THE BERKSHIRE GAS COMPANY

AUDITED FINANCIAL STATEMENTS

AS OF AND FOR THE YEARS ENDED

DECEMBER 31, 2020 AND 2019

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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, 2020 and 2019, 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, 2020 and 2019, 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 12, 2021

THE BERKSHIRE GAS COMPANY
STATEMENTS OF INCOME

Years Ended December 31,	2020	2019
(Thousands)		
Operating Revenues	$ 77,141	$ 82,336
Operating Expenses		
Natural gas purchased	24,092	30,545
Operation and maintenance	30,054	26,127
Depreciation and amortization	8,172	8,039
Taxes other than income taxes	5,221	4,963
Total Operating Expenses	67,539	69,674
Operating Income	9,602	12,662
Other Income and (Expense), net	(1,086)	(400)
Interest Expense, net	2,928	3,225
Income Before Income Tax	5,588	9,037
Income Tax	1,203	1,436
Net Income	$ 4,385	$ 7,601

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

THE BERKSHIRE GAS COMPANY
STATEMENTS OF CASH FLOWS

Years Ended December 31,	**2020**	**2019**
(Thousands)		
Cash Flows From Operating Activities		
Net income	$ 4,385	$ 7,601
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	8,292	8,159
Deferred income taxes	2,307	(592)
Uncollectible expense	1,187	569
Pension expense	2,131	1,932
Regulatory assets/liabilities amortization	612	702
Regulatory assets/liabilities carrying costs	-	7
Other non-cash items, net	1,532	106
Changes in:		
Accounts receivable and unbilled revenue, net	624	(2,166)
Natural gas in storage	388	(26)
Accounts payable and accrued liabilities	(911)	(3,615)
Accrued pension and other post-retirement	(3,039)	(2,062)
Regulatory assets/liabilities	(1,331)	4,100
Other assets	(264)	2,374
Other liabilities	395	(383)
Total Adjustments	11,923	9,105
Net Cash provided by Operating Activities	16,308	16,706
Cash Flows from Investing Activities		
Plant expenditures including AFUDC debt	(15,923)	(17,243)
Net Cash used in Investing Activities	(15,923)	(17,243)
Cash Flows from Financing Activities		
Payment of long-term debt	(9,455)	(11,455)
Issuance of long-term debt	25,000	20,000
Payment of common stock dividend	(2,000)	-
Notes payable to affiliates	(14,033)	(7,713)
Other	(167)	(139)
Net Cash used in Financing Activities	(655)	693
Unrestricted Cash and Temporary Cash Investments:		
Net change for the period	(270)	156
Balance at beginning of period	482	326
Balance at end of period	$ 212	$ 482
Cash paid during the period for:		
Interest (net of amount capitalized)	$ 2,788	$ 3,144
Non-cash investing activity:		
Plant expenditures included in ending accounts payable	$ 2,004	$ 1,782

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THE BERKSHIRE GAS COMPANY
BALANCE SHEETS
ASSETS

As of December 31,	**2020**	**2019**
(Thousands)		
Assets		
Current Assets		
Unrestricted cash and temporary cash investments	$ 212	$ 482
Accounts receivable and unbilled revenues, net	14,862	15,978
Accounts receivable from affiliates	623	1,773
Regulatory assets	10,977	9,975
Gas in storage	2,085	2,473
Materials and supplies	1,309	1,116
Other current assets	1,967	1,967
Total Current Assets	32,035	33,764
Other Investments	89	246
Net Property, Plant and Equipment	200,116	191,448
Regulatory Assets	30,119	33,316
Deferred Charges and Other Assets		
Goodwill	51,933	51,933
Other	2,072	2,001
Total Deferred Charges and Other Assets	54,005	53,934
Total Assets	$ 316,364	$ 312,708

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

THE BERKSHIRE GAS COMPANY
BALANCE SHEETS
LIABILITIES AND CAPITALIZATION

As of December 31,	**2020**	**2019**
(Thousands)		
Liabilities		
Current Liabilities		
Notes payable to affiliates	$ 9,010	$ 23,030
Current portion of long-term debt	1,646	10,062
Accounts payable and accrued liabilities	12,615	12,745
Accounts payable to affiliates	861	2,052
Other current liabilities	2,042	1,410
Interest accrued	768	789
Regulatory liabilities	1,152	2,132
Total Current Liabilities	28,094	52,220
Deferred Income Taxes	28,064	24,693
Regulatory Liabilities	51,390	51,374
Other Noncurrent Liabilities		
Pension	19,854	21,724
Environmental remediation costs	3,950	3,950
Other	2,459	2,064
Total Other Noncurrent Liabilities	26,263	27,738
Capitalization		
Long-term debt	59,498	36,013
Common Stock Equity		
Paid-in capital	106,095	106,095
Retained earnings	16,960	14,575
Net Common Stock Equity	123,055	120,670
Total Capitalization	182,553	156,683
Total Liabilities and Capitalization	$ 316,364	$ 312,708

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

(Thousands, except share amounts)	**Common Stock Shares**	**Amount**	**Paid-in Capital**	**Retained Earnings**	**Total**
As of December 31, 2018	100	$ -	$ 106,095	$ 6,974	$ 113,069
Net income				7,601	7,601
As of December 31, 2019	100	$ -	$ 106,095	$ 14,575	$ 120,670
Net income				4,385	4,385
Payment of common stock dividend				(2,000)	(2,000)
As of December 31, 2020	100	-	106,095	16,960	123,055

The accompanying Notes to Financial Statements
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NOTES TO FINANCIAL STATEMENTS

(A) BACKGROUND AND 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. (Avangrid), 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 are 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.

Certain immaterial amounts reported on the Balance Sheet in previous periods have been reclassified to conform to the current presentation.

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

Revenues

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, 2020	Year Ended December 31, 2019
Regulated operations – natural gas	$ 73,542	$ 80,340
Other (a)	16	77
Revenue from contracts with customers	**73,558**	**80,417**
Leasing revenue	1,117	1,135
Alternative revenue programs	2,466	784
Total operating revenues	**$ 77,141**	**$ 82,336**

(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 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, 2020 and 2019 included the following:

	Remaining Period	December 31, 2020	December 31, 2019
(In Thousands)			
Regulatory Assets:			
Pension and other post-retirement benefit plan	(a)	$ 22,998	$ 24,324
Environmental remediation costs	7 years	5,501	6,135
Debt premium	1 year	191	607
Deferred purchased gas	(b)	6,586	6,516
Unfunded future income taxes	(c)	482	724
Decoupling	(e)	1,317	-
Recoverable bad debt	(d)	1,012	557
Other	(d)	3,009	4,428
Total regulatory assets		41,096	43,291
Less current portion of regulatory assets		10,977	9,975
Regulatory Assets, Net		$ 30,119	$ 33,316
Regulatory Liabilities:			
Pension and other postretirement benefit plan	(a)	$ 1,103	$ 425
Asset removal costs	(d)	37,391	36,097
Tax reform	18 years	13,547	15,423
Non-firm margin sharing credits	10 months	84	634
Decoupling	(e)	-	884
Other	(d)	417	43
Total regulatory liabilities		52,542	53,506
Less current portion of regulatory liabilities		1,152	2,132
Regulatory Liabilities, Net		$ 51,390	$ 51,374

(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 deferral is not currently earning a return. The collection from or return 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 2020 and 2019 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, 2020 and 2019 were comprised as follows:

	2020	2019
	(In Thousands)	
Gas distribution plant	$ 224,523	$ 213,079
Land	2,305	2,304
Buildings and improvements	29,738	29,395
Other plant	35,979	31,323
Total property, plant & equipment	292,545	276,101
Less accumulated depreciation	97,086	91,418
	195,459	184,683
Construction work in progress	4,657	6,765
Net property, plant & equipment	$ 200,116	$ 191,448

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 2020 and 2019 was 1.01% and 2.57% respectively. The portion of the allowance applicable to equity funds was immaterial for 2020 and 2019.

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 2020 and 2019 were approximately $8.2 million and $8.0 million, respectively, or 2.9% and 3.0%, 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, 2020, 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, 2020 and 2019 include unbilled revenues of $6.1 million and $5.9 million, respectively and are shown net of an allowance for doubtful accounts of $3.2 million and $1.4 million as of December 31, 2020 and 2019, 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, 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

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 (ASC 326). 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 collectability 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 ASC 326 to clarify transition and scope requirements, make narrow-scope codification improvements, including in March 2020, and corrections and provide targeted transition relief. Berkshire adopted the amendments effective January 1, 2020, including the narrow-scope improvements issued in March 2020 with no effect to its results of operations, financial position, cash flows and disclosures.

Simplifying the test for goodwill impairment

In January 2017, the FASB issued amendments to simplify the test for goodwill impairment, which is 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. BGC adopted the amendments effective January 1, 2020, with no material effect to its consolidated results of operations, financial position, cash flows and disclosures. As required, Berkshire is applying the amendments on a prospective basis.

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. Berkshire adopted the amendments effective January 1, 2020, with no material effect to its disclosures. Certain amendments are to be applied prospectively, and all others are to be applied retrospectively.

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. The amendments change annual disclosures requirements, including removal of disclosures that are no longer considered cost beneficial, adding certain new relevant disclosures and clarifying specific requirements of disclosures concerning information for defined benefit pension plans. Berkshire adopted the amendments effective January 1, 2020, and they will not materially affect the disclosures for the fiscal year ending December 31, 2020. As required, the application will be on a retrospective basis.

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. Berkshire adopted the amendments effective January 1, 2020, with no material effect to its results of operations, financial position, cash flows and disclosures. As required, Berkshire retrospectively applied the amendments to the date of our initial application of ASC 606.

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 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 in equity method investments 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.

Facilitation of the effects of reference rate reform on financial reporting

In March 2020, the FASB issued amendments and created ASC 848 to provide temporary optional guidance to entities to ease the potential burden in accounting for, or recognizing the effects of, reference rate reform on financial reporting. The amendments respond to concerns about structural risks of interbank offered rates, and particularly, the risk of cessation of the London Interbank Offered Rate (LIBOR). The guidance is elective and applies to all entities, subject to meeting certain criteria, that have contracts, hedging relationships, and other transactions that reference LIBOR or another reference rate expected to be discontinued due to reference rate reform, around the end of 2021. The guidance applies to contracts that have modified terms that affect, or have the potential to affect, the amount or timing of contractual cash flows resulting from the discontinuance of the reference rate reform. The amendments are effective for all entities as of March 12, 2020, through December 31, 2022, although the FASB has indicated it will monitor developments in the marketplace and consider whether developments warrant an extension.

In January 2021, the FASB issued amendments to clarify the scope of ASC 848 and respond to questions from stakeholders about whether ASC 848 can be applied to derivative instruments that do not reference a rate that is expected to be discontinued but that use an interest rate for margining, discounting, or contract price alignment that is modified because of reference rate reform. The modification, commonly referred to as the “discounting transition,” may have accounting implications, raising concerns about the need to reassess previous accounting determinations related to those derivatives and about the possible hedge accounting consequences of the discounting transition. The amendments clarify that certain optional expedients and exceptions in ASC 848 for contract modifications and hedge accounting apply to derivatives that are affected by the discounting transition, capture the incremental consequences of the scope clarification and tailor the existing guidance to derivative instruments affected by the discounting transition. The amendments are effective immediately, and may be elected retrospectively to eligible modifications as of any date from the beginning of the interim period that includes March 12, 2020, or prospectively to new modifications made on or after any date within the interim period that includes January 7, 2021.

Berkshire expects the adoption of reference rate reform and the subsequent scope clarification will not materially affect its consolidated results of operations, financial position and cash flows.

Use of Estimates and Assumptions

The preparation of Berkshire’s 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 credit losses and unbilled revenues; (2) asset impairments, including goodwill; (3) investments in equity instruments; (4) depreciable lives of assets; (5) income tax valuation allowances; (6) uncertain tax positions; (7) reserves for professional, workers’ compensation and comprehensive general insurance liability risks; (8) contingency and litigation reserves; (9) fair value measurements; (10) earnings sharing mechanisms; (11) environmental remediation liabilities; (12) AROs; (13) pension and other postretirement employee benefits and (14) noncontrolling interest balances. Future events and their effects cannot be predicted with certainty; accordingly, the accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of the financial statements will change as new events occur, as more experience is acquired, as additional information is obtained and as the operating environment changes. Berkshire evaluates and updates the assumptions and estimates on an ongoing basis and may employ outside specialists to assist in evaluations, as necessary. Actual results could differ from those estimates.

Berkshire continues to utilize information reasonably available; however, the business and economic uncertainty resulting from COVID-19 has made such estimates and assumptions more difficult to assess and calculate. Affected estimates include, but are not limited to, evaluations of certain long-lived assets and goodwill for impairment, expected credit losses and potential regulatory deferral or recovery of certain costs. While Berkshire has not yet had material effects of COVID-19 on its financial results, actual results could differ from those estimates, which could result in material effects to the financial statements in future reporting periods.

B) CAPITALIZATION

Common Stock

Berkshire had 100 shares of its common stock, $2.50 par value, outstanding as of December 31, 2020 and 2019.

Long-Term Debt

As of December 31,		**2020**		**2019**	
(Thousands)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
Senior unsecured notes	2021-2050	61,454	3.68%-7.80%	45,909	4.07%-9.60%
Unamortized debt (costs) premium, net		(310)		166	
Total Debt		**61,144**		**46,075**	
Less: debt due within one year, included in current liabilities		1,646		10,062	
Total Non-current Debt		**59,498**		**36,013**	

(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 $76.8 million and $53.7 million as of December 31, 2020 and 2019, 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:

	2021	**2022**	**2023**	**2024**	**2025 & Thereafter**	**Total**
			(In Thousands)			
Maturities:	$ 1,454	$ -	$ -	$ -	$ 60,000	$ 61,454

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, 2020, 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, 2020, such ratio was 49.7%.
- A fixed charges coverage ratio of no less than 1.50 to 1.00. As of December 31, 2020, such ratio was 2.91 to 1.00.
- To maintain an adjusted tangible net worth of at least $9 million. As of December 31, 2020, Berkshire's adjusted tangible net worth was $32.7 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 new distribution rates for Berkshire. The distribution rate increase was based on an ROE of 9.70% and 54.0% equity ratio. The new tariffs provided for the implementation of a revenue decoupling mechanism and pension expense tracker and also provide 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, 2020, Berkshire was a party to a 90-day contract expiring on February 28, 2021 for a fixed daily quantity of natural gas. Berkshire's remaining commitment as of December 31, 2020 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 were 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 2020 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, 2020, there was $7.5 million outstanding under this agreement. As of December 31, 2019, there was $15.0 million 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 $1.6 million and $8.0 million outstanding under this agreement as of December 31, 2020 and 2019, respectively.

On June 29, 2020, Avangrid, Inc. and its subsidiaries, including Berkshire, amended its revolving credit facility agreement in place with several lenders (the 2020 Avangrid Credit Facility) that provides for maximum borrowings up to $2.5 billion in the aggregate. The 2020 Avangrid Credit Facility replaces and supersedes the prior revolving credit facility entered into by Avangrid, Inc. and its subsidiaries on June 29, 2018, which provided maximum borrowings of up to $2.5 billion in the aggregate.

Under the 2020 Avangrid Credit Facility, Berkshire has a maximum sublimit of $40 million. Additionally, under the 2020 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 15 to 30 basis points. The maturity date for the 2020 Avangrid Credit Facility is June 29, 2024. As of December 31, 2020 and 2019, Berkshire did not have any outstanding borrowings under the 2020 Avangrid Credit Facility.

(E) INCOME TAXES

	Year Ended December 31, 2020	Year Ended December 31, 2019
	(In Thousands)	
Income tax expense consists of:		
Income tax provisions:		
Current		
Federal	$ (393)	$ 1,476
State	(710)	552
Total current	(1,103)	2,028
Deferred		
Federal	1,060	(501)
State	1,247	(91)
Total deferred	2,306	(592)
Total income tax expense	$ 1,203	$ 1,436

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:

(In Thousands)	Year Ended December 31, 2020	Year Ended December 31, 2019
Book income before income taxes	$ 5,588	$ 9,037
Computed tax at federal statutory rate	$ 1,173	$ 1,898
Increases (reductions) resulting from:		
State income taxes, net of federal income tax benefits	424	364
Amortization of excess accumulated deferred income taxes	(838)	(1,144)
Other items, net	444	318
Total income tax expense	$ 1,203	$ 1,436
Effective income tax rates	21.5%	15.9%

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, 2020 and 2019, 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, 2020:

Jurisdiction	*Tax years*
Federal	2014 - 2020
Massachusetts	2017 - 2020

The following table summarizes Berkshire's deferred tax assets and liabilities as of December 31, 2020 and 2019:

	2020	**2019**
(In Thousands)		
Property related	$ (30,918)	$ (27,626)
Deferred gas and other deferred charges	(1,229)	(1,628)
Deferred tax liability on 2017 Tax Act remeasurement	3,701	4,397
Federal and State net operating losses and other attributes	953	985
Post-retirement benefits, net	(547)	(777)
Other assets (liabilities)	(25)	(44)
	$ (28,064)	$ (24,693)

As of each of December 31, 2020 and December 31, 2019, 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)

<u>Pension Plans</u>

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. Berkshire also offers 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 are consolidated in one master trust. 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. Networks' primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with risk tolerance. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. Networks' 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 their 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 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, 2020 and 2019. Plan assets and obligations have been measured as of December 31, 2020 and 2019.

	Pension Benefits		Other Post-Retirement Benefits	
	Year Ended December 31, 2020	Year Ended December 31, 2019	Year Ended December 31, 2020	Year Ended December 31, 2019
(In Thousands)				
Change in Benefit Obligation:				
Benefit obligation at beginning of year	$ 57,321	$ 51,114	$ 3,050	$ 3,194
Service cost	949	853	39	46
Interest cost	1,745	1,988	92	125
Actuarial (gain) loss	3,326	6,087	(679)	(256)
Benefits paid (including expenses)	(2,554)	(2,721)	(142)	(59)
Benefit obligation at end of year	$ 60,787	$ 57,321	$ 2,360	$ 3,050
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 37,256	$ 32,148	$ -	$ -
Actual return on plan assets	5,335	6,172	-	-
Employer contributions	1,865	1,657	142	59
Benefits paid (including expenses)	(2,554)	(2,721)	(142)	(59)
Fair value of plan assets at end of year	$ 41,902	$ 37,256	$ -	$ -
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ 18,885	$ 20,065	$ 2,360	$ 3,050
Amounts Recognized in the Consolidated Balance Sheet consist of:				
Non-current liabilities	$ 18,885	$ 20,065	$ 2,360	$ 3,050
Amounts Recognized as a Regulatory Asset (Liability) consist of:				
Prior service cost	$ 1	$ 1	$ -	$ -
Net (gain) loss	$ 11,434	$ 11,718	(787)	(120)
Total recognized as a regulatory asset (liability)	$ 11,435	$ 11,719	$ (787)	$ (120)
Information on Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:				
Projected benefit obligation	$ 59,395	$ 55,929	N/A	N/A
Accumulated benefit obligation	$ 54,534	$ 50,491	N/A	N/A
Fair value of plan assets	$ 41,902	$ 37,256	N/A	N/A
The following weighted average actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate (Pension Benefits)	2.56%	3.19%	N/A	N/A
Discount rate (Other Post-Retirement Benefits)	N/A	N/A	2.00%	3.19%
Average wage increase	3.08%	3.50%	N/A	N/A
Interest crediting rate	2.84%	2.86%	N/A	N/A
Health care trend rate (current year - pre/post-65)	N/A	N/A	6.50%/7.25%	6.75%/7.50%
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

During 2020, the pension benefit obligation had an actuarial loss of $3.3 million, primarily due to a $4.7 million loss from decreases in discount rates, partially offset by gains in mortality, demographic and other assumptions. During 2020, the postretirement benefit obligation had an actuarial gain of $0.7 million.

During 2019, the pension benefit obligation had an actuarial loss of $6.1 million, primarily due to a $6.1 million loss from decreases in discount rates. During 2019, the postretirement benefit obligation had an actuarial gain of $0.3 million.

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, 2020 and 2019 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, 2020	Year Ended December 31, 2019	Year Ended December 31, 2020	Year Ended December 31, 2019
(In Thousands)				
Components of net periodic benefit cost:				
Service cost	$ 949	$ 853	$ 39	$ 46
Interest cost	1,745	1,988	93	125
Expected return on plan assets	(2,663)	(2,354)	-	-
Amortization of actuarial (gain) loss	937	844	(12)	16
Amortization of prior service cost	-	43	-	-
Net periodic benefit cost	$ 968	$ 1,374	$ 120	$ 187
Other Changes in Plan Assets and Benefit Obligations Recognized as a Regulatory Asset (Liability):				
Net (gain) loss	$ 654	$ 2,269	$ (680)	$ (256)
Amortization of prior service cost	-	(43)	-	-
Amortization of Actuarial gain (loss)	(937)	(844)	12	(16)
Total recognized as regulatory asset (liability)	$ (283)	$ 1,382	$ (668)	$ (272)
Total recognized in Net Periodic Benefit Costs and Regulatory Asset (Liability):				
	$ 685	$ 2,756	$ (548)	$ (85)
The following actuarial weighted average assumptions were used in calculating net periodic benefit cost:				
Discount rate	3.19%	4.09%	3.19%	4.09%
Average wage increase	3.50%	3.50%	N/A	N/A
Return on plan assets	7.21%	7.20%	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 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. Berkshire amortizes unrecognized actuarial gains and losses over ten years from the time they are incurred as required by the DPU.

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 contributions of approximately $1.9 million in 2021. 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)	
2021	$ 2,653	$ 185
2022	$ 2,841	$ 178
2023	$ 2,829	$ 148
2024	$ 2,865	$ 157
2025	$ 2,942	$ 180
2026-2030	$ 15,311	$ 825

The fair values of the Plans' assets as of December 31, 2020, 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
(In Thousands)				
December 31, 2020				
Pension assets				
Cash and cash equivalents	$ 1	$ 933	$ -	$ 934
U.S. government securities	2,419	1	-	2,420
Common stocks	1,425	-	-	1,425
Registered investment companies	4,118	-	-	4,118
Corporate bonds	-	9,696	-	9,696
Preferred stocks	13	-	-	13
Common collective trusts	-	15,891	-	15,891
Other, principally annuity, fixed income	87	(29)	-	58
	$ 8,063	$ 26,492	$ -	34,555
Other investments measured at net asset value				7,347
TOTAL				$ 41,902

*Corporate Bonds includes $0.5 million of Non-US Government Bonds

	Level 1	Level 2	Level 3	Total
December 31, 2019				
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

Valuation Techniques

Berkshire values its' 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 – at the closing price reported in the active market in which the security is traded.
- Common stocks – 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.
- Preferred stocks – at the closing price reported in the active market in which the individual investment is traded.
- Common collective trusts/Registered investment companies – Level 1: at the closing price reported in the active market in which the individual investment is traded. Level 2: 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.

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 the years ending December 31, 2020 and 2019 was $0.6 and $0.5 million, respectively.

(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, 2020, 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 year ended December 31, 2020, Berkshire paid a common stock dividend of $2.0 million to BER. For the year ended December 31, 2019, Berkshire did not pay 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, 2020 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, 2020. 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, 2020, 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, 2020 and December 31, 2019.

	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, 2020		(In Thousands)		
Noncurrent investments	$ 89	$ -	$ -	$ 89
Total fair value assets, December 31, 2020	$ 89	$ -	$ -	$ 89
December 31, 2019				
Noncurrent investments	$ 246	$ -	$ -	$ 246
Total fair value assets, December 31, 2019	$ 246	$ -	$ -	$ 246

(J) SUBSEQUENT EVENTS

Berkshire has evaluated subsequent events through the date its financial statements were available to be issued, April 12, 2021.

Central Maine Power Company
and Subsidiaries
Consolidated Financial Statements
As of and for the Years Ended December 31, 2020 and 2019

Central Maine Power Company
and Subsidiaries

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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, 2020 and 2019, 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[7]. 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, 2020 and 2019, 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, 2021

Central Maine Power Company and Subsidiaries
Consolidated Statements of Income

Years Ended December 31,		2020		2019
(Thousands)				
Operating Revenues	$	**888,225**	$	**819,057**
Operating Expenses				
Electricity purchased		19,497		17,162
Operations and maintenance		443,678		399,447
Depreciation and amortization		123,156		116,248
Taxes other than income taxes, net		73,895		69,725
Total Operating Expenses		**660,226**		**602,582**
Operating Income		**227,999**		**216,475**
Other income		16,369		12,095
Other deductions		(15,899)		(15,238)
Interest expense, net of capitalization		(46,148)		(51,433)
Income Before Income Tax		**182,321**		**161,899**
Income tax expense		41,681		41,922
Net Income		**140,640**		**119,977**
Less: net income attributable to noncontrolling interest		2,430		1,921
Net Income Attributable to CMP	$	**138,210**	$	**118,056**

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

Central Maine Power Company and Subsidiaries
Consolidated Statements of Comprehensive Income

Years Ended December 31,		2020		2019
(Thousands)				
Net Income	$	**140,640**	$	**119,977**
Other Comprehensive (Loss) Income, Net of Tax				
Amortization of pension for non-qualified plans, net of income tax		(188)		—
Unrealized gain during period on derivatives qualifying as cash flow hedges, net of income tax		(257)		71
Reclassification adjustment for loss included in net income, net of income tax		245		211
Reclassification adjustment for loss on settled cash flow treasury hedges, net of income tax		130		714
Other Comprehensive (Loss) Income, Net of Tax		**(70)**		**996**
Comprehensive Income		**140,570**		**120,973**
Less:				
Comprehensive income attributable to noncontrolling interests		2,430		1,921
Comprehensive Income Attributable to CMP	$	**138,140**	$	**119,052**

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,	2020	2019
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$ 23,855	$ 15,287
Accounts receivable and unbilled revenues, net	241,407	207,049
Accounts receivable from affiliates	1,408	896
Notes receivable from affiliates	—	23,020
Materials and supplies	24,674	18,788
Prepayments and other current assets	20,162	9,822
Income tax receivable	32,727	22,996
Regulatory assets	49,248	14,818
Total Current Assets	**393,481**	**312,676**
Utility plant, at original cost	4,699,672	4,469,740
Less accumulated depreciation	(1,261,090)	(1,151,685)
Net Utility Plant in Service	**3,438,582**	**3,318,055**
Construction work in progress	358,843	262,119
Total Utility Plant	**3,797,425**	**3,580,174**
Operating lease right-of-use assets	15,549	16,672
Other property and investments	846	856
Regulatory and Other Assets		
Regulatory assets	475,985	429,288
Goodwill	324,938	324,938
Other	28,149	34,531
Total Regulatory and Other Assets	**829,072**	**788,757**
Total Assets	**$ 5,036,373**	**$ 4,699,135**

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,		2020		2019
(Thousands)				
Liabilities				
Current Liabilities				
Current portion of debt	$	149,549	$	513
Notes payable to affiliates		72,974		705
Accounts payable and accrued liabilities		229,153		177,797
Accounts payable to affiliates		8,124		8,321
Interest accrued		22,693		23,775
Taxes accrued		9,490		2,795
Operating lease liabilities		1,146		753
Other current liabilities		66,487		56,223
Regulatory liabilities		24,135		26,794
Total Current Liabilities		**583,751**		**297,676**
Regulatory and Other Liabilities				
Regulatory liabilities		403,228		424,604
Other Non-current liabilities				
Deferred income taxes		595,593		533,158
Pension and other postretirement		181,503		191,732
Operating lease liabilities		15,204		16,306
Other		36,403		35,703
Total Regulatory and Other Liabilities		**1,231,931**		**1,201,503**
Non-current debt		1,085,966		1,185,635
Total Liabilities		**2,901,648**		**2,684,814**
Commitments and Contingencies				
Redeemable Preferred Stock		**571**		**571**
CMP Common Stock Equity				
Common stock ($5 par value, 80,000,000 shares authorized and 31,211,471 shares outstanding at December 31, 2020 and 2019)		156,057		156,057
Additional paid-in capital		824,039		764,170
Retained earnings		1,125,689		1,067,514
Accumulated other comprehensive loss		(3,793)		(3,723)
Total CMP Common Stock Equity		**2,101,992**		**1,984,018**
Noncontrolling interest		32,162		29,732
Total Equity		**2,134,154**		**2,013,750**
Total Liabilities and Equity	**$**	**5,036,373**	**$**	**4,699,135**

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,	2020	2019
(Thousands)		
Cash Flow from Operating Activities:		
Net income	**$ 140,640**	**$ 119,977**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	123,156	116,248
Regulatory assets/liabilities amortization	(2,303)	3,234
Regulatory assets/liabilities carrying cost	(1,076)	1,619
Amortization of debt issuance costs	658	(154)
Deferred taxes	42,861	31,308
Pension cost	14,478	16,220
Stock-based compensation	256	83
Accretion expenses	49	47
Gain from disposal of property	(432)	(558)
Other non-cash Items	(4,493)	(1,895)
Changes in operating assets and liabilities:		
Accounts receivable, from affiliates, and unbilled revenues	(34,870)	(7,234)
Inventories	(5,886)	(1,685)
Accounts payable, to affiliates, and accrued liabilities	46,129	(2,751)
Taxes accrued	24,534	6,019
Other assets/liabilities	(30,722)	16,803
Regulatory assets/liabilities	(97,291)	(52,025)
Net Cash Provided by Operating Activities	**215,688**	**245,256**
Cash Flow from Investing Activities:		
Capital expenditures	(347,858)	(315,000)
Contributions in aid of construction	15,196	12,710
Notes receivable from affiliates	23,020	(10,320)
Proceeds from sale of property, plant and equipment	2,412	1,700
Investments, net	63	396
Net Cash Used in Investing Activities	**(307,167)**	**(310,514)**
Cash Flow from Financing Activities:		
Non-current note issuance	49,696	239,020
Repayments of non-current debt	(993)	(151,183)
Repayments of financing leases	(925)	(851)
Proceeds of short term debt - affiliates	72,269	533
Capital contribution	60,000	—
Contributions from noncontrolling interest	—	1,900
Dividends paid	(80,000)	(25,000)
Net Cash Provided by Financing Activities	**100,047**	**64,419**
Net Increase (Decrease) in Cash and Cash Equivalents	**8,568**	**(839)**
Cash and Cash Equivalents, Beginning of Year	**15,287**	**16,126**
Cash and Cash Equivalents, End of Year	**$ 23,855**	**$ 15,287**

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

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

	CMP Stockholder							
(Thousands, except per share amounts)	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, 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	—	—	—	—	—	—	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**
Adoption of accounting standards	—	—	(275)	—	—	(275)	—	(275)
Net income	—	—	—	138,210	—	138,210	2,430	140,640
Other comprehensive loss, net of tax	—	—	—	—	(70)	(70)	—	(70)
Comprehensive income								140,570
Stock-based compensation	—	—	144	—	—	144	—	144
Capital contribution	—	—	60,000	—	—	60,000	—	60,000
Preferred stock dividends	—	—	—	(35)	—	(35)	—	(35)
Common stock dividends	—	—	—	(80,000)	—	(80,000)	—	(80,000)
Balances, December 31, 2020	**31,211,471**	**$ 156,057**	**$ 824,039**	**$1,125,689**	**$ (3,793)**	**$ 2,101,992**	**$ 32,162**	**$ 2,134,154**

(*) Par value of share amounts is $5

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

Note 1. Summary of Significant Accounting Policies, New Accounting Pronouncements and Use of Estimates

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 646,818 customers as of December 31, 2020, 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, MEPCO, Chester, and NORVARCO. All intercompany transactions and accounts have been eliminated in consolidation in all periods presented.

Significant Accounting Policies: 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 an independent, third-party regulator; (ii) rates are designed to recover the entity's specific costs of providing the 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 can 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.

We amortize regulatory assets and liabilities and recognize the related expense or revenue in our consolidated 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.

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 represents future economic benefits arising from other assets acquired in a business combination that are not individually identified and separately recognized. Goodwill is initially measured at cost, being the excess of the aggregate of the consideration transferred, the fair value of any noncontrolling interest and the acquisition date fair value of any previously held equity interest in the acquiree over the fair value of the net identifiable assets acquired and liabilities assumed.

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 would more likely than not reduce the fair value of the reporting unit to which goodwill is assigned 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 to first perform a qualitative assessment to determine whether a quantitative assessment is necessary. If we determine, based on 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 the qualitative assessment, or perform the qualitative assessment but determine it is more likely than not that its fair value is less than its carrying amount, we perform a quantitative test to compare 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, we record an impairment loss as a reduction to goodwill and a charge to operating expenses, but the loss recognized would not exceed the total amount of goodwill allocated to the reporting unit.

Utility plant: We account for utility plant 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 add an equal amount to the carrying amount of the asset.

Development and construction of our various facilities are carried out in stages. We expense project costs 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.

We transfer assets 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 of to accumulated depreciation. Our composite rates for depreciation were 2.5% of average depreciable property for both 2020 and 2019. 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 $165.6 million as of December 31, 2020, and $159.4 million as of December 31, 2019. Depreciation expense was $113.4 million in 2020 and $106.7 million in 2019. Amortization of capitalized software was $9.8 million in 2020 and $9.6 million in 2019.

We charge repairs and minor replacements to operating expenses, and capitalize renewals and betterments, including certain indirect costs.

Allowance for funds used during construction (AFUDC) is a non-cash item that 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 record the remainder as other income.

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)**	**2020**	**2019**
(Thousands)			
Electric			
Transmission	4-70	$ 2,642,294	$ 2,500,371
Distribution	20-82	1,551,773	1,483,540
Vehicles	4-10	60,729	57,864
Other	2-54	444,876	427,965
Total Utility Plant in Service		**4,699,672**	**4,469,740**
Total accumulated depreciation		(1,261,090)	(1,151,685)
Total Net Utility Plant in Service		**3,438,582**	**3,318,055**
Construction work in progress		358,843	262,119
Total Utility Plant		**$ 3,797,425**	**$ 3,580,174**

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. We use the incremental borrowing rate based on information available at the lease commencement date to determine the present value of future payments, except when the rate implicit in the lease is determinable. 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 an option 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 non-lease 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. We are required to recognize an impairment loss 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 amount of the long-lived asset exceeds the asset's fair value. 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 our 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, which we present in the same income statement line item as the earnings effect of the hedged item. 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.

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. We report changes in book overdrafts 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:

		2020		2019
(Thousands)				
Cash paid during the year ended December 31:				
Interest, net of amounts capitalized	$	42,705	$	42,180
Income taxes paid, net	$	6,275	$	16,961

Of the income taxes paid, substantially all was paid to AGR under the tax sharing agreement. Interest capitalized was $10.6 million in 2020 and $5.3 million in 2019. Accrued liabilities for utility plant additions were $32.0 million in 2020 and $20.8 million in 2019.

