning derivative instruments and hedging activities.

We currently have a non by-passable wires charge adjustment that allows us to pass through rates any changes in the market price of electricity. We use electricity contracts, both physical and financial, to manage fluctuations in electricity commodity prices in order to provide price stability to customers. We include the cost or benefit of those contracts in the amount expensed for electricity purchased when the related electricity is sold. We record changes in the fair value of electric hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations.

We have a purchased gas adjustment clause that allows us to recover through rates any changes in the market price of purchased natural gas, substantially eliminating our exposure to natural gas price risk. We use natural gas futures and forwards to manage fluctuations in natural gas commodity prices in order to provide price stability to customers. We include the cost or benefit of natural gas futures and forwards in the commodity cost that is passed on to customers when the related sales commitments are fulfilled. We record changes in the fair value of natural gas hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations.

The amounts for electricity hedge contracts and natural gas hedge contracts recognized in regulatory liabilities and assets as of December 31, 2019 and 2018 and amounts reclassified from regulatory assets and liabilities into income for the years ended December 31, 2019 and 2018 are as follows:

(Thousands)	Loss or Gain Recognized in Regulatory Assets/ Liabilities		Location of Loss (Gain) Reclassified from Regulatory Assets/ Liabilities into Income	Loss (Gain) Reclassified from Regulatory Assets/ Liabilities into Income	
As of			**Years Ended December 31,**		
December 31, 2019	**Electricity**	**Natural Gas**	**2019**	**Electricity**	**Natural Gas**
Regulatory assets	$ 8,529	$ 2,902	Purchased power, natural gas and fuel used	$ 8,520	$ 433
Regulatory liabilities	$ —	$ —			
December 31, 2018			**2018**		
Regulatory assets	$ —	$ —	Purchased power, natural gas and fuel used	$ (4,636)	$ (500)
Regulatory liabilities	$ 1,433	$ 195			

Our derivative volumes by commodity type that are expected to settle each year are:

	Electricity Contracts	Natural Gas Contracts	Other Fuel Contracts
Year to settle	**Mwhs**	**Dths**	**Gallons**
As of December 31, 2019			
2020	1,489,775	4,960,000	367,900
2021	438,000	840,000	—
As of December 31, 2018			
2019	1,313,375	4,560,000	397,100
2020	219,600	730,000	—

The offsetting of derivatives, location in the balance sheet and amounts of derivatives as of December 31, 2019 and 2018, respectively, consisted of:

December 31, 2019	Derivative Assets-current	Derivative Assets-Non-current	Derivative Liabilities-current	Derivative Liabilities-Non-current
(Thousands)				
Not designated as hedging instruments				
Derivative assets	$ 499	$ 778	$ 499	$ 778
Derivative liabilities	(499)	(778)	(11,444)	(1,264)
	—	—	(10,945)	(486)
Designated as hedging instruments				
Derivative assets	—	—	—	—
Derivative liabilities	—	—	(72)	—
	—	—	(72)	—
Total derivatives before offset of cash collateral	—	—	(11,017)	(486)
Cash collateral receivable	—	—	10,945	486
Total derivatives as presented in the balance sheet	**$ —**	**$ —**	**$ (72)**	**$ —**

December 31, 2018	Derivative Assets-current	Derivative Assets-Non-current	Derivative Liabilities-current	Derivative Liabilities-Non-current
(Thousands)				
Not designated as hedging instruments				
Derivative assets	$ 5,347	$ 625	$ 3,630	$ 591
Derivative liabilities	(3,630)	(591)	(3,630)	(714)
	1,717	34	—	(123)
Designated as hedging instruments				
Derivative assets	—	—	—	—
Derivative liabilities	—	—	(327)	—
	—	—	(327)	—
Total derivatives before offset of cash collateral	1,717	34	(327)	(123)
Cash collateral receivable	—	—	—	123
Total derivatives as presented in the balance sheet	**$ 1,717**	**$ 34**	**$ (327)**	**$ —**

As of both December 31, 2019 and 2018, the derivative assets and derivative liabilities are presented within other current and non-current assets and liabilities of the balance sheet, respectively.

