THE UNITED ILLUMINATING COMPANY

AUDITED FINANCIAL STATEMENTS

AS OF AND FOR THE YEARS ENDED

DECEMBER 31, 2018 AND 2017

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

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, 2018 and 2017, and the related statements of income, changes in shareholder's equity, and cash flows for the years then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

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

Auditors' Responsibility

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

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

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

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of The United Illuminating Company as of December 31, 2018 and 2017, 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
April 12, 2019

THE UNITED ILLUMINATING COMPANY

STATEMENT OF INCOME

For the Years Ended December 31, 2018 and 2017

(In Thousands)

	2018	2017
Operating Revenues	$ 970,052	$ 921,181
Operating Expenses		
Purchased power	202,827	169,000
Operation and maintenance	382,544	361,219
Depreciation and amortization	80,481	77,491
Taxes other than income taxes	109,999	107,676
Total Operating Expenses	775,851	715,386
Operating Income	194,201	205,795
Other Income and (Expense), net	(9,178)	(8,304)
Interest Expense, net	42,734	41,092
Income from Equity Investments	11,038	12,720
Income Before Income Tax	153,327	169,119
Income Tax	37,388	63,936
Net Income	$ 115,939	$ 105,183

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

THE UNITED ILLUMINATING COMPANY
STATEMENT OF CASH FLOWS
(Thousands of Dollars)

	Year Ended December 31, 2018	Year Ended December 31, 2017
Cash Flows From Operating Activities		
Net income	$ 115,939	$ 105,183
Adjustments to reconcile net income		
to net cash provided by operating activities:		
Depreciation and amortization	81,762	79,306
Deferred income taxes	(3,751)	34,483
Uncollectible expense	25,736	19,878
Pension expense	24,144	28,824
Allowance for funds used during construction (AFUDC) - equity	(1,457)	(1,966)
Undistributed (earnings) in equity investments	(11,038)	(12,720)
Regulatory assets/liabilities amortization	7,277	1,856
Regulatory assets/liabiities carrying cost	(1,310)	(1,567)
Other non-cash items, net	1,010	(1,001)
Changes in:		
Accounts receivable and unbilled revenues, net	(18,420)	(58,033)
Accounts payable and accrued liabilties	16,752	24,399
Cash distribution received from GenConn	10,866	12,675
Taxes accrued	726	22,070
Pension and post-retirement	(14,071)	(10,431)
Regulatory assets/liabilities	38,636	(26,666)
Environmental liabilities	(11,033)	(13,433)
Other assets	(111)	1,212
Other liabilities	842	(4,708)
Total Adjustments	146,560	94,178
Net Cash provided by Operating Activities	262,499	199,361
Cash Flows from Investing Activities		
Plant expenditures including AFUDC debt	(254,929)	(163,138)
Proceeds from sale of building	6,206	-
Notes receivable from affiliates	(10,850)	-
Cash distribution from GenConn	3,853	4,088
Net Cash used in Investing Activities	(255,720)	(159,050)
Cash Flows from Financing Activities		
Line of credit (repayments) borrowings	(100,000)	100,000
Issuances of long-term debt	214,460	-
Payment of long-term debt	(100,000)	(70,000)
Payment of common stock dividend	-	(125,000)
Notes payable to affiliates	(68,543)	52,400
Equity infusion from parent	50,000	-
Other	(1,865)	(42)
Net Cash used in Financing Activities	(5,948)	(42,642)
Cash, Restricted Cash, and Cash Equivalents:		
Net change for the period	831	(2,331)
Balance at beginning of period	1,988	4,319
Balance at end of period	$ 2,819	$ 1,988
Cash paid during the period for:		
Interest (net of amount capitalized)	$ 39,286	$ 42,107
Non-cash investing activity:		
Plant expenditures included in ending accounts payable	$ 25,786	$ 23,917

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THE UNITED ILLUMINATING COMPANY
BALANCE SHEET

ASSETS
(In Thousands)