***Trade receivables and unbilled revenues, net of allowance for credit losses*:** We record trade receivables at amounts billed to customers and we record unbilled revenues based on an estimate of energy delivered or services provided to customers. The estimates for unbilled revenues 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 credit losses 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 credit losses 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 credit losses estimates.

Trade receivables at December 31 include unbilled revenues of $32.2 million for 2020 and $29.8 million for 2019, and are shown net of an allowance for credit losses at December 31 of $23.8 million for 2020 and $9.1 million for 2019. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $14.1 million in 2020 and $9.5 million in 2019.

Trade receivables 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 over an extended period without interest, 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. Failure to make payments on a DPA results in the full amount of a receivable under a DPA being due. These accounts are part of the regular operating cycle and we classify them as short term.

We establish our allowance for credit losses, including for unbilled revenue (also referred to as contract assets), by using both historical average loss percentages to project future losses, and by establishing a specific allowance for known credit issues or for specific items not considered in the historical average calculation. Due to our adoption of Accounting Standards Codification (ASC) 326 effective January 1, 2020, we now also consider whether we need to adjust historical loss rates to reflect the effects of current conditions and forecasted changes considering various economic indicators (e.g., Gross Domestic Product, Personal Income, Consumer Price Index, Unemployment Rate) over the contractual life of the trade receivables. We write off amounts when we have exhausted reasonable collection efforts. The allowance for credit losses for DPAs at December 31 was $4.8 million for 2020 and $5.1 million for 2019. DPA receivable balances at December 31 were $18.9 million for 2020 and $18.6 million for 2019.

Debentures, bonds and bank borrowings: We record bonds, debentures and bank borrowings as a liability equal to the proceeds of the borrowings. We treat the difference between the proceeds and the face amount of the issued liability as discount or premium and accrete the amounts as interest expense or income over the life of the instrument. We defer incremental costs associated with the issuance of the debt instruments and amortize them over the same period as debt discount or premium. We present bonds, debentures and bank borrowings net of unamortized discount, premium and debt issuance costs on our consolidated balance sheets.

Inventory: Inventory comprises materials and supplies that we use 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 consolidated balance sheets within “Materials and supplies.”

Government grants**:** We record government grants as a reduction to the related 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 which we incur the expenses.

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. 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. 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.

The following table reconciles the beginning and ending aggregate carrying amount of the ARO, including our conditional ARO, which is recorded in Other Non-current Liabilities for the years ended December 31, 2020 and 2019.

Years Ended December 31,	**2020**	**2019**
(Thousands)		
ARO, beginning of year	$ 926	$ 879
Accretion expenses	49	47
ARO, end of year	**$ 975**	**$ 926**

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. We expect to pay our environmental liability accruals through the year 2053.

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 generally 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 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 taxes: 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 $32.8 million for 2020 and $23.0 million for 2019.

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 netted and classified as non-current on our consolidated balance sheets.

We record the excess of state franchise tax computed as the higher of a tax based on income or a tax based on capital in "Taxes other than income taxes" and "Taxes accrued" in our consolidated financial statements.

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 2020 and 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 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) 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 (ASC 326). The amendments affect entities that hold financial assets and net investments 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 ASC 326 to clarify transition and scope requirements, make narrow-scope codification improvements, including in March 2020, and corrections and provide targeted transition relief. We adopted the amendments effective January 1, 2020, including the narrow-scope improvements issued in March 2020, and recorded a cumulative-effect adjustment of $0.3 million to retained earnings at the beginning of the period of adoption, with no material effect to our consolidated results of operations, financial position, cash flows and disclosures.

(b) Simplifying the test for goodwill impairment

In January 2017, the FASB issued amendments to simplify the test for goodwill impairment, which is 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. We adopted the amendments effective January 1, 2020, with no material effect to our consolidated results of operations, financial position, cash flows and disclosures. As required, we are applying the amendments on a prospective basis.

(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 to improve the overall usefulness of the disclosures and reduce unnecessary costs to companies to prepare the disclosures. We adopted the amendments effective January 1, 2020, with no material effect to our disclosures. Certain amendments are to be applied prospectively, and all others are to be applied retrospectively.

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. The amendments change annual disclosures requirements, including removal of disclosures that are no longer considered cost beneficial, adding certain new relevant disclosures and clarifying specific requirements of disclosures concerning information for defined benefit pension plans. We adopted the amendments effective January 1, 2020, and they did not materially affect the disclosures for our fiscal year ending December 31, 2020. As required, we applied the amendments on a retrospective basis.

(d) 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. We adopted the amendments effective January 1, 2020, with no material effect to our consolidated results of operations, financial position, cash flows and disclosures. As required, we retrospectively applied the amendments to the date of our initial application of ASC 606.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements not yet adopted, including those issued since December 31, 2020, that we have evaluated or are evaluating to determine their effect on our consolidated financial statements.

(a) 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 in equity method investments 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.

(b) Facilitation of the effects of reference rate reform on financial reporting, and subsequent scope clarification

In March 2020, the FASB issued amendments and created ASC 848 to provide temporary optional guidance to entities to ease the potential burden in accounting for, or recognizing the effects of, reference rate reform on financial reporting. The amendments respond to concerns about structural risks of interbank offered rates, and particularly, the risk of cessation of the London Interbank Offered Rate (LIBOR). The guidance is elective and applies to all entities, subject to meeting certain criteria, that have contracts, hedging relationships, and other transactions that reference LIBOR or another reference rate expected to be discontinued due to reference rate reform, around the end of 2021. The guidance applies to contracts that have modified terms that affect, or have the potential to affect, the amount or timing of contractual cash flows resulting from the discontinuance of the reference rate reform. The amendments are effective for all entities as of March 12, 2020, through December 31, 2022, although the FASB has indicated it will monitor developments in the marketplace and consider whether developments warrant an extension.

In January 2021, the FASB issued amendments to clarify the scope of ASC 848 and respond to questions from stakeholders about whether ASC 848 can be applied to derivative instruments that do not reference a rate that is expected to be discontinued but that use an interest rate for margining, discounting, or contract price alignment that is modified because of reference rate reform. The modification, commonly referred to as the “discounting transition,” may have accounting implications, raising concerns about the need to reassess previous accounting determinations related to those derivatives and about the possible hedge accounting consequences of the discounting transition. The amendments clarify that certain optional expedients and exceptions in ASC 848 for contract modifications and hedge accounting apply to derivatives that are affected by the discounting transition, capture the incremental consequences of the scope clarification and tailor the existing guidance to derivative instruments affected by the discounting transition. The amendments are effective immediately, and may be elected retrospectively to eligible modifications as of any date from the beginning of the interim period that includes March 12, 2020, or prospectively to new modifications made on or after any date within the interim period that includes January 7, 2021.

We expect our adoption of the reference rate reform and the subsequent scope clarification 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 credit losses 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) fair value measurements; (9) environmental remediation liabilities; (10) AROs; (11) pension and other postretirement employee benefits (OPEB); and (12) noncontrolling interest balances. 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.

We continue to utilize information reasonably available to us; however, the business and economic uncertainty resulting from the global pandemic of the novel coronavirus (COVID-19) has made such estimates and assumptions more difficult to assess and calculate. Affected estimates include, but are not limited to, evaluations of certain long-lived assets and goodwill for impairment, expected credit losses and potential regulatory deferral or recovery of certain costs. While we have not yet had material effects of COVID-19 on our financial results, actual results could differ from those estimates, which could result in material effects to our consolidated financial statements in future reporting periods.

Union collective bargaining agreements: Approximately 70% 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 2021. 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 2021.

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 $26.0 million as of December 31, 2020 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 resumed and resulted in the filing of an uncontested settlement on June 15, 2020. The settlement was subsequently certified by the presiding Administrative Law Judge on August 18, 2020 and the FERC approved the settlement by its order issued on December 28, 2020. The revised formula rate will become effective on January 1, 2022.

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 2021. 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 instead initiates 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. The management audit commenced in August 2020 and has not yet concluded.

Under Maine law 35-A M.R.S.A §§ 3210-C, 3210-D and 3210-G, 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. Pursuant to M.R.S.A §3210-G, the MPUC must conduct two competitive solicitation processes to procure, in the aggregate, an amount of energy or RECs from Class 1A resources that is equal to 14% of retail electricity sales in the State during calendar year 2018, or 1.715 Million MWh. Of that 14% total, the MPUC must acquire at least 7%, but not more than 10%, through contracts approved by December 31, 2020 (Tranche 1), and acquire the remaining amount (Tranche 2) through a solicitation process to be initiated no later than January 15, 2021. Pursuant to 3210-G, on September 23, 2020, the MPUC issued an order accepting term sheet proposals from 17 projects and ordered the MPUC Staff, CMP and Versant Power to negotiate and execute contracts to implement the accepted terms. 14 of the accepted proposals are for projects in the CMP service territory and will require contracts with CMP. Since the MPUC order, one project has withdrawn from the solicitation and as of December 31, 2020, CMP has executed contracts with 5 of the remaining 13 projects for 20-year terms. These include contracts with Brookfield White Pine Hydro, LLC, ReEnergy Livermore Falls, LLC, BD Solar Church Hill, LLC, Canton Solar Energy Center, LLC and Roxbury Solar, LLC. Annual payments under these 5 agreements are expected to total approximately $27 million. In accordance with MPUC orders, CMP either sells the purchased energy and RECs 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 and MPUC orders, 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.

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 addressed 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 $205.1 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, 2020 and 2019 consisted of:

As of December 31,	**2020**	**2019**
(Thousands)		
Current		
Transmission revenue reconciliation mechanism	$ 31,276	$ 5,479
Deferred meter replacement costs	2,004	1,984
Environmental remediation costs	126	209
Storm in rates	7,012	—
Stranded costs	2,117	1,851
Energy efficiency programs	6,116	5,177
Federal tax depreciation normalization adjustment	436	—
Other	161	118
Total current regulatory assets	**49,248**	**14,818**
Non-current		
Federal tax depreciation normalization adjustment	13,523	14,481
Storm costs	83,105	33,304
Unamortized losses on reacquired debt	258	351
Pension and other postretirement benefits costs	202,425	205,182
Unfunded future income taxes	150,687	143,503
Deferred meter replacement costs	22,930	24,950
Other	3,057	7,517
Total non-current regulatory assets	**$ 475,985**	**$ 429,288**

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 Power Tax 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 $90.1 million at December 31, 2020 and $33.3 million at December 31, 2019.

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 Revenue Accrual 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. Regional Network Service (RNS) is a new deferral incorporating the method of determining the RNS credit using an actual vs forecasted method.

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 Unamortized Losses on Reacquired Debt in current, Electric Thermal Storage (ETS), CRM&B (Billing System Costs), Arrears

Forgiveness Program, OPA Consulting Costs, Non-Wire Alternative Costs, Management Audit Costs, Vegetation Management, and Net Energy Billing Admin Costs.

Current and non-current regulatory liabilities at December 31, 2020 and 2019 consisted of:

As of December 31,	**2020**	**2019**
(Thousands)		
Current		
Accrued removal obligations	$ 2,251	$ 2,251
Transmission revenue reconciliation mechanism	5,580	9,829
Revenue decoupling mechanism	9,351	12,529
Tax Act - remeasurement	6,011	1,145
Other	942	1,040
Total current regulatory liabilities	**24,135**	**26,794**
Non-current		
Environmental remediation costs	1,453	1,469
Rate refund - FERC ROE proceeding	26,040	24,542
Accrued removal obligations	42,310	50,075
Tax Act - remeasurement	332,925	346,881
Other	500	1,637
Total non-current regulatory liabilities	**$ 403,228**	**$ 424,604**

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.

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.

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. A portion of this balance is amortized through current rates; the remaining portion will be refunded in future periods through future rate cases.

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), Management Audit Reserve, and Disconnect Notice Cost.

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, 2020 and 2019 are as follows:

Years Ended December 31,	2020	2019
(Thousands)		
Regulated operations – electricity	$ 822,410	$ 771,013
Other(a)	17,409	21,404
Revenue from contracts with customers	**839,819**	**792,417**
Leasing revenue	1,598	1,540
Alternative revenue programs	31,702	8,569
Other revenue	15,106	16,531
Total operating revenues	**$ 888,225**	**$ 819,057**

(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 our annual impairment assessment testing at least annually as described in Note 1, in the fourth quarter, as of October 1. Our qualitative assessment involves evaluating key events and circumstances that could affect the fair value of our company, 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 CMP.

Our quantitative impairment testing includes various assumptions, primarily the discount rate, and forecasted cash flows. We use a discount rate that is developed using market participant assumptions, which consider the risk and nature of our cash flows and the rates of return market participants would require in order to invest their capital in CMP. We test the reasonableness of the conclusions of our quantitative impairment testing using a range of discount rates and a range of assumptions for long-term cash flows.

We had no impairment of goodwill in 2020 and 2019 as a result of our impairment testing. There were no events or circumstances subsequent to our annual impairment assessment for 2020 or 2019 that required us to update the assessment.

The carrying amount of goodwill was $325.0 million at both December 31, 2020 and 2019, with no accumulated impairment losses and no changes during 2020 and 2019.

Note 6. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2020 and 2019 consisted of:

Years Ended December 31,	2020	2019
(Thousands)		
Current		
Federal	$ 2,325	$ 13,725
State	(3,505)	(3,111)
Current taxes charged to (benefit) expense	**(1,180)**	**10,614**
Deferred		
Federal	23,948	12,993
State	18,913	18,315
Deferred taxes charged to expense	**42,861**	**31,308**
Total Income Tax Expense	**$ 41,681**	**$ 41,922**

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, 2020 and 2019 consisted of:

Years Ended December 31,	2020	2019
(Thousands)		
Tax expense at federal statutory rate	$ 38,287	$ 33,999
Depreciation/ amortization and other plant differences not normalized	(4,932)	(5,005)
State taxes net of federal benefit	12,172	12,011
Excess ADIT amortization	(6,017)	—
Other, net	2,171	917
Total Income Tax Expense	**$ 41,681**	**$ 41,922**

Income tax expense for the year ended December 31, 2020 was $3.4 million higher than it would have been at the statutory federal income tax rate of 21% due predominately to state taxes, partially offset by Excess ADIT amortization and Depreciation, amortization and other plant differences not normalized. This resulted in an effective tax rate of 22.9%. 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, amortization and other plant differences not normalized. This resulted in an effective tax rate of 25.9%.

In 2020, CMP began refunding previously deferred protected and unprotected Excess ADITs, established as a result of the 2017 Tax Act, pursuant to a regulatory order and as determined by the MPUC and IRS normalization rules.

Deferred tax assets and liabilities as of December 31, 2020 and 2019 consisted of:

December 31,		2020		2019
(Thousands)				
Non-current Deferred Income Tax Liabilities (Assets)				
Property related	$	623,698	$	574,723
Unfunded future income taxes		42,538		40,148
Pension and other postretirement benefits		11,274		10,606
Regulatory liability due to "Tax Cuts and Jobs Act"		(95,087)		(97,233)
Federal and state tax credits		—		(5,752)
Federal and state NOL's		(7,315)		(214)
Other		20,485		10,880
Total Non-current Deferred Income Tax Liabilities	**$**	**595,593**	**$**	**533,158**
Deferred tax assets	$	102,402	$	103,199
Deferred tax liabilities		697,995		636,357
Net Accumulated Deferred Income Tax Liabilities	**$**	**595,593**	**$**	**533,158**

CMP has gross Maine state net operating losses of $122.9 million for the year ended December 31, 2020. CMP had 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.

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.

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2020 and 2019 consisted of:

Years Ended December 31,		2020		2019
(Thousands)				
Beginning Balance	$	21,545	$	25,660
Reduction for tax positions related to prior years		(2,882)		(4,115)
Ending Balance	**$**	**18,663**	**$**	**21,545**

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, 2020 or 2019.

Note 7. Non-current Debt

Long-term debt as of December 31, 2020 and 2019 consisted of:

As of December 31,	2020			2019	
(Thousands)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
First mortgage bonds (a)	2021-2045	$ 1,100,000	1.87%-5.68%	$ 1,050,000	3.07%-5.68%
Senior unsecured notes	2025-2037	140,000	5.375%-6.40%	140,000	5.375%-6.40%
Chester: Promissory and Senior Notes (b)		—		993	7.05%-10.48%
Unamortized debt issuance costs and discount		(4,485)		(4,845)	
Total Debt		**1,235,515**		**1,186,148**	
Less: debt due within one year, included in current liabilities		149,549		513	
Total Non-current Debt		**$ 1,085,966**		**$ 1,185,635**	

(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.

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%.

On December 15, 2020, CMP issued $50 million aggregate principal amount of first mortgage bonds maturing in 2030 at an interest rate of 1.87%.

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

	2021	2022	2023	2024	2025	Total
(Thousands)						
	$ 149,549	$ 125,000	$ —	$ —	$ 80,000	$ 354,549

We have no debt covenant requirements related to the maintenance of financial ratios in our long-term debt agreements at December 31, 2020 and 2019.

Note 8. Bank Loans and Other Borrowings

CMP had $72.9 million of notes payable at December 31, 2020 and $0.7 million at December 31, 2019. 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 $42.1 million outstanding under this agreement at December 31, 2020 and no debt outstanding under this agreement at December 31, 2019.

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 $30.8 million outstanding under this agreement at December 31, 2020 and $0.7 million outstanding at December 31, 2019.

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”)) executed a new credit facility with an aggregate limit of $2.5 billion and a termination date of June 29, 2023. Effective on June 29, 2019, the termination date for the AGR Credit Facilit was extended to June 29, 2024. 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 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. Effective on June 29, 2020, the AGR Credit Facility was amended to reduce AGR’s maximum sublimit to $1.5 billion and to establish minimum sublimits of $400 million for NYSEG, $250 million for RG&E, $150 million for UI, $100 million for CMP, $40 million for CNG and SCG, and $20 million for BGC. Under the AGR Credit Facility, each of the borrowers are charged an annual facility fee that is dependent on their credit rating. The facility fees range from 10.0 to 17.5 basis points. CMP had not borrowed under this agreement as of both December 31, 2020 and 2019.

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 0.38 to 1.00 at December 31, 2020. We are not in default as of December 31, 2020.

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, 2020 and 2019, our redeemable preferred stock was:

				Amount (Thousands)	
Series	**Par Value per Share**	**Redemption Price per Share**	**Shares Authorized and Outstanding(1)**	**2020**	**2019**
CMP, 6% Non-callable	$ 100	$ —	5,713	$ 571	$ 571
Total				**$ 571**	**$ 571**

(1) At December 31, 2020 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 63 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 Years Ended December 31,	2020	2019
(Thousands)		
Lease cost		
Finance lease cost		
Amortization of right-of-use assets	$ 540	$ 540
Interest on lease liabilities	190	405
Total finance lease cost	730	945
Operating lease cost	1,750	1,749
Short-term lease cost	60	3,706
Variable lease cost	62	113
Total lease cost	**$ 2,602**	**$ 6,513**

Balance sheet and other information for the years ended December 31, 2020 and 2019 was as follows:

As of December 31,	2020	2019
(Thousands, except lease term and discount rate)		
Operating Leases		
Operating lease right-of-use assets	$ 15,549	$ 16,672
Operating lease liabilities, current	1,146	753
Operating lease liabilities, long-term	15,204	16,306
Total operating lease liabilities	$ 16,350	$ 17,059
Finance Leases		
Other assets	$ 4,400	$ 4,941
Other current liabilities	267	890
Other non-current liabilities	(13)	290
Total finance lease liabilities	$ 254	$ 1,180
Weighted-average Remaining Lease Term (years)		
Finance leases	0.25	1.25
Operating leases	19.76	20.20
Weighted-average Discount Rate		
Finance leases	27.44 %	27.44 %
Operating leases	4.00 %	3.97 %

For the years ended December 31, 2020 and 2019, supplemental cash flow information related to leases was as follows:

For the Years Ended December 31,	2020	2019
(Thousands)		
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 1,480	$ 1,349
Operating cash flows from finance leases	$ 190	$ 405
Financing cash flows from finance leases	$ 925	$ 851
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases	$ 76	$ 1,091

As of December 31, 2020, maturities of lease liabilities were as follows:

	Finance Leases	Operating Leases
(Thousands)		
Year ending December 31,		
2021	$ 260	$ 1,718
2022	—	1,151
2023	—	1,135
2024	—	1,151
2025	—	1,165
Thereafter	—	18,712
Total lease payments	**260**	**25,032**
Less: imputed interest	(6)	(8,682)
Total	**$ 254**	**$ 16,350**

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.

Note 11. Commitments and Contingent Liabilities

Power purchase contracts including non-utility generator

We recognized expense of approximately $19.3 million for NUG power in 2020 and $17.2 million in 2019.

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 seven waste sites. The seven sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the seven 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 seven sites at December 31, 2020.

We have recorded an estimated liability of $2.3 million at December 31, 2020, 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 11 total sites ranges from $2.6 million to $8.8 million as of December 31, 2020. 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 $1.1 million at December 31, 2020. 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, 2020 and 2019. 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, 2020 and December 31, 2019, and are included in current liabilities.

The effect of hedging instruments on OCI and income was:

Years 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)				
2020				
Interest rate contracts	$ —	Interest expense	$ (181)	$ 46,148
Commodity contracts: Other	(358)	Other operating expenses	(341)	$ 443,678
Total	**$ (358)**		**$ (522)**	
2019				
Interest rate contracts	$ —	Interest expense	$ (957)	$ 51,433
Commodity contracts: Other	95	Other operating expenses	(283)	$ 399,447
Total	**$ 95**		**$ (1,240)**	

The amount in AOCI related to previously settled interest rate hedging contracts at December 31 is a net loss of $2.5 million for 2020 and $2.7 million for 2019. For the year ended December 31, 2020, we recorded $0.2 million in net derivative losses related to discontinued cash flow hedges. We will amortize approximately $0.2 million of discontinued cash flow hedges in 2021.

At December 31, 2020, $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, 2020			
2021	—	—	675,200
As of December 31, 2019			
2020	—	—	590,800

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

The estimated fair value of debt amounted to $1,548 million and $1,383 million as of December 31, 2020 and 2019, 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)				
2020				
Liabilities				
Derivatives	$ (137)	$ —	$ —	$ (137)
Total	**$ (137)**	**$ —**	**$ —**	**$ (137)**
2019				
Assets				
Non-current investments available for sale	$ 63	$ 63	$ —	$ —
Total	**$ 63**	**$ 63**	$ —	$ —
Liabilities				
Derivatives	$ (120)	$ —	$ —	$ (120)
Total	**$ (120)**	**$ —**	**$ —**	**$ (120)**

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2020 and 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.

<u>Valuation techniques</u>: We measure the fair value of our non-current 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, 2020 and 2019 consisted of:

Years Ended December 31,	**2020**	**2019**
(Thousands)		
Beginning balance	$ (120)	$ (498)
Total (losses) gains (realized/unrealized)		
Included in earnings	341	283
Included in other comprehensive income	(358)	95
Ending balance	**$ (137)**	**$ (120)**

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, 2020 and 2019 consisted of:

(Thousands)	Balance December 31, 2018	Adoption of new accounting standard	2019 Change	Balance December 31, 2019	2020 Change	Balance December 31, 2020
Amortization of pension cost for non-qualified plans, net of income tax expense of $607 for 2020 (a)	$ (1,791)	$ —	$ —	$ (1,791)	$ (188)	$ (1,979)
Unrealized (loss) gain on derivatives qualified as hedges:						
Unrealized (loss) gain during period on derivatives qualified as hedges, net of income tax expense (benefit) of $24 for 2019 and ($101) for 2020			71		(257)	
Reclassification adjustment for loss included in net income, net of income tax expense of $72 for 2019 and $96 for 2020		(761)	211		245	
Reclassification adjustment for loss on settled cash flow treasury hedges, net of income tax expense of $243 for 2019 and $51 for 2020			714		130	
Net unrealized (loss) gain on derivatives qualified as hedges	(2,167)	(761)	996	(1,932)	118	(1,814)
Accumulated Other Comprehensive Loss	**$ (3,958)**	**$ (761)**	**$ 996**	**$ (3,723)**	**$ (70)**	**$ (3,793)**

(a) $607 tax expense in 2020 includes $490 adjustment related to prior periods.

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 non-contributory 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 $4.5 million for 2020 and $3.7 million for 2019.

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.

Non-Qualified Retirement Benefit Plans

We also sponsor various unfunded non-qualified pension plans for certain current employees, former employees and former directors. The total liability for these plans, which is included in Other non-current liabilities on our balance sheets, was $1.7 million and $2.1 million at December 31, 2020 and 2019, respectively.

Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2020 and 2019 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2020**	**2019**	**2020**	**2019**
(Thousands)				
Change in benefit obligation				
Benefit obligation as of January 1,	**$ 441,533**	**$ 401,698**	**$ 102,653**	**$ 99,658**
Service cost	8,005	7,143	571	498
Interest cost	12,665	15,421	2,912	3,783
Actuarial loss	26,842	43,011	8,536	5,243
Benefits paid	(26,339)	(25,740)	(6,500)	(6,529)
Benefit obligation as of December 31,	**$ 462,706**	**$ 441,533**	**$ 108,172**	**$ 102,653**
Change in plan assets				
Fair value of plan assets at January 1,	**$ 319,167**	**$ 277,626**	**$ 33,287**	**$ 31,447**
Actual return on plan assets	42,082	47,281	4,008	4,978
Employer contributions	20,000	20,000	3,670	3,391
Benefits paid	(26,339)	(25,740)	(6,500)	(6,529)
Fair value of plan assets at December 31,	**$ 354,910**	**$ 319,167**	**$ 34,465**	**$ 33,287**
Funded status at December 31,	**$ (107,796)**	**$ (122,366)**	**$ (73,707)**	**$ (69,366)**

During 2020, the pension benefit obligation had an actuarial loss of $26.8 million, primarily due to a $22.4 million loss from decreases in discount rates. There were no significant plan design changes in 2020. There were no significant gains and losses relating to the postretirement benefit obligations.

During 2019, the pension benefit obligation had an actuarial loss of $43.0 million, primarily due to a $54.1 million loss from decreases in discount rates. There were no significant plan design changes in 2019. There were no significant gains and losses relating to the postretirement benefit obligations.

Amounts recognized as of December 31, 2020 and 2019 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	2020	2019	2020	2019
(Thousands)				
Non-current liabilities	$ (107,796)	$ (122,366)	$ (73,707)	$ (69,366)

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, 2020 and 2019 consisted of:

	Pension Benefits		Postretirement Benefits	
Years Ended December 31,	2020	2019	2020	2019
(Thousands)				
Net loss	$ 167,453	$ 176,501	$ 37,622	$ 33,344
Prior service cost (credit)	$ —	$ —	$ (2,650)	$ (4,663)

Our accumulated benefit obligation (ABO) for all qualified defined benefit pension plans was $426.8 million and $406.0 million as of December 31, 2020 and 2019. Our postretirement benefits were partially funded at December 31, 2020 and 2019.

The projected benefit obligation (PBO) and ABO exceeded the fair value of pension plan assets for our qualified plans as of December 31, 2020 and 2019. 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,	2020	2019
(Thousands)		
Projected benefit obligation	$462,706	$441,533
Accumulated benefit obligation	$426,816	$405,994
Fair value of plan assets	$354,910	$319,167

As of December 31, 2020 and 2019, the accumulated postretirement benefits obligation for all the qualified plans exceeded the fair value of plan assets.

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, 2020 and 2019 consisted of:

	Pension Benefits		Postretirement Benefits	
For the years ended December 31,	2020	2019	2020	2019
(Thousands)				
Net Periodic Benefit Cost:				
Service cost	$8,005	$7,143	$571	$498
Interest cost	12,665	15,421	2,912	3,783
Expected return on plan assets	(23,035)	(21,875)	(1,979)	(1,868)
Amortization of prior service cost (benefit)	—	—	(2,013)	(2,013)
Amortization of net loss	16,843	15,531	2,230	2,520
Net Periodic Benefit Cost	**$14,478**	**$16,220**	**$1,721**	**$2,920**

Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities:				
Net loss (gain)	$ 7,796	$ 17,604	$ 6,507	$ 2,133
Amortization of net loss	(16,843)	(15,531)	(2,230)	(2,520)
Amortization of prior service (cost) benefit	—	—	2,013	2,013
Total Other Changes	**(9,047)**	**2,073**	**6,290**	**1,626**
Total Recognized	**$ 5,431**	**$ 18,293**	**$ 8,011**	**$ 4,546**

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.

The weighted-average assumptions used to determine benefit obligations as of December 31, 2020 and 2019 consisted of:

	Pension Benefits		**Postretirement Benefits**	
	2020	**2019**	**2020**	**2019**
Discount rate	2.56%	2.93%	2.29%	2.93%
Rate of compensation increase	Age-Related Rates / 3.50% union	Age-Related Rates	0.035	Age-Related Rates
Interest crediting rate	2.00% non-union/ 4.50% union	2.00%	N/A	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 non-callable 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, 2020 and 2019 consisted of:

	Pension Benefits		**Postretirement Benefits**	
Years Ended December 31,	**2020**	**2019**	**2020**	**2019**
Discount rate	2.93 %	3.93 %	2.93 %	3.93 %
Expected long-term return on plan assets	7.30 %	7.30 %	—	—
Expected long-term return on plan assets - non-taxable 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)	Age-Related Rates	3.70%-4.20%	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. 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, 2020 and 2019 consisted of:

As of December 31,	2020	2019
Health care cost trend rate assumed for next year	6.75%/7.50%	6.75%/7.50%
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	2029/2027

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 and $3.2 million, respectively, to our pension and other postretirement benefit plans during 2021.

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, 2020 consisted of:

(Thousands)		Pension Benefits		Postretirement Benefits		Medicare Act Subsidy Receipts
2021	$	19,036	$	6,628	$	—
2022	$	19,957	$	6,560	$	—
2023	$	20,785	$	6,471	$	—
2024	$	21,476	$	6,416	$	—
2025	$	22,657	$	6,371	$	—
2026 - 2030	$	121,572	$	30,453	$	1

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 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, 2020, consisted of:

As of December 31, 2020		**Fair Value Measurements**		
(Thousands)	**Total**	**Level 1**	**Level 2**	**Level 3**
Asset Category				
Cash and cash equivalents	$ 15,726	$ 12	$ 15,714	$ —
U.S. government securities	20,317	20,311	6	—
Common stocks	12,411	12,411	—	—
Registered investment companies	34,487	34,487	—	—
Corporate bonds	81,500	—	81,500	—
Preferred stocks	113	113	—	—
Common collective trusts	111,139	—	111,139	—
Other, principally annuity, fixed income	7,834	728	7,106	—
	$ 283,527	**$ 68,062**	**$ 215,465**	**$ —**
Other investments measured at net asset value	71,383			
Total	**$ 354,910**			

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**			

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 values of other postretirement benefits plan assets, by asset category, as of December 31, 2020, consisted of:

As of December 31, 2020		Fair Value Measurements		
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 1,125	$ —	$ 1,125	$ —
U.S. government securities	101	101	—	—
Common stocks	62	62	—	—
Registered investment companies	31,863	31,863	—	—
Preferred stocks	405	—	405	—
Corporate bonds	1	1	—	—
Common collective trusts	550	—	550	—
Other, principally annuity, fixed income	3	4	(1)	—
	$ 34,110	**$ 32,031**	**$ 2,079**	**$ —**
Other investments measured at net asset value	$ 355			
Total	**$ 34,465**			

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	$ 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**	**$ —**

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, 2020 and 2019.

Note 17. Other Income and Other Deductions

Other Income and Other Deductions for the years ended December 31, 2020 and 2019 consisted of:

Years Ended December 31,		2020		2019
(Thousands)				
Gain on sale of property	$	559	$	557
Interest and dividends income		251		720
Allowance for funds used during construction		11,532		9,030
Carrying costs on regulatory assets		3,688		975
Equity earnings		53		105
Miscellaneous		286		708
Total other income	**$**	**16,369**	**$**	**12,095**
Pension non-service components	$	(7,158)	$	(10,946)
Miscellaneous		(8,741)		(4,292)
Total other deductions	**$**	**(15,899)**	**$**	**(15,238)**

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 $46.3 million and $43.1 million for 2020 and 2019, respectively. Cost for services includes amounts capitalized in utility plant, which was approximately $7.8 million in 2020 and $6.2 million in 2019. The remainder was primarily recorded as operations and maintenance expense. The charge for services provided by CMP to AGR and its subsidiaries were approximately $6.0 million for 2020 and $5.7 million for 2019. 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 $8.1 million at December 31, 2020 is mostly payable to Avangrid Service Company and the balance of $8.3 million at December 31, 2019 is mostly payable to Avangrid Service Company and The United Illuminating Company.

The balance in accounts receivable from affiliates of $1.4 million at December 31, 2020 and $0.9 million at December 31, 2019 is from various companies.

The balance in notes receivable from affiliates of $23.0 million at December 31, 2019 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, 2021, which is the date these financial statements were available to be issued.

In 2018, the New England Clean Energy Connect, or NECEC, transmission project, proposed in a joint bid by CMP and Hydro-Québec, was selected by the Massachusetts electric distribution utilities and the Massachusetts Department of Energy Resources in the Commonwealth of

Massachusetts' 83D clean energy Request for Proposal. The NECEC transmission project includes a 145-mile transmission line linking the electrical grids in Québec, Canada and New England.

The NECEC project required, among multiple other federal, state and local permits, a Certificate of Public Convenience and Necessity, or CPCN, from the MPUC. On May 3, 2019, the MPUC issued an Order granting the CPCN (CPCN Order) for the NECEC project and approving a stipulation (Stipulation) dated February 21, 2019, which among other things provided for the transfer of the NECEC from CMP to NECEC Transmission LLC, a new subsidiary of Avangrid Networks, Inc. On January 4, 2021, CMP transferred the NECEC project to NECEC Transmission LLC pursuant to the terms of a transfer agreement dated November 3, 2020, and in accordance with the CPCN Order and Stipulation. At that time, NECEC Transmission LLC reimbursed to CMP approximately $101 million in construction and other costs CMP had incurred in connection with the NECEC through the date of transfer.