Derivatives designated as hedging instruments

The effect of derivatives in cash flow hedging instruments on OCI and income for the years ended December 31, 2019 and 2018, respectively, consisted of:

Year Ended December 31,		(Loss) Gain Recognized in OCI on Derivatives	Location of (Loss) Gain Reclassified From Accumulated OCI into Income		Loss Reclassified From Accumulated OCI into Income		Total Amount per Income Statement
(Thousands)							
2019							
Interest rate contracts	$	—	Interest expense	$	(4,723)	$	70,784
Commodity contracts: Other		89	Other operating expenses		(166)	$	282,270
Total	**$**	**89**		**$**	**(4,889)**		
2018							
Interest rate contracts	$	—	Interest expense	$	(5,768)	$	71,322
Commodity contracts: Other		(287)	Other operating expenses		(1)	$	271,177
Total	**$**	**(287)**		**$**	**(5,769)**		

The amount in AOCI related to previously settled forward starting interest rate swaps and accumulated amortization, at December 31, 2019 is a net loss of $52.0 million as compared to $56.7 million at December 31, 2018. For the year ended December 31, 2019, we recorded $4.7 million in net derivative losses related to discontinued cash flow hedges. We will amortize approximately $3.7 million of discontinued cash flow hedges in 2020.

As of December 31, 2019, $0.1 million in losses are reported in AOCI because the forecasted transaction is considered to be probable. We expect that those losses will be reclassified into earnings within the next 12 months, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted energy transactions.

We face risks related to counterparty performance on hedging contracts due to counterparty credit default. We have developed a matrix of unsecured credit thresholds that are dependent on a counterparty's or the counterparty guarantor's applicable credit rating (normally Moody's or Standard & Poor's). When our exposure to risk for counterparty exceeds the unsecured credit threshold, the counterparty is required to post additional collateral or we will no longer transact with the counterparty until the exposure drops below the unsecured credit threshold.

We have various master netting arrangements in the form of multiple contracts with various single counterparties that are subject to contractual agreements that provide for the net settlement of all contracts through a single payment. Those arrangements reduce our exposure to a counterparty in the event of default on or termination of any one contract. For financial statement presentation, we offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement.

Certain of our derivative instruments contain provisions that require us to maintain an investment grade credit rating on our debt from each of the major credit rating agencies. If our debt were to fall below investment grade, it would be in violation of those provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position on December 31, 2019 is $11.4 million for which we have posted collateral.

Note 12. Fair Value of Financial Instruments and Fair Value Measurements

The estimated fair value of debt amounted to $1,249.0 million as of December 31, 2019 and $1,176.0 million as of December 31, 2018. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the electricity industry and the credit ratings of the borrowers in each case. The fair value of these unsecured pollution control notes-variable are determined using unobservable interest rates as the market for these notes is inactive.

The financial instruments measured at fair value as of December 31, 2019 and 2018 consisted of:

Description	Level 1	Level 2	Level 3	Netting	Total
(Thousands)					
As of December 31, 2019					
Assets					
Noncurrent investments, primarily money market funds	$ 184	$ —	$ —	$ —	$ 184
Derivatives					
Commodity contracts:					
Electricity	1,242	—	—	(1,242)	—
Natural Gas	35	—	—	(35)	—
Other	—	—	—	—	—
Total	**$ 1,461**	**$ —**	**$ —**	**$ (1,277)**	**$ 184**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	$ (9,771)	$ —	$ —	$ 9,771	$ —
Natural gas	(2,937)	—	—	2,937	—
Other	—	—	(72)	—	(72)
Total	**$ (12,708)**	**$ —**	**$ (72)**	**$ 12,708**	**$ (72)**

Description	Level 1	Level 2	Level 3	Netting	Total
(Thousands)					
As of December 31, 2018					
Assets					
Noncurrent investments, primarily money market funds	$ 2,662	$ —	$ —	$ —	$ 2,662
Derivatives					
Commodity contracts:					
Electricity	5,082	—	—	(3,526)	1,556
Natural Gas	890	—	—	(695)	195
Other	—	—	—	—	—
Total	**$ 8,634**	**$ —**	**$ —**	**$ (4,221)**	**$ 4,413**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	$ (3,650)	$ —	$ —	$ 3,650	$ —
Natural gas	(694)	—	—	694	—
Other	—	—	(327)	—	(327)
Total	**$ (4,344)**	**$ —**	**$ (327)**	**$ 4,344**	**$ (327)**

We had no transfers to or from Level 1 and 2 during the year ended December 31, 2019. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

Valuation techniques: We measure the fair value of our noncurrent investments available for sale using quoted market prices in active markets for identical assets and include the measurements in Level 1. The investments which are Rabbi Trusts for deferred compensation plans primarily consist of money market funds.