	December 31, 2018	December 31, 2017
Assets		
Current Assets		
Cash and cash equivalents	$ 1,305	$ -
Accounts receivable and unbilled revenues, net	165,140	154,261
Accounts receivable from affiliates	13,028	31,623
Notes receivable from affiliates	10,850	-
Regulatory assets	26,430	61,328
Materials and supplies	5,619	5,507
Derivative assets	3,413	6,912
Prepayments and other current assets	3,492	2,982
Total Current Assets	229,277	262,613
Other Investments		
Equity investment in GenConn	98,473	102,160
Other	9,990	10,592
Total Other Investments	108,463	112,752
Net Property, Plant and Equipment	2,481,423	2,303,128
Regulatory Assets	454,358	453,920
Deferred Charges and Other Assets		
Derivative assets	1,942	4,735
Other	3,213	4,197
Total Deferred Charges and Other Assets	5,155	8,932
Total Assets	$ 3,278,676	$ 3,141,345

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

THE UNITED ILLUMINATING COMPANY
BALANCE SHEET

LIABILITIES AND CAPITALIZATION
(In Thousands)

	December 31, 2018	December 31, 2017
Liabilities		
Current Liabilities		
Line of credit borrowings	$ -	$ 100,000
Notes payable to affiliates	-	68,900
Current portion of long-term debt	31,000	100,000
Accounts payable and accrued liabilities	108,178	113,443
Accounts payable to affiliates	45,529	25,151
Regulatory liabilities	5,395	7,058
Interest accrued	11,189	9,903
Taxes accrued	26,226	25,499
Derivative liabilities	11,966	15,776
Other liabilities	23,893	20,383
Total Current Liabilities	263,376	486,113
Deferred Income Taxes	318,169	305,526
Regulatory Liabilities	443,064	440,618
Other Noncurrent Liabilities		
Pension and postretirement	252,545	246,363
Derivative liabilities	67,969	63,317
Environmental remediation costs	8,104	20,664
Other	14,474	16,160
Total Other Noncurrent Liabilities	343,092	346,504
Capitalization		
Long-term debt	811,554	629,102
Common Stock Equity		
Common stock	1	1
Paid-in capital	759,230	709,230
Retained earnings	340,190	224,251
Net Common Stock Equity	1,099,421	933,482
Total Capitalization	1,910,975	1,562,584
Total Liabilities and Capitalization	$ 3,278,676	$ 3,141,345

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

THE UNITED ILLUMINATING COMPANY
STATEMENT OF CHANGES IN SHAREHOLDER'S EQUITY
December 31, 2018
(Thousands of Dollars)

	Common Stock		Paid-in	Retained	
	Shares	Amount	Capital	Earnings	Total
Balance as of December 31, 2016	100	$ 1	$ 709,230	$ 244,068	$ 953,299
Net income				105,183	105,183
Payment of common stock dividend				(125,000)	(125,000)
Balance as of December 31, 2017	100	$ 1	$ 709,230	$ 224,251	$ 933,482
Net income				115,939	115,939
Equity infusion from parent			50,000		50,000
Balance as of December 31, 2018	100	$ 1	$ 759,230	$ 340,190	$ 1,099,421

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. (formerly NRG Yield, 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. In February 2018, NRG Energy, Inc. announced that it had agreed to sell its ownership stake in NRG Yield, Inc. to GIP. The sale closed on August 31, 2018 and did not have an impact on GenConn.

Accounting Records

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

Basis of Presentation

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

UI's total comprehensive income is equal to net income for the years ended December 31, 2018 and 2017.

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

UI has evaluated subsequent events through the date its financial statements were available to be issued, April 12, 2019.

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

Revenues

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

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, the UI acts as an agent and delivers the electricity by that supplier. Revenue in those cases is only for providing the service of delivery of the electricity. UI calculates revenue earned but not yet billed based on the number of days not billed in the month, the estimated amount of energy delivered during those days and the estimated average price per customer class for that month. Differences between actual and estimated unbilled revenue are immaterial.