CONNECTICUT NATURAL GAS CORPORATION

AUDITED FINANCIAL STATEMENTS

AS OF AND FOR THE YEARS ENDED

DECEMBER 31, 2020 AND 2019

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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, 2020 and 2019, and the related statements of income, comprehensive 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, 2020 and 2019, 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 9, 2021

CONNECTICUT NATURAL GAS CORPORATION
STATEMENTS OF INCOME

Years Ended December 31,	**2020**	**2019**
(Thousands)		
Operating Revenue	$ 368,550	$ 403,334
Operating Expenses		
Natural gas purchased	143,289	180,139
Operation and maintenance	102,112	99,588
Depreciation and amortization	43,067	42,540
Taxes other than income taxes	29,063	30,233
Total Operating Expenses	317,531	352,500
Operating Income (Loss)	51,019	50,834
Other Income and (Expense), net	(3,282)	(3,213)
Interest Expense, net	9,255	9,382
Income Before Income Tax	38,482	38,239
Income Tax	11,030	12,164
Net Income	$ 27,452	$ 26,075
Less: Preferred Stock Dividends of Subsidiary, Noncontrolling Interests	27	27
Net Income attributable to Connecticut Natural Gas Corporation	$ 27,425	$ 26,048

CONNECTICUT NATURAL GAS CORPORATION
STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31,	**2020**	**2019**
(Thousands)		
Net Income	$ 27,452	$ 26,075
Other Comprehensive Income, net of income tax		
Amortization of pension cost for non-qualified plans, net of tax expense	(332)	-
Total Other Comprehensive Income, net of income tax	27,120	26,075
Comprehensive Income		
Less: Preferred Stock Dividends of Subidiary, Noncontrolling Interest	27	27
Comprehensive Income Attributable to Connecticut Natural Gas Corporation	$ 27,093	$ 26,048

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

CONNECTICUT NATURAL GAS CORPORATION
STATEMENT OF CASH FLOWS

Years Ended December 31,	**2020**	**2019**
(Thousands)		
Cash Flows From Operating Activities		
Net Income	$ 27,452	$ 26,075
Adjustments to reconcile net income		
Depreciation and amortization	43,167	42,638
Deferred income taxes	14,839	22,078
Uncollectible expense	6,959	9,221
Pension expense	8,512	7,776
Regulatory assets/liabilities amortization	4,342	2,374
Regulatory assets/liabiities carrying cost	339	66
Other non-cash items, net	2,946	1,204
Changes in:		
Accounts receivable and unbilled revenues, net	(3,786)	(13,272)
Natural gas in storage	3,751	810
Accounts payable and accrued liabilities	(9,388)	(5,491)
Interest accrued	12	940
Taxes accrued/refundable, net	1,758	(351)
Accrued pension and other post-retirement	(15,518)	(8,322)
Regulatory assets/liabilities	(18,457)	(3,434)
Other assets	59	(4,044)
Other liabilities	1,270	(978)
Total Adjustments	40,805	51,215
Net Cash provided by Operating Activities	68,257	77,290
Cash Flows from Investing Activities		
Plant expenditures including AFUDC debt	(52,986)	(51,187)
Notes receivable from affiliates	7,250	(12,300)
Net Cash used in Investing Activities	(45,736)	(63,487)
Cash Flows from Financing Activities		
Issuance of long-term debt	30,000	50,000
Equity infusion from parent	40,000	43,000
Return of capital	(12,000)	-
Payment of common stock dividend	(80,000)	-
Payment of preferred stock dividend	(27)	(27)
Notes payable to affiliates	(58)	(108,432)
Other	(181)	(287)
Net Cash used in Financing Activities	(22,266)	(15,746)
Cash, Restricted Cash, and Cash Equivalents:		
Net change for the period	255	(1,943)
Balance at beginning of period	576	2,519
Balance at end of period	$ 831	$ 576
Cash paid during the period for:		
Interest (net of amount capitalized)	$ 8,270	$ 7,706
Non-cash investing activity:		
Plant expenditures included in ending accounts payable	$ 7,878	$ 6,933

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

CONNECTICUT NATURAL GAS CORPORATION
BALANCE SHEETS
ASSETS

As of December 31,		**2020**		**2019**
(Thousands)				
Assets				
Current Assets				
Unrestricted cash and temporary cash investments	$	831	$	513
Notes receivable from affiliates		5,050		12,300
Accounts receivable and unbilled revenues, net		88,797		85,902
Accounts receivable from affiliates		2,419		9,087
Regulatory assets		29,845		22,079
Gas in storage		23,393		27,144
Materials and supplies		1,574		1,463
Other tax receivables		2,707		4,644
Prepayments and other current assets		1,130		1,243
Total Current Assets		155,746		164,375
Other Investments		960		1,051
Net Property, Plant and Equipment		754,705		729,061
Operating lease right of use assets		475		935
Regulatory Assets		112,275		120,531
Deferred Charges and Other Assets				
Goodwill		79,341		79,341
Other		203		323
Total Deferred Charges and Other Assets		79,544		79,664
Total Assets	$	1,103,705	$	1,095,617

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

CONNECTICUT NATURAL GAS CORPORATION
BALANCE SHEETS
LIABILITIES AND CAPITALIZATION

As of December 31,		**2020**		**2019**
(Thousands)				
Liabilities				
Current Liabilities				
Accounts payable and accrued liabilities	$	62,658	$	64,873
Accounts payable to affiliates		6,242		12,873
Other current liabilities		4,885		4,482
Regulatory liabilities		10,195		12,408
Interest accrued		2,597		2,585
Taxes accrued		5,534		5,713
Operating lease liabilities		419		419
Total Current Liabilities		92,530		103,353
Deferred Income Taxes		35,459		20,099
Regulatory Liabilities		252,514		246,850
Other Noncurrent Liabilities				
Pension and other postretirement		97,749		105,491
Asset retirement obligations		6,499		6,576
Operating lease liabilities		253		817
Other		3,101		1,795
Total Other Noncurrent Liabilities		107,602		114,679
Capitalization				
Long-term debt, net of unamortized premium		188,971		159,100
Preferred Stock, not subject to mandatory redemption		340		340
Common Stock Equity				
Common stock		33,233		33,233
Paid-in capital		386,302		358,302
Accumulated other comprehensive income (loss)		(332)		-
Retained earnings		7,086		59,661
Net Common Stock Equity		426,289		451,196
Total Capitalization		615,600		610,636
Total Liabilities and Capitalization	$	1,103,705	$	1,095,617

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

(Thousands, except share amounts)	Common Stock Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
As of December 31, 2019	10,634,436	$ 33,233	$ 358,302	$ 59,661	$ -	$ 451,196
Net income				27,452		27,452
Payment of common stock dividend				(80,000)		(80,000)
Payment of preferred stock dividend				(27)		(27)
Return of capital			(12,000)			(12,000)
Equity infusion from parent			40,000			40,000
Other comprehensive income (loss), net of tax expense of $123					(332)	(332)
As of December 31, 2020	10,634,436	$ 33,233	$ 386,302	$ 7,086	$ (332)	$ 426,289

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

NOTES TO FINANCIAL STATEMENTS

(A) BACKGROUND AND 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 (UIL Holdings). 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. (Avangrid), 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.

Certain immaterial amounts reported on the Balance Sheet in previous periods have been reclassified to conform to the current presentation.

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

Revenues

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 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, 2020	Year Ended December 31, 2019
Regulated operations – natural gas	$ 354,341	$ 396,653
Other (a)	662	2,479
Revenue from contracts with customers	**355,003**	**399,132**
Leasing revenue	101	92
Alternative revenue programs	13,446	4,110
Total operating revenues	**$ 368,550**	**$ 403,334**

(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, 2020 and 2019 included the following:

	Remaining Period	December 31, 2020	December 31, 2019
		(In Thousands)	
Regulatory Assets:			
Pension and other post-retirement benefit plans	(a)	$ 108,222	$ 115,025
Hardship programs	(b)	3,075	8,868
Unfunded future income taxes	(c)	3,958	3,958
Deferred purchased gas	(f)	11,973	10,074
Decoupling	(g)	8,622	-
Other	(d)	6,270	4,685
Total regulatory assets		142,120	142,610
Less current portion of regulatory assets		29,845	22,079
Regulatory Assets, Net		$ 112,275	$ 120,531
Regulatory Liabilities:			
Pension and other postretirement benefit plans	(a)	$ 5,681	$ 6,011
Asset removal costs	(d)	213,364	200,019
Asset retirement obligation	(e)	10,266	9,692
Rate credits	1 to 7 years	8,750	10,000
Tax reform	1 to 30 years	13,810	18,014
Non-firm margin sharing credits	0 to 2 years	7,194	7,509
Decoupling	(g)	-	5,745
Other	(d)	3,644	2,268
Total regulatory liabilities		262,709	259,258
Less current portion of regulatory liabilities		10,195	12,408
Regulatory Liabilities, Net		$ 252,514	$ 246,850

(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 asset is not currently earning a return. The current portion of $5.2 million will be collected from customers in 2021.

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 2020 and 2019 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, 2020 and 2019 were comprised as follows:

	2020	2019
	(In Thousands)	
Gas distribution plant	$ 909,160	$ 883,195
Software	34,575	34,259
Land	1,618	1,618
Building and improvements	35,298	34,917
Other plant	102,847	100,832
Total property, plant & equipment	1,083,498	1,054,821
Less accumulated depreciation	354,919	339,601
	728,579	715,219
Construction work in progress	26,126	13,841
Net property, plant & equipment	$ 754,705	$ 729,061

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 2020 and 2019 were 1.64% and 2.66%, respectively. The portion of the allowance applicable to equity funds was immaterial for both 2020 and 2019.

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 2020 and 2019 were approximately $43.1 million and $42.5 million, respectively, or 4.03% and 4.13% 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, 2020, 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 did not have any restricted cash balances as of December 31, 2020 and had $0.1 million of restricted cash at December 31, 2019.

Accounts receivable and unbilled revenues

Accounts receivable at December 31, 2020 and 2019 include unbilled revenues of $27.2 million and $29.3 million, respectively and are shown net of an allowance for doubtful accounts of $2.3 million and $1.8 million for 2020 and 2019, respectively. Accounts receivable do not bear interest, although late fees may be assessed. Due to COVID-19, CNG has suspended the late payment charges. Once reinstated, a late payment charge will be assessed on the outstanding late balance at the time of reinstatement. Also due to COVID-19, PURA required CNG to offer to customers, through early February 2021, a 24-month repayment plan.

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 2020 and 2019 is as follows:

	2020	2019
	(In Thousands)	
Balance as of January 1	$ 6,576	$ 6,637
Liabilities settled during the year	(422)	(409)
Accretion	345	348
Balance as of December 31	$ 6,499	$ 6,576

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

<u>Measurement of credit losses on financial instruments, amendments and updates</u>

The FASB issued an accounting standards update in June 2016 that requires more timely recording of credit losses on loans and other financial instruments (ASC 326). 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 collectability 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 ASC 326 to clarify transition and scope requirements, make narrow-scope codification improvements, including in March 2020, and corrections and provide targeted transition relief. CNG adopted the amendments effective January 1, 2020, including the narrow-scope improvements issued in March 2020 with no effect to its results of operations, financial position, cash flows and disclosures.

Simplifying the test for goodwill impairment

In January 2017, the FASB issued amendments to simplify the test for goodwill impairment, which is 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. CNG adopted the amendments effective January 1, 2020, with no material effect to its consolidated results of operations, financial position, cash flows and disclosures. As required, CNG is applying the amendments on a prospective basis.

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. CNG adopted the amendments effective January 1, 2020, with no material effect to its disclosures. Certain amendments are to be applied prospectively, and all others are to be applied retrospectively.

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. The amendments change annual disclosures requirements, including removal of disclosures that are no longer considered cost beneficial, adding certain new relevant disclosures and clarifying specific requirements of disclosures concerning information for defined benefit pension plans. CNG adopted the amendments effective January 1, 2020, and they will not materially affect the disclosures for the fiscal year ending December 31, 2020. As required, the application will be on a retrospective basis. Certain immaterial changes were made to 2019 disclosures to comply with the newly adopted amendments.

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. CNG adopted the amendments effective January 1, 2020, with no material effect to its results of operations, financial position, cash flows and disclosures. As required, CNG retrospectively applied the amendments to the date of our initial application of ASC 606.

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.

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 in equity method investments 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.

Facilitation of the effects of reference rate reform on financial reporting

In March 2020, the FASB issued amendments and created ASC 848 to provide temporary optional guidance to entities to ease the potential burden in accounting for, or recognizing the effects of, reference rate reform on financial reporting. The amendments respond to concerns about structural risks of interbank offered rates, and particularly, the risk of cessation of the London Interbank Offered Rate (LIBOR). The guidance is elective and applies to all entities, subject to meeting certain criteria, that have contracts, hedging relationships, and other transactions that reference LIBOR or another reference rate expected to be discontinued due to reference rate reform, around the end of 2021. The guidance applies to contracts that have modified terms that affect, or have the potential to affect, the amount or timing of contractual cash flows resulting from the discontinuance of the reference rate reform. The amendments are effective for all entities as of March 12, 2020, through December 31, 2022, although the FASB has indicated it will monitor developments in the marketplace and consider whether developments warrant an extension.

In January 2021, the FASB issued amendments to clarify the scope of ASC 848 and respond to questions from stakeholders about whether ASC 848 can be applied to derivative instruments that do not reference a rate that is expected to be discontinued but that use an interest rate for margining, discounting, or contract price alignment that is modified because of reference rate reform. The modification, commonly referred to as the "discounting transition," may have accounting implications, raising concerns about the need to reassess previous accounting determinations related to those derivatives and about the possible hedge accounting consequences of the discounting transition. The amendments clarify that certain optional expedients and exceptions in ASC 848 for contract modifications and hedge accounting apply to derivatives that are affected by the discounting transition, capture the incremental consequences of the scope clarification and tailor the existing guidance to derivative instruments affected by the discounting transition. The amendments are effective immediately, and may be elected retrospectively to eligible modifications as of any date from the beginning of the interim period that includes March 12, 2020, or prospectively to new modifications made on or after any date within the interim period that includes January 7, 2021.

CNG expects the adoption of reference rate reform and the subsequent scope clarification will not materially affect its consolidated results of operations, financial position and cash flows.

Use of Estimates and Assumptions

The preparation of CNG's 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 credit losses and unbilled revenues; (2) asset impairments, including goodwill; (3) investments in equity instruments; (4) depreciable lives of assets; (5) income tax valuation allowances; (6) uncertain tax positions; (7) reserves for professional, workers' compensation and comprehensive general insurance liability risks; (8) contingency and litigation reserves; (9) fair value measurements; (10) earnings sharing mechanisms; (11) environmental remediation liabilities; (12) AROs; (13) pension and other postretirement employee benefits and (14) noncontrolling interest balances. Future events and their effects cannot be predicted with certainty; accordingly, the accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of the financial statements will change as new events occur, as more experience is acquired, as additional information is obtained and as the operating environment changes. CNG evaluates and updates the assumptions and estimates on an ongoing basis and may employ outside specialists to assist in evaluations, as necessary. Actual results could differ from those estimates.

CNG continues to utilize information reasonably available; however, the business and economic uncertainty resulting from COVID-19 has made such estimates and assumptions more difficult to assess and calculate. Affected estimates include, but are not limited to, evaluations of certain long-lived assets and goodwill for impairment, expected credit losses and potential regulatory deferral or recovery of certain costs. While CNG has not yet had material effects of COVID-19 on its financial results, actual results could differ from those estimates, which could result in material effects to the financial statements in future reporting periods.

B) CAPITALIZATION

Common Stock

CNG had 10,634,436 shares of its common stock, $3.125 par value, outstanding as of December 31, 2020 and 2019.

In December 2020 and October 2019, CNG received equity infusions from CTG of $40 million and $43 million, respectively, 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, 2020, there were 108,706 shares issued and outstanding with a value of approximately $0.3 million.

Long-Term Debt

As of December 31, (In Thousands)	Maturity Dates	2020 Balances	2020 Interest Rates	2019 Balances	2019 Interest Rates
Senior unsecured debt	2028-2049	$ 190,000	2.02%-6.66%	$ 160,000	4.30%-6.66%
Unamortized debt (costs) premium, net		(1,029)		(900)	
Total Debt		**188,971**		**159,100**	
Less: debt due within one year, included in current liabilities		-		-	
Total Non-current Debt		**$ 188,971**		**$ 159,100**	

The estimated fair value of debt amounted to $257.4 million and $202.8 million as of December 31, 2020 and 2019, 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 December 15, 2020, CNG issued $30 million of notes with a maturity of 2030 and interest rate of 2.02%. 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:

(In Thousands)	2021	2022	2023	2024	2025 & Thereafter	Total
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, 2020, CNG's debt ratio was 31%.

(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 an 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 2020 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, 2020 and 2019.

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, 2020 and 2019.

On June 29, 2020, Avangrid, Inc. and its subsidiaries, including CNG, amended its revolving credit facility agreement in place with several lenders (the 2020 Avangrid Credit Facility) that provides for maximum borrowings up to $2.5 billion in the aggregate. The 2020 Avangrid Credit Facility replaces and supersedes the prior revolving credit facility entered into by Avangrid, Inc. and its subsidiaries on June 29, 2018, which provided maximum borrowings of up to $2.5 billion in the aggregate.

Under the 2020 Avangrid Credit Facility, CNG has a maximum sublimit of $150 million. Additionally, under the 2020 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 15 to 30 basis points. The maturity date for the 2020 Avangrid Credit Facility is June 29, 2024. As of December 31, 2020 and 2019, CNG did not have any outstanding borrowings under the 2020 Avangrid Credit Facility.

(E) INCOME TAXES

	Year Ended December 31, 2020	Year Ended December 31, 2019
(In Thousands)		
Income tax expense consists of:		
Income tax provisions (benefits):		
Current		
Federal	$ (531)	$ (8,799)
State	(3,278)	(1,115)
Total current	(3,809)	(9,914)
Deferred		
Federal	8,772	23,625
State	6,067	(1,547)
Total deferred	14,839	22,078
Total income tax expense	$ 11,030	$ 12,164

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:

(In Thousands)	Year Ended December 31, 2020	Year Ended December 31, 2019
Book income before income taxes	$ 38,482	$ 38,239
Computed tax at federal statutory rate	$ 8,081	$ 8,030
Increases (reductions) resulting from:		
Tax Return related adjustments	203	3,304
State income taxes, net of federal income tax	2,204	(2,103)
Other items, net	542	2,933
Total income tax expense	$ 11,030	$ 12,164
Effective income tax rates	28.7%	31.8%

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, 2020:

Jurisdiction	*Tax years*
Federal	2014 - 2020
Connecticut	2015 - 2020

The following table summarizes CNG's deferred tax assets and liabilities as of December 31, 2020 and 2019:

(In Thousands)	**2020**	**2019**
CT credit carryforward	$ 5,362	$ 4,438
Valuation Allowance - State Credits	(1,955)	-
Deferred tax liability on 2017 Tax Act remeasurement	3,719	4,850
Property related	(30,971)	(20,760)
Unfunded future income taxes	(1,066)	(1,065)
Goodwill	(4,789)	(4,320)
Pension (net)	(509)	(555)
Other assets (liabilities)	(5,250)	(2,687)
	$ (35,459)	$ (20,099)

As of December 31, 2020, CNG had a net state credit carry forward of $5.4 million and a state net operating loss carry forward of $0.8 million. 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. CNG's state tax credit carry forwards will begin to expire for the 2021 tax year.

Valuation allowances are recorded to reduce deferred tax assets when it is more likely than not that all or a portion of a tax benefit will not be realized. For 2020, CNG has recorded a valuation allowance on its state tax credit carryforwards of $2.0 million.

(F) PENSION AND OTHER POSTRETIREMENT BENEFITS

Defined Benefit Plans (the Plans)

Pension Plans

CNG 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 plans are traditional defined benefit plans or cash balance plans depending on date of hire and 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 are consolidated in one master trust. 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. Networks' primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with risk tolerance. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. Networks' 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 their 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.

CONNECTICUT NATURAL GAS CORPORATION

NOTES TO FINANCIAL STATEMENTS

The following table represents the change in benefit obligation, change in plan assets and the respective funded status of CNG's qualified pension and other postretirement plans as of December 31, 2020 and 2019. Plan assets and obligations have been measured as of December 31, 2020 and 2019.

	Pension Benefits		Other Post-Retirement Benefits	
	Year Ended December 31, 2020	Year Ended December 31, 2019	Year Ended December 31, 2020	Year Ended December 31, 2019
(In Thousands)				
Change in Benefit Obligation:				
Benefit obligation at beginning of year	$ 302,617	$ 269,499	$ 18,848	$ 19,588
Service cost	4,847	4,594	141	152
Interest cost	9,414	10,729	573	768
Actuarial (gain) loss	16,759	30,585	1,199	293
Benefits paid (including expenses)	(12,706)	(12,790)	(1,671)	(1,953)
Benefit obligation at end of year	$ 320,931	$ 302,617	$ 19,090	$ 18,848
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 203,341	$ 175,020	$ 11,499	$ 11,482
Actual return on plan assets	29,052	35,400	1,567	786
Employer contributions	9,050	5,711	1,003	1,184
Benefits paid (including expenses)	(12,706)	(12,790)	(1,671)	(1,953)
Fair value of plan assets at end of year	$ 228,737	$ 203,341	$ 12,398	$ 11,499
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ 92,194	$ 99,276	$ 6,692	$ 7,349
Amounts Recognized in the Consolidated Balance Sheet consist of:				
Non-current liabilities	$ 92,194	$ 99,276	$ 6,692	$ 7,349
Amounts Recognized as a Regulatory Asset (Liability)				
Prior service cost	$ -	$ -	$ 396	$ 597
Net (gain) loss	50,727	51,787	(1,868)	(2,293)
Total recognized as a regulatory asset (liability)	$ 50,727	$ 51,787	$ (1,472)	$ (1,696)
Information on Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:				
Projected benefit obligation	$ 319,796	$ 301,482	N/A	N/A
Accumulated benefit obligation	$ 298,804	$ 277,585	N/A	N/A
Fair value of plan assets	$ 228,737	$ 203,341	N/A	N/A
The following weighted average actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate (Qualified Plans)	2.63%	3.19%	N/A	N/A
Discount rate (Other Post-Retirement Benefits)	N/A	N/A	2.00%	3.19%
Average wage increase	3.20%	3.50%	N/A	N/A
Interest crediting rate	3.17%	3.17%	N/A	N/A
Health care trend rate (current year - pre/post-65)	N/A	N/A	6.50%/7.25%	6.75%/7.50%
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

During 2020, the qualified pension benefit obligation had an actuarial loss of $16.8 million, primarily due to a $23.3 million loss from decreases in discount rates, partially offset by gains due to changes in mortality, demographic and other assumptions. There were no significant plan design changes in 2020. During 2020, the postretirement benefit obligation had an actuarial loss of $1.2 million

During 2019, the pension benefit obligation had an actuarial loss of $30.6 million, primarily due to a $34.1 million loss from decreases in discount rates, partially offset by gains in mortality and demographic assumptions. During 2019, the postretirement benefit obligation had an actuarial gain of $0.3 million.

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, 2020 and 2019 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, 2020	Year Ended December 31, 2019	Year Ended December 31, 2020	Year Ended December 31, 2019
(In Thousands)				
Components of net periodic benefit cost:				
Service cost	$ 4,847	$ 4,594	$ 141	$ 152
Interest cost	9,414	10,729	572	768
Expected return on plan assets	(14,908)	(12,692)	(563)	(562)
Amortization of prior service costs	-	-	201	201
Amortization of actuarial (gain) loss	3,675	3,389	(229)	(262)
Net periodic benefit cost	$ 3,028	$ 6,020	$ 122	$ 297
Other Changes in Plan Assets and Benefit Obligations Recognized as a Regulatory Asset (Liability):				
Net (gain) loss	$ 2,615	$ 7,876	$ 196	$ 69
Amortization of prior service costs	-	-	(201)	(201)
Amortization of actuarial gain (loss)	(3,675)	(3,389)	229	262
Total recognized as regulatory asset (liability)	$ (1,060)	$ 4,487	$ 224	$ 130
Total recognized in net periodic benefit costs and regulatory asset (liability)	$ 1,968	$ 10,507	$ 346	$ 427
The following actuarial weighted average assumptions were used in calculating net periodic benefit cost:				
Discount rate	3.19%	4.09%	4.90%	4.09%
Average wage increase	3.50%	3.50%	N/A	N/A
Return on plan assets	7.40%	7.40%	4.90%	4.90%
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 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.

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. Unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans are amortized over ten years from the time they are incurred as required by the PURA. 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.

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 contributions of approximately $10.5 million in 2021. 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 31,2020 consisted of:

Year	Pension Benefits	Other Post-Retirement Benefits	Medicare Act Subsidy
	(In Thousands)		
2021	$ 12,930	$ 1,757	$ 133
2022	$ 13,225	$ 1,651	$ 139
2023	$ 13,409	$ 1,568	$ 146
2024	$ 13,839	$ 1,483	$ 150
2025	$ 14,222	$ 1,408	$ 156
2026-2030	$ 78,511	$ 6,171	$ 818

The fair values of the Plans' assets as of December 31, 2020 and 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
(In Thousands)				
December 31, 2020				
Pension assets				
Cash and cash equivalents	$ 8	$ 3,899	$ -	$ 3,907
U.S. government securities	13,220	4	-	13,224
Common stocks	7,798	-	-	7,798
Registered investment companies	22,261	-	-	22,261
Corporate bonds	-	52,918	-	52,918
Preferred stocks	73	-	-	73
Common collective trusts	-	85,295	-	85,295
Other, principally annuity, fixed income	475	(158)	-	317
	$ 43,835	$ 141,958	$ -	185,793
Other investments measured at net asset value				42,944
TOTAL				$ 228,737
*Corporate Bonds includes $2.8 million of Non-US Government Bonds				
OPEB assets				
Cash and cash equivalents	$ -	$ 615	$ -	$ 615
U.S. government securities	91	0	-	91
Common stocks	53	-	-	53
Registered investment companies	8,248	-	-	8,248
Corporate bonds	-	363	-	363
Preferred stocks	1	-	-	1
Common collective trusts	-	580	-	580
Other, principally annuity, fixed income	3	2,150	-	2,153
	$ 8,396	$ 3,708	$ -	$ 12,104
Other investments measured at net asset value				294
TOTAL				$ 12,398
*Includes 401H Assets				
December 31, 2019				
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

Valuation Techniques

CNG values its' 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 – at the closing price reported in the active market in which the security is traded.
- Common stocks – 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.
- Preferred stocks – at the closing price reported in the active market in which the individual investment is traded.
- Common collective trusts/Registered investment companies – Level 1: at the closing price reported in the active market in which the individual investment is traded. Level 2 - 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.

CNG values its' 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.
- U.S. government securities – at the closing price reported in the active market in which the security is traded.
- 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.
- Common collective trusts – 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.

Pension and postretirement benefit plan equity securities did not include any Iberdrola common stock as of both December 31, 2020 and 2019.

CNG also sponsors various non-qualified unfunded pension plans for certain current employees, former employees and former directors. The total liability for these plans, which is included in Other current and Other non-current liabilities on the balance sheets, was $1.4 million and $1.2 million at December 31, 2020 and 2019, respectively.

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 2020 and 2019 was $1.6 million, and $1.5 million, respectively.

(G) RELATED PARTY TRANSACTIONS

Inter-company Transactions

In December 2020 and October 2019, CNG received equity infusions 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, 2020, CNG recorded inter-company expenses of $12.1 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, 2020, CNG paid $80 million in dividends to CTG. For the year ended December 31, 2019, CNG did not pay any 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 0.67 years to 4.2 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.

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

	Year Ended	
	December 31, 2020	December 31, 2019
(In Thousands)		
Operating lease cost	$ 1,382	$ 1,859

	As of	
	December 31, 2020	December 31, 2019
(In Thousands)		
Operating Leases		
Operating lease right of use assets	$ 475	$ 935
Operating lease liabilities, current	$ 419	$ 419
Operating lease liabilities, long-term	253	817
Total operating lease liabilities	$ 672	$ 1,236
Weighted-average Remaining Lease Term (years):		
Operating leases	1.27	1.86
Weighted-average Discount Rate:		
Operating leases	1.41%	3.03%

Supplemental cash flow information related to leases was as follows:

	Year Ended	
	December 31, 2020	December 31, 2019
(In Thousands)		
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 468	$ 428

As of December 31, 2020, maturities of lease liabilities were as follows:

	Operating Leases
(In Thousands)	
Year ending December 31,	
2021	$ 584
2022	31
2023	25
2024	43
2025	2
Thereafter	-
Total lease payments	685
Less: imputed interest	13
Total	$ 672

(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, 2020, 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, 2020 and December 31, 2019.

	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, 2020		(In Thousands)		
Noncurrent investments	$ 960	$ -	$ -	$ 960
Total fair value assets, December 31, 2020	$ 960	$ -	$ -	$ 960
December 31, 2019				
Noncurrent investments	$ 1,051	$ -	$ -	$ 1,051
Total fair value assets, December 31, 2019	$ 1,051	$ -	$ -	$ 1,051

(K) SUBSEQUENT EVENTS

CNG has evaluated subsequent events through the date its financial statements were available to be issued, April 9, 2021.

New York State Electric & Gas Corporation

Financial Statements

As of and for the Years Ended December 31, 2020 and 2019

New York State Electric & Gas Corporation

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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, 2020 and 2019, 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, 2020 and 2019, 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, 2021

New York State Electric & Gas Corporation
Statements of Income

Years Ended December 31,	2020	2019
(Thousands)		
Operating Revenues	$ 1,564,241	$ 1,548,367
Operating Expenses		
Electricity purchased	268,829	303,190
Natural gas purchased	81,324	110,833
Operations and maintenance	705,205	648,039
Depreciation and amortization	159,438	145,316
Taxes other than income taxes, net	157,657	150,466
Total Operating Expenses	**1,372,453**	**1,357,844**
Operating Income	**191,788**	**190,523**
Other income	33,664	28,197
Other deductions	(26,365)	(42,157)
Interest expense, net of capitalization	(65,777)	(73,246)
Income Before Income Tax	**133,310**	**103,317**
Income tax expense	3,362	36,015
Net Income	**$ 129,948**	**$ 67,302**

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,	2020	2019
(Thousands)		
Net Income	**$ 129,948**	**$ 67,302**
Other Comprehensive Income (Loss), Net of Tax		
Amortization of pension cost for non-qualified plans, net of income tax	(459)	(124)
Unrealized (loss) gain during the year on derivatives qualifying as cash flow hedges, net of income tax	(92)	139
Reclassification to net income of loss on settled cash flow commodity hedges, net of income tax	85	306
Reclassification to net income of loss on settled cash flow treasury hedges, net of income tax	14	77
Total Other Comprehensive Income (Loss), Net of Tax	**(452)**	**398**
Comprehensive Income	**$ 129,496**	**$ 67,700**

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

New York State Electric & Gas Corporation
Balance Sheets

As of December 31,	2020	2019
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$ 266	$ 1
Accounts receivable and unbilled revenues, net	254,762	265,499
Accounts receivable from affiliates	4,790	1,148
Notes receivable from affiliates	7,150	—
Fuel and natural gas in storage, at average cost	10,181	14,363
Materials and supplies	21,231	18,145
Broker margin accounts	6,521	6,773
Income tax receivable	—	21,939
Prepaid property taxes	38,109	37,214
Other current assets	5,272	5,014
Regulatory assets	98,096	138,162
Total Current Assets	**446,378**	**508,258**
Utility plant, at original cost	6,816,853	6,375,471
Less accumulated depreciation	(2,263,857)	(2,228,040)
Net Utility Plant in Service	**4,552,996**	**4,147,431**
Construction work in progress	531,695	385,134
Total Utility Plant	**5,084,691**	**4,532,565**
Operating lease right-of-use assets	8,896	9,341
Other property and investments	10,447	8,207
Regulatory and Other Assets		
Regulatory assets	867,559	822,285
Other	41,417	51,743
Total Regulatory and Other Assets	**908,976**	**874,028**
Total Assets	**$ 6,459,388**	**$ 5,932,399**

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

New York State Electric & Gas Corporation
Balance Sheets

As of December 31,	2020	2019
(Thousands, except share information)		
Liabilities		
Current Liabilities		
Current portion of long-term debt	$ —	$ 198,439
Notes payable to affiliates	—	71,255
Accounts payable and accrued liabilities	413,454	413,367
Accounts payable to affiliates	33,989	29,840
Interest accrued	11,233	10,572
Taxes accrued	6,284	2,617
Operating lease liabilities	1,015	1,339
Derivative liabilities	270	222
Environmental remediation costs	31,695	27,760
Customer deposits	13,978	15,048
Regulatory liabilities	107,565	106,709
Other	72,922	77,476
Total Current Liabilities	**692,405**	**954,644**
Regulatory and Other Liabilities		
Regulatory liabilities	1,144,783	1,192,343
Other Non-current Liabilities		
Deferred income taxes	595,376	553,434
Pension and other postretirement	261,218	281,952
Operating lease liabilities	8,659	8,385
Asset retirement obligation	12,284	12,928
Environmental remediation costs	78,661	90,713
Other	40,547	41,220
Total Regulatory and Other Liabilities	**2,141,528**	**2,180,975**
Non-current debt	1,724,239	1,325,181
Total Liabilities	**4,558,172**	**4,460,800**
Commitments and Contingencies		
Common Stock Equity		
Common stock ($6.66 2/3 par value, 90,000,000 shares authorized and 64,508,477 shares outstanding at December 31, 2020 and 2019)	430,057	430,057
Additional paid-in capital	868,686	468,459
Retained earnings	603,995	574,153
Accumulated other comprehensive loss	(1,522)	(1,070)
Total Common Stock Equity	**1,901,216**	**1,471,599**
Total Liabilities and Equity	**$ 6,459,388**	**$ 5,932,399**

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,	2020	2019
(Thousands)		
Cash Flow from Operating Activities:		
Net income	**$ 129,948**	**$ 67,302**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	159,438	145,316
Regulatory assets/liabilities amortization	9,174	43,448
Regulatory assets/liabilities carrying cost	2,402	4,114
Amortization of debt issuance costs	985	3,491
Deferred taxes	14,549	28,401
Pension cost	51,064	51,434
Stock-based compensation	312	28
Accretion expenses	685	718
Gain from disposal of property	(847)	(752)
Other non-cash items	(50,165)	(24,316)
Changes in assets and liabilities		
Accounts receivable, from affiliates, and unbilled revenues	7,095	25,609
Inventories	1,096	1,071
Accounts payable, to affiliates, and accrued liabilities	3,702	(25,157)
Taxes accrued	25,789	(172)
Other assets/liabilities	30,941	(49,314)
Regulatory assets/liabilities	(134,585)	5,427
Net Cash Provided by Operating Activities	**251,583**	**276,648**
Cash Flow from Investing Activities:		
Capital expenditures	(693,054)	(593,577)
Contributions in aid of construction	21,309	42,968
Proceeds from sale of property, plant and equipment	2,652	2,189
Notes receivable from affiliates	(7,150)	—
Net Cash Used in Investing Activities	**(676,243)**	**(548,420)**
Cash Flow from Financing Activities:		
Non-current debt issuance	198,006	307,485
Repayments of finance leases	(1,826)	(21,535)
Notes payable to affiliates	(71,255)	30,880
Capital contribution	400,000	50,000
Dividends paid	(100,000)	(100,000)
Net Cash Provided by Financing Activities	**424,925**	**266,830**
Net Increase (Decrease) in Cash and Cash Equivalents	**265**	**(4,942)**
Cash and Cash Equivalents, Beginning of Year	**1**	**4,943**
Cash and Cash Equivalents, End of Year	**$ 266**	**$ 1**

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, 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**
Adoption of accounting standards	—	—	—	(106)	—	(106)
Net income	—	—	—	129,948	—	129,948
Other comprehensive loss, net of tax	—	—	—	—	(452)	(452)
Comprehensive income						129,496
Stock-based compensation	—	—	227	—	—	227
Common stock dividends	—	—	—	(100,000)	—	(100,000)
Capital contribution	—	—	400,000	—	—	400,000
Balance, December 31, 2020	**64,508,477**	**$ 430,057**	**$ 868,686**	**$ 603,995**	**$ (1,522)**	**$ 1,901,216**

(*) 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. Summary of Significant Accounting Policies, New Accounting Pronouncements and Use of Estimates

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 907,000 electricity and 270,000 natural gas customers as of December 31, 2020, 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).