We determine the fair value of our various derivative assets and liabilities utilizing market approach valuation techniques:

- We enter into electric energy derivative contracts to hedge the forecasted purchases required to serve our electric load obligations. We hedge our electric load obligations using derivative contracts that are settled based upon Locational Based Marginal Pricing published by the NYISO. We hedge approximately 70% of their electric load obligations using contracts for a NYISO location where an active market exists. The forward market prices used to value the companies' open electric energy derivative contracts are based on quotes prices in active markets for identical assets or liabilities with no adjustment required and therefore we include the fair value in Level 1.
- We enter into natural gas derivative contracts to hedge the forecasted purchases required to serve our natural gas load obligations. The forward market prices used to value our open natural gas derivative contracts are exchange-based prices for the identical derivative contracts traded actively on the New York Mercantile Exchange. Because we use prices quoted in an active market, we include those fair value measurements in Level 1.
- We enter into fuel derivative contracts to hedge our unleaded and diesel fuel requirements for our fleet vehicles. Exchange based forward market prices are used but because a basis adjustment is added to the forward prices, we include the fair value measurement for these contracts in Level 3.

The reconciliation of changes in the fair value of financial instruments based on Level 3 inputs for the years ended December 31, 2019 and 2018 consisted of:

	Derivatives, Net	
Years Ended December 31,	**2019**	**2018**
(Thousands)		
Beginning balance	$ (327)	$ (41)
Realized losses included in earnings	166	1
Unrealized gains (losses) included in other comprehensive income	89	(287)
Ending balance	**$ (72)**	**$ (327)**

The gains and losses included in earnings for the periods above are reported in Operations and maintenance of the statements of income.

Note 13. Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss for the years ended December 31, 2019 and 2018, consisted of:

	Balance December 31, 2017	Adoption of new accounting standard	2018 Change	Balance December 31, 2018	Adoption of new accounting standard	2019 Change	Balance December 31, 2019
(Thousands)							
Net unrealized holding gain on investments	$ 39	$ —	$ —	$ 39	$ —	$ (39)	$ —
Amortization of pension cost for nonqualified plans, net of tax expense (benefit) of $114 for 2018 and $(100) for 2019	(1,702)	—	323	(1,379)	—	(283)	(1,662)
Loss on nonqualified pension plans	—	(54)	—	—	—	—	—
Unrealized gain (loss) on derivatives qualified as hedges:							
Unrealized gain (loss) during period on derivatives qualified as hedges, net of income tax (benefit) expense of $(75) for 2018 and $37 for 2019	—	—	(212)	—	—	105	—
Reclassification adjustment for loss included in net income, net of income tax expense of $0 for 2018 and $43 for 2019	—	—	1	—	(8,643)	123	—
Reclassification adjustment for loss on settled cash flow treasury hedges included in net income, net of income tax expense of $1,508 for 2018 and $1,235 for 2019	—	—	4,260	—	—	3,488	—
Net unrealized (loss) gain on derivatives qualified as hedges	(37,695)	—	4,049	(33,646)	(8,643)	3,716	(38,573)
Accumulated Other Comprehensive (Loss) Income	**$ (39,358)**	**$ (54)**	**$ 4,372**	**$ (35,040)**	**$ (8,643)**	**$ 3,394**	**$ (40,289)**

Note 14. Post-retirement and Similar Obligations

We have funded noncontributory defined benefit pension plans that cover the eligible employees. For most employees, generally those hired before 2002, the plans provide defined benefits based on years of service and final average salary. Employees hired in 2002 or later are covered under a cash balance plan or formula where their benefit accumulates based on a percentage of annual salary and credited interest. During 2013 the company announced that we would freeze the benefits for all non-union employees covered under the cash balance plans effective December 31, 2013. Their earned balances would continue to accrue interest, but would no longer be increased by a percentage of earnings. In place of the pension benefit for these employees, they will receive a minimum contribution to their account under their respective company's defined contribution plan. There was no change to the defined benefit plans for employees covered under the plans that provide defined benefits based on years of service and final average salary.

The company maintains a 401(k) Savings and Retirement Plan (the Plan) for all eligible employees as defined in the Plan agreement. Participants in the Plan may contribute a percentage of their compensation and the company may match a predetermined percentage of the participant contributions. Expenses under the Plan for the Company totaled approximately $3.3 million in 2019 and $3.1 million 2018.