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

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

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

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

Revenues disaggregated by major source are as follows:

(Thousands)		Year Ended December 31, 2018
Regulated operations – electricity	$	924,929
Other (a)		8,935
Revenue from contracts with customers		**933,864**
Leasing revenue		2,829
Alternative revenue programs		33,359
Total operating revenues	**$**	**970,052**

(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, 2018 and December 31, 2017 included the following:

	Remaining Period	December 31, 2018	December 31, 2017
		(In Thousands)	
Regulatory Assets:			
Unamortized redemption costs	3 to 15 years	$ 7,347	$ 8,127
Pension and other post-retirement benefit plans	(a)	217,503	215,560
Unfunded future income taxes	(b)	148,391	144,406
Contracts for differences	(c)	74,580	67,445
Deferred transmission expense	(e)	11,316	36,673
Other	(f)	21,651	43,037
Total regulatory assets		480,788	515,248
Less current portion of regulatory assets		26,430	61,328
Regulatory Assets, Net		$ 454,358	$ 453,920
Regulatory Liabilities:			
Accumulated deferred investment tax credits	16.5 - 20 years	$ 13,586	$ 14,032
Excess generation service charge	(d)	6,686	2,388
Middletown/Norwalk local transmission network service collections	32 years	18,535	19,109
Pension and other post-retirement benefit plans	(a)	17,368	14,514
Asset removal costs	(f)	65,332	68,051
Tax reform	(g)	309,018	312,776
Other	(f)	17,934	16,806
Total regulatory liabilities		448,459	447,676
Less current portion of regulatory liabilities		5,395	7,058
Regulatory Liabilities, Net		$ 443,064	$ 440,618

(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 - 10 years); balance fluctuates based upon quarterly market analysis performed on the related derivatives (Note J); amount, which does not earn a return, is fully offset by corresponding derivative asset/liability. See "Contracts for Differences" discussion above for additional information.

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

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

(f) Amortization period and/or balance vary depending on the nature, cost of removal and/or remaining life of the underlying assets/liabilities; liability amount as of December 31, 2018 includes decoupling ($2.3 million) and certain other amounts that are not currently earning a return.

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

Property, Plant and Equipment

The cost of additions to property, plant and equipment and the cost of renewals and betterments are capitalized. Cost consists 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, 2018 and 2017 were comprised as follows:

	2018	2017
	(In Thousands)	
Distribution plant	$ 1,486,969	$ 1,393,065
Transmission plant	845,262	771,480
Software	225,581	109,054
Land	55,203	54,862
Building and improvements	234,997	213,989
Other plant	152,869	146,288
Total property, plant & equipment	3,000,881	2,688,738
Less accumulated depreciation	700,827	586,088
	2,300,054	2,102,650
Construction work in progress	181,369	200,478
Net property, plant & equipment	$ 2,481,423	$ 2,303,128

Allowance for Funds Used During Construction

In accordance with the uniform systems of accounts, the UI capitalizes allowance for funds used during construction (AFUDC), which represents the approximate cost of debt and equity capital devoted to plant under construction. The portion of the allowance applicable to borrowed funds is presented as interest expense, net and the portion of the allowance applicable to equity funds is presented as other income in the Statement of Income. Although the allowance does not represent current cash income, it has been recoverable under the ratemaking process over the service lives of the related properties. Weighted-average AFUDC rates for 2018 and 2017 were 3.34% and 3.60%, respectively. The portion of the allowance applicable to equity funds for 2018 and 2017 was $1.5 million and $2.0 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 2018 and 2017 were approximately $80.5 million and $78.0 million, respectively or 2.8% and 3.0%, 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, 2018, UI has recorded a gross derivative asset of $5.3 million, a regulatory asset of $74.6 million and a gross derivative liability of $79.9 million ($73.2 million of which is related to UI's portion of the CfD signed by CL&P). See Note (J) "Fair Value of Financial Instruments" for additional CfD information.