Significant Accounting Policies: 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 an independent, third-party regulator; (ii) rates are designed to recover the entity's specific costs of providing the 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 can 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.

We amortize regulatory assets and liabilities and recognize the related expense or revenue in our 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**:** We account for utility plant 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 add an equal amount to the carrying amount of the asset.

Development and construction of our various facilities are carried out in stages. We expense project costs 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.

We transfer assets 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 of to accumulated depreciation. Our composite rates for depreciation were 2.3% of average depreciable property for 2020 and 2.2% for 2019. 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 $223.4 million as of December 31, 2020 and $209.9 million as of December 31, 2019. Depreciation expense was $149.5 million in 2020 and $136.7 million in 2019. Amortization of capitalized software was $10 million in 2020 and $8.6 million in 2019.

We charge repairs and minor replacements to operating expenses, and capitalize renewals and betterments, including certain indirect costs.

Allowance for funds used during construction (AFUDC) is a non-cash item that 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 record the remainder as other income.

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)**	**2020**	**2019**
(Thousands)			
Electric	29-80	$ 4,912,866	$ 4,577,776
Natural Gas	28-75	1,175,900	1,118,425
Common	7-70	728,087	679,270
Total Utility Plant in Service		**6,816,853**	**6,375,471**
Total accumulated depreciation		(2,263,857)	(2,228,040)
Total Net Utility Plant in Service		**4,552,996**	**4,147,431**
Construction work in progress		531,695	385,134
Total Utility Plant		**$ 5,084,691**	**$ 4,532,565**

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. We use the incremental borrowing rate based on information available at the lease commencement date to determine the present value of future payments, except when the rate implicit in the lease is determinable. 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 an option 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 non-lease 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. We are required to recognize an impairment loss 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 amount of the long-lived asset exceeds the asset's fair value. 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 our 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, which we present in the same income statement line item as the earnings effect of the hedged item. 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.

Notes to Financial Statements

***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. We report changes in book overdrafts in the operating activities section of the statements of cash flows.

Statements of cash flows: Supplemental disclosure of cash flow information is as follows:

(Thousands)		2020		2019
Cash paid during the years ended December 31:				
Interest, net of amounts capitalized	$	47,163	$	37,869
Income taxes (refunded) paid, net	$	(35,236)	$	9,656

Of the income taxes paid, substantially all was paid to AGR under the tax sharing agreement. Interest capitalized was $7.9 million in 2020 and in $6.1 million in 2019. Accrued liabilities for utility plant additions were $52.1 million in 2020 and $50.3 million in 2019.

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.

***Trade receivables and unbilled revenues, net*:** We record trade receivables at amounts billed to customers and we record unbilled revenues based on an estimate of energy delivered or services provided to customers. The estimates for unbilled revenues 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 credit losses is our best estimate of the amount of probable credit losses in our existing trade receivables, determined based on experience for each service region. Each month we review our allowance for credit losses 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 credit losses estimates.

Trade receivables at December 31 include unbilled revenues of $82.1 million for 2020 and $88.1 million for 2019, and are shown net of an allowance for credit losses at December 31 of $35.8 million for 2020 and $23.8 million for 2019. Trade receivable do not bear interest, although late fees may be assessed. Credit loss expense was $18.4 million in 2020 and $17.2 million in 2019.

Trade receivables 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. Failure to make payments on a DPA results in the full amount of a receivable under a DPA being due. These accounts are part of the regular operating cycle and we classify them as short term.

We establish our allowance for credit losses, including for unbilled revenue (also referred to as contract assets), by using both historical average loss percentages to project future losses, and by establishing a specific allowance for known credit issues or for specific items not considered in the historical average calculation. Due to our adoption of Accounting Standards Codification (ASC) 326 effective January 1, 2020, we now also consider whether we need to adjust historical loss rates to reflect the effects of current conditions and forecasted changes considering various economic indicators (e.g., Gross Domestic Product, Personal Income, Consumer Price Index, Unemployment Rate) over the contractual life of the trade receivables. We write off amounts when we have exhausted reasonable collection efforts. The allowance for credit losses for DPAs at December 31 was $17.7 million for 2020 and $13 million for 2019. DPA receivable balances at December 31 were $25.1 million for 2020 and $23.7 million for 2019.

Debentures, bonds and bank borrowings: We record bonds, debentures and bank borrowings as a liability equal to the proceeds of the borrowings. We treat the difference between the proceeds and the face amount of the issued liability as discount or premium and accrete the amounts as interest expense or income over the life of the instrument. We defer incremental costs associated with the issuance of the debt instruments and amortize them over the same period as debt discount or premium. We present bonds, debentures and bank borrowings 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, which we record as inventory. We price injections of inventory into storage at the market purchase cost at the time of injection, and price withdrawals of working gas from storage 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. We report inventories to support gas operations 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.” We combine inventory items for the statement of cash flows presentation purposes.

In addition, stand-alone renewable energy credits that are generated or purchased and held for sale are recorded at the lower of cost or net realizable value and are reported on our balance sheets within “Materials and supplies”.

Government grants: We record government grants as a reduction to the related 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 we incur the expenses.

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. 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 and electricity generation facilities. 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.

The following table reconciles the beginning and ending aggregate carrying amount of the ARO for the years ended December 31, 2020 and 2019.

Years ended December 31,		**2020**		**2019**
(Thousands)				
ARO, beginning of year	$	12,928	$	13,506
Liabilities settled during the year		(1,329)		(1,296)
Accretion expense		685		718
ARO, end of year	**$**	**12,284**	**$**	**12,928**

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. We expect to pay our environmental liability accruals through the year 2056.

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 generally 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 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 taxes*:** 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 payable to AGR at December 31, 2020 is $3.1 million. The aggregate amount of the related party income tax receivable from AGR at December 31, 2019 is $21.9 million.

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. We had no intra-entity transfers of assets other than inventory during the years ended December 31, 2020 and 2019.

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 netted and classified as non-current on our balance sheets.

We record the excess of state franchise tax computed as the higher of a tax based on income or a tax based on capital in “Taxes other than income taxes” and “Taxes accrued” in our financial statements.

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 2020 and 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 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) 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 (ASC 326). The amendments affect entities that hold financial assets and net investments 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 ASC 326 to clarify transition and scope requirements, make narrow-scope codification improvements, including in March 2020, and corrections and provide targeted transition relief. We adopted the amendments effective January 1, 2020, including the narrow-scope improvements issued in March 2020, and recorded a cumulative-effect adjustment of $0.1 million to retained earnings at the beginning of the period of adoption, with no material effect to our results of operations, financial position, cash flows and disclosures.

(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 to improve the overall usefulness of the disclosures and reduce unnecessary costs to companies to prepare the disclosures. We adopted the amendments effective January 1, 2020, with no material effect to our disclosures. Certain amendments are to be applied prospectively, and all others are to be applied retrospectively.

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. The amendments change annual disclosures requirements, including removal of disclosures that are no longer considered cost beneficial, adding certain new relevant disclosures and clarifying specific requirements of disclosures concerning information for defined benefit pension plans. We adopted the amendments effective January 1, 2020, and they did not materially affect the disclosures for our fiscal year ending December 31, 2020. As required, we applied the amendments on a retrospective basis.

(c) 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 its guidance. We adopted the amendments effective January 1, 2020, with no material effect to our results of operations, financial position, cash flows and disclosures. As required, we retrospectively applied the amendments to the date of our initial application of ASC 606.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements not yet adopted, including those issued since December 31, 2020, that we have evaluated or are evaluating to determine their effect on our financial statements.

(a) 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 in equity method investments 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.

(b) Facilitation of the effects of reference rate reform on financial reporting, and subsequent scope clarification

In March 2020, the FASB issued amendments and created ASC 848 to provide temporary optional guidance to entities to ease the potential burden in accounting for, or recognizing the effects of, reference rate reform on financial reporting. The amendments respond to concerns about structural risks of interbank offered rates, and particularly, the risk of cessation of the London Interbank Offered Rate (LIBOR). The guidance is elective and applies to all entities, subject to meeting certain criteria, that have contracts, hedging relationships, and other transactions that reference LIBOR or another reference rate expected to be discontinued due to reference rate reform, around the end of 2021. The guidance applies to contracts that have modified terms that affect, or have the potential to affect, the amount or timing of contractual cash flows resulting from the discontinuance of the reference rate reform. The amendments are effective for all entities as of March 12, 2020, through December 31, 2022, although the FASB has indicated it will monitor developments in the marketplace and consider whether developments warrant an extension.

In January 2021, the FASB issued amendments to clarify the scope of ASC 848 and respond to questions from stakeholders about whether ASC 848 can be applied to derivative instruments that do not reference a rate that is expected to be discontinued but that use an interest rate for margining, discounting, or contract price alignment that is modified because of reference rate reform. The modification, commonly referred to as the "discounting transition," may have accounting implications, raising concerns about the need to reassess previous accounting determinations related to those derivatives and about the possible hedge accounting consequences of the discounting transition. The amendments clarify that certain optional expedients and exceptions in ASC 848 for contract modifications and hedge accounting apply to derivatives that are affected by the discounting transition, capture the incremental consequences of the scope clarification and tailor the existing guidance to derivative instruments affected by the discounting transition. The amendments are effective immediately, and may be elected retrospectively to eligible modifications as of any date from the beginning of the interim period that includes March 12, 2020, or prospectively to new modifications made on or after any date within the interim period that includes January 7, 2021.

We expect our adoption of the reference rate reform and the subsequent scope clarification 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 credit losses 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.

We continue to utilize information reasonably available to us; however, the business and economic uncertainty resulting from the global pandemic of the novel coronavirus (COVID-19) has made such estimates and assumptions more difficult to assess and calculate. Affected estimates include, but are not limited to, evaluations of certain long-lived assets for impairment, expected credit losses and potential regulatory deferral or recovery of certain costs. While we have not yet had material effects of COVID-19 on our financial results, actual results could differ from those estimates, which could result in material effects to our financial statements in future reporting periods.

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 New York State Public Service Commission (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 was set at 9.00%. The equity ratio for each company is 48%; however, the equity ratio is set at the lower of the actual equity ratio or 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) and any subsequent rate years 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 continued 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 maintained 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 modified 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 established 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, NYSEG implemented the RAM, which is 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 provided 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 included downward-only reconciliations for the costs of: electric distribution and gas vegetation management; pipeline integrity; and other incremental maintenance programs. The Proposal provided 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 a series of extensions of the litigation schedule to allow the Company, the Department of Public Service Staff (DPS Staff), and other parties to enter into and conduct settlement discussions. A Joint Proposal for a three year rate plan term was filed on June 22, 2020. A modified Joint Proposal was approved by the NYPSC on November 19, 2020, which included modifications to the electric business proposed rate increases to limit the projected total bill increases to 2% per year in consideration of the current COVID-driven economic climate. The effective date of new tariffs was December 1, 2020 with a make-whole provision back to April 17, 2020. The approved Joint Proposal includes several COVID-19 provisions, including the provision of up to $16.5 million in bill credits for the Company's most vulnerable residential and small business customers. The Joint Proposal bases delivery revenues on an 8.80% ROE and 48% equity ratio; however, for the proposed earnings sharing mechanism, the equity ratio is the lower of the actual equity ratio or 50%. The approved Joint Proposal was signed in whole or in part by more than 20 parties, and includes delivery rate increases (excluding the impact of moving energy efficiency costs from a surcharge to delivery rates) as summarized below:

	May 1, 2020		May 1, 2021		May 1, 2022	
	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %
Electric	$34.3	4.6%	$45.6	5.9%	$36.0	4.2%
Gas	$0.0	0.0%	$1.6	0.8%	$3.3	1.6%

The approved Joint Proposal also reflects increased distribution vegetation management, investments in aging infrastructure, and increases in the Company's workforce, as well as continuation of many of the components of the last Joint Proposal described above. The rate plans continue the RAM designed to return or collect certain defined reconciled revenues and costs, have new depreciation rates and continue RDMs for each business.

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 and filed their next bi-annual update on June 30, 2020.

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 was included in the companies' May 20, 2019 rate filing and is reflected in the recently approved Rate Plan.

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 EAM framework; 2) further DSIP requirements, including 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.

The March 2017 Order stated that should a new compensation methodology not be in place by January 1, 2020, mass market 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 December 9, 2019, DPS Staff filed a whitepaper on rate design for mass market NEM successor tariffs. The Department of Public Service Staff (Staff) recommended the continuation of NEM as a compensation mechanism for all eligible mass market and commercial DER projects under 750 kW. Staff also proposed that these projects should be eligible for the range of options currently provided in delivery rates. For projects with load profiles or expertise that may benefit from time-varying price signals, projects would have the option to forgo the use of standard delivery rates and instead utilize more sophisticated time-of-use (TOU) or new mass market standby rates, coupled with a modest charge to collect public benefit funds that are otherwise avoided by using NEM. Initial comments on the whitepaper were submitted on February 24, 2020 and reply comments were submitted on March 16, 2020. On July 16, 2020, the Commission issued an Order establishing a net metering successor tariff. The Order continues Phase One NEM for all eligible mass market and commercial projects under 750 kW interconnected after January 1, 2022 and implements a modest customer benefit contribution (CBC) for onsite DERs to address cost recovery of certain public benefit programs. Customers that install DERs interconnected after January 1, 2022 shall be charged a monthly per kW fee based on the nameplate rating of the DER. Draft tariff leaves implementing the Commission's Order and proposed CBC calculations were filed on November 1, 2020.

On April 18, 2019, the Commission issued an Order on Future Value Stack Compensation and Capacity Value Compensation. The Order established 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 expanded eligibility for Phase One Net Metering for certain projects that have a rated capacity of 750 kW AC or lower. The changes became effective on June 1, 2019. The NYPSC also issued an Order on Value Stack Compensation for High-Capacity-Factor Resources on December 12, 2019, modifying the treatment of certain high-capacity-factor DER in the Value Stack compensation framework. The modification per the December 12, 2019 Order became effective February 1, 2020. On March 19, 2020, the Commission issued an additional Order regarding Value Stack Compensation. The Order directed National Grid, NYSEG, and RGE to reallocate capacity from closed tranches where available capacity remained due to projects being canceled since the issuance of the VDER Compensation Order, and to assign that capacity to a new Community Credit Tranche with compensation at 2 cents per kWh. The utilities must also continue to reallocate capacity to this new Tranche for the next six months when there are cancellations of projects that have received a Market Transition Credit (MTC) or Community Credit allocation. The new provisions per the March 19, 2020 Order became effective May 1, 2020.

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 requested preliminary comments from stakeholders by November 25, 2019, and additional information from the Utilities in February 2020 regarding their marginal cost methodologies. At this time it is not known when the DPS Staff whitepaper on marginal cost methodologies will be issued.

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. NYSEG filed draft tariffs on September 23, 2019 as required, with further analysis and discussion regarding approval and implementation of the optional rates occurring through the Rate Design

Working Group of the VDER proceeding. On November 25, 2020 DPS Staff, jointly with NYSERDA, issued a whitepaper on further recommendations regarding standby and buyback rates that were based on the electric utilities' September 23, 2019 filings. Comments on the recommendations in the whitepaper are due March 8, 2021, and reply comments are due April 12, 2021.

On May 14, 2020, the Commission issued an Order extending and expanding distributed solar incentives. In addition to authorizing the extension of and additional funding for the NY-Sun program, the Commission modified certain program rules related to the NY-Sun program and the VDER policy. As part of the ordered modifications, the Commission directed the electric utilities with VDER tariffs to add tariff language for a Remote Crediting program that will allow Value-Stack-eligible generation resources to distribute the credits they receive for generation injected into the utility system to the utility bills of multiple, separately sited, non-residential customers. The Commission ordered the utilities to submit tariff leaves that implement the modifications associated with the Remote Crediting program to become effective November 1, 2020. Given the complexity of the program changes, the utilities petitioned the Commission for tariffs filings to be made on February 15, 2021, with an effective date of March 1, 2021. Stakeholders have since requested residential customers be permitted to participate as remote crediting satellites and the frequency of credit allocation and adding/removing satellites be increased to allow for monthly changes rather than annual changes only. Given these requests, the Commission granted the utilities an additional extension to file tariffs by August 2, 2021, to become effective August 16, 2021.

On April 24, 2018, the Commission instituted a proceeding to consider the role of utilities in providing infrastructure and rate design to encourage the expansion electric vehicles and electric vehicle supply equipment. The Commission issued an Order on February 2, 2019 to establish a Direct Current Fast Charger incentive program, and subsequently clarified its Order on July 12, 2019 and March 3, 2020. A Whitepaper was issued by DPS Staff on January 13, 2020, proposing a make-ready infrastructure program with a budget estimated at $582 million. Utilities and other stakeholders filed comments on April 27, 2020 regarding the make-ready program proposal. Reply comments are due May 11, 2020. An order in this proceeding was issued on July 16, 2020.

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 Public Service Commission (NYPSC) initiated a comprehensive investigation of all the New York electric utilities' preparation and response to those events. The investigation has been expanded to include other 2018 New York spring storm events.

On April 18, 2019, the New York Public Service Department (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 (ERPs). 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 joint settlement agreement to avoid litigation including NYSEG and RG&E's agreement to pay a penalty of $10.5 million (allocated as $9.0 million to NYSEG and $1.5 million to RG&E) was filed with the NYPSC on December 17, 2019. On February 6, 2020, the NYPSC approved the joint settlement agreement, and the penalty amount is reflected as a rate moderator in the recently approved rate case Joint Proposal.

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 NYPSC filed a Verified Petition to commence the action against NYSEG and NYSEG and the NYPSC settled the causes of action asserted in the Verified Petition and entered into a Consent and Stipulation. On December 24, 2019, NYSEG and the NYPSC submitted a joint motion to the New York State Supreme Court (the "Court") requesting that the court approve and enter a Consent Order and Judgment reflecting the settlement. The Court issued the requested Consent Order and Judgment on January 24, 2020.

NYDPS Investigation of the Preparation for and Response to the Tropical Storm Isaias

On August 5, 2020, the NYDPS commenced an investigation into the preparation for and response to the Tropical Storm Isaias by several utilities in New York including NYSEG. In addition, the New York State Senate and Assembly held a joint hearing to examine the response of various utility companies during the aftermath of Tropical Storm Isaias. In August 2020, the Company received a letter from the Department of Public Service requesting a series of follow-on actions, which the Company has completed or is in the process of completing. At its November 19, 2020 session, the NYPSC provided an interim status report on the investigation, and NYSEG was identified as having a few items for improvement. The NYDPS subsequently provided NYSEG with a proposed settlement at $500,000 per violation, related to three alleged violations. NYSEG has signed an agreement associated with the settlement, and that agreement was accepted by the NYPSC at its January session. The investigation is ongoing. We cannot predict the outcome of this investigation.

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 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 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 approved Joint Proposal associated with the Company's last rate case.

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 $387.8 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 November 19, 2020, the NYPSC approved the Proposal in connection with a three-year rate plan for electric and gas service at NYSEG effective April 17, 2020. Following the approval of the proposal most of these items related to NYSEG are amortized over a three- or five-year period, except the portion of storm costs to be recovered over ten years, plant related tax items which are amortized over the life of associated plant, and unfunded deferred taxes which are amortized over forty six years. In accordance with the Schedule of Regulatory Amortizations included in the approved Joint Proposal, annual net amortization revenue for NYSEG is approximately $62.2 million for the year ended December 31, 2020.

Current and non-current regulatory assets at December 31, 2020 and 2019 consisted of:

December 31,	2020	2019
(Thousands)		
Current		
Electric supply reconciliation	$ 1,201	$ 4,667
Environmental remediation costs	—	5,705
Federal tax depreciation normalization adjustment	3,788	—
Hedge losses	10,620	15,720
Low income programs	945	1,826
Pension and other post-retirement benefits cost deferrals	14,688	23,886
Property tax deferrals	—	9,766
Rate adjustment mechanism	20,695	17,395
Revenue decoupling mechanism	8,712	10,227
Storm costs	25,992	40,128
Unamortized loss on re-acquired debt	1,718	1,496
Other	9,737	7,346
Total current regulatory assets	**98,096**	**138,162**
Non-current		
Asset retirement obligation	12,428	13,037
Environmental remediation costs	86,764	84,693
Federal tax depreciation normalization adjustment	83,224	87,823
Low income programs	3,593	3,321
Merger capital expenditure	291	246
Pension and other post-retirement benefits	278,118	347,735
Pension and other post-retirement benefits cost deferrals	57,676	52,503
Property tax deferrals	—	8,276
Rate adjustment mechanism	10,749	26,350
Storm costs	265,227	171,096
Unamortized loss on re-acquired debt	13,129	14,996
Other	56,360	12,209
Total non-current regulatory assets	**$ 867,559**	**$ 822,285**

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 three 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. A portion of this balance is amortized through current rates over a five-year amortization period which began in 2020. The remaining balance will be refunded in future periods through future rate cases.

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,REV costs and fees not covered in other recovery mechanisms, energy efficiency program costs, and COVID customer bill credits.

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 $291.2 million at December 31, 2020 and $211.2 million at December 31, 2019. Pursuant to the most recent Joint Proposal approved by the Commission, which began May 1, 2020, NYSEG will recover $33.0 million of the balance over five years and $119.2 million of the balance over ten years for non-super-storms, and $74.8 million of the balance over ten years for the super-storm balance.

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 COVID customer bill credits not in RAM, danger tree, and Reforming the Energy Vision (REV).

Current and non-current regulatory liabilities at December 31, 2020 and 2019 consisted of:

December 31,	2020	2019
(Thousands)		
Current		
Carrying costs on deferred income tax depreciation	$ 3,338	$ 12,934
Carrying costs on mixed use 263(a)	2,666	5,173
Debt rate reconciliation	8,741	2,825
Economic development	1,052	3,487
Energy efficiency programs	8,241	36,189
Gas supply charge and deferred natural gas cost	876	5,174
Non by-passable charges	7,629	7,301
NYS excess DIT – in rates	—	2,676
Pension and other postretirement benefits cost deferral	4,621	13,601
Positive benefit adjustment	969	2,685
Property tax	1,401	—
Rate change levelization	1,318	—
Service quality performance mechanism	2,922	—
Tax Act-remeasurement	48,034	—
Theoretical reserve flow through impact	2,097	5,367
New York 2018 winter storm settlement	3,000	—
Other	10,660	9,297
Total current regulatory liabilities	**107,565**	**106,709**
Non-current		
Accrued removal obligation	518,571	525,035
Accumulated deferred investment tax credits	12,102	—
Carrying costs on deferred income tax depreciation	3,333	314
Debt rate reconciliation	30,347	37,923
Economic development	6,288	4,309
Pension and other postretirement benefits	8,615	14,958
Pension and other postretirement benefits cost deferral	17,890	14,153
Positive benefit adjustment	1,061	895
Service quality performance mechanism	12,658	—
Tax Act-remeasurement	410,145	504,359
Unfunded future income taxes	9,562	16,980
New York 2018 winter storm settlement	5,688	—
Other	108,523	73,417
Total non-current regulatory liabilities	**$ 1,144,783**	**$ 1,192,343**

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.

Accumulated deferred investment tax credits represent investment tax credits related to plant investments that are deferred when earned and amortized over the estimated lives of the related assets.

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 costs of energy efficiency programs deferred for future recovery to the extent they exceed the amount in rates. A portion of this balance is amortized through current rates; the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is three years and began in 2020.

New York 2018 winter storm settlement represents the settlement amount with the NYSPSC following the comprehensive investigation of New York's major utility companies' preparation and response to March 2018 storms. This balance is amortized through current rates over an amortization period of three years, beginning in 2020.

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. A portion of this balance is amortized through current rates; the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is five years and began in 2020.

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 three years following the approval of the proposal by the NYPSC and included in the Ginna RSSA settlement.

Service quality performance mechanism represents negative revenue adjustments as well positive rate adjustments for exceeding and/or failing to meet targets for certain performance measures including the system average interruption frequency index (SAIFI) and the customer average interruption duration index (CAIDI), certain gas safety performance measures and for uncollectible/terminations/arrears measures.

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 amortization period in current rates is from one and half to ten years and began in 2020.

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.

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 $8.2 million at December 31, 2020, and $9.4 million at December 31, 2019, and are presented in "Other current liabilities" on our balance sheets. We recognized $19.7 million and $19.6 million as revenue during the years ended December 31, 2020 and 2019, 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, 2020 and 2019 are as follows:

Years Ended December 31,	**2020**	**2019**
(Thousands)		
Regulated operations – electricity	$ 1,240,267	$ 1,203,096
Regulated operations – natural gas	282,569	305,286
Other(a)	19,953	26,202
Revenue from contracts with customers	**1,542,789**	**1,534,584**
Leasing revenue	1,132	1,078
Alternative revenue programs	14,985	10,003
Other revenue	5,335	2,702
Total operating revenues	**$ 1,564,241**	**$ 1,548,367**

(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, 2020 and 2019 consisted of:

Years Ended December 31,	2020	2019
(Thousands)		
Current		
Federal	$ (5,538)	$ 44
State	(5,649)	7,570
Current taxes charged to expense (benefit)	**(11,187)**	**7,614**
Deferred		
Federal	3,290	29,043
State	11,642	(132)
Deferred taxes charged to expense (benefit)	**14,932**	**28,911**
Investment tax credit adjustments	(383)	(510)
Total Income Tax Expense	**$ 3,362**	**$ 36,015**

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, 2020 and 2019, respectively, consisted of:

Years Ended December 31,	2020	2019
(Thousands)		
Tax expense at statutory rate	$ 27,995	$ 21,697
Equity AFUDC tax effects	(3,095)	(5,082)
Excess ADIT giveback	(25,247)	—
Investment tax credit	—	13,638
Investment tax credit amortization	(383)	(510)
State tax expense, net of federal benefit	4,734	5,876
Other, net	(642)	396
Total Income Tax Expense	**$ 3,362**	**$ 36,015**

Income tax expense for the year ended December 31, 2020 was $24.6 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to excess ADIT amortization and AFUDC Equity tax effects, partially offset by state taxes. This resulted in an effective tax rate of 2.5%. 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%.

In 2020, NYSEG began refunding previously deferred protected and unprotected Excess ADIT, established as a result of the 2017 Tax Act as part of the 2020 Joint Proposal and as determined by the NYPSC and IRS normalization rules.

Deferred tax assets and liabilities as of December 31, 2020 and 2019 consisted of:

December 31,		2020		2019
(Thousands)				
Non-current Deferred Income Tax Liabilities (Assets)				
Property related	$	692,624	$	605,817
Storm costs		82,290		72,115
Pension and other post-retirement benefits		17,645		29,173
Power tax DIT		22,767		23,656
Regulatory liability due to "Tax Cuts and Jobs Act"		(119,883)		(132,470)
Environmental		(28,875)		(30,999)
Federal and state NOL's		(48,557)		(1,295)
Other		(22,635)		(12,563)
Total Non-current Deferred Income Tax Liabilities	**$**	**595,376**	**$**	**553,434**
Deferred tax assets	$	219,950	$	177,327
Deferred tax liabilities		815,326		730,761
Net Accumulated Deferred Income Tax Liabilities	**$**	**595,376**	**$**	**553,434**

NYSEG has gross federal net operating losses of $141.9 million and gross NY state net operating losses of $346 million for the year ended December 31, 2020. NYSEG had no gross federal net operating losses and gross NY state net operating losses of $25.2 million for the year ended December 31, 2019.

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. In 2020 and 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, 2020 and 2019 consisted of:

Years Ended December 31,		2020		2019
(Thousands)				
Balance as of January 1	$	45,197	$	45,269
Increases for tax positions related to prior years		—		—
Reduction for tax positions related to prior years		(73)		(72)
Balance as of December 31	**$**	**45,124**	**$**	**45,197**

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, 2020 and 2019.

Note 6. Long-term Debt

Long-term debt as of December 31, 2020 and 2019 consisted of:

As of December 31,		2020		2019	
(Thousands)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
Senior unsecured debt	2022-2049	$ 1,350,000	1.95%-5.75%	$ 1,150,000	3.24%-5.75%
Unsecured pollution control notes – fixed	2023-2029	386,000	1.40% - 3.50%	386,000	2.00%-3.50%
Unamortized debt issuance costs and discount		(11,761)		(12,380)	
Total Debt		**$1,724,239**		**$1,523,620**	
Less: debt due within one year, included in current liabilities		—		198,439	
Total Non-current Debt		**$ 1,724,239**		**$ 1,325,181**	

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%.

On May 1, 2020, NYSEG remarketed $200 million of Pollution Control Notes maturing during 2026 through 2029 at an interest ranging from 1.40% to 1.61%.

On September 25, 2020, NYSEG issued $200 million aggregate principal amount of unsecured notes maturing in 2030 at an interest of 1.95%.

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

2021	2022	2023	2024	2025	Total
(Thousands)					
$—	$75,000	$300,000	$12,000	$—	$387,000

Note 7. Bank Loans and Other Borrowings

NYSEG had no notes payable at December 31, 2020 and $71.3 million of notes payable at December 31, 2019, 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 no debt outstanding under this agreement at December 31, 2020 and $20.3 million outstanding under this agreement at December 31, 2019, 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 no debt outstanding under this agreement at December 31, 2020 and $51 million outstanding under this agreement at December 31, 2019, 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. Effective on June 29, 2019, the termination date for the AGR Credit Facility was extended to June 29, 2024. 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. Effective on June 29, 2020, the AGR Credit Facility was amended to reduce AGR's maximum sublimit to $1.5 billion and to establish minimum sublimits of $400 million for NYSEG, $250 million for RG&E, $150 million for UI, $100 million for CMP, $40 million for CNG and SCG, and $20 million for BGC. Under the AGR Credit Facility, each of the borrowers are charged a facility fee that is dependent on their credit rating. The facility fees range from 10.0 to 17.5 basis points. NYSEG had no outstanding balance as of December 31, 2020 and December 31, 2019.

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 0.48 to 1.00 at December 31, 2020. We are not in default as of December 31, 2020.

Note 8. Preferred Stock Redeemable Solely at the Option of the Company

At December 31, 2020, 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 26 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.

Notes to Financial Statements

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

Years Ended December 31,	2020	2019
(Thousands)		
Lease cost		
Finance lease cost		
Amortization of right-of-use assets	$ 4,884	$ 4,911
Interest on lease liabilities	188	367
Total finance lease cost	5,072	5,278
Operating lease cost	1,865	2,039
Short-term lease cost	581	787
Variable lease cost	385	477
Intercompany	(93)	(48)
Total lease cost	**$ 7,810**	**$ 8,533**

Balance sheet and other information for the years ended December 31, 2020 and 2019 was as follows:

As of December 31,	2020	2019
(Thousands, except lease term and discount rate)		
Operating Leases		
Operating lease right of use assets	$ 8,896	$ 9,341
Operating lease liabilities, current	1,015	1,339
Operating lease liabilities, long-term	8,659	8,385
Total operating lease liabilities	$ 9,674	$ 9,724
Finance Leases		
Other assets	$ 34,964	$ 39,620
Other current liabilities	321	1,218
Other non-current liabilities	2,235	2,952
Total finance lease liabilities	$ 2,556	$ 4,170
Weighted-average Remaining Lease Term (years):		
Finance leases	9.71	7.55
Operating leases	10.53	9.72
Weighted-average Discount Rate:		
Finance leases	5.60 %	7.78 %
Operating leases	3.33 %	3.73 %

Supplemental cash flows information related to leases was as follows:

Years Ended December 31,	2020	2019
(Thousands)		
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 1,615	$ 1,604
Operating cash flows from finance leases	$ 188	$ 365
Financing cash flows from finance leases	$ 1,826	$ 21,535
Right-of-use assets obtained in exchange for lease obligations:		
Finance leases	$ 228	$ 122
Operating leases	$ 990	$ 619

Maturities of lease liabilities were as follows:

	Finance	Operating
(Thousands)		
Years Ended December 31,		
2021	$ 441	$ 1,144
2022	320	1,058
2023	320	1,113
2024	320	943
2025	320	895
Thereafter	1,665	6,634
Total lease payments	**3,386**	**11,787**
Less: imputed interest	(830)	(2,113)
Total	**$ 2,556**	**$ 9,674**

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.

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 $66.8 million for Normal Purchase Normal Sale (NPNS) purchase power and natural gas contracts including non-utility generators in 2020 and $68.4 million in 2019.

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, 2020, 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 $5.5 million to $6.0 million as of December 31, 2020. 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 $95.7 million to $180.5 million at December 31, 2020. 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 $104.9 million at December 31, 2020 and $113.0 million at December 31, 2019. 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 2056.

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 $19.0 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.