We also have pension and other postretirement health care benefit plans covering substantially all of our employees. The health care plans are contributory with participants' contributions adjusted annually.

Obligations and funded status as of December 31, 2019 and 2018 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2019**	**2018**	**2019**	**2018**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	$ 377,221	$ 414,289	$ 64,646	$ 75,425
Service cost	5,388	5,457	148	278
Interest cost	14,114	14,084	2,440	2,644
Plan participants' contributions	—	—	—	664
Amendments	—	—	—	(3,442)
Actuarial loss/(gain)	20,316	(15,000)	2,339	(5,739)
Benefits paid	(38,480)	(41,610)	(3,691)	(5,184)
Benefit obligation at December 31	**$ 378,559**	**$ 377,220**	**$ 65,882**	**$ 64,646**
Change in plan assets				
Fair value of plan assets at January 1	$ 266,734	$ 309,048	$ —	$ —
Actual return on plan assets	45,639	(13,681)	—	—
Employer and plan participants' contributions	13,006	12,977	3,691	5,184
Benefits paid	(38,480)	(41,610)	(3,691)	(5,184)
Fair value of plan assets at December 31	**$ 286,899**	**$ 266,734**	**$ —**	**$ —**
Funded status	**$ (91,660)**	**$ (110,486)**	**$ (65,882)**	**$ (64,646)**

Amounts recognized in the balance sheet as of December 31, 2019 and 2018 consisted of:

Amounts recognized in the balance sheet	Pension Benefits		Postretirement Benefits	
December 31,	2019	2018	2019	2018
(Thousands)				
Other current liabilities	$ —	$ —	$ (5,149)	$ (5,244)
Pension and other postretirement benefits	(91,660)	(110,486)	(60,733)	(59,402)
Total	**$ (91,660)**	**$ (110,486)**	**$ (65,882)**	**$ (64,646)**

We have determined that we are allowed to defer as regulatory assets or regulatory liabilities items that would otherwise be recorded in accumulated other comprehensive income pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans. Amounts recognized as regulatory assets or regulatory liabilities consist of:

	Pension Benefits		Postretirement Benefits	
December 31,	2019	2018	2019	2018
(Thousands)				
Net loss (gain)	$ 68,981	$ 87,928	$ (2,149)	$ (3,825)
Prior service cost (credit)	$ —	$ —	$ (3,758)	$ (5,149)

Our accumulated benefit obligation for all defined benefit pension plans was $349.5 million at December 31, 2019 and $349.5 million at December 31, 2018.

The projected benefit obligation and the accumulated benefit obligation exceeded the fair value of pension plan assets as of both December 31, 2019 and 2018. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets as of December 31, 2019 and 2018.

December 31,	2019	2018
(Thousands)		
Projected benefit obligation	$ 378,559	$ 377,220
Accumulated benefit obligation	$ 349,475	$ 349,547
Fair value of plan assets	$ 286,899	$ 266,734

Components of net periodic benefit cost and other changes in plan assets and benefit obligations recognized in income and regulatory assets and liabilities for the years ended

December 31, 2019 and 2018 consisted of:

	Pension Benefits		Postretirement Benefits	
Years Ended December 31,	**2019**	**2018**	**2019**	**2018**
(Thousands)				
Net periodic benefit cost				
Service cost	$ 5,388	$ 5,457	$ 148	$ 278
Interest cost	14,114	14,084	2,440	2,644
Expected return on plan assets	(20,437)	(21,028)	—	—
Amortization of prior service cost (credit)	—	222	(1,390)	(1,082)
Amortization of net loss	14,062	27,059	663	1,314
Net periodic benefit cost	**$ 13,127**	**$ 25,794**	**$ 1,861**	**$ 3,154**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net (gain) loss	$ (4,886)	$ 19,708	$ 2,339	$ (5,739)
Amortization of net (loss)	(14,062)	(27,059)	(663)	(1,314)
Prior service credit/(cost)	—	—	1,390	(3,442)
Amortization of prior service (cost) credit	—	(223)	—	1,082
Total recognized in regulatory assets and regulatory liabilities	(18,948)	(7,574)	3,066	(9,413)
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$ (5,821)**	**$ 18,220**	**$ 4,927**	**$ (6,259)**

We include the service component of net periodic benefit cost in other operating expenses and the non-service component in other income and deductions. The net periodic benefit cost for postretirement benefits represents the amount expensed for providing health care benefits to retirees and their eligible dependents.