The gross derivative assets and liabilities as of December 31, 2018 and December 31, 2017 were as follows:

	December 31, 2018	December 31, 2017
	(In Thousands)	
Gross derivative assets:		
Current Assets	$ 3,413	$ 6,912
Deferred Charges and Other Assets	$ 1,942	$ 4,735
Gross derivative liabilties:		
Current Liabilities	$ 11,966	$ 15,776
Noncurrent Liabilities	$ 67,969	$ 63,317

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, 2018 and 2017, were as follows:

	Year Ended December 31, 2018	Year Ended December 31, 2017
	(In Thousands)	
Regulatory Assets - Derivative liabilities	$ 7,134	$ (7,838)

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 $98.5 million and $102.2 million as of December 31, 2018 and December 31, 2017, respectively. As of December 31, 2018, there was an immaterial amount of undistributed earnings from UI's equity investment in GenConn.

UI's pre-tax income from its equity investment in GenConn was $11.0 million and $12.7 million for the years ended December 31, 2018 and 2017, 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 $14.7 million and $16.8 million during the years ended December 31, 2018 and 2017, respectively.

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

	2018	2017
	(In Thousands)	
Current assets	$ 42,268	$ 37,963
Noncurrent assets	$ 358,231	$ 373,576
Current liabilities	$ 22,099	$ 17,936
Noncurrent liabilities	$ 181,863	$ 189,271
Operating revenues	$ 65,319	$ 70,761
Income	$ 21,652	$ 25,357

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, 2018, 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, 2018 and 2017 totaled \$1.5 million and \$2.0 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, 2018 and 2017 include unbilled revenues of \$47.9 million and \$42.9 million, respectively and are shown net of an allowance for doubtful accounts of \$2.8 million and \$2.4 million for 2018 and 2017, respectively. Accounts receivable do not bear interest, although late fees may be assessed.

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

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

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.

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 Standards Pronouncements

(a) Revenue from contracts with customers

In May 2014, the Financial Accounting Standards Board (FASB) issued ASC 606 replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The FASB further amended ASC 606 through various updates issued thereafter. The core principle is for an entity to recognize revenue to represent the transfer of promised goods or services to customers in amounts that reflect the consideration to which the entity expects to be entitled in exchange for those goods or services. UI adopted ASC 606 effective January 1, 2018, and applied the modified retrospective method, for which they did not have a cumulative effect adjustment to retained earnings for initial application of the guidance. Refer to "Revenues" above for further details.

(b) Improving the presentation of net periodic benefit costs

In March 2017, the FASB issued amendments to improve the presentation of net periodic pension cost and net periodic postretirement benefit cost in the financial statements. UI retrospectively adopted the amendments that require them to present the service cost component separately from the other (non-service) components of net benefit cost, to report the service cost component in the income statement line item where we report the corresponding compensation cost and to present all non-service components outside of operating cost. As a result, the non-service components – interest cost, expected return on plan assets, amortization of prior service cost (benefit), amortization of net loss, and settlement charge – have been reclassified from "Operations and maintenance" to "Other Income and (Expense), net" within the consolidated statement of income. Prospectively, from adoption, UI capitalizes only the service cost component when applicable (for example, as a cost of a self-constructed asset). UI elected to apply the practical expedient that allows them to retrospectively apply the amendments on adoption to net benefit costs for comparative periods by using the amounts disclosed in the notes to financial statements for Pension and Other Benefits as the basis for those periods. In connection with applying the practical expedient, in periods after adoption UI continues to include in operating income all legacy net benefit costs previously capitalized as a cost of self-constructed assets and other deferred regulatory costs. The adoption of the amendments did not affect prior period net income. Beginning in 2018, non-service cost components incurred are no longer eligible for construction capitalization. For the year ended December 31, 2018, UI incurred $2.8 million of additional expense as a result of the adoption of this standard for which PURA has approved for recovery and UI has recorded as a regulatory asset.

The following table summarizes the impact to the prior period as a result of the adoption of this standard:

Year Ended December 30, 2017	As Revised	Reported	Higher/(Lower)
(in thousands)