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, 2020 and 2019, respectively, and amounts reclassified from regulatory assets and liabilities into income for the years ended December 31, 2020 and 2019, 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, 2020	**Electricity**	**Natural Gas**	**2020**	**Electricity**	**Natural Gas**
Regulatory assets	$ 10,519	$ 152	Purchased power, natural gas and fuel used	$ 34,926	$ 859
Regulatory liabilities	$ (44)	$ —			
December 31, 2019			**2019**		
Regulatory assets	$ 15,631	$ 1,047	Purchased power, natural gas and fuel used	$ 16,401	$ 195
Regulatory liabilities	$ —	$ —			

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, 2020			
2021	2,539,725	2,690,000	1,435,000
2022	876,000	320,000	—
As of December 31, 2019			
2020	2,432,700	2,430,000	1,201,200
2021	773,600	260,000	—

The offsetting of derivatives, location in the balance sheet and amounts of derivatives as of December 31, 2020 and 2019, respectively, consisted of:

December 31, 2020	**Derivative Assets-current**	**Derivative Assets-Non-current**	**Derivative Liabilities-current**	**Derivative Liabilities-Non-current**
(Thousands)				
Not designated as hedging instruments				
Derivative assets	$ 1,692	$ 1,817	$ 1,692	$ 1,773
Derivative liabilities	(1,692)	(1,773)	(12,312)	(1,824)
	—	44	(10,620)	(51)
Designated as hedging instruments				
Derivative assets	5	—	5	—
Derivative liabilities	(5)	—	(275)	—
	—	—	(270)	—
Total derivatives before offset of cash collateral	—	44	(10,890)	(51)
Cash collateral receivable	—	—	10,620	51
Total derivatives as presented in the balance sheet	**$ —**	**$ 44**	**$ (270)**	**$ —**

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)**	**$ —**

As of both December 31, 2020 and 2019, the derivative assets – non-current are presented within other non-current assets of the balance sheet. The derivative liabilities – non-current 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 years ended December 31, 2020 and 2019, respectively, consisted of:

Years 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)				
2020				
Interest rate contracts	$ —	Interest expense	$ (105)	$ 65,777
Commodity contracts: Other	(682)	Other operating expenses	(634)	$ 705,205
Total	**$ (682)**		**$ (739)**	
2019				
Interest rate contracts	$ —	Interest expense	$ (105)	$ 73,246
Commodity contracts: Other	188	Other operating expenses	(414)	$ 648,039
Total	**$ 188**		**$ (519)**	

The amounts in AOCI related to previously settled forward starting swaps, and accumulated amortization, as of December 31, 2020, is a net loss of $0.3 million as compared to a net loss of $0.4 million for 2019. For the year ended December 31, 2020, 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 2021.

As of December 31, 2020, $0.3 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, 2020.

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, 2020 is $17 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 $1,918 million and $1,598 million as of December 31, 2020 and 2019, 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, 2020 and 2019, consisted of:

Notes to Financial Statements

Description	(Level 1)	(Level 2)	(Level 3)	Netting	Total
(Thousands)					
As of December 31, 2020					
Assets					
Non-current investments available for sale, primarily money market funds	$ 10,447	$ —	$ —	$ —	$ 10,447
Derivatives					
Commodity contracts:					
Electricity	3,413	—	—	(3,369)	44
Natural gas	96	—	—	(96)	—
Other	—	—	5	(5)	—
Total	**$ 13,956**	**$ —**	**$ 5**	**$ (3,470)**	**$ 10,491**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	$ (13,888)	$ —	$ —	$ 13,888	$ —
Natural gas	(248)	—	—	248	—
Other	—	—	(275)	5	(270)
Total	**$ (14,136)**	**$ —**	**$ (275)**	**$ 14,141**	**$ (270)**
As of December 31, 2019					
Assets					
Non-current 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)**

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2020 and 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.

Notes to Financial Statements

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, 2020 and 2019 consisted of:

	(Level 3) Derivatives, Net	
Years Ended December 31,	**2020**	**2019**
(Thousands)		
Beginning balance	$ (222)	$ (824)
Realized (gains) losses included in earnings	634	414
Unrealized gains (losses) included in other comprehensive income	(682)	188
Ending balance	**$ (270)**	**$ (222)**

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, 2020 and 2019, consisted of:

(Thousands)	Balance, December 31, 2018	Adoption of new accounting standard	Change 2019	Balance, December 31, 2019	Change 2020	Balance, December 31, 2020
Amortization of pension cost for non-qualified plans, net of income tax expense (benefit) of ($44) for 2019 and $10 for 2020	$ (414)	$ —	$ (124)	$ (538)	$ (459)	$ (997)
Unrealized gain (loss) on derivatives qualified as hedges:						
Unrealized gain (loss) during period on derivatives qualified as hedges, net of income tax expense (benefit) of $49 for 2019 and ($590) for 2020			139		(92)	
Reclassification adjustment for loss included in net income, net of income tax expense of $108 for 2019 and $549 for 2020		(201)	306		85	
Reclassification adjustment for loss on settled cash flow treasury hedges, net of income tax expense of $28 for 2019 and $91 for 2020			77		14	
Net unrealized gain (loss) on derivatives qualified as hedges	(853)	(201)	522	(532)	7	(525)
Accumulated Other Comprehensive Loss	**$ (1,267)**	**$ (201)**	**$ 398**	**$ (1,070)**	**$ (452)**	**$ (1,522)**

Note 15. Post-retirement and Similar Obligations

We have funded non-contributory 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 $8.3 million for 2020 and $6.9 million for 2019.

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.

Non-Qualified Retirement Benefit Plans

We also sponsor various unfunded non-qualified pension plans for certain current employees, former employees and former directors. The total liability for these plans, which is included in Other non-current liabilities on our balance sheets, was $3.8 million and $3.7 million at December 31, 2020 and 2019, respectively.

Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2020 and 2019 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2020**	**2019**	**2020**	**2019**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	$ 1,649,246	$ 1,508,082	$ 160,382	$ 151,159
Service cost	19,378	14,915	1,084	994
Interest cost	47,012	57,524	4,523	5,706
Actuarial loss/(gain)	112,401	161,924	7,899	15,851
Benefits paid	(97,126)	(93,199)	(12,288)	(13,328)
Benefit obligation at December 31	**$ 1,730,911**	**$ 1,649,246**	**$ 161,600**	**$ 160,382**
Change in plan assets				
Fair value of plan assets at January 1	$ 1,450,765	$ 1,314,984	$ 76,911	$ 73,273
Actual return on plan assets	197,345	228,980	9,030	10,438
Employer & plan participants' contributions	—	—	6,656	6,528
Benefits paid	(97,126)	(93,199)	(12,288)	(13,328)
Fair value of plan assets at December 31	**$ 1,550,984**	**$ 1,450,765**	**$ 80,309**	**$ 76,911**
Funded status	**$ (179,927)**	**$ (198,481)**	**$ (81,291)**	**$ (83,471)**

During 2020, the pension benefit obligation had an actuarial loss of $112.4 million. This loss was primarily driven by $121.5 million loss from decrease in discount rates. There were no significant plan design changes in 2020. There were no significant gains and losses relating to the postretirement benefit obligations.

During 2019, the pension benefit obligation had an actuarial loss of $161.9 million. This loss was primarily driven by $172.9 million loss from decrease in discount rates. There were no significant plan design changes in 2019. There were no significant gains and losses relating to the postretirement benefit obligations.

Amounts recognized in the balance sheet as of December 31, 2020 and 2019 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	2020	2019	2020	2019
(Thousands)				
Noncurrent liabilities	$ (179,927)	$ (198,481)	$ (81,291)	$ (83,471)

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,	2020	2019	2020	2019
(Thousands)				
Net loss	$ 275,337	$ 344,163	$ (5,937)	$ (6,785)
Prior service cost (credit)	$ 2,781	$ 3,572	$ (2,678)	$ (8,173)

Our accumulated benefit obligation for all qualified defined benefit pension plans was $1,664 million and $1,578 million as of December 31, 2020 and 2019. NYSEG's postretirement benefits were partially funded as of December 31, 2020 and 2019.

The projected benefit obligation and the accumulated benefit obligation exceeded the fair value of pension plan assets for our qualified plans as of both December 31, 2020 and 2019. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets as of December 31, 2020 and 2019.

As of December 31,	2020	2019
(Thousands)		
Projected benefit obligation	$ 1,730,911	$ 1,649,246
Accumulated benefit obligation	$ 1,663,645	$ 1,578,437
Fair value of plan assets	$ 1,550,984	$ 1,450,765

The postretirement benefits obligation for all the qualified plans exceeded the fair value of plan assets as of December 31, 2020 and 2019.

Components of net periodic benefit cost and other amounts recognized in regulatory assets and regulatory liabilities for the years ended December 31, 2020 and 2019 consisted of:

Notes to Financial Statements

Years Ended December 31,	Pension Benefits 2020	Pension Benefits 2019	Postretirement Benefits 2020	Postretirement Benefits 2019
(Thousands)				
Net periodic benefit cost				
Service cost	$ 19,378	$ 14,915	$ 1,084	$ 994
Interest cost	47,012	57,524	4,523	5,706
Expected return on plan assets	(99,997)	(100,694)	(3,230)	(3,077)
Amortization of prior service cost (credit)	791	919	(5,495)	(5,597)
Amortization of net loss	83,880	78,770	1,252	(796)
Net periodic benefit cost	**$ 51,064**	**$ 51,434**	**$ (1,866)**	**$ (2,770)**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net loss (gain)	$ 15,054	$ 33,636	$ 2,100	$ 8,490
Amortization of net (loss)	(83,880)	(78,769)	(1,252)	796
Amortization of prior service (cost) credit	(791)	(919)	5,495	5,597
Total recognized in regulatory assets and regulatory liabilities	**$ (69,617)**	**$ (46,052)**	**$ 6,343**	**$ 14,883**
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$ (18,553)**	**$ 5,382**	**$ 4,477**	**$ 12,113**

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.

The weighted-average assumptions used to determine benefit obligations as of December 31, 2020 and 2019 consisted of:

As of December 31,	Pension Benefits 2020	Pension Benefits 2019	Postretirement Benefits 2020	Postretirement Benefits 2019
Discount rate	2.29 %	2.93 %	2.15 %	2.93 %
Rate of compensation increase	Age-Related Rates	Age-Related Rates	3.00 %	Age-Related Rates
Interest crediting rate	3.00 %	3.00 %	N/A	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 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, 2020 and 2019 consisted of:

Years Ended December 31,	Pension Benefits 2020	Pension Benefits 2019	Postretirement Benefits 2020	Postretirement Benefits 2019
Discount rate	2.93 %	3.93 %	2.93 %	3.93 %
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	Age-Related Rates	3.80 %	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 to determine benefit obligations as of December 31, 2020 and 2019 consisted of:

As of December 31,	2020	2019
Health care cost trend rate (pre 65/post 65)	6.75% / 7.50%	6.75% / 7.50%
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

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 2021. We expect to contribute $5.6 million to our postretirement benefits plan in 2021.

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
2021	$ 91,455	$ 11,236	$ —
2022	$ 93,798	$ 11,077	$ —
2023	$ 95,731	$ 10,897	$ —
2024	$ 97,265	$ 10,658	$ —
2025	$ 98,432	$ 10,394	$ —
2025-2029	$ 490,905	$ 46,756	$ —

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, 2020, by asset category, consisted of:

		Fair Value Measurements		
Asset Category	**Total**	**(Level 1)**	**(Level 2)**	**(Level 3)**
(Thousands)				
As of December 31, 2020				
Cash and cash equivalents	$ 68,721	$ 52	$ 68,669	$ —
U.S. government securities	88,789	88,762	27	—
Common stocks	54,237	54,237	—	—
Registered investment companies	150,711	150,711	—	—
Corporate bonds	356,162	—	356,162	—
Preferred stocks	493	493	—	—
Common collective trusts	485,686	—	485,686	—
Other, principally annuity, fixed income	34,238	3,182	31,056	—
	$ 1,239,037	**$ 297,437**	**$ 941,600**	**$ —**
Other investments measured at net asset value	311,947			
Total	**$ 1,550,984**			

The fair values of pension benefits plan assets as of December 31, 2019, by asset category, consisted of:

Asset Category		Total	Fair Value Measurements (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**					

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 - at the closing price reported in the active market in which the security is traded.
- Common stock - 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.
- 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.
- Common collective trusts – 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, 2020 consisted of:

		Fair Value Measurements		
Asset Category	**Total**	**(Level 1)**	**(Level 2)**	**(Level 3)**
(Thousands)				
As of December 31, 2020				
Cash and cash equivalents	$ 2,624	$ —	$ 2,624	$ —
U.S. government securities	235	235	—	—
Common stocks	144	144	—	—
Registered investment companies	74,246	74,246	—	—
Corporate bonds	944	—	944	—
Preferred stocks	1	1	—	—
Common collective trusts	1,281	—	1,281	—
Other, principally annuity, fixed income	5	8	(3)	—
	$ 79,480	**$ 74,634**	**$ 4,846**	**$ —**
Other investments measured at net asset value	829			
Total	**$ 80,309**			

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	**$ 76,911**	**$ 73,762**	**$ 3,149**	**$ —**

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.
- U.S. government securities - 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.
- Common stock - at the closing price reported in the active market in which the individual investment is traded.
- 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.
- Common collective trusts – 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.

Pension and postretirement benefit plan equity securities did not include any AGR and Iberdrola common stock as of both December 31, 2020 and 2019.

Note 16. Other Income and Other Deductions

Other income and deductions for the years ended December 31, 2020 and 2019, consisted of:

Years Ended December 31,		**2020**		**2019**
(Thousands)				
Interest and dividend income	$	604	$	265
Carrying costs on regulatory assets		15,806		11,845
Allowance for funds used during construction		15,725		14,428
Gain on sale of property		1,445		1433
Miscellaneous		84		226
Total other income	**$**	**33,664**	**$**	**28,197**
Pension non-service components	$	(24,496)	$	(30,343)
Miscellaneous		(1,869)		(11,814)
Total other deductions	**$**	**(26,365)**	**$**	**(42,157)**

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 $102.6 million for 2020 and $98 million for 2019. Cost for services includes amounts capitalized in utility plant, which was approximately $13.1 million in 2020 and $12.3 million in 2019. The remainder was primarily recorded as operations and maintenance expense. The charges for services provided by NYSEG to AGR and its subsidiaries were approximately $16.3 million for 2020 and $12.4 million for 2019. 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 $34.0 million at December 31, 2020 and $29.8 million at December 31, 2019 is mostly payable to Avangrid Service Company. The balance in accounts receivable from affiliates of $4.8 million at December 31, 2020 and $1.1 million at December 31, 2019 is from various companies. The balance in notes receivable from affiliates of $7.2 million at December 31, 2020 is receivable from CMP. There were no notes receivable from affiliates at December 31, 2019. Notes receivable from affiliates relate to the Virtual Money Pool Agreement as discussed in Note 7 of these financial statements.

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, 2020 and 2019 we had no outstanding receivable balance from New York TransCo.

Note 18. Subsequent Events

The company has performed a review of subsequent events through March 31, 2021, which is the date these financial statements were available to be issued.

Rochester Gas and Electric Corporation

Financial Statements

As of and for the Years Ended December 31, 2020 and 2019

Rochester Gas and Electric Corporation

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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, 2020 and 2019, 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, 2020 and 2019, 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, 2021

Rochester Gas and Electric Corporation
Statements of Income

Years Ended December 31,	2020	2019
(Thousands)		
Operating Revenues	**$ 871,943**	**$ 893,042**
Operating Expenses		
Electricity purchased and fuel used in generation	105,341	94,958
Natural gas purchased	75,743	108,138
Operations and maintenance	288,655	282,270
Depreciation and amortization	104,044	94,619
Taxes other than income taxes, net	132,624	125,842
Total Operating Expenses	**706,407**	**705,827**
Operating Income	**165,536**	**187,215**
Other income	26,831	24,121
Other deductions	(13,052)	(12,343)
Interest expense, net of capitalization	(46,186)	(70,784)
Income Before Tax	**133,129**	**128,209**
Income tax expense	19,635	33,354
Net Income	**$ 113,494**	**$ 94,855**

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

Rochester Gas and Electric Corporation
Statements of Comprehensive Income

Years Ended December 31,	2020	2019
(Thousands)		
Net Income	**$ 113,494**	**$ 94,855**
Other Comprehensive Income, Net of Tax		
Amortization of pension cost for non-qualified plans, net of income tax	(1,008)	(283)
Unrealized (loss) gain during period on derivatives qualifying as hedges, net of income tax	(126)	66
Reclassification adjustment for loss included in net income, net of income tax	129	123
Reclassification adjustment for loss on settled cash flow treasury hedges, net of income tax	2,903	3,488
Other Comprehensive Income, Net of Tax	**1,898**	**3,394**
Comprehensive Income	**$ 115,392**	**$ 98,249**

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

Rochester Gas and Electric Corporation
Balance Sheets

As of December 31,	2020	2019
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$ 1	$ 579
Accounts receivable and unbilled revenues, net	146,321	149,647
Accounts receivable from affiliates	4,761	2,656
Notes receivable from affiliates	19,200	—
Fuel and gas in storage	6,535	9,728
Materials and supplies	14,202	12,214
Broker margin accounts	5,072	4,424
Income tax receivable	26,305	30,215
Prepaid property taxes	40,053	37,182
Regulatory assets	49,295	52,328
Other current assets	3,413	2,887
Total Current Assets	**315,158**	**301,860**
Utility plant, at original cost	4,481,101	3,956,748
Less accumulated depreciation	(1,123,051)	(1,060,419)
Net Utility Plant in Service	**3,358,050**	**2,896,329**
Construction work in progress	245,206	406,367
Total Utility Plant	**3,603,256**	**3,302,696**
Operating lease right of use assets	1,774	9,469
Other property and investments	—	184
Regulatory and Other Assets		
Regulatory assets	413,798	433,733
Other	50,195	12,784
Total Regulatory and Other Assets	**463,993**	**446,517**
Total Assets	**$ 4,384,181**	**$ 4,060,726**

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

Rochester Gas and Electric Corporation
Balance Sheets

As of December 31,	2020	2019
(Thousands)		
Liabilities		
Current Liabilities		
Current portion of debt	$ 123,738	$ —
Notes payable to affiliates	—	33,201
Accounts payable and accrued liabilities	218,475	208,708
Accounts payable to affiliates	16,332	12,307
Interest accrued	10,067	9,713
Taxes accrued	1,250	1,355
Operating lease liabilities	142	1,344
Environmental remediation costs	1,142	1,327
Regulatory liabilities	103,528	67,676
Other	47,518	44,250
Total Current Liabilities	**522,192**	**379,881**
Regulatory and Other Liabilities		
Regulatory liabilities	703,806	749,053
Other Non-current Liabilities		
Deferred income taxes	365,121	331,111
Nuclear plant obligations	129,349	128,749
Pension and other postretirement	154,199	152,393
Operating lease liabilities	2,618	9,026
Asset retirement obligations	2,562	2,713
Environmental remediation costs	95,056	131,336
Other	71,252	26,836
Total Regulatory and Other Liabilities	**1,523,963**	**1,531,217**
Non-current debt	1,118,136	1,045,203
Total Liabilities	**3,164,291**	**2,956,301**
Commitments and Contingencies		
Common Stock Equity		
Common stock ($5 par value, 50,000,000 shares authorized, 38,885,813 shares outstanding at December 31, 2020 and 2019)	194,429	194,429
Additional paid-in capital	655,111	605,022
Retained earnings	525,979	462,501
Accumulated other comprehensive loss	(38,391)	(40,289)
Treasury stock, at cost (4,379,300 shares at December 31, 2020 and 2019)	(117,238)	(117,238)
Total Common Stock Equity	**1,219,890**	**1,104,425**
Total Liabilities and Equity	**$ 4,384,181**	**$ 4,060,726**

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

Rochester Gas and Electric Corporation
Statements of Cash Flows

Years Ended December 31,	2020	2019
(Thousands)		
Cash Flow From Operating Activities:		
Net income	**$ 113,494**	**$ 94,855**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	104,044	94,619
Regulatory assets/liabilities amortization	(35,066)	2,398
Regulatory assets/liabilities carrying cost	5,260	7,394
Amortization of debt issuance costs	1,239	440
Deferred taxes	16,657	34,468
Pension cost	12,027	13,127
Stock-based compensation	115	24
Accretion expenses	143	150
Gain from disposal of property	(49)	(144)
Other non-cash items	(23,314)	(10,588)
Changes in operating assets and liabilities:		
Accounts receivable, from affiliates, and unbilled revenues	1,221	25,780
Inventories	1,205	809
Accounts payable, to affiliates, and accrued liabilities	4,241	(29,117)
Taxes accrued	3,640	(28,717)
Other assets/liabilities	5,438	(37,196)
Regulatory assets/liabilities	4,673	47,685
Net Cash Provided by Operating Activities	**214,968**	**215,987**
Cash Flow From Investing Activities:		
Capital expenditures	(364,143)	(374,472)
Contributions in aid of construction	6,459	14,234
Proceeds from sale of property, plant and equipment	655	1,441
Notes receivable from affiliates	(19,200)	106,350
Investments	—	2,473
Net Cash Used in Investing Activities	**(376,229)**	**(249,974)**
Cash Flow From Financing Activities:		
Non-current note issuance	196,320	153,454
Repayments of non-current debt	—	(150,000)
Repayments of finance leases	(2,436)	(2,259)
Notes payable to affiliates	(33,201)	33,201
Capital contributions	50,000	—
Dividends paid	(50,000)	—
Net Cash Provided by Financing Activities	**160,683**	**34,396**
Net (Decrease) Increase in Cash and Cash Equivalents	**(578)**	**409**
Cash and Cash Equivalents, Beginning of Period	**579**	**170**
Cash and Cash Equivalents, End of Period	**$ 1**	**$ 579**

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, 2018	**38,885,813**	**$**	**194,429**	**$**	**604,998**	**$**	**359,003**	**$**	**(35,040)**	**$**	**(117,238)**	**$**	**1,006,152**
Adoption of accounting standards	—		—		—		8,643		(8,643)		—		—
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
Balance, December 31, 2019	**38,885,813**		**194,429**		**605,022**		**462,501**		**(40,289)**		**(117,238)**		**1,104,425**
Adoption of accounting standards	—		—		—		(16)				—		(16)
Net income	—		—		—		113,494		—		—		113,494
Other comprehensive income, net of tax	—		—		—		—		1,898		—		1,898
Comprehensive income													115,392
Stock-based compensation	—		—		89		—		—		—		89
Common stock dividends	—		—		—		(50,000)		—		—		(50,000)
Capital contributions	—		—		50,000		—		—		—		50,000
Balance, December 31, 2020	**38,885,813**	**$**	**194,429**	**$**	**655,111**	**$**	**525,979**	**$**	**(38,391)**	**$**	**(117,238)**	**$**	**1,219,890**

(*) Par value of share amounts is $5

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

Note 1. Summary of Significant Accounting Policies, New Accounting Pronouncements and Use of Estimates

***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 385,900 electricity and 319,700 natural gas customers as of December 31, 2020, 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).

***Significant Accounting Policies*:** 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 an independent, third-party regulator; (ii) rates are designed to recover the entity's specific costs of providing the 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 can 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.

We amortize regulatory assets and liabilities and recognize the related expense or revenue in our 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*:** We account for utility plant 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 add an equal amount to the carrying amount of the asset.

Development and construction of our various facilities are carried out in stages. We expense project costs 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.

We transfer assets 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 of to accumulated depreciation. Our composite rate for depreciation was 2.3% of average depreciable property for 2020 and 2.4% for 2019. 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 $136.4 million as of December 31, 2020 and $128.6 million as of December 31, 2019. Depreciation expense was $99.9 million in 2020 and $91.0 million in 2019. Amortization of capitalized software was $4.1 million in 2020 and $3.7 million in 2019.

We charge repairs and minor replacements to operating expenses, and capitalize renewals and betterments, including certain indirect costs.

Allowance for funds used during construction (AFUDC) is a non-cash item that 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 record the remainder as other income.

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)**		**2020**		**2019**
(thousands)					
Electric	29-75	$	3,036,488	$	2,587,615
Natural Gas	30-80		1,034,476		993,590
Common	6-50		410,137		375,543
Utility plant at original cost			**4,481,101**		**3,956,748**
Less accumulated depreciation			(1,123,051)		(1,060,419)
Net Utility Plant in Service			**3,358,050**		**2,896,329**
Construction work in progress			245,206		406,367
Total Utility Plant		**$**	**3,603,256**	**$**	**3,302,696**

***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. We use the incremental borrowing rate based on information available at the lease commencement date to determine the present value of future payments, except when the rate implicit in the lease is determinable. 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 an option 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 non-lease 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. We are required to recognize an impairment loss 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 amount of the long-lived asset exceeds the asset's fair value. 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 our 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, which we present in the same income statement line item as the earnings effect of the hedged item. 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. We report changes in book overdrafts in the operating activities section of our statements of cash flows.

Statements of cash flows**:** Supplemental disclosure of cash flow information is as follows:

	2020	2019
(Thousands)		
Cash paid during the years ended December 31:		
Interest, net of amounts capitalized	$ 31,998	$ 46,111
Income taxes (refunded) paid, net	$ (304)	$ 27,509

Of the income taxes paid, substantially all was paid to AGR under the tax sharing agreement. Interest capitalized was $15.7 million in 2020 and $11.6 million in 2019. Accrued liabilities for utility plant additions were $34.7 million in 2020 and $33.9 million in 2019.

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.

Trade receivables and unbilled revenue, net of allowance for credit losses**:** We record trade receivables at amounts billed to customers and we record unbilled revenues based on an estimate of energy delivered or services provided to customers. The estimates for unbilled revenues 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 credit losses 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 credit losses 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 credit losses estimates.

Trade receivables at December 31 include unbilled revenues of $51.8 million for 2020 and $53.8 million for 2019, and are shown net of an allowance for credit losses at December 31 of $33.6 million for 2020 and $25.0 million for 2019. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $14.0 million in 2020 and $15.0 million in 2019.

Trade receivables 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 over an extended period without interest, 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. Failure to make payments on a DPA results in the full amount of a receivable under a DPA being due. These accounts are part of the regular operating cycle and we classify them as short-term.

We establish our allowance for credit losses, including for unbilled revenue (also referred to as contract assets), by using both historical average loss percentages to project future losses, and by establishing a specific allowance for known credit issues or for specific items not considered in the historical average calculation. Due to our adoption of Accounting Standards Codification (ASC) 326 effective January 1, 2020, we now also consider whether we need to adjust historical loss rates to reflect the effects of current conditions and forecasted changes considering various economic indicators (e.g., Gross Domestic Product, Personal Income, Consumer Price Index, Unemployment Rate) over the contractual life of the trade receivables. We write off amounts when we have exhausted reasonable collection efforts. The allowance for credit losses for DPAs at December 31 was $18.9 million in 2020 and $15.0 million in 2019. DPA receivable balances at December 31 were $25.7 million in 2020 and $23.0 million in 2019.

***Debentures, bonds and bank borrowings*:** We record bonds, debentures and bank borrowings as a liability equal to the proceeds of the borrowings. We treat the difference between the proceeds and the face amount of the issued liability as discount or premium and accrete the amounts as interest expense or income over the life of the instrument. We defer incremental costs associated with the issuance of the debt instruments and amortize them over the same period as debt discount or premium. We present bonds, debentures and bank borrowings 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, which we record as inventory. We price injections of inventory into storage at the market purchase cost at the time of injection, and price withdrawals of working gas from storage 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. We report inventories to support gas operations on our balance sheets within “Fuel and natural gas in storage.”

We also have materials and supplies inventories that we use 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.” We combine inventory items for the statement of cash flow presentation purposes.

In addition, stand-alone renewable energy credits that are generated or purchased and held for sale are recorded at the lower of cost or net realizable value and are reported on our balance sheets within “Materials and supplies.”

Government grants: We record government grants as a reduction to the related 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 we incur the expenses.

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. 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 and electricity generation facilities. 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.

The following table reconciles the beginning and ending aggregate carrying amount of the ARO, including our conditional ARO, for the years ended December 31, 2020 and 2019.

Years Ended December 31,	**2020**	**2019**
(Thousands)		
ARO, beginning of year	$ 2,713	$ 2,846
Liabilities settled during the year	(295)	(283)
Accretion expense	144	150
ARO, end of year	**$ 2,562**	**$ 2,713**

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. We expect to pay our environmental liability accruals through the year 2050.

***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 generally 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 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 taxes*: **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 $26.3 million for 2020 and $30.2 million for 2019.

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. We had no intra-entity transfers of assets other than inventory during the years ended December 31, 2020 and 2019.

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 netted and classified as non-current in our balance sheets.

We record the excess of state franchise tax computed as the higher of a tax based on income or a tax based on capital in “Taxes other than income taxes” and “Taxes accrued” in our financial statements.

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 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) 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 (ASC 326). The amendments affect entities that hold financial assets and net investments 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 ASC 326 to clarify transition and scope requirements, make narrow-scope codification improvements, including in March 2020, and corrections and provide targeted transition relief. We adopted the amendments effective January 1, 2020, including the narrow-scope improvements issued in March 2020, and recorded a cumulative-effect adjustment of $16 thousand to retained earnings at the beginning of the period of adoption, with no material effect to our results of operations, financial position, cash flows and disclosures.

(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 to improve the overall usefulness of the disclosures and reduce unnecessary costs to companies to prepare the disclosures. We adopted the amendments effective January 1, 2020, with no material effect to our disclosures. Certain amendments are to be applied prospectively, and all others are to be applied retrospectively.

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. The amendments change annual disclosures requirements, including removal of disclosures that are no longer considered cost beneficial, adding certain new relevant disclosures and clarifying specific requirements of disclosures concerning information for defined benefit pension plans. We adopted the amendments effective January 1, 2020, and they did not materially affect the disclosures for our fiscal year ending December 31, 2020. As required, we applied the amendments on a retrospective basis.

(c) 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 its guidance. We adopted the amendments effective January 1, 2020, with no material effect to our results of operations, financial position, cash flows and disclosures. As required, we retrospectively applied the amendments to the date of our initial application of ASC 606.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements not yet adopted, including those issued since December 31, 2020, that we have evaluated or are evaluating to determine their effect on our financial statements.

(a) 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 in equity method investments 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.

(b) Facilitation of the effects of reference rate reform on financial reporting, and subsequent scope clarification

In March 2020, the FASB issued amendments and created ASC 848 to provide temporary optional guidance to entities to ease the potential burden in accounting for, or recognizing the effects of, reference rate reform on financial reporting. The amendments respond to concerns about structural risks of interbank offered rates, and particularly, the risk of cessation of the London Interbank Offered Rate (LIBOR). The guidance is elective and applies to all entities, subject to meeting certain criteria, that have contracts, hedging relationships, and other transactions that reference LIBOR or another reference rate expected to be discontinued due to reference rate reform, around the end of 2021. The guidance applies to contracts that have modified terms that affect, or have the potential to affect, the amount or timing of contractual cash flows resulting from the discontinuance of the reference rate reform. The amendments are effective for all entities as of March 12, 2020, through December 31, 2022, although the FASB has indicated it will monitor developments in the marketplace and consider whether developments warrant an extension.

In January 2021, the FASB issued amendments to clarify the scope of ASC 848 and respond to questions from stakeholders about whether ASC 848 can be applied to derivative instruments that do not reference a rate that is expected to be discontinued but that use an interest rate for margining, discounting, or contract price alignment that is modified because of reference rate reform. The modification, commonly referred to as the “discounting transition,” may have accounting implications, raising concerns about the need to reassess previous accounting determinations related to those derivatives and about the possible hedge accounting consequences of the discounting transition. The amendments clarify that certain optional expedients and exceptions in ASC 848 for contract modifications and hedge accounting apply to derivatives that are affected by the discounting transition, capture the incremental consequences of the scope clarification and tailor the existing guidance to derivative instruments affected by the discounting transition. The amendments are effective immediately, and may be elected retrospectively to eligible modifications as of any date from the beginning of the interim period that includes March 12, 2020, or prospectively to new modifications made on or after any date within the interim period that includes January 7, 2021.

We expect our adoption of the reference rate reform and the subsequent scope clarification 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 credit losses 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) fair value measurements; (9) earnings sharing mechanisms; (10) environmental remediation liabilities; (11) AROs; and (12) pension and other postretirement employee benefits. 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.

We continue to utilize information reasonably available to us; however, the business and economic uncertainty resulting from the global pandemic of the novel coronavirus (COVID-19) has made such estimates and assumptions more difficult to assess and calculate. Affected estimates include, but are not limited to, evaluations of certain long-lived assets for impairment, expected credit losses and potential regulatory deferral or recovery of certain costs. While we have not yet had material effects of COVID-19 on our financial results, actual results could differ from those estimates, which could result in material effects to our financial statements in future reporting periods.

Union collective bargaining agreements: Approximately 49% 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 and New York State Electric & Gas Corporation (NYSEG) (together, “the companies”) filed electric and gas rate cases with the NYPSC. We requested a rate increase for RG&E Gas and a rate decrease for RG&E Electric.

On February 19, 2016, RG&E 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 RG&E 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	$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 was set at 9.00%. The equity ratio for each company is 48%; however, the equity ratio is set at the lower of actual equity ratio or 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) and any subsequent rate years 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 continued 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 maintained 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 modified 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 established 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 implemented the RAM, which is 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 provided 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 included downward-only reconciliations for the costs of: electric distribution and gas vegetation management; pipeline integrity; and other incremental maintenance programs. The Proposal provided 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 a series of extensions of the litigation schedule to allow the Company, the Department of Public Service Staff ("DPS Staff"), and other parties to enter into and conduct settlement discussions. A Joint Proposal for a three-year rate plan term was filed on June 22, 2020. A modified Joint Proposal was approved by the NYPSC on November 19, 2020, which included modifications to the electric business proposed rate increases to limit the projected total bill increases to 2% per year in consideration of the current COVID-driven economic climate. The effective date of new tariffs was December 1, 2020 with a make-whole provision back to April 17, 2020. The approved Joint Proposal includes several COVID-19 provisions, including the provision of up to $13.5 million in bill credits for the Company's most vulnerable residential and small business customers. The Joint Proposal bases delivery revenues on an 8.80% ROE and 48% equity ratio; however, for the proposed earnings sharing mechanism, the equity ratio is the lower of the actual equity ratio or 50%. The approved Joint Proposal was signed in whole or in part by more than 20 parties, and includes delivery rate increases (excluding the impact of moving energy efficiency costs from a surcharge to delivery rates) as summarized below:

	May 1, 2020		May 1, 2021		May 1, 2022	
	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %
Electric	$16.8	3.8%	$13.9	3.2%	$15.8	3.3%
Gas	$0.0	0.0%	$0.0	0.0%	$2.4	1.3%

The approved Joint Proposal also reflects increased distribution vegetation management, investments in aging infrastructure, and increases in the Company's workforce, as well as continuation of many of the components of the last Joint Proposal described above. The rate plans continue the RAM designed to return or collect certain defined reconciled revenues and costs, have new depreciation rates and continue RDMs for each business.