Amounts expected to be amortized from regulatory assets or liabilities into net periodic benefit cost for the year ending December 31, 2020 consist of:

	Pension Benefits	Postretirement Benefits
(Thousands)		
Estimated net loss	$ 15,454	$ 644
Estimated prior service cost (credit)	$ —	$ (1,390)

We expect that no pension benefit or postretirement benefit plan assets will be returned to us during the fiscal year ending December 31, 2020.

The weighted-average assumptions used to determine benefit obligations as of December 31, 2019 and 2018 consisted of:

	Pension Benefits		Postretirement Benefits	
	2019	**2018**	**2019**	**2018**
Discount rate	2.93%	3.93%	2.93%	3.93%
Rate of compensation increase	Age-Related Rates	3.90%	Age-Related Rates	N/A

The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rate by developing a yield curve derived from a portfolio of high grade non-callable bonds with above median yields that closely matches the duration of the expected cash flows of our benefit obligations.

The weighted-average assumptions used to determine net periodic benefit cost for the years ended December 31, 2019 and 2018 consisted of:

	Pension Benefits		Postretirement Benefits	
	2019	**2018**	**2019**	**2018**
Discount rate	3.93%	3.63%	3.93%	3.63%
Expected long-term return on plan assets	7.30%	7.30%	—	—
Expected long-term return on plan assets - nontaxable trust	—	—	6.40%	6.40%
Expected long-term return on plan assets - taxable trust	—	—	4.20%	4.20%
Rate of compensation increase	3.90%	4.00%	Age-Related Rates	Age-Related Rates

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations and the effect of rebalancing of plan assets discussed below. That analysis considered current capital market conditions and projected conditions. Our policy is to calculate the expected return on plan assets using the market related value of assets. We amortize unrecognized actuarial gains and losses over 10 years from the time they are incurred.

Assumed health care cost trend rates used to determine benefit obligations as of December 31, 2019 and 2018 consisted of:

	2019	**2018**
Health care cost trend rate (pre 65/post 65)	6.75%/7.50%	7.00%/7.75%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	4.50%	4.50%
Year that the rate reaches the ultimate trend rate	2029/2027	2029/2027

The assumed health care cost trend rates can have a significant effect on the amounts reported for the health care plans. Due to the RG&E retirees having moved into a different program, it is no longer sensitive to medical trend changes. The company is limited to a specific dollar amount and will not change in the future.

Contributions: In accordance with our funding policy, we make annual contributions of not less than the minimum required by applicable regulations. We expect to contribute $12.4 million to our pension benefit plans in 2020.

Estimated future benefit payments: Our expected benefit payments and expected Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) subsidy receipts, which reflect expected future service, as appropriate, are:

(Thousands)	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
2020	$ 35,588	$ 5,152	$ —
2021	$ 34,391	$ 5,049	$ —
2022	$ 34,078	$ 4,927	$ —
2023	$ 33,614	$ 4,808	$ —
2024	$ 32,709	$ 4,658	$ —
2025-2029	$ 143,807	$ 20,990	$ —

Plan assets: Our pension benefits plan assets are held in a master trust providing for a single trustee/custodian, a uniform investment manager lineup, and an efficient, cost-effective means of allocating expenses and investment performance to each plan under the master trust. Our primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our tolerance for risk. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. Our primary means for achieving capital preservation is through diversification of the trust's investments while avoiding significant concentrations of risk in any one area of the securities markets. Within each asset group, further diversification is achieved through utilizing multiple asset managers and systematic allocation to various asset classes; providing broad exposure to different segments of the equity, fixed-income and alternative investment markets.

Networks' asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets within broad categories of asset classes made up of Return-Seeking and Liability-Hedging investments. Within the Return-Seeking category, we have targets of 35%-53% in equity securities, 40%-45% for Liability-Hedging assets and 7%-20% for alternative investments. Return-Seeking investments generally consist of domestic, international, global, and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking assets also include investments in real estate, absolute return, and strategic markets. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS, and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of pension benefits plan assets, by asset category, as of December 31, 2019, consisted of:

Asset Category	Total	Fair Value Measurements at December 31, Using Level 1	Level 2	Level 3
(Thousands)				
2019				
Cash and cash equivalents	$ 4,980	$ 1	$ 4,979	$ —
U.S. government securities	12,107	12,107	—	—
Registered investment companies	45,540	45,540	—	—
Corporate bonds	63,824	—	63,824	—
Preferred stocks	179	179	—	—
Other investments, principally annuity and fixed income	11,783	—	11,783	—
	$ 138,413	**$ 57,827**	**$ 80,586**	**$ —**
Other investments measured at net asset value	148,486			
Total	**$ 286,899**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2018, consisted of:

Asset Category	Total	Fair Value Measurements at December 31, Using Level 1	Level 2	Level 3
(Thousands)				
2018				
Cash and cash equivalents	$ 5,490	$ —	$ 5,490	$ —
U.S. government securities	1,609	1,609	—	—
Common stocks	10	10	—	—
Registered investment companies	23,006	23,006	—	—
Corporate bonds	43,856	—	43,856	—
Preferred stocks	374	29	345	—
Equity commingled funds	86,411	19,075	67,336	—
Other investments, principally annuity and fixed income	7,589	—	7,589	—
	$ 168,345	**$ 43,729**	**$ 124,616**	**$ —**
Other investments measured at net asset value	98,389			
Total	**$ 266,734**			

Valuation techniques: We value our pension benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities, common stocks and registered investment companies - at the closing price reported in the active market in which the security is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks - at the closing price reported in the active market in which the individual investment is traded.
- Equity commingled funds – the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.

- Other investments, principally annuity and fixed income - Level 1: at the closing price reported in the active market in which the individual investment is traded. Level 2: based on yields currently available on comparable securities of issuers with similar credit ratings. Level 3: when quoted prices are not available for identical or similar instruments, under a discounted cash flows approach that maximizes observable inputs such as current yields of similar instruments but includes adjustments for certain risks that may not be observable such as credit and liquidity risks.
- Other investments measured at net asset value (NAV) – alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

Pension plan equity securities did not include any AGR and Iberdrola common stock as of both December 31, 2019 and 2018.

Note 15. Other Income and Other Deductions

Other income and deductions for the years ended December 31, 2019 and 2018, consisted of:

Years Ended December 31,		2019		2018
(Thousands)				
Interest and dividend income	$	991	$	1,781
Allowance for funds used during construction		15,879		11,533
Gain on sale of property		9		60
Carrying costs on regulatory assets		6,719		7,175
Miscellaneous		523		89
Total other income	**$**	**24,121**	**$**	**20,638**
Pension non-service components	$	(9,675)	$	(23,817)
Miscellaneous		(2,668)		(589)
Total other deductions	**$**	**(12,343)**	**$**	**(24,406)**

Note 16. Related Party Transactions

Certain Networks subsidiaries borrow from AGR, the parent of Networks, through intercompany revolving credit agreements, including RG&E. For RG&E the intercompany revolving credit agreements provide access to supplemental liquidity. See Note 7 for further detail on the credit facility with AGR.

Avangrid Service Company provides some administrative and management services to Networks operating utilities, including RG&E, pursuant to service agreements. The cost of those services is allocated in accordance with methodologies set forth in the service agreements. The cost allocation methodologies vary depending on the type of service provided. Management believes such allocations are reasonable. The cost for services provided to RG&E by AGR and its affiliates were approximately $52.9 million in 2019 and $52.8 million in 2018 and the charge for services provided by RG&E to AGR and its subsidiaries were approximately $14.4 million in 2019 and $14.6 million in 2018. All charges for services are at cost. All of the charges associated with services provided are recorded as revenues to offset other operating expenses on the financial statements. The balance in accounts payable to affiliates of $12.3 million at December 31, 2019 and $42.7 million at December 31, 2018 is mostly payable to Avangrid Service Company.

There were no notes receivable from affiliates at December 31, 2019. Of the balance of $106.4 million at December 31, 2018, $91.8 million is from the UIL companies and $14.6 million is from NYSEG. Notes receivable from affiliates relate to the Virtual Money Pool Agreement as discussed in Note 7 of these financial statements.

AGR, on behalf of RG&E, guarantees $123 million to fund the clean-up of the GNPP.

Note 17. Subsequent Events

The company has performed a review of subsequent events through March 31, 2020, which is the date these financial statements were available to be issued.

In March 2020 the World Health Organization declared a global pandemic due to the outbreak of COVID-19. The company is assessing the possible impacts to our business and financial results.