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 and filed their next bi-annual update on June 30, 2020.

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 was included in the companies' May 20, 2019 rate filing and is reflected in the recently approved Rate Plan.

In March 2017, the NYPSC issued three separate REV-related orders. These orders created a series of filing requirements for RG&E beginning in March 2017 and extending through the end of 2018. The three orders involve: 1) modifications to the electric utilities' proposed interconnection EAM framework; 2) further DSIP requirements, including 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.

The March 2017 Order stated that should a new compensation methodology not be in place by January 1, 2020, mass market 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 December 9, 2019, DPS Staff filed a whitepaper on rate design for mass market NEM successor tariffs. The Department of Public Service Staff (Staff) recommended the continuation of NEM as a compensation mechanism for all eligible mass market and commercial DER projects under 750 kW. Staff also proposed that these projects should be eligible for the range of options currently provided in delivery rates. For projects with load profiles or expertise that may benefit from time-varying price signals, projects would have the option to forego the use of standard delivery rates and instead utilize more sophisticated time-of-use (TOU) or new mass market standby rates, coupled with a modest charge to collect public benefit funds that are otherwise avoided by using NEM. Initial comments on the whitepaper were submitted on February 24, 2020 and reply comments were submitted on March 16, 2020. On July 16, 2020, the Commission issued an Order establishing a net metering successor tariff. The Order continues Phase One NEM for all eligible mass market and commercial projects under 750 kW interconnected after January 1, 2022, and implements a modest customer benefit contribution (CBC) for onsite DERs to address cost recovery of certain public benefit programs. Customers that install DERs interconnected after January 1, 2022 shall be charged a monthly per kW fee based on the nameplate rating of the DER. Draft tariff leaves implementing the Commission’s Order and proposed CBC calculations were filed on November 1, 2020.

On April 18, 2019, the Commission issued an Order on Future Value Stack Compensation and Capacity Value Compensation. The Order established 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 expanded eligibility for Phase One Net Metering for certain projects that have a rated capacity of 750 kW AC or lower. The changes became effective on June 1, 2019. The NYPSC also issued an Order on Value Stack Compensation for High-Capacity-Factor Resources on December 12, 2019, modifying the treatment of certain high-capacity-factor DER in the Value Stack compensation framework. The modification per the December 12, 2019 Order became effective February 1, 2020. On March 19, 2020, the Commission issued an additional Order regarding Value Stack Compensation. The Order directed National Grid, NYSEG, and RGE to reallocate capacity from closed tranches where available capacity remained due to projects being canceled since the issuance of the VDER Compensation Order, and to assign that capacity to a new Community Credit Tranche with compensation at 2 cents per kWh. The utilities must also continue to reallocate capacity to this new Tranche for the next six months when there are cancellations of projects that have received a Market Transition Credit (MTC) or Community Credit allocation. The new provisions per the March 19, 2020 Order became effective May 1, 2020.

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 requested preliminary comments from stakeholders by November 25, 2019, and additional information from the Utilities in February 2020 regarding their marginal cost methodologies. At this time it is not known when the DPS Staff whitepaper on marginal cost methodologies will be issued.

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. RG&E filed draft tariffs on September 23, 2019 as required, with further analysis and discussion regarding approval and implementation of the optional rates occurring through the Rate Design Working Group of the VDER proceeding.

On November 25, 2020 DPS Staff, jointly with NYSERDA, issued a whitepaper on further recommendations regarding standby and buyback rates that were based on the electric utilities' September 23, 2019 filings. Comments on the recommendations in the whitepaper are due March 8, 2021, and reply comments are due April 12, 2021.

On May 14, 2020, the Commission issued an Order extending and expanding distributed solar incentives. In addition to authorizing the extension of and additional funding for the NY-Sun program, the Commission modified certain program rules related to the NY-Sun program and the VDER policy. As part of the ordered modifications, the Commission directed the electric utilities with VDER tariffs to add tariff language for a Remote Crediting program that will allow Value-Stack-eligible generation resources to distribute the credits they receive for generation injected into the utility system to the utility bills of multiple, separately sited, non-residential customers. The Commission ordered the utilities to submit tariff leaves that implement the modifications associated with the Remote Crediting program to become effective November 1, 2020. Given the complexity of the program changes, the utilities petitioned the Commission for tariffs filings to be made on February 15, 2021, with an effective date of March 1, 2021. Stakeholders have since requested residential customers be permitted to participate as remote crediting satellites and the frequency of credit allocation and adding/removing satellites be increased to allow for monthly changes rather than annual changes only. Given these requests, the Commission granted the utilities an additional extension to file tariffs by August 2, 2021, to become effective August 16, 2021.

On April 24, 2018, the Commission instituted a proceeding to consider the role of utilities in providing infrastructure and rate design to encourage the expansion electric vehicles and electric vehicle supply equipment. The Commission issued an Order on February 2, 2019 to establish a Direct Current Fast Charger incentive program, and subsequently clarified its Order on July 12, 2019 and March 3, 2020. A Whitepaper was issued by DPS Staff on January 13, 2020, proposing a make-ready infrastructure program with a budget estimated at $582 million. Utilities and other stakeholders filed comments on April 27, 2020 regarding the make-ready program proposal. Reply comments are due May 11, 2020. An order in this proceeding was issued by the Commission on July 16, 2020.

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 over more than a million electric utility customers in New York, including 520,000 NYSEG and RG&E customers, the New York Public Service Commission ("NYPSC") initiated a comprehensive investigation of all the New York electric utilities' preparation and response to those events. The investigation has been expanded to include other 2018 New York spring storm events.

On April 18, 2019 the New York Public Service Department (NYPSD) 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 ("ERPs"). 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 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 through December 31, 2019 to respond to the portion of the Order to Show Cause with respect to why the NYPSC should not pursue a penalty action. A joint settlement agreement to avoid litigation including NYSEG and RG&E's agreement to pay a penalty of $10.5 million (allocated as $9.0 million to NYSEG and $1.5 million to RG&E) was filed with the NYPSC on December 17, 2019. On February 6, 2020, the NYPSC approved the joint settlement agreement, and the penalty amount is reflected as a rate moderator in the recently approved rate case Joint Proposal.

NYDPS Investigation of the Preparation for and Response to the Tropical Storm Isaias

On August 5, 2020, the NYDPS commenced an investigation into the preparation for and response to the Tropical Storm Isaias by several utilities in New York including RG&E. In addition, the New York State Senate and Assembly held a joint hearing to examine the response of various utility companies during the aftermath of Tropical Storm Isaias. The investigation is ongoing. In August, 2020, the Company received a letter from the Department of Public Service requesting a series of follow-on actions, which the Company has completed or is in the process of completing. At its November 19, 2020 session, the NYPSC provided an interim status report on the investigation and RG&E was not identified in the report other than to acknowledge the letter regarding follow-on actions that had been received by the Company. We cannot predict the final outcome of this investigation.

New York State Public Service Commission Show Cause Order Regarding Greenlight Pole Attachments

On November 20, 2020, the NYPSC issued an Order Instituting Proceeding and to Show Cause (the Show Cause Order) regarding alleged violations of the NYPSC's 2004 Order Adopting Policy Statement on Pole Attachments, dated August 6, 2004 (the 2004 Pole Order) by RG&E, Greenlight Networks, Inc, (Greenlight), and Frontier Communications (Frontier). The alleged violations detailed in the Show Cause Order arise from Greenlight's installation of unauthorized and substandard communications attachments throughout RG&E's and Frontier's service territories. The Show Cause Order directs RG&E to show cause within 30 days why the NYPSC should not pursue civil and/or administrative penalties or initiate a prudency proceeding or civil action for injunctive relief for more than 11,000 alleged violations of the 2004 Pole Order. Under NY Public Service Law Section 25-a, each alleged violation carries a potential penalty of up to $100,000 where it can be shown that the violator failed to "reasonably comply" with a statute or NYPSC order.

RG&E, Greenlight and Frontier filed respective notices to initiate settlement negotiations with respect to the alleged violations and to extend the deadline for filing a response to the Show Cause Order. The NYPSC granted the extension requests initiating settlement discussions. We cannot predict the 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 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 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 recently approved Joint Proposal associated with the Company's last rate case.

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 $169.7 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 November 19, 2020, the NYPSC approved the proposal in connection with a three-year rate plan for electric and gas service at RG&E effective April 17, 2020. 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 forty-six years. A majority of the other items related to RG&E will be amortized over a five-year period. In accordance with the Schedule of Regulatory Amortizations included in the approved Joint Proposal, net annual amortization revenue for RG&E is approximately $46.3 million for the year ended December 31, 2020.

Current and non-current regulatory assets at December 31, 2020 and 2019 consisted of:

December 31,		2020		2019
(Thousands)				
Current				
Decommissioning	$	676	$	4,856
Environmental remediation costs		—		6,363
Federal tax depreciation normalization adjustment		1,413		—
Hedge losses		6,879		10,945
Low income program		1,393		—
Pension and other postretirement benefits cost deferrals		7,388		—
Post Term Amortization		904		—
Rate adjustment mechanism		1,345		14,907
REV demand response		1,003		—
Revenue decoupling mechanism		13,898		8,554
Storm costs		9,804		—
Unfunded future income taxes		—		2,738
Other		4,592		3,965
Total current regulatory assets	**$**	**49,295**	**$**	**52,328**
Non-current				
Asset retirement obligation	$	3,203	$	3,201
Decommissioning		1,546		—
Environmental remediation costs		53,841		73,569
Federal tax depreciation normalization adjustment		45,001		45,940
Low income program		8,363		—
Pension and other postretirement benefits		69,590		71,320
Pension and other postretirement benefits cost deferrals		25,064		42,335
Post term amortization		3,013		—
Rate adjustment mechanism		589		20,180
Storm costs		43,912		27,064
Unamortized losses on reacquired debt		4,564		5,008
Unfunded future income taxes		136,389		125,378
Other		18,723		19,738
Total long-term regulatory assets	**$**	**413,798**	**$**	**433,733**

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. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is seven years and began in 2020. 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. It is being amortized over a thirty-five year period starting in 2020.

Hedge losses represents deferred fair value losses on electric and gas hedge contracts.

Low income programs represent various hardship and payment plan programs approved for recovery. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is five years and began in 2020.

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.

Post term amortization represents the amortization costs deferred from previous rate cases. It is being amortized over a five-year period starting in 2020.

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.

REV demand response are the costs associated with the Reforming the Energy Program to rapidly develop and scale a clean and resilient energy economy, yet keep affordability for customers.

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.

Other includes items such as electric supply reconciliation and unamortized loss on reacquired debt.

Deferred income taxes regulatory: see Note 1.

Current and non-current regulatory liabilities at December 31, 2020 and 2019 consisted of:

December 31,		2020		2019
(Thousands)				
Current				
Asset sale gain account	$	5,444	$	—
Carrying costs on deferred income tax bonus depreciation		8,114		10,000
Debt rate reconciliations		5,670		—
Delivery rate shaping		8,165		—
Earnings sharing		2,106		—
Economic development		3,000		—
Electric supply reconciliation		—		860
Energy efficiency programs		6,335		35,739
Environmental costs		7,509		—
Gas supply charge		1,898		5,461
Mixed use 263(a)		1,236		—
Net plant reconciliation		4,520		—
Nine Mile II - TCC		4,229		—
Positive benefit adjustment utilization		6,528		—
Property tax		6,939		—
Rate adjustment mechanism		—		5,280
Reliability support services		1,528		—
Tax Act – remeasurement		18,231		6,439
Unfunded future income taxes		3,124		—
Other		8,952		3,897
Total current regulatory liabilities	**$**	**103,528**	**$**	**67,676**
Non-current				
Accrued removal obligations	$	192,794	$	187,927
Asset sale gain account		1,827		10,851
Carrying costs on deferred income tax bonus depreciation		19,854		25,769
Debt rate reconciliations		19,057		26,124
Deferred property taxes		17,651		15,225
Deferred transmission congestion contracts		17,739		23,293
Earnings sharing		8,997		12,326
Economic development		17,373		19,936
Energy efficiency programs		21,599		—
Merger capital expense		3,969		5,953
NEIL (Nuclear Electric Insurance Limited) credits		9,606		7,147
Net plant reconciliation		15,392		22,656
Pension and other postretirement benefits		2,080		8,246
Pension and other postretirement benefits cost deferrals		1,185		4,260
Positive benefit adjustment		21,759		32,639
Rate adjustment mechanism		—		5,280
Tax Act – remeasurement		271,217		297,409
Theoretical reserve flow through impact		4,186		6,279
Other		57,521		37,733
Total non-current regulatory liabilities	**$**	**703,806**	**$**	**749,053**

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.

Asset sale gain account represents the net gain on the sale of certain assets that will be used for the future benefit of customers. The amortization period in current rates is two years for RG&E and began in 2020.

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.

Delivery rate shaping represents the NY delivery rate levelization to smooth the rate increase across the three-year plan to avoid unnecessary spikes and offsetting dips in customer rates The amortization period in current rates is five years and began in 2020.

Earning sharing provisions represents the annual earnings over the earning sharing threshold. The amortization period in current rates is five years and began in 2020.

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.

Mixed services 263(a) represent the carrying costs benefit of increased accumulated deferred income taxes created by Section 263(a) IRC. The amortization period in current rates is three years and began in 2020.

Net plant reconciliation represents the reconciliation of the actual electric and gas net plant and book depreciation to the targets set forth in the Joint Proposal. The amortization period in current rates is five years and began in 2020.

Nine Mile transmission congestion contracts represents deferral of the Nine Mile 2 Nuclear Plant transmission congestion contract at RG&E. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is five years and began in 2020.

Positive benefit adjustment resulted from Iberdrola's 2008 acquisition of AVANGRID (formerly Energy East Corporation). The amortization period in current rates is five years and began in 2020.

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 amortization period in current rates is from one and half to ten years and began in 2020.

Other includes items such as asset retirement obligations, other taxes, and vegetation management.

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 $0.6 million at December 31, 2020, and $0.4 million at December 31, 2019, and are presented in "Other current liabilities" on our balance sheets. We recognized $1.1 million as revenue in both 2020 and 2019.

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, 2020 and 2019 are as follows:

Years Ended December 31,		2020		2019
(Thousands)				
Regulated operations – electricity	$	590,201	$	580,043
Regulated operations – natural gas		255,556		285,256
Other (a)		11,832		12,699
Revenue from contracts with customers		**857,589**		**877,998**
Leasing revenue		70		140
Alternative revenue programs		17,021		13,575
Other revenue		(2,737)		1,329
Total operating revenues	**$**	**871,943**	**$**	**893,042**

(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, 2020 and 2019 consisted of:

Years Ended December 31,		2020		2019
(Thousands)				
Current				
Federal	$	5,733	$	(6,079)
State		(2,755)		4,965
Current taxes charged to (benefit) expense		**2,978**		**(1,114)**
Deferred				
Federal		7,608		31,850
State		9,049		2,618
Deferred taxes charged to expense (benefit)		**16,657**		**34,468**
Total Income Tax Expense	**$**	**19,635**	**$**	**33,354**

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, 2020 and 2019, respectively, consisted of:

Years Ended December 31,		2020		2019
(Thousands)				
Tax expense at federal statutory rate	$	27,957	$	26,924
Equity AFUDC tax impacts not normalized		(4,052)		(10,026)
Excess ADIT amortization		(6,418)		—
State tax expense, net of federal benefit		4,972		5,990
Other, net		(2,824)		10,466
Total Income Tax Expense	**$**	**19,635**	**$**	**33,354**

Income tax expense for the year ended December 31, 2020 was $8.3 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to Excess ADIT amortization and Equity AFUDC tax effects, partially offset by state tax expense. This resulted in an effective tax rate of 14.7%. 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 taxes, partially offset by Equity AFUDC tax effects. This resulted in an effective tax rate of 26.0%.

In 2020, RG&E began refunding previously deferred protected and unprotected Excess ADITs, established as a result of the 2017 Tax Act as part of the 2020 Joint Proposal and as determined by the NYPSC and IRS normalization rules.

Deferred tax assets and liabilities as of December 31, 2020 and 2019 consisted of:

December 31,		**2020**		**2019**
(Thousands)				
Non-current Deferred Income Tax Liabilities (Assets)				
Property related	$	491,224	$	459,299
Unfunded future income taxes		33,045		29,068
Storms		14,184		16,916
Regulatory liability due to "Tax Cuts and Jobs Act"		(75,648)		(79,410)
Pension and other postretirement benefits		(18,134)		(16,241)
Derivative assets		(12,640)		(14,903)
Environmental		(13,033)		(13,781)
Federal and state NOLs		(4,436)		(1,564)
Other		(49,441)		(48,273)
Total Non-current Deferred Income Tax Liabilities	**$**	**365,121**	**$**	**331,111**
Deferred tax assets	$	173,332	$	174,172
Deferred tax liabilities		538,453		505,283
Net Accumulated Deferred Income Tax Liabilities	**$**	**365,121**	**$**	**331,111**

RG&E has gross federal net operating losses of $4.1 million and gross New York state net operating losses of $69.7 million for the year ended December 31, 2020. RG&E had no gross federal net operating losses and gross New York state net operating losses of $30.5 million for the year ended December 31, 2019.

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. In 2020 and 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, 2020 and 2019 consisted of:

Years Ended December 31,		**2020**		**2019**
(Thousands)				
Beginning Balance	$	49,674	$	49,961
Reduction for tax positions related to prior years		(287)		(287)
Ending Balance	**$**	**49,387**	**$**	**49,674**

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, 2020 and December 31, 2019.

Note 6. Long-term Debt

Long-term debt as of December 31, 2020 and 2019 consisted of:

As of December 31,		2020		2019	
(Thousands)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
First mortgage bonds (a)	2021-2033	$ 1,160,500	1.85%-8.00%	$ 900,000	3.10%-8.00%
Unsecured pollution control notes - fixed	2025	91,900	3.00%	152,400	2.875%-3.00%
Unamortized debt issuance cost and discount		(10,526)		(7,197)	
Total Debt		**$ 1,241,874**		**$ 1,045,203**	
Less: debt due within one year, included in current liabilities		123,738		—	
Total Non-current Debt		**$ 1,118,136**		**$ 1,045,203**	

(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.

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%.

On November 23, 2020, RG&E issued $200 million aggregate principal amount of first mortgage bonds maturing in 2030 at an interest rate of 1.85%.

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

2021	2022	2023	2024	2025	Total
(Thousands)					
$ 123,738	$ —	$ —	$ —	$ 152,400	$ 276,138

We have no financial debt covenant requirements related to our long-term debt at December 31, 2020 and 2019.

Note 7. Bank Loans and Other Borrowings

RG&E had no notes payable as of December 31, 2020 and $33.2 million of notes payable outstanding as of December 31, 2019. 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. RG&E had no debt outstanding under this agreement as of December 31, 2020 and December 31, 2019.

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 no debt outstanding under this agreement as of December 31, 2020 and $33.2 million outstanding as of December 31, 2019.

On June 29, 2018, AGR and its investment-grade rated utility subsidiaries (New York State Electric and Gas Corporation (“NYSEG”), Rochester Gas and Electric Corporation (“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. Effective on June 29, 2019, the termination date for the AGR Credit Facility was extended to June 29, 2024.

Under the terms of the AGR Credit Facility, each 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. 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. Effective on June 29, 2020, the AGR Credit Facility was amended to reduce AGR’s maximum sublimit to $1.5 billion and to establish minimum sublimits of $400 million for NYSEG, $250 million for RG&E, $150 million for UI, $100 million for CMP, $40 million for CNG and SCG, and $20 million for BGC. Under the AGR Credit Facility, each of the borrowers are charged a facility fee that is dependent on their credit rating. The facility fees range from 10.0 to 17.5 basis points. RG&E had not borrowed under this agreement as of both December 31, 2020 and December 31, 2019.

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 0.52 to 1.00 at December 31, 2020. We are not in default as of December 31, 2020.

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 15 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:

For the Years Ended December 31,	2020	2019
(Thousands)		
Lease cost		
Finance lease cost		
Amortization of right-of-use assets	$ 6,636	$ 2,264
Interest on lease liabilities	1,465	528
Total finance lease cost	8,101	2,792
Operating lease cost	938	2,337
Short-term lease cost	193	102
Variable lease cost	(103)	332
Intercompany	93	48
Total lease cost	**$ 9,222**	**$ 5,611**

Balance sheet and other information for the years ended December 31, 2020 and 2019 was as follows:

As of December 31,	2020	2019
(Thousands, except lease term and discount rate)		
Operating Leases		
Operating lease right-of-use assets	$ 1,774	$ 9,469
Operating lease liabilities, current	142	1,344
Operating lease liabilities, long-term	2,618	9,026
Total operating lease liabilities	$ 2,760	$ 10,370
Finance Leases		
Other assets	$ 47,809	$ 9,307
Other current liabilities	3,692	1,757
Other non-current liabilities	46,379	5,611
Total finance lease liabilities	$ 50,071	$ 7,368
Weighted-average Remaining Lease Term (years):		
Finance leases	8.83	3.92
Operating leases	5.23	5.19
Weighted-average Discount Rate:		
Finance leases	2.89 %	6.53 %
Operating leases	3.27 %	3.31 %

Supplemental cash flows information related to leases was as follows:

For the Years Ended December 31,	2020	2019
(Thousands)		
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 455	$ 1,503
Operating cash flows from finance leases	$ 1,101	$ 528
Financing cash flows from finance leases	$ 2,436	$ 2,259
Right-of-use assets obtained in exchange for lease obligations:		
Finance leases	$ 45,138	$ 850
Operating leases	$ 8	$ 365

As of December 31, 2020, maturities of lease liabilities were as follows:

	Finance Leases	Operating Leases
(Thousands)		
Years ending December 31,		
2021	$ 4,927	$ 121
2022	4,956	111
2023	4,822	2,162
2024	22,059	54
2025	1,698	54
Thereafter	19,486	606
Total lease payments	**57,948**	**3,108**
Less: imputed interest	(7,877)	(348)
Total	**$ 50,071**	**$ 2,760**

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.

Note 9. Commitments and Contingencies

Purchase power and natural gas contracts, including non-utility 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 $44.7 million for Normal Purchase Normal Sale (NPNS) purchase power and natural gas contracts including non-utility generators in 2020 and $43.9 million in 2019.

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, eight 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, 2020, related to eight sites. We have recorded an estimated liability of $5.5 million related to another six 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 $5.3 million to $6.2 million as of December 31, 2020. 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 eleven 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 eleven sites ranges from $81.3 million to $111.9 million at December 31, 2020. 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 $90.4 million at December 31, 2020, and $128.3 million at December 31, 2019. 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 2050.

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, 2020 and 2019 and amounts reclassified from regulatory assets and liabilities into income for the years ended December 31, 2020 and 2019 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, 2020	**Electricity**	**Natural Gas**	**2020**	**Electricity**	**Natural Gas**
Regulatory assets	$ 6,914	$ 528	Purchased power, natural gas and fuel used	$ 20,084	$ 2,870
Regulatory liabilities	$ —	$ —			
December 31, 2019			**2019**		
Regulatory assets	$ 8,529	$ 2,902	Purchased power, natural gas and fuel used	$ 8,520	$ 433
Regulatory liabilities	$ —	$ —			

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

	Electricity Contracts	Natural Gas Contracts	Other Fuel Contracts
Years to settle	**Mwhs**	**Dths**	**Gallons**
As of December 31, 2020			
2021	1,662,800	5,630,000	402,000
2022	540,000	900,000	—
As of December 31, 2019			
2020	1,489,775	4,960,000	367,900
2021	438,000	840,000	—

The offsetting of derivatives, location in the balance sheet and amounts of derivatives as of December 31, 2020 and 2019, respectively, consisted of:

December 31, 2020	Derivative Assets Current	Derivative Assets Non-current	Derivative Liabilities Current	Derivative Liabilities Non-current
(Thousands)				
Not designated as hedging instruments				
Derivative assets	$ 1,173	$ 754	$ 1,173	$ 754
Derivative liabilities	(1,173)	(754)	(8,052)	(1,317)
	—	—	(6,879)	(563)
Designated as hedging instruments				
Derivative assets	7	—	7	—
Derivative liabilities	(7)	—	(74)	—
	—	—	(67)	—
Total derivatives before offset of cash collateral	—	—	(6,946)	(563)
Cash collateral receivable	—	—	6,879	563
Total derivatives as presented in the balance sheet	**$ —**	**$ —**	**$ (67)**	**$ —**

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)**	**$ —**

As of both December 31, 2020 and 2019, 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, 2020 and 2019, respectively, consisted of:

Years Ended December 31,	(Loss) Gain Recognized in OCI on Derivatives	Location of Loss Reclassified From Accumulated OCI into Income	Loss Reclassified From Accumulated OCI into Income	Total Amount per Income Statement
(Thousands)				
2020				
Interest rate contracts	$ —	Interest expense	$ (3,678)	$ 46,186
Commodity contracts: Other	(159)	Other operating expenses	(164)	288,655
Total	**$ (159)**		**$ (3,842)**	
2019				
Interest rate contracts	$ —	Interest expense	$ (4,723)	$ 70,784
Commodity contracts: Other	89	Other operating expenses	(166)	282,270
Total	**$ 89**		**$ (4,889)**	

The amount in AOCI related to previously settled forward starting interest rate swaps and accumulated amortization, at December 31, 2020 is a net loss of $48.3 million as compared to $52.0 million at December 31, 2019. For the year ended December 31, 2020, we recorded $3.7 million in net derivative losses related to discontinued cash flow hedges. We will amortize approximately $3.7 million of discontinued cash flow hedges in 2021.

As of December 31, 2020, $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, 2020 is $12.3 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 $1,538 million as of December 31, 2020 and $1,249 million as of December 31, 2019. 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, 2020 and 2019 consisted of:

Description	Level 1	Level 2	Level 3	Netting	Total
(Thousands)					
As of December 31, 2020					
Assets					
Derivatives					
Commodity contracts:					
Electricity	1,770	—	—	(1,770)	—
Natural Gas	157	—	—	(157)	—
Other	—	—	7	(7)	—
Total	**$ 1,927**	**$ —**	**$ 7**	**$ (1,934)**	**$ —**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	$ (8,684)	$ —	$ —	$ 8,684	$ —
Natural gas	(685)	—	—	685	—
Other	—	—	(74)	7	(67)
Total	**$ (9,369)**	**$ —**	**$ (74)**	**$ 9,376**	**$ (67)**

Description	Level 1	Level 2	Level 3	Netting	Total
(Thousands)					
As of December 31, 2019					
Assets					
Non-current 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)**

We had no transfers to or from Level 1 and 2 during the year ended December 31, 2020. 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 non-current 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, 2020 and 2019 consisted of:

Years Ended December 31,	2020	2019
(Thousands)		
Beginning balance	$ (72)	$ (327)
Realized losses included in earnings	164	166
Unrealized gains (losses) included in other comprehensive income	(159)	89
Ending balance	**$ (67)**	**$ (72)**

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, 2020 and 2019, consisted of:

	Balance December 31, 2018	Adoption of new accounting standard	2019 Change	Balance December 31, 2019	2020 Change	Balance December 31, 2020
(Thousands)						
Net unrealized holding gain on investments	$ 39	$ —	$ (39)	$ —		$ —
Amortization of pension cost for non-qualified plans, net of tax (benefit) expense of $(100) for 2019 and $159 for 2020	(1,379)	—	(283)	(1,662)	(1,008)	(2,670)
(Loss) gain on non-qualified pension plans	(54)	—	—	(54)	54	—
Unrealized gain (loss) on derivatives qualified as hedges:						
Unrealized gain (loss) during period on derivatives qualified as hedges, net of income tax expense (benefit) of $37 for 2019 and $(34) for 2020	—	—	105	—	(180)	—
Reclassification adjustment for loss included in net income, net of income tax expense of $43 for 2019 and $35 for 2020	—	(8,643)	123	—	129	—
Reclassification adjustment for loss on settled cash flow treasury hedges included in net income, net of income tax expense of $1,235 for 2019 and $775 for 2020	—	—	3,488	—	2,903	—
Net unrealized (loss) gain on derivatives qualified as hedges	(33,646)	(8,643)	3,716	(38,573)	2,852	(35,721)
Accumulated Other Comprehensive (Loss) Income	**$ (35,040)**	**$ (8,643)**	**$ 3,394**	**$ (40,289)**	**$ 1,898**	**$ (38,391)**

Note 14. Post-retirement and Similar Obligations

We have funded non-contributory 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 $3.6 million in 2020 and $3.3 million 2019.

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.

Non-Qualified Retirement Benefit Plans

We also sponsor various unfunded pension plans for certain current employees, former employees and former directors. The total liability for these plans, which is included in Other non-current liabilities on our balance sheets, was $12.0 million and $11.5 million at December 31, 2020 and 2019, respectively.

Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2020 and 2019 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2020**	**2019**	**2020**	**2019**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	$ 378,559	$ 377,221	$ 65,882	$ 64,646
Service cost	5,696	5,388	148	148
Interest cost	10,574	14,114	1,855	2,440
Actuarial loss/(gain)	33,615	20,316	3,082	2,339
Benefits paid	(35,618)	(38,480)	(3,499)	(3,691)
Benefit obligation at December 31	**$ 392,826**	**$ 378,559**	**$ 67,468**	**$ 65,882**
Change in plan assets				
Fair value of plan assets at January 1	$ 286,899	$ 266,734	$ —	$ —
Actual return on plan assets	37,249	45,639	—	—
Employer and plan participants' contributions	12,390	13,006	3,499	3,691
Benefits paid	(35,619)	(38,480)	(3,499)	(3,691)
Fair value of plan assets at December 31	**$ 300,919**	**$ 286,899**	**$ —**	**$ —**
Funded status	**$ (91,907)**	**$ (91,660)**	**$ (67,468)**	**$ (65,882)**

During 2020, the pension benefit obligation had an actuarial loss of $33.6 million, primarily due to a $35.1 million loss from decreases in discount rates. There were no significant gains or losses relating to the postretirement benefit obligations.

During 2019, the pension benefit obligation had an actuarial loss of $20.3 million, primarily due to a $26.8 million loss from decreases in discount rates. There were no significant gains or losses relating to the postretirement benefit obligations.

Amounts recognized in the balance sheet as of December 31, 2020 and 2019 consisted of:

Amounts recognized in the balance sheet	**Pension Benefits**		**Postretirement Benefits**	
December 31,	**2020**	**2019**	**2020**	**2019**
(Thousands)				
Other current liabilities	$ —	$ —	$ (5,176)	$ (5,149)
Pension and other postretirement benefits	(91,907)	(91,660)	(62,292)	(60,733)
Total	**$ (91,907)**	**$ (91,660)**	**$ (67,468)**	**$ (65,882)**

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,	**2020**	**2019**	**2020**	**2019**
(Thousands)				
Net loss (gain)	$ 69,590	$ 68,981	$ 288	$ (2,149)
Prior service cost (credit)	$ —	$ —	$ (2,368)	$ (3,758)

Our accumulated benefit obligation for all qualified defined benefit pension plans was $364.2 million at December 31, 2020 and $349.5 million at December 31, 2019.

The projected benefit obligation and the accumulated benefit obligation exceeded the fair value of pension plan assets for all of our qualified plans as of both December 31, 2020 and 2019. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets of our plans as of December 31, 2020 and 2019.

December 31,	**2020**	**2019**
(Thousands)		
Projected benefit obligation	$ 392,826	$ 378,559
Accumulated benefit obligation	$ 364,166	$ 349,475
Fair value of plan assets	$ 300,919	$ 286,899

The postretirement benefits obligation for all qualified plans exceeded the fair value of plan assets as of December 31, 2020 and 2019.

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, 2020 and 2019 consisted of:

Years Ended December 31,	Pension Benefits 2020	Pension Benefits 2019	Postretirement Benefits 2020	Postretirement Benefits 2019
(Thousands)				
Net periodic benefit cost				
Service cost	$ 5,696	$ 5,388	$ 148	$ 148
Interest cost	10,574	14,114	1,855	2,440
Expected return on plan assets	(19,697)	(20,437)	—	—
Amortization of prior service cost (credit)	—	—	(1,390)	(1,390)
Amortization of net loss	15,454	14,062	644	663
Net periodic benefit cost	**$ 12,027**	**$ 13,127**	**$ 1,257**	**$ 1,861**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net (gain) loss	$ 16,063	$ (4,886)	$ 3,081	$ 2,339
Amortization of net (loss)	(15,454)	(14,062)	(644)	(663)
Prior service credit/(cost)	—	—	—	1,390
Amortization of prior service (cost) credit	—	—	1,390	—
Total recognized in regulatory assets and regulatory liabilities	609	(18,948)	3,827	3,066
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$ 12,636**	**$ (5,821)**	**$ 5,084**	**$ 4,927**

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.

The weighted-average assumptions used to determine benefit obligations as of December 31, 2020 and 2019 consisted of:

	Pension Benefits 2020	Pension Benefits 2019	Postretirement Benefits 2020	Postretirement Benefits 2019
Discount rate	1.70%	2.93%	2.00%	2.93%
Rate of compensation increase	Age-Related Rates	Age-Related Rates	3.00 %	Age-Related Rates
Interest crediting rate	2.00%	2.00%	N/A	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, 2020 and 2019 consisted of:

	Pension Benefits		Postretirement Benefits	
	2020	2019	2020	2019
Discount rate	2.93%	3.93%	2.93%	3.93%
Expected long-term return on plan assets	7.30%	7.30%	—	—
Expected long-term return on plan assets, non-taxable trust	—	—	6.40%	6.40%
Expected long-term return on plan assets, taxable trust	—	—	4.20%	4.20%
Rate of compensation increase	Age-Related Rates	3.90%	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, 2020 and 2019 consisted of:

	2020	2019
Health care cost trend rate (pre 65/post 65)	6.75%/7.50%	6.75%/7.50%
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

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 $21.1 million and $5.2 million, respectively, to our pension and other postretirement benefit plans during 2021.

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)			
2021	$ 35,290	$ 5,176	$ —
2022	$ 33,757	$ 5,031	$ —
2023	$ 33,574	$ 4,890	$ —
2024	$ 32,542	$ 4,712	$ —
2025	$ 31,380	$ 4,537	$ —
2026-2030	$ 136,175	$ 20,158	$ —

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.

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, by asset category, as of December 31, 2020, consisted of:

		Fair Value Measurements at December 31, Using		
Asset Category	**Total**	**Level 1**	**Level 2**	**Level 3**
(Thousands)				
2020				
Cash and cash equivalents	$ 13,333	$ 10	$ 13,323	$ —
U.S. government securities	17,226	17,221	5	—
Common stocks	10,523	10,523	—	—
Registered investment companies	29,241	29,241	—	—
Corporate bonds	69,102	—	69,102	—
Preferred stocks	96	96	—	—
Common collective trusts	94,232	—	94,232	—
Other investments, principally annuity and fixed income	6,642	617	6,025	—
	$ 240,395	**$ 57,708**	**$ 182,687**	**$ —**
Other investments measured at net asset value	60,524			
Total	**$ 300,919**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2019, consisted of:

		Fair Value Measurements at December 31, Using		
Asset Category	**Total**	**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**			

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, 2020 and 2019.

Note 15. Other Income and Other Deductions

Other income and deductions for the years ended December 31, 2020 and 2019, consisted of:

Years Ended December 31,		2020		2019
(Thousands)				
Interest and dividend income	$	87	$	991
Allowance for funds used during construction		20,739		15,879
Gain on sale of property		15		9
Carrying costs on regulatory assets		5,941		6,719
Miscellaneous		49		523
Total other income	**$**	**26,831**	**$**	**24,121**
Pension non-service components	$	(8,133)	$	(9,675)
Miscellaneous		(4,919)		(2,668)
Total other deductions	**$**	**(13,052)**	**$**	**(12,343)**

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 was approximately $58.3 million in 2020 and $52.9 million in 2019. Cost for services includes amounts capitalized in utility plant, which was approximately $8.2 million in 2020 and $6.4 million in 2019. The remainder was primarily recorded as operations and maintenance expense. The charge for services provided by RG&E to AGR and its subsidiaries was approximately $14.3 million in 2020 and $14.4 million in 2019. 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 $16.3 million at December 31, 2020 and $12.3 million at December 31, 2019 is mostly payable to Avangrid Service Company. The balance in accounts receivable from affiliates of $4.8 million at December 31, 2020 and $2.7 million at December 31, 2019 is from various companies.

Of the balance in notes receivable from affiliates of $19.2 million at December 31, 2020, $11.7 million is from CMP and $7.5 million is from BGC. There were no notes receivable from affiliates at December 31, 2019. 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, 2021, which is the date these financial statements were available to be issued.

THE SOUTHERN CONNECTICUT GAS COMPANY

AUDITED CONSOLIDATED FINANCIAL STATEMENTS

AS OF AND FOR THE YEARS ENDED

DECEMBER 31, 2020 AND 2019

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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, 2020 and 2019, and the related consolidated statements of income, comprehensive 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, 2020 and 2019, 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 9, 2021

THE SOUTHERN CONNECTICUT GAS COMPANY
CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31,	2020	2019
(Thousands)		
Operating Revenues	$ 353,243	$ 390,789
Operating Expenses		
Natural gas purchased	133,789	176,607
Operation and maintenance	89,828	85,980
Depreciation and amortization	41,260	37,824
Taxes other than income taxes	30,654	31,379
Total Operating Expenses	295,531	331,790
Operating Income	57,712	58,999
Other Income and (Expense), net	(5,126)	(3,943)
Interest Expense, net	15,636	15,120
Income Before Income Tax	36,950	39,936
Income Tax	10,748	10,151
Net Income	$ 26,202	$ 29,785
Less: Net Income Attributable to Noncontrolling Interest	1,683	1,921
Net Income Attributable to The Southern Connecticut Gas Company	$ 24,519	$ 27,864

THE SOUTHERN CONNECTICUT GAS COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31,	2020	2019
(Thousands)		
Net Income	$ 26,202	$ 29,785
Other Comprehensive Income, net of income tax		
Amortization of pension cost for non-qualified plans, net of tax expense	(5,032)	-
Total Other Comprehensive Income, net of income tax	21,170	29,785
Comprehensive Income		
Less: Comprehensive Income Attributable to Noncontrolling Interest	1,683	1,921
Comprehensive Income Attributable to The Southern Connecticut Gas	$ 19,487	$ 27,864

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

Years Ended December 31,	2020	2019
(Thousands)		
Cash Flows From Operating Activities		
Net income	$ 26,202	$ 29,785
Adjustments to reconcile net income to net cash provided by operating		
Depreciation and amortization	41,559	38,138
Uncollectible expense	4,797	8,189
Deferred income taxes	21,892	32,326
Pension expense	5,040	6,144
Regulatory assets/liabilities amortization	(1,641)	(1,386)
Regulatory assets/liabilities carrying cost	1,945	976
Other non-cash items, net	3,174	182
Changes in:		
Accounts receivable and unbilled revenue, net	(5,801)	(13,397)
Gas in storage	3,786	332
Accounts payable and accrued liabilities	(3,735)	(6,259)
Taxes accrued/refundable, net	(9,940)	(1,269)
Interest accrued	41	1,439
Accrued pension and other post-retirement	(11,266)	(8,350)
Regulatory assets/liabilities	(82)	11,390
Other assets	8,461	(7,122)
Other liabilities	(3,290)	(1,736)
Total Adjustments	54,940	59,597
Net Cash provided by Operating Activities	81,142	89,382
Cash Flows from Investing Activities		
Plant expenditures including AFUDC debt	(88,952)	(81,935)
Notes receivable from affiliates	(5,391)	(1,138)
Net Cash used in Investing Activities	(94,343)	(83,073)
Cash Flows from Financing Activities		
Issuances of long-term debt	50,000	75,000
Equity infusion from parent	40,000	18,000
Payment of common stock dividend	(55,000)	-
Notes payable to affiliates	(19,321)	(100,484)
Other	(295)	(448)
Net Cash provided by (used in) Financing Activities	15,384	(7,932)
Cash, Restricted Cash, and Cash Equivalents:		
Net change for the period	2,183	(1,623)
Balance at beginning of period	836	2,459
Balance at end of period	$ 3,019	$ 836
Cash paid during the period for:		
Interest (net of amount capitalized)	$ 12,898	$ 11,865
Non-cash investing activity:		
Plant expenditures included in ending accounts payable	$ 8,877	$ 11,268

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

THE SOUTHERN CONNECTICUT GAS COMPANY
CONSOLIDATED BALANCE SHEETS
ASSETS

As of December 31,	2020	2019
(Thousands)		
Assets		
Current Assets		
Unrestricted cash and temporary cash investments	$ 3,019	$ 324
Accounts receivable and unbilled revenues, net	87,314	82,056
Accounts receivable from affiliates	4,558	11,212
Notes receivable from affiliates	6,529	1,138
Regulatory assets	27,707	21,050
Gas in storage	25,489	29,275
Materials and supplies	1,860	1,587
Other tax receivables	9,696	8,587
Prepayments and other current assets	424	520
Total Current Assets	166,596	155,749
Other Investments	10,683	9,832
Net Property, Plant and Equipment	864,835	816,338
Operating lease right of use assets	461	592
Regulatory Assets	133,522	137,312
Deferred Charges and Other Assets		
Goodwill	134,931	134,931
Other	181	744
Total Deferred Charges and Other Assets	135,112	135,675
Total Assets	$ 1,311,209	$ 1,255,498

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

As of December 31,	2020	2019
(Thousands)		
Liabilities		
Current Liabilities		
Notes payable to affiliates	$ 19,028	$ 38,297
Current portion of long-term debt	25,911	911
Accounts payable and accrued liabilities	58,011	62,058
Accounts payable to affiliates	7,012	13,294
Regulatory liabilities	11,672	10,766
Other current liabilities	11,541	7,338
Interest accrued	4,254	4,213
Taxes accrued	5,180	5,424
Operating lease liabilities	601	601
Total Current Liabilities	143,210	142,902
Deferred Income Taxes	75,083	52,521
Regulatory Liabilities	213,971	210,801
Other Noncurrent Liabilities		
Pension and other postretirement	64,518	62,680
Asset retirement obligations	12,599	12,434
Operating lease liabilities	267	335
Environmental remediation costs	41,464	45,659
Other	8,949	7,230
Total Other Noncurrent Liabilities	127,797	128,338
Capitalization		
Long-term debt, net of unamortized premium	267,658	243,616
Common Stock Equity		
Common stock	18,761	18,761
Paid-in capital	427,737	387,737
Accumulated other comprehensive income (loss)	(5,032)	-
Retained earnings	19,167	49,648
Net Common Stock Equity of The Southern Connecticut Gas Company	460,633	456,146
Noncontrolling interest	22,857	21,174
Total Common Stock Equity	483,490	477,320
Total Capitalization	751,148	720,936
Total Liabilities and Capitalization	$ 1,311,209	$ 1,255,498

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

	Common Stock Shares	Common Stock Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
As of December 31, 2018	1,407,072	$ 18,761	$ 369,737	$ 21,784	$ -	$ 19,253	$ 429,535
Net income attributable to The Southern Connecticut Gas Company				27,864			27,864
Net income attributable to Noncontrolling interest						1,921	1,921
Equity infusion from parent			18,000				18,000
As of December 31, 2019	1,407,072	$ 18,761	$ 387,737	$ 49,648	$ -	$ 21,174	$ 477,320
Net income attributable to The Southern Connecticut Gas Company				24,519			24,519
Net income attributable to Noncontrolling interest						1,683	1,683
Payment of common stock dividend				(55,000)			(55,000)
Equity infusion from parent			40,000				40,000
Other comprehensive income (loss), net of tax expense of $1,861					(5,032)		(5,032)
As of December 31, 2020	1,407,072	$ 18,761	$ 427,737	$ 19,167	$ (5,032)	$ 22,857	$ 483,490

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) BACKGROUND AND 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.

Immaterial Corrections to Prior Periods

SCG identified an immaterial correction to prior periods primarily related to property, plant and equipment and deferred tax liabilities that originated in prior periods. SCG evaluated the effects of these corrections on its previously-issued consolidated financial statements, individually and in the aggregate, in accordance with the guidance in ASC Topic 250, Accounting Changes and Error Corrections, ASC Topic 250-10-S99-1, Assessing Materiality, and ASC Topic 250-10-S99-2, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements, and concluded that no prior period is materially misstated. Accordingly, SCG has revised its consolidated financial statements for the prior period presented herein. The revision decreased retained earnings by $6.8 million as of December 31, 2019.

A summary of the effect of the correction on the consolidated balance sheet as of December 31, 2019 is as follows:

As of December 31, 2019	As Reported	Correction	As Revised
(thousands)			
Assets			
Net Property, Plant and Equipment	825,711	(9,373)	816,338
Total Assets	1,264,871	(9,373)	1,255,498
Liabilities			
Deferred income taxes	55,045	(2,524)	52,521
Retained earnings	56,497	(6,849)	49,648
Net Common Stock Equity of The Southern Connecticut Gas Company	462,995	(6,849)	456,146
Total Common Stock Equity	484,169	(6,849)	477,320
Total Capitalization	727,785	(6,849)	720,936
Total Liabilities and Capitalization	1,264,871	(9,373)	1,255,498

A summary of the effect of the correction on the consolidated statement of income for the year ended December 31, 2019 is as follows:

Year Ended December 31, 2019	As Reported	Correction	As Revised
(thousands)			
Operation and maintenance	85,164	816	85,980
Depreciation and amortization	38,149	(325)	37,824
Total Operating Expenses	331,299	491	331,790
Operating Income	59,490	(491)	58,999
Income Before Income Tax	40,427	(491)	39,936
Income Tax	10,283	(132)	10,151
Net Income	30,144	(359)	29,785
Net Income Attributable to The Southern Connecticut Gas Company	28,223	(359)	27,864

A summary of the effect of the correction on the consolidated statement of cash flows for the year ended December 31, 2019 is as follows:

Year Ended December 31, 2019	As Reported	Correction	As Revised
(thousands)			
Net income	30,144	(359)	29,785
Depreciation and amortization	38,463	(325)	38,138
Deferred taxes	32,458	(132)	32,326
Net Cash provided by Operating Activities	90,198	(816)	89,382
Plant expenditures including AFUDC debt	(82,751)	816	(81,935)
Net Cash used in Investing Activities	(83,889)	816	(83,073)

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 $42.5 million and income of $1.7 million as of and for the year ended December 31, 2020. Intercompany operating revenues and natural gas purchased expenses of $12.0 million and intercompany receivables and payables of $0.5 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, 2020	December 31, 2019
	(In Thousands)	
Assets:		
Current assets	$ 12,001	$ 11,607
Long-term assets	30,502	32,068
Total Assets	$ 42,503	$ 43,675
Liabilities		
Current liabilities	$ 19,646	$ 22,501
Total Liabilities	$ 19,646	$ 22,501

Revenues

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:

	Year Ended December 31, 2020	Year Ended December 31, 2019
(Thousands)		
Regulated operations – natural gas	$ 341,139	$ 382,286
Other (a)	757	2,014
Revenue from contracts with customers	**341,896**	**384,300**
Leasing revenue	574	556
Alternative revenue programs	10,773	5,933
Total operating revenues	**$ 353,243**	**$ 390,789**

(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, 2020 and 2019 included the following:

	Remaining Period	December 31, 2020	December 31, 2019
		(In Thousands)	
Regulatory Assets:			
Pension and other post-retirement benefit plans	(a)	$ 76,600	$ 79,609
Hardship programs	(b)	3,034	6,816
Deferred purchased gas	(c)	10,377	7,908
Environmental remediation costs	(g)	49,265	49,627
Debt premium	1 to 17 years	7,311	8,221
Decoupling	(i)	6,926	-
Other	(e)	7,716	6,181
Total regulatory assets		161,229	158,362
Less current portion of regulatory assets		27,707	21,050
Regulatory Assets, Net		$ 133,522	$ 137,312
Regulatory Liabilities:			
Pension and other post-retirement benefit plans	(a)	3,421	4,186
Asset removal costs	(e)	109,825	106,156
Rate Credits	1 to 7 years	5,250	6,000
Unfunded future income taxes	(d)	18,921	21,592
Tax reform	(h)	47,542	38,140
Low income program	(f)	28,054	33,023
Non-firm margin sharing credits	7 years	6,370	7,386
Decoupling	(i)	-	735
Other	(e)	6,260	4,349
Total regulatory liabilities		225,643	221,567
Less current portion of regulatory liabilities		11,672	10,766
Regulatory Liabilities, Net		$ 213,971	$ 210,801

(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.
(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.
(i) represents the mechanism established to disassociate the utility's profits from its delivery/commodity sales. not currently earning a return.

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 2020 and 2019 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, 2020 and 2019 were comprised as follows:

	2020	2019
(In Thousands)		
Gas distribution plant	$ 1,003,922	$ 939,776
Software	38,131	35,932
Land	3,747	3,748
Building and improvements	28,456	27,385
VIE	41,365	41,225
Other plant	44,328	43,216
Total property, plant & equipment	1,159,949	1,091,283
Less accumulated depreciation	321,380	294,181
	838,569	797,102
Construction work in progress	26,266	19,236
Net property, plant & equipment	$ 864,835	$ 816,338

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 2020 and 2019 were 0.87% and 2.60% respectively. The portion of the allowance applicable to equity funds for 2020 was $0.1 million and 2019 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 2020 and 2019 were approximately $41.3 million and $37.8 million, respectively, or approximately 3.7% and 3.6% for 2020 and 2019, 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, 2020, 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 did not have any restricted cash at December 31, 2020 and had $0.5 million as of December 31,2019.

Accounts receivable and unbilled revenues

Accounts receivable at December 31, 2020 and 2019 include unbilled revenues of $21.1 million and $21.8 million, respectively and are shown net of an allowance for doubtful accounts of $4.0 million and $1.7 million for 2020 and 2019, respectively. Accounts receivable do not bear interest, although late fees may be assessed. Due to COVID-19, SCG has suspended the late payment charges. Once reinstated, a late payment charge will be assessed on the outstanding late balance at the time of reinstatement. Also due to COVID-19, PURA required SCG to offer to customers, through early February 2021, a 24-month repayment plan.

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 2020 and 2019 is as follows:

	2020	2019
	(In Thousands)	
Balance as of January 1	$ 12,434	$ 12,264
Liabilities settled during the year	(488)	(474)
Accretion	653	644
Balance as of December 31	$ 12,599	$ 12,434

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

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 (ASC 326). 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 collectability 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 ASC 326 to clarify transition and scope requirements, make narrow-scope codification improvements, including in March 2020, and corrections and provide targeted transition relief. SCG adopted the amendments effective January 1, 2020, including the narrow-scope improvements issued in March 2020 with no effect to its consolidated results of operations, financial position, cash flows and disclosures.

Simplifying the test for goodwill impairment

In January 2017, the FASB issued amendments to simplify the test for goodwill impairment, which is 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. SCG adopted the amendments effective January 1, 2020, with no material effect to its consolidated results of operations, financial position, cash flows and disclosures. As required, SCG is applying the amendments on a prospective basis.

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. SCG adopted the amendments effective January 1, 2020, with no material effect to its disclosures. Certain amendments are to be applied prospectively, and all others are to be applied retrospectively.

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. The amendments change annual disclosures requirements, including removal of disclosures that are no longer considered cost beneficial, adding certain new relevant disclosures and clarifying specific requirements of disclosures concerning information for defined benefit pension plans. SCG adopted the amendments effective January 1, 2020, and they will not materially affect the disclosures for the fiscal year ending December 31, 2020. As required, the application was applied on a retrospective basis. Certain immaterial changes were made to 2019 disclosures to comply with the newly adopted amendments.

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. SCG adopted the amendments effective January 1, 2020, with no material effect to its consolidated results of operations, financial position, cash flows and disclosures. As required, SCG retrospectively applied the amendments to the date of our initial application of ASC 606.

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 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 in equity method investments 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.

Facilitation of the effects of reference rate reform on financial reporting

In March 2020, the FASB issued amendments and created ASC 848 to provide temporary optional guidance to entities to ease the potential burden in accounting for, or recognizing the effects of, reference rate reform on financial reporting. The amendments respond to concerns about structural risks of interbank offered rates, and particularly, the risk of cessation of the London Interbank Offered Rate (LIBOR). The guidance is elective and applies to all entities, subject to meeting certain criteria, that have contracts, hedging relationships, and other transactions that reference LIBOR or another reference rate expected to be discontinued due to reference rate reform, around the end of 2021. The guidance applies to contracts that have modified terms that affect, or have the potential to affect, the amount or timing of contractual cash flows resulting from the discontinuance of the reference rate reform. The amendments are effective for all entities as of March 12, 2020, through December 31, 2022, although the FASB has indicated it will monitor developments in the marketplace and consider whether developments warrant an extension.

In January 2021, the FASB issued amendments to clarify the scope of ASC 848 and respond to questions from stakeholders about whether ASC 848 can be applied to derivative instruments that do not reference a rate that is expected to be discontinued but that use an interest rate for margining, discounting, or contract price alignment that is modified because of reference rate reform. The modification, commonly referred to as the "discounting transition," may have accounting implications, raising concerns about the need to reassess previous accounting determinations related to those derivatives and about the possible hedge accounting consequences of the discounting transition. The amendments clarify that certain optional expedients and exceptions in ASC 848 for contract modifications and hedge accounting apply to derivatives that are affected by the discounting transition, capture the incremental consequences of the scope clarification and tailor the existing guidance to derivative instruments affected by the discounting transition. The amendments are effective immediately, and may be elected retrospectively to eligible modifications as of any date from the beginning of the interim period that includes March 12, 2020, or prospectively to new modifications made on or after any date within the interim period that includes January 7, 2021.

SCG expects the adoption of reference rate reform and the subsequent scope clarification will not materially affect its consolidated results of operations, financial position and cash flows.

Use of Estimates and Assumptions

The preparation of SCG's 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 credit losses and unbilled revenues; (2) asset impairments, including goodwill; (3) investments in equity instruments; (4) depreciable lives of assets; (5) income tax valuation allowances; (6) uncertain tax positions; (7) reserves for professional, workers' compensation and comprehensive general insurance liability risks; (8) contingency and litigation reserves; (9) fair value measurements; (10) earnings sharing mechanisms; (11) environmental remediation liabilities; (12) AROs; (13) pension and other postretirement employee benefits and (14) noncontrolling interest balances. Future events and their effects cannot be predicted with certainty; accordingly, the accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of the financial statements will change as new events occur, as more experience is acquired, as additional information is obtained and as the operating environment changes. CNG evaluates and updates the assumptions and estimates on an ongoing basis and may employ outside specialists to assist in evaluations, as necessary. Actual results could differ from those estimates.

CNG continues to utilize information reasonably available; however, the business and economic uncertainty resulting from COVID-19 has made such estimates and assumptions more difficult to assess and calculate. Affected estimates include, but are not limited to, evaluations of certain long-lived assets and goodwill for impairment, expected credit losses and potential regulatory deferral or recovery of certain costs. While CNG has not yet had material effects of COVID-19 on its financial results, actual results could differ from those estimates, which could result in material effects to the financial statements in future reporting periods.

B) CAPITALIZATION

Common Stock

SCG had 1,407,072 shares of its common stock, $13.33 par value, outstanding as of December 31, 2020 and 2019.

In December 2020 and March 2019, SCG received equity infusions from CEC of $40 million and $18 million, respectively, in order to maintain its allowed capitalization ratio which was impacted by the long-term debt activity noted below.

On December 15, 2020, SCG issued $50 million of notes with a maturity of 2030 and interest rate of 1.87%. On January 15, 2019, SCG issued $75 million of notes with a maturity of 2049 and interest rate of 4.42%.

Long-Term Debt

As of December 31,		**2020**		**2019**	
(Thousands)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
First mortgage bonds [a]	2021-2049	$ 289,000	1.87%-7.95%	$ 239,000	3.88%-7.95%
Unamortized debt (costs) premium, net		4,569		5,527	
Total Debt		**293,569**		**244,527**	
Less: debt due within one year, included in current liabilities		25,911		911	
Total Long-term Debt		**$ 267,658**		**$ 243,616**	

(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 $381.6 million and $302.5 million as of December 31, 2020 and 2019, 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:

	2021	2022	2023	2024	2025 & Thereafter	Total
			(In Thousands)			
Maturities:	$ 25,000	$ -	$ -	$ -	$ 264,000	$ 289,000

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, 2020, SCG's debt ratio was 39%.

(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 an 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 2020 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 were no borrowings under this agreement as of December 31, 2020. There was $19.3 million outstanding under this agreement as of December 31, 2019.

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, 2020. There was $1.5 million outstanding under this agreement as of December 31, 2019.

On June 29, 2020, Avangrid, Inc. and its subsidiaries, including SCG, amended its revolving credit facility agreement in place with several lenders (the 2020 Avangrid Credit Facility) that provides for maximum borrowings up to $2.5 billion in the aggregate. The 2020 Avangrid Credit Facility replaces and supersedes the prior revolving credit facility entered into by Avangrid, Inc. and its subsidiaries on June 29, 2018, which provided maximum borrowings of up to $2.5 billion in the aggregate.

Under the 2020 Avangrid Credit Facility, SCG has a maximum sublimit of $150 million. Additionally, under the 2020 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 15 to 30 basis points. The maturity date for the 2020 Avangrid Credit Facility is June 29, 2024. As of December 31, 2020 and 2019, SCG did not have any outstanding borrowings under the 2020 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, 2020 and 2019 TPS had $19.0 million and $17.5 million, respectively, outstanding under its agreement. CNE did not have any amounts outstanding under its agreement as of December 31, 2020 and 2019.

(E) INCOME TAXES

	Year Ended December 31, 2020	Year Ended December 31, 2019
(In Thousands)		
Income tax expense consists of:		
Income tax provisions (benefits):		
Current		
Federal	$ (3,642)	$ (19,147)
State	(7,502)	(3,028)
Total current	(11,144)	(22,175)
Deferred		
Federal	11,134	24,716
State	10,758	7,610
Total deferred	21,892	32,326
Total Income tax expense	$ 10,748	$ 10,151

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:

(In Thousands)	Year Ended December 31, 2020	Year Ended December 31, 2019
Book income before income taxes	$ 36,950	$ 39,936
Computed tax at federal statutory rate	$ 7,760	$ 8,387
Increases (reductions) resulting from:		
State taxes, net of federal income tax benefits	2,572	3,619
Variable interest entity	(463)	(529)
Other items, net	879	(1,326)
Total income tax expense	$ 10,748	$ 10,151
Effective income tax rates	29.1%	25.4%

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, 2020 and 2019, 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, 2020:

Jurisdiction	*Tax years*
Federal	2014 - 2020
Connecticut	2015 - 2020

The following table summarizes SCG's deferred tax assets and liabilities as of December 31, 2020 and 2019:

	2020	2019
(In Thousands)		
Property related	$ (85,868)	$ (73,411)
Unfunded future income taxes	5,814	6,533
Valuation Allowance - State Credits	(4,865)	-
Federal and state tax credits	9,177	7,844
Goodwill	(18,201)	(16,410)
Deferred tax asset on 2017 Tax Act remeasurement	12,802	10,269
Federal and state net operating loss	5,659	6,517
Post-retirement benefits, net	(2,318)	(3,342)
Other liabilities	2,717	9,478
	$ (75,083)	$ (52,521)

As of December 31, 2020, SCG had a net state credit carry forward of $9.2 million, a state net operating loss carry forward of $0.9 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, 2019, SCG had a net state credit carry forward of $7.8 million, a state net operating loss carry forward of $1.6 million and a federal net operating loss carry forward of $4.9 million.

Valuation allowances are recorded to reduce deferred tax assets when it is more likely than not that all or a portion of a tax benefit will not be realized. For 2020, SCG has recorded a valuation allowance on its state tax credit carryforwards of $4.9 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. The plans are traditional defined benefit plans or cash balance plans depending on date of hire and 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 are consolidated in one master trust. 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. Networks' primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with risk tolerance. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. Networks' 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 their 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 SOUTHERN CONNECTICUT GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table represents the change in benefit obligation, change in plan assets and the respective funded status of SCG's qualified pension and other postretirement plans as of December 31, 2020 and 2019. Plan assets and obligations have been measured as of December 31, 2020 and 2019.

	Pension Benefits		Other Post-Retirement Benefits	
	Year Ended December 31, 2020	Year Ended December 31, 2019	Year Ended December 31, 2020	Year Ended December 31, 2019
(In Thousands)				
Change in Benefit Obligation:				
Benefit obligation at beginning of year	$ 178,707	$ 164,770	$ 18,639	$ 18,941
Service cost	2,109	1,982	111	109
Interest cost	5,546	6,543	571	743
Actuarial (gain) loss	18,214	15,168	562	366
Benefits paid (including expenses)	(9,656)	(9,756)	(1,679)	(1,520)
Benefit obligation at end of year	$ 194,920	$ 178,707	$ 18,204	$ 18,639
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 129,517	$ 110,827	$ 5,151	$ 5,429
Actual return on plan assets	18,071	22,536	552	823
Employer contributions	5,889	5,910	761	419
Benefits paid (including expenses)	(9,656)	(9,756)	(1,679)	(1,520)
Fair value of plan assets at end of year	$ 143,821	$ 129,517	$ 4,785	$ 5,151
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ 51,099	$ 49,190	$ 13,419	$ 13,488
Amounts Recognized in the Consolidated Balance Sheet consist of:				
Non-current liabilities	$ 51,099	$ 49,190	$ 13,419	$ 13,488
Amounts Recognized as a Regulatory Asset (Liability) consist of:				
Prior service cost	$ -	$ 152	$ 187	$ 306
Net (gain) loss	$ 37,520	$ 30,069	(2,054)	(2,735)
Total recognized as a regulatory asset (liability)	$ 37,520	$ 30,221	$ (1,867)	$ (2,429)
Information on Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:				
Projected benefit obligation	$ 194,921	$ 178,707	N/A	N/A
Accumulated benefit obligation	$ 191,535	$ 174,266	N/A	N/A
Fair value of plan assets	$ 143,821	$ 129,517	N/A	N/A
The following weighted average actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate (Qualified Plans)	2.31%	3.19%	N/A	N/A
Discount rate (Other Post-Retirement Benefits)	N/A	N/A	2.29%	3.19%
Average wage increase	3.26%	3.50%	N/A	N/A
Interest crediting rate	2.65%	2.65%	N/A	N/A
Health care trend rate (current year pre/post-65)	N/A	N/A	6.50%/7.25%	6.75%/7.50%
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

During 2020, the pension benefit obligation had an actuarial loss of $18.2 million, primarily due to a $18.2 million loss from decreases in discount rates. During 2020, the postretirement benefit obligation had an actuarial loss of $0.6 million

During 2019, the pension benefit obligation had an actuarial loss of $15.2 million, primarily due to a $17.2 million loss from decreases in discount rates, partially offset by gains due to changes in demographic assumptions. During 2019, the postretirement benefit obligation had an actuarial gain of $0.4 million.

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, 2020 and 2019 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, 2020	Year Ended December 31, 2019	Year Ended December 31, 2020	Year Ended December 31, 2019
(In Thousands)				
Components of net periodic benefit cost:				
Service cost	$ 2,109	$ 1,982	$ 111	$ 109
Interest cost	5,546	6,543	571	743
Expected return on plan assets	(9,443)	(8,054)	(361)	(373)
Amortization of prior service cost	152	759	118	371
Amortization of actuarial (gain) loss	2,134	2,378	(309)	(379)
Net periodic benefit cost	$ 498	$ 3,608	$ 130	$ 471
Other Changes in Plan Assets and Benefit Obligations Recognized as a Regulatory Asset (Liability):				
Net (gain) loss	$ 9,585	$ 719	$ 371	$ (84)
Amortization of current year prior service (credit)/costs	-	-	-	-
Transition obligation (asset)	-	-	-	-
Amortization of prior service cost	(152)	(759)	(118)	(371)
Amortization of actuarial gain (loss)	(2,134)	(2,378)	309	379
Total recognized as regulatory asset (liability)	$ 7,299	$ (2,418)	$ 562	$ (76)
Total recognized in net periodic benefit costs and regulatory asset (liability)	$ 7,797	$ 1,190	$ 692	$ 395
The following actuarial weighted average assumptions were used in calculating net periodic benefit cost:				
Discount rate	3.19%	4.09%	3.19%	4.09%
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	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 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.

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. Unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans are amortized over ten years from the time they are incurred as required by the PURA. 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.

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 contributions of approximately $6.5 million in 2021. 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, 2020 consisted of:

Year	Pension Benefits	Other Post-Retirement Benefits	Medicare Act Subsidy
		(In Thousands)	
2021	$ 10,086	$ 1,357	$ 93
2022	$ 10,123	$ 1,290	$ 80
2023	$ 10,301	$ 1,203	$ 69
2024	$ 10,516	$ 1,122	$ 63
2025	$ 10,505	$ 1,074	$ 57
2026-2030	$ 53,808	$ 4,878	$ 308

The fair values of the Plans' assets as of December 31, 2020 and 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
(In Thousands)				
December 31, 2020				
Pension assets				
Cash and cash equivalents	$ 5	$ 1,681	$ -	$ 1,686
U.S. government securities	8,349	3	-	8,352
Common stocks	4,922	-	-	4,922
Registered investment companies	14,074	-	-	14,074
Corporate bonds	-	33,421	-	33,421
Preferred stocks	46	-	-	46
Common collective trusts	-	53,988	-	53,988
Other, principally annuity, fixed income	300	(100)	-	200
	$ 27,696	$ 88,993	$ -	116,689
Other investments measured at net asset value				27,132
TOTAL				$ 143,821
*Corporate Bonds includes $1.8 million of Non-US Government Bonds				
OPEB assets				
Cash and cash equivalents	$ -	$ 237	$ -	$ 237
U.S. government securities	35	-	-	35
Common stocks	21	-	-	21
Registered investment companies	3,184	-	-	3,184
Corporate bonds	-	140	-	140
Common collective trusts	-	224	-	224
Other, principally annuity, fixed income	1	830	-	831
	$ 3,241	$ 1,431	$ -	4,672
Other investments measured at net asset value				113
TOTAL				$ 4,785
*Includes 401H Assets				
December 31, 2019				
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

Valuation Techniques

SCG values its' 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 – at the closing price reported in the active market in which the security is traded.
- Common stocks – 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.
- Preferred stocks – at the closing price reported in the active market in which the individual investment is traded.
- Common collective trusts/Registered investment companies – Level 1: at the closing price reported in the active market in which the individual investment is traded. Level 2 - 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.

SCG values its' 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.
- U.S. government securities – at the closing price reported in the active market in which the security is traded.
- 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.
- Common collective trusts – 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.

Pension and postretirement benefit plan equity securities did not include any Iberdrola common stock as of both December 31, 2020 and 2019.

SCG also sponsors various non-qualified unfunded pension plans for certain current employees, former employees and former directors. The total liability for these plans, which is included in Other current and Other non-current liabilities on the balance sheets, was $6.6 million and $5.9 million at December 31, 2020 and 2019, respectively

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 2020 and 2019 was $1.2 million and $1.0 million, respectively.

(G) RELATED PARTY TRANSACTIONS

Inter-company Transactions

In December 2020 and March 2019, SCG received equity infusions from CEC of $40 million and $18.0 million, respectively. 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, 2020, SCG recorded inter-company expenses of $14.8 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, 2020, SCG paid $55 million in dividends to CEC. For the year ended December 31, 2019, SCG did not pay any dividends to CEC.

(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 2.04 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:

	Year Ended December 31, 2020	Year Ended December 31, 2019
(In Thousands)		
Operating lease cost	$ 1,370	$ 1,850

	As of December 31, 2020	As of December 31, 2019
(In Thousands)		
Operating Leases		
Operating lease right of use assets	$ 461	$ 592
Operating lease liabilities, current	$ 601	$ 601
Operating lease liabilities, long-term	267	335
Total operating lease liabilities	$ 868	$ 936
Weighted-average Remaining Lease Term (years):		
Operating leases	2.04	1.67
Weighted-average Discount Rate:		
Operating leases	2.69%	3.06%

Supplemental cash flow information related to leases was as follows:

	Year Ended December 31, 2020	Year Ended December 31, 2019
(In Thousands)		
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 91	$ 290

As of December 31, 2020, maturities of lease liabilities were as follows:

	Operating Leases
(In Thousands)	
Year ending December 31,	
2021	$ 677
2022	19
2023	20
2024	20
2025	21
Thereafter	315
Total lease payments	1,072
Less: imputed interest	204
Total	$ 868

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.

(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, 2020 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, 2020, SCG reserved $45.1 million related to the property located in New Haven which was offset by a regulatory asset. Additionally, as of December 31, 2020, SCG has determined that remediation of the property in Bridgeport is not estimable at this time 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, 2020 and December 31, 2019.

	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, 2020				
Noncurrent investments	$ 10,683	$ -	$ -	$ 10,683
Total fair value assets, December 31, 2020	$ 10,683	$ -	$ -	$ 10,683
December 31, 2019				
Noncurrent investments	$ 9,832	$ -	$ -	$ 9,832
Total fair value assets, December 31, 2019	$ 9,832	$ -	$ -	$ 9,832

(K) SUBSEQUENT EVENTS

SCG has evaluated subsequent events through the date its consolidated financial statements were available to be issued, April 9, 2021.

THE UNITED ILLUMINATING COMPANY

AUDITED FINANCIAL STATEMENTS

AS OF AND FOR THE YEARS ENDED

DECEMBER 31, 2020 AND 2019

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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, 2020 and 2019, and the related statements of income, comprehensive 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, 2020 and 2019, 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 9, 2021

THE UNITED ILLUMINATING COMPANY
STATEMENTS OF INCOME

Years Ended December 31, (Thousands)	2020	2019
Operating Revenues	$ 1,046,846	$ 988,798
Operating Expenses		
Purchased power	265,149	212,948
Operation and maintenance	371,604	377,349
Depreciation and amortization	108,205	99,834
Taxes other than income taxes	112,674	109,020
Total Operating Expenses	857,632	799,151
Operating Income	189,214	189,647
Other Income and (Expense), net	(234)	(6,195)
Interest Expense, net	44,352	42,923
Income from Equity Investments	8,249	8,697
Income Before Income Tax	152,877	149,226
Income Tax	31,637	26,605
Net Income	$ 121,240	$ 122,621

THE UNITED ILLUMINATING COMPANY
STATEMENTS OF COMPREHENSIVE INCOME

Twelve Months Ended December 31, (Thousands)	2020	2019
Net Income	$ 121,240	$ 122,621
Amortization of pension cost for non-qualified plans, net of tax expense	(6,589)	-
Comprehensive Income	$ 114,651	$ 122,621

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

THE UNITED ILLUMINATING COMPANY
STATEMENTS OF CASH FLOWS

Years Ended December 31,	2020	2019
(Thousands)		
Cash Flows From Operating Activities		
Net income	$ 121,240	$ 122,621
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	109,724	101,338
Deferred income taxes	32,722	15,752
Uncollectible expense	21,619	28,064
Pension expense	17,348	22,296
Allowance for funds used during construction (AFUDC) - equity	(7,972)	(5,560)
Undistributed (earnings) in equity investments	(8,249)	(8,697)
Environmental liabilities	4,900	-
Regulatory assets/liabilities amortization	1,926	5,189
Regulatory assets/liabiities carrying cost	1,402	1,291
Other non-cash items, net	(5,555)	1,866
Changes in:		
Accounts receivable and unbilled revenues, net	(2,153)	(57,046)
Accounts payable and accrued liabilties	5,101	13,115
Cash distribution received from GenConn	7,920	8,782
Taxes accrued and refundable	(1,734)	(18,684)
Pension and post-retirement	(33,877)	(16,660)
Regulatory assets/liabilities	(58,787)	(15,876)
Environmental liabilities	1,673	1,357
Other assets	(11,524)	(475)
Other liabilities	3,605	886
Total Adjustments	78,089	76,938
Net Cash provided by Operating Activities	199,329	199,559
Cash Flows from Investing Activities		
Plant expenditures including AFUDC debt	(195,009)	(169,444)
Cash distribution from GenConn	3,014	4,722
Notes receivable from affiliates	4,400	(8,525)
Net Cash used in Investing Activities	(187,595)	(173,247)
Cash Flows from Financing Activities		
Issuances of long-term debt	75,000	50,000
Payment of long-term debt	(50,000)	-
Line of credit borrowings	-	(31,000)
Notes payable to affiliates	(162)	(145)
Payment of common stock dividend	(40,000)	(90,000)
Equity infusion from parent	-	47,000
Other	(418)	(365)
Net Cash sed in Financing Activities	(15,580)	(24,510)
Cash, Restricted Cash, and Cash Equivalents:		
Net change for the period	(3,846)	1,802
Balance at beginning of period	4,621	2,819
Balance at end of period	$ 775	$ 4,621
Cash paid during the period for:		
Interest (net of amount capitalized)	$ 38,744	$ 38,744
Non-cash investing activity:		
Plant expenditures included in ending accounts payable	$ 25,218	$ 29,913

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

THE UNITED ILLUMINATING COMPANY
BALANCE SHEETS
ASSETS

As of December 31,	2020	2019
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$ 169	$ 3,643
Accounts receivable and unbilled revenues, net	170,913	150,352
Accounts receivable from affiliates	15,171	56,498
Notes receivable from affiliates	14,975	19,375
Regulatory assets	44,415	35,086
Materials and supplies	6,264	5,986
Derivative assets	390	331
Refundable taxes	10,536	7,100
Prepayments and other current assets	14,662	3,244
Total Current Assets	277,495	281,615
Other Investments		
Equity investment in GenConn	90,951	93,647
Other	14,513	12,771
Total Other Investments	105,464	106,418
Net Property, Plant and Equipment	2,666,016	2,568,455
Operating lease right of use assets	10,041	12,220
Regulatory Assets	411,926	472,693
Deferred Charges and Other Assets		
Derivative assets	1,648	1,807
Other	2,489	3,033
Total Deferred Charges and Other Assets	4,137	4,840
Total Assets	$ 3,475,079	$ 3,446,241

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

THE UNITED ILLUMINATING COMPANY
BALANCE SHEETS
LIABILITIES AND CAPITALIZATION

As of December 31,	**2020**	**2019**
(Thousands)		
Liabilities		
Current Liabilities		
Current portion of long-term debt	$ -	$ 50,000
Accounts payable and accrued liabilities	135,721	123,637
Accounts payable to affiliates	28,631	52,794
Regulatory liabilities	16,430	17,326
Interest accrued	11,587	11,362
Taxes accrued	16,344	14,642
Derivative liabilities	13,378	11,442
Operating lease liabilities	1,510	1,790
Other liabilities	30,896	18,411
Total Current Liabilities	254,497	301,404
Deferred Income Taxes	379,659	340,930
Regulatory Liabilities	385,474	444,520
Other Noncurrent Liabilities		
Pension and post-retirement	204,713	260,828
Derivative liabilities	57,844	63,382
Environmental remediation costs	22,034	15,461
Operating lease liabilities	12,806	14,484
Other	17,432	14,422
Total Other Noncurrent Liabilities	314,829	368,577
Capitalization		
Long-term debt	886,927	811,768
Common Stock Equity		
Common stock	1	1
Paid-in capital	806,230	806,230
Accumulated other comprehensive income (loss)	(6,589)	-
Retained earnings	454,051	372,811
Net Common Stock Equity	1,253,693	1,179,042
Total Capitalization	2,140,620	1,990,810
Total Liabilities and Capitalization	$ 3,475,079	$ 3,446,241

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

(Thousands, except share amounts)	Common Stock Shares	Common Stock Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
As of December 31, 2019	100	1	806,230	372,811	-	1,179,042
Net income				121,240		121,240
Payment of common stock dividend				(40,000)		(40,000)
Other comprehensive income (loss), net of tax expense of $2,473					(6,589)	(6,589)
As of December 31, 2020	100	$ 1	$ 806,230	$ 454,051	$ (6,589)	$ 1,253,693

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 considers 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:

	Year Ended December 31, 2020	Year Ended December 31, 2019
(Thousands)		
Regulated operations – electricity	$ 988,727	$ 946,733
Other (a)	5,853	7,087
Revenue from contracts with customers	**994,580**	**953,820**
Leasing revenue	1,294	1,318
Alternative revenue programs	49,438	32,154
Other Revenue	1,534	1,506
Total operating revenues	**$ 1,046,846**	**$ 988,798**

(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 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, 2020 and December 31, 2019 included the following:

(In Thousands)	Remaining Period	December 31, 2020	December 31, 2019
Regulatory Assets:			
Unamortized redemption costs	1 to 13 years	$ 5,787	$ 6,567
Pension and other post-retirement benefit plans	(a)	169,082	217,917
Unfunded future income taxes	(b)	103,103	154,538
Contracts for differences	(c)	69,184	72,686
Excess generation service charge	(d)	21,548	-
Deferred transmission expense	(e)	25,594	10,967
COVID-19 cost recovery	(f)	918	-
Revenue decoupling mechanism	2 years	17,992	7,540
Other	(g)	43,133	37,564
Total regulatory assets		456,341	507,779
Less current portion of regulatory assets		44,415	35,086
Regulatory Assets, Net		$ 411,926	$ 472,693
Regulatory Liabilities:			
Accumulated deferred investment tax credits	14.5 - 18 years	$ 12,285	$ 13,015
Excess generation service charge	(d)	-	11,418
Middletown/Norwalk local transmission network service collections	30 years	17,389	17,962
Pension and other post-retirement benefit plans	(a)	13,950	14,861
Asset removal costs	(f)	67,138	65,452
Tax reform	(h)	265,642	316,378
Other	(g)	25,500	22,760
Total regulatory liabilities		401,904	461,846
Less current portion of regulatory liabilities		16,430	17,326
Regulatory Liabilities, Net		$ 385,474	$ 444,520

(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; or liability has been realized or settled, respectively.

(c) Asset life is equal to delivery term of related contracts (which vary from approximately 3.5 – 5.5 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) COVID-19 cost recovery represents deferred COVID-19 related costs in the state of Connecticut based on the order issued by PURA on April 29, 2020 requiring the utilities to track COVID-19 related expenses and lost revenue and create a regulatory asset.

(g) Amortization period and/or balance vary depending on the nature, cost of removal and/or remaining life of the underlying assets/liabilities; revenue decoupling mechanism and certain other amounts are not currently earning a return.
(h) Balance includes customer impacts from the 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 and currently collected from customers for these deferred taxes to be refundable to such customers, generally through future rates. The amount and timing of potential settlement are determined PURA 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, 2020 and 2019 were comprised as follows:

(In Thousands)	2020	2019
Distribution plant	$ 1,693,411	$ 1,577,357
Transmission plant	898,294	859,524
Software	253,458	258,608
Land	56,419	55,162
Building and improvements	255,327	249,214
Other plant	178,633	161,991
Total property, plant & equipment	3,335,542	3,161,856
Less accumulated depreciation	863,071	768,057
	2,472,471	2,393,799
Construction work in progress	193,545	174,656
Net property, plant & equipment	$ 2,666,016	$ 2,568,455

Allowance for Funds Used During Construction

In accordance with the uniform systems of accounts, 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 2020 and 2019 were 7.42% and 7.51%, respectively. The portion of the allowance applicable to equity funds for 2020 and 2019 was $8.0 million and $5.6 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 2020 and 2019 were approximately $108.2 million and $99.8 million, respectively or 3.3% and 3.2%, 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, 2020, UI has recorded a gross derivative asset of $2.0 million, a regulatory asset of $69.2 million and a gross derivative liability of $71.2 million ($68.7 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, 2020 and December 31, 2019 were as follows:

	December 31, 2020	December 31, 2019
(In Thousands)		
Gross derivative assets:		
Current Assets	$ 390	$ 331
Deferred Charges and Other Assets	$ 1,648	$ 1,807
Gross derivative liabilties:		
Current Liabilities	$ 13,378	$ 11,442
Noncurrent Liabilities	$ 57,844	$ 63,382

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, 2020 and 2019, were as follows:

	Year Ended December 31, 2020	Year Ended December 31, 2019
(In Thousands)		
Regulatory Assets - Derivative liabilities	$ (3,502)	$ (1,894)

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 $91.0 million and $93.6 million as of December 31, 2020 and December 31, 2019, respectively. As of December 31, 2020, there was $0.5 million of undistributed earnings from UI's equity investment in GenConn.

UI's pre-tax income from its equity investment in GenConn was $8.2 million and $8.7 million for the years ended December 31, 2020 and 2019, 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 $10.9 million and $13.5 million during the years ended December 31, 2020 and 2019, respectively.

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

	2020	2019
(In Thousands)		
Current assets	$ 39,733	$ 36,938
Noncurrent assets	$ 344,354	$ 341,693
Current liabilities	$ 17,229	$ 16,470
Noncurrent liabilities	$ 185,097	$ 175,539
Operating revenues	$ 59,671	$ 60,006
Income	$ 17,008	$ 17,093

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, 2020, 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, 2020 and 2019 totaled $0.6 million and $1.0 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, 2020 and 2019 include unbilled revenues of $44.1 million and $46.6 million, respectively and are shown net of an allowance for doubtful accounts of $4.4 million and $3.1 million for 2020 and 2019, respectively. Accounts receivable do not bear interest, although late fees may be assessed. Due to COVID-19, PURA required UI to offer to customers, through early February 2021, a 24-month repayment plan.

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

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 (ASC 326). 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 collectability 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 ASC 326 to clarify transition and scope requirements, make narrow-scope codification improvements, including in March 2020, and corrections and provide targeted transition relief. UI adopted the amendments effective January 1, 2020, including the narrow-scope improvements issued in March 2020 with no effect to 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. UI adopted the amendments effective January 1, 2020, with no material effect to its disclosures. Certain amendments are to be applied prospectively, and all others are to be applied retrospectively.

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. The amendments change annual disclosures requirements, including removal of disclosures that are no longer considered cost beneficial, adding certain new relevant disclosures and clarifying specific requirements of disclosures concerning information for defined benefit pension plans. UI adopted the amendments effective January 1, 2020, and they will not materially affect the disclosures for the fiscal year ending December 31, 2020. As required, the application will be on a retrospective basis. Certain immaterial changes were made to 2019 disclosures to comply with the newly adopted amendments.

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. UI adopted the amendments effective January 1, 2020, with no material effect to its results of operations, financial position, cash flows and disclosures. As required, UI retrospectively applied the amendments to the date of our initial application of ASC 606.

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.

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.

Facilitation of the effects of reference rate reform on financial reporting

In March 2020, the FASB issued amendments and created ASC 848 to provide temporary optional guidance to entities to ease the potential burden in accounting for, or recognizing the effects of, reference rate reform on financial reporting. The amendments respond to concerns about structural risks of interbank offered rates, and particularly, the risk of cessation of the London Interbank Offered Rate (LIBOR). The guidance is elective and applies to all entities, subject to meeting certain criteria, that have contracts, hedging relationships, and other transactions that reference LIBOR or another reference rate expected to be discontinued due to reference rate reform, around the end of 2021. The guidance applies to contracts that have modified terms that affect, or have the potential to affect, the amount or timing of contractual cash flows resulting from the discontinuance of the reference rate reform. The amendments are effective for all entities as of March 12, 2020, through December 31, 2022, although the FASB has indicated it will monitor developments in the marketplace and consider whether developments warrant an extension.

In January 2021, the FASB issued amendments to clarify the scope of ASC 848 and respond to questions from stakeholders about whether ASC 848 can be applied to derivative instruments that do not reference a rate that is expected to be discontinued but that use an interest rate for margining, discounting, or contract price alignment that is modified because of reference rate reform. The modification, commonly referred to as the "discounting transition," may have accounting implications, raising concerns about the need to reassess previous accounting determinations related to those derivatives and about the possible hedge accounting consequences of the discounting transition. The amendments clarify that certain optional expedients and exceptions in ASC 848 for contract modifications and hedge accounting apply to derivatives that are affected by the discounting transition, capture the incremental consequences of the scope clarification and tailor the existing guidance to derivative instruments affected by the discounting transition. The amendments are effective immediately, and may be elected retrospectively to eligible modifications as of any date from the beginning of the interim period that includes March 12, 2020, or prospectively to new modifications made on or after any date within the interim period that includes January 7, 2021.

UI expects the adoption of reference rate reform and the subsequent scope clarification will not materially affect its results of operations, financial position and cash flows.

Use of Estimates and Assumptions

The preparation of UI's 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 credit losses and unbilled revenues; (2) asset impairments, including goodwill; (3)

investments in equity instruments; (4) depreciable lives of assets; (5) income tax valuation allowances; (6) uncertain tax positions; (7) reserves for professional, workers' compensation and comprehensive general insurance liability risks; (8) contingency and litigation reserves; (9) fair value measurements; (10) earnings sharing mechanisms; (11) environmental remediation liabilities; (12) AROs; (13) pension and other postretirement employee benefits and (14) noncontrolling interest balances. Future events and their effects cannot be predicted with certainty; accordingly, the accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of the financial statements will change as new events occur, as more experience is acquired, as additional information is obtained and as the operating environment changes. UI evaluates and updates the assumptions and estimates on an ongoing basis and may employ outside specialists to assist in evaluations, as necessary. Actual results could differ from those estimates.

UI continues to utilize information reasonably available; however, the business and economic uncertainty resulting from COVID-19 has made such estimates and assumptions more difficult to assess and calculate. Affected estimates include, but are not limited to, evaluations of certain long-lived assets and goodwill for impairment, expected credit losses and potential regulatory deferral or recovery of certain costs. While UI has not yet had material effects of COVID-19 on its financial results, actual results could differ from those estimates, which could result in material effects to the financial statements in future reporting periods.

(B) CAPITALIZATION

Common Stock

UI had 100 shares of common stock, no par value, outstanding at December 31, 2020 and December 31, 2019.

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,		**2020**		**2019**	
(Thousands)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
Senior unsecured debt	2022 - 2049	$ 891,960	2.02%-6.51%	$ 866,960	3.61%-6.61%
Unamortized debt (costs) premium, net		(5,033)		(5,192)	
Total Debt		**$ 886,927**		**$ 861,768**	
Less: debt due within one year, included in current liabilities		-		50,000	
Total Non-current Debt		**$ 886,927**		**$ 811,768**	

The estimated fair value of debt amounted to $1,100.2 million and $1,004.8 million as of December 31, 2020 and 2019, 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.

On December 1, 2020, UI issued $75 million of notes with a maturity of 2030 and interest rate of 2.02%. 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%.

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

	2021	2022	2023	2024	2025 & thereafter	Total
			(In Thousands)			
Maturities	$ -	$ 162,500	$ 139,460	$ -	$ 590,000	$ 891,960

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, 2020, UI's debt ratio was 42%.

(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 2021, 70% of its standard service load for the second half of 2021 and 20% of its standard service load for the first half of 2022. 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 2021. 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, 2020, UI would have had to post an aggregate of approximately $18.2 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 was initially 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 pursuant to state law that provides the net costs of the PPAs are recoverable through electric rates. On December 19, 2018, PURA approved the PPAs, and approved UI's use of the nonbypassable federally mandated congestion charges for all customers to recover the net costs of the PPAs.

In 2019, UI entered into PPAs with 11 projects, totaling approximately 12 million MWh, pursuant to state law that provides that the net costs of the PPAs are recoverable through electric rates.

Revenues are recorded gross from contracts with customers when UI is a principal if it controls a promised good or service before transferring that good or service to the customer. Revenues are recorded net of expenses and regulatory deferrals from contracts with customers when UI is an agent if it arranges for another entity to provide the goods or services. In 2019, UI entered into a PPA contract to purchase nuclear energy generation from Millstone which it is mandated to sell into ISO-NE at the market price. Such transaction is reflected net because UI is acting as agent to sell the energy into the market.

In 2020, Pursuant to Connecticut Act Concerning the Procurement of Energy Derived From Offshore Wind, UI entered into a PPA with Vineyard Wind, an affiliate of UI, to provide 804 MW of offshore wind through the development of its Park City Wind Project. 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 2020, UI's overall allowed weighted-average ROE for its transmission business was 11.26%.

On December 28, 2015, the FERC issued an order instituting section 206 proceedings and establishing hearing and settlement judgement 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 (PTOs), 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. On June 15, 2020, the PTOs submitted an uncontested formula rate settlement. The FERC approved the uncontested formula rate settlement on December 28, 2020 which makes the formula rate tariff sheets effective on January 1, 2022.

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 $7.2 million as of December 31, 2020, which has not changed since December 31, 2019, 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). 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, which was granted. On May 21, 2020, FERC issued a ruling, which, among other things, adjusted the methodology to determine the MISO transmission owners' ROE, resulting in an increase in ROE from 9.88% to 10.02% by utilizing the risk premium model in addition to the DCF model and capital-asset pricing model under both prongs of Section 206 of the FPA, and calculated the zone of reasonableness into equal thirds rather than employing the quartile approach. UI cannot predict the outcome of these proceedings, including the potential impact the MISO transmission owners' ROE proceeding may have in establishing a precedent for the 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.

GenConn filed its annual revenue requirements request with PURA on June 12, 2020, seeking approval of its 2021 revenue requirements for the period commencing January 1, 2021 for both the GenConn Devon and GenConn Middletown facilities. A final decision was received on December 23, 2020, approving 2021 revenue requirements of $49.388 million for GenConn ($21.967 million for GenConn Devon, and $27.421 million for GenConn Middletown). Additionally, GenConn was granted a 9.85% Return on Equity (ROE) for 2021. PURA disallowed $3.236 million from the original 2021 revenue requirements request which includes a disallowance of $2.861 million of interest expense associated with GenConn's debt, and $0.375 million related to a proposed expense project to paint Exhaust Stacks at GenConn Devon. On February 4, 2021, GenConn filed an appeal with the CT Superior Court, appealing PURA's disallowance of the $2.861 million interest expense.

PURA had approved revenue requirements for the period from January 1, 2020 through December 31, 2020, however, GenConn filed to reopen the related docket with PURA on April 3, 2020, for the purpose of resetting 2020 revenue requirements after a recalculation of excess deferred income taxes. GenConn received a final decision from PURA on December 23, 2020 approving $1.219 million of the additional $2.118 million requested for 2020 revenue requirements. The $0.899 million difference is due to an acceleration of

$0.641 million related to Excess Accumulated Deferred Income Taxes (EADIT's) associated with Intangible Plant that otherwise would have been refunded over a longer period of time, and $0.258 million is related to actual tangible plant timing differences.

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, 2020 and 2019. There were $15.0 million and $19.4 million in note receivables under this arrangement as of December 31, 2020 and 2019, 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, 2020 and 2019.

On June 29, 2020, Avangrid, Inc. and its subsidiaries, including UI, amended its revolving credit facility agreement in place with several lenders (the 2020 Avangrid Credit Facility) that provides for maximum borrowings up to $2.5 billion in the aggregate. The 2020 Avangrid Credit Facility replaces and supersedes the prior revolving credit facility entered into by Avangrid, Inc. and its subsidiaries on June 29, 2018, which provided maximum borrowings of up to $2.5 billion in the aggregate.

Under the 2020 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 15 to 30 basis points. The maturity date for the Avangrid Credit Facility is June 28, 2024. As of December 31, 2020 and 2019, UI did not have any outstanding borrowings under the 2020 Avangrid Credit Facility.

(E) INCOME TAXES

(In Thousands)	2020	2019
Income tax expense consists of:		
Income tax provisions (benefits):		
Current		
Federal	$ 32	$ 13,405
State	(387)	(1,803)
Total current	(355)	11,602
Deferred		
Federal	27,336	13,671
State	5,386	2,081
Total deferred	32,722	15,752
Investment tax credits	(730)	(749)
Total income tax expense	$ 31,637	$ 26,605

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:

(In Thousands)	2020	2019
Book income before income taxes	$ 152,877	$ 149,226
Computed tax at federal statutory rate	$ 32,104	$ 31,337
Increases (reductions) resulting from:		
Property related	(3,075)	(2,868)
State income taxes, net of federal income tax benefits	3,950	220
ITC taken into income	(730)	(749)
Other items, net	(612)	(1,335)
Total income tax expense	$ 31,637	$ 26,605
Effective income tax rates	20.7%	17.8%

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, 2020 and 2019, 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, 2020:

Jurisdiction	*Tax years*
Federal	2013 – 2020
Connecticut	2015 – 2020

The following table summarizes UI's deferred income tax assets and liabilities as of December 31, 2020 and 2019.

(In Thousands)	**2020**	**2019**
Deferred income taxes:		
Property related	$ (400,863)	$ (377,540)
Unfunded future income taxes	(33,822)	(47,990)
Federal and state tax credits	15,943	15,273
Investment in GenConn	(32,124)	(31,838)
Post-retirement benefits	13,941	15,828
Merger settlement agreement	-	5,582
Regulatory liability due to tax cuts and jobs act	71,524	85,185
Other	(14,258)	(5,430)
	$ (379,659)	$ (340,930)

As of December 31, 2020, UI had $6 million of state tax credit carry forwards with an offset of $0.6 million valuation allowance that will begin to expire in 2025. As of December 31, 2019 UI had $3.2 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 are consolidated in one master trust. 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. Networks' primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with risk tolerance. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. Networks' 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 their 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, 2020 and 2019. Plan assets and obligations have been measured as of December 31, 2020 and 2019.

	Pension Benefits		Other Post-Retirement Benefits	
	2020	2019	2020	2019
(In Thousands)				
Change in Benefit Obligation:				
Benefit obligation at beginning of year	$ 612,284	$ 554,497	$ 59,066	$ 56,871
Service cost	5,248	5,178	651	754
Interest cost	18,795	21,921	1,826	2,252
Amendments	7,382	(2,407)	-	-
Settlements	(18,490)	-	-	-
Actuarial (gain) loss	18,873	67,878	7,955	2,913
Benefits paid (including expenses)	(39,871)	(34,783)	(5,320)	(3,724)
Benefit obligation at end of year	$ 604,221	$ 612,284	$ 64,178	$ 59,066
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 383,517	$ 332,756	$ 27,006	$ 26,065
Actual return on plan assets	52,862	68,884	10,425	4,142
Employer contributions	32,730	16,660	2,146	523
Benefits paid (including expenses)	(39,871)	(34,783)	(5,320)	(3,724)
Fair value of plan assets at end of year	$ 429,238	$ 383,517	$ 34,257	$ 27,006
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ 174,983	$ 228,767	$ 29,921	$ 32,060
Amounts Recognized in the Balance Sheet consist of:				
Non-current liabilities	$ 174,983	$ 228,767	$ 29,921	$ 32,060
Amounts Recognized as a Regulatory Asset consist of:				
Prior service cost	7,309	-	(4,130)	(5,667)
Net (gain) loss	166,052	213,196	(6,509)	(6,523)
Total recognized as a regulatory asset	$ 173,361	$ 213,196	$ (10,639)	$ (12,190)
Information on Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:				
Projected benefit obligation	$ 604,221	$ 612,284	N/A	N/A
Accumulated benefit obligation	$ 575,083	$ 562,878	N/A	N/A
Fair value of plan assets	$429,238	$383,517	N/A	N/A
The following weighted average actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate (Qualified Plans)	2.56%	3.19%	N/A	N/A
Discount rate (Other Post-Retirement Benefits)	N/A	N/A	2.29%	3.19%
Average wage increase	3.80%	3.80%	N/A	N/A
Interest crediting rate	N/A	N/A	N/A	N/A
Health care trend rate (current year - pre/post-65)	N/A	N/A	6.50%/5.25%	6.75%/5.50%
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

During 2020, the pension benefit obligation had an actuarial loss of $18.9 million, primarily due to a $47.2 million loss from decreases in discount rates, offset by offset by gains due to changes in mortality, demographic and other assumptions of $4.8 million, $10.6 million and $12.1 million, respectively. During 2020, the postretirement benefit obligation had an actuarial loss of $8.0 million.

During 2019, the pension benefit obligation had an actuarial loss of $67.9 million, primarily due to a $68.2 million loss from decreases in discount rates. During 2019, the postretirement benefit obligation had an actuarial gain of $2.9 million.

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, 2020 and 2019 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	
	2020	2019	2020	2019
(In Thousands)				
Components of net periodic benefit cost:				
Service cost	$ 5,248	$ 5,178	$ 651	$ 754
Interest cost	18,795	21,921	1,826	2,252
Expected return on plan assets	(28,451)	(24,097)	(1,688)	(1,616)
Amortization of prior service costs	73	(2,407)	(1,537)	(1,537)
Amortization of actuarial (gain) loss	23,116	22,952	(798)	(1,098)
Net periodic benefit cost	$ 18,781	$ 23,547	$ (1,546)	$ (1,245)
Other Changes in Plan Assets and Benefit Obligations Recognized as a Regulatory Asset (Liability):				
Net (gain) loss	$ (5,538)	$ 23,092	$ (784)	$ 389
Curtailments	(18,489)	-	-	-
Prior service cost	7,382	(2,407)	-	-
Amortization of prior service costs	(73)	2,407	1,537	1,537
Amortization of actuarial (gain) loss	(23,116)	(22,952)	798	1,098
Total recognized as regulatory asset (liability)	$ (39,834)	$ 140	$ 1,551	$ 3,024
Total recognized in net periodic benefit costs and regulatory asset (liability)	$ (21,053)	$ 23,687	$ 5	$ 1,779
The following actuarial weighted average assumptions were used in calculating net periodic benefit cost:				
Discount rate	3.19%/2.58%*	4.09%	3.19%	4.09%
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	6.75%/5.50%	7.00%/5.75%
Health care trend rate (2029/2025 - pre/post-65)	N/A	N/A	4.50%/4.50%	4.50%/4.50%

*Due to plan changes, pension expense was remeasured on December 9, 2020.
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.

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 contributions of approximately $17.4 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)	
2021	$ 34,389	$ 3,977
2022	$ 44,537	$ 3,941
2023	$ 34,712	$ 3,870
2024	$ 37,122	$ 3,723
2025	$ 34,319	$ 3,680
2026-2030	$ 170,275	$ 16,831

The fair values of the Plans' assets as of December 31, 2020 and 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			
	in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
(In Thousands)				
December 31, 2020				
Pension assets				
Cash and cash equivalents	$ 14	$ 14,609	$ -	$ 14,623
U.S. government securities	24,296	7	-	24,303
Common stocks	14,512	-	-	14,512
Registered investment companies	41,087	-	-	41,087
Corporate bonds*	-	97,255	-	97,255
Preferred stocks	134	-	-	134
Common collective trusts	-	157,458	-	157,458
Other, principally annuity, fixed income	872	(290)	-	582
	$ 80,915	$ 269,039	$ -	$ 349,954
Other investments measured at net asset value				79,284
TOTAL				$ 429,238
*Corporate Bonds includes $5.1 million of Non-US Government Bonds				
OPEB assets				
Cash and cash equivalents	$ -	$ 1,700	$ -	$ 1,700
U.S. government securities	251	-	-	251
Common stocks	147	-	-	147
Registered investment companies	22,791	-	-	22,791
Corporate bonds	-	1,004	-	1,004
Preferred stocks	1	-	-	1
Common collective trusts	-	1,602	-	1,602
Other, principally annuity, fixed income	9	5,940	-	5,949
	$ 23,199	$ 10,246	$ -	$ 33,445
Other investments measured at net asset value				812
TOTAL				$ 34,257
December 31, 2019				
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

UI values its' 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 – at the closing price reported in the active market in which the security is traded.
- Common stocks – 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.
- Preferred stocks – at the closing price reported in the active market in which the individual investment is traded.
- Common collective trusts/Registered investment companies – Level 1: at the closing price reported in the active market in which the individual investment is traded. Level 2 - 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.

UI values its' 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.
- U.S. government securities – at the closing price reported in the active market in which the security is traded.
- 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.
- Common collective trusts – 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.

Pension and postretirement benefit plan equity securities did not include any Iberdrola common stock as of both December 31, 2020 and 2019.

UI also sponsors various non-qualified unfunded pension plans for certain current employees, former employees and former directors. The total liability for these plans, which is included in Other current and Other non-current liabilities on the balance sheets, was $9.5 million and $8.3 million at December 31, 2020 and 2019, respectively.

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 2020 and 2019 was $5.5 million and $5.3 million, respectively.

(G) RELATED PARTY TRANSACTIONS

During the years ended December 31, 2020 and 2019, 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, 2020 and 2019, UI recorded inter-company expenses of $54.0 million and $58.0 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 years ended December 31, 2020 and 2019, UI paid $40 million and $90.0 million, respectively, in 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 1.17 years to 38 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:

	Year Ended December 31, 2020	Year Ended December 31, 2019
(In Thousands)		
Operating lease cost	$ 2,652	$ 4,738

	As of December 31, 2020	As of December 31, 2019
(In Thousands)		
Operating Leases		
Operating lease right of use assets	$ 10,041	$ 12,220
Operating lease liabilities, current	$ 1,510	$ 1,790
Operating lease liabilities, long-term	12,806	14,484
Total operating lease liabilities	$ 14,316	$ 16,274
Weighted-average Remaining Lease Term (years):		
Operating leases	22.63	21.34
Weighted-average Discount Rate:		
Operating leases	3.91%	3.84%

Supplemental cash flow information related to leases was as follows:

	Year Ended December 31, 2020	December 31, 2019
(In Thousands)		
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 1,650	$ 1,748

As of December 31, 2020, maturities of lease liabilities were as follows:

	Operating Leases
(In Thousands)	
Year ending December 31,	
2021	$ 1,485
2022	3,376
2023	543
2024	542
2025	532
Thereafter	16,525
Total lease payments	23,003
Less: imputed interest	8,687
Total	$ 14,316

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.

(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 Holdings and UI and adding former UIL Holdings 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 Holdings. 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, 2020 and 2019, the amount reserved for this matter was $21.7 million and $16.4 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, 2020 and 2019, the amount reserved for this property was $7.8 million.

(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, 2020 and December 31, 2019:

	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, 2020	(In Thousands)			
Assets:				
Derivative assets	$ -	$ -	2,038	$ 2,038
Supplemental retirement benefit trust life insurance policies	-	14,299	-	14,299
	-	14,299	2,038	16,337
Liabilities:				
Derivative liabilities	-	-	71,222	71,222
	-	-	71,222	71,222
Net fair value assets/(liabilities), December 30, 2020	$ -	$ 14,299	$ (69,184)	$ (54,885)
December 31, 2019				
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)

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, 2020 or December 31, 2019 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, 2020	Range at December 31, 2019
Contracts for differences	Risk of non-performance	0.50% - 0.51%	0.05% - 0.45%
	Discount rate	0.17% - 0.36%	1.69% - 1.83%
	Forward pricing ($ per MW)	$2.00 - $5.30	$3.80 - $7.03

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, 2020 and December 31, 2019 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, 2020 and 2019:

	Year Ended December 31, 2020 (In Thousands)
Net derivative assets/(liabilities), December 31, 2019	$ (72,686)
Unrealized gains and (losses), net	3,502
Net derivative assets/(liabilities), December 31, 2020	$ (69,184)
Change in unrealized gains (losses), net relating to net derivative assets/(liabilities), still held as of December 31, 2020	$ 3,502

	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 assets/(liabilities), still held as of December 31, 2019	$ 1,894

(K) SUBSEQUENT EVENTS

UI has evaluated subsequent events through the date its financial statements were available to be issued, April 9, 2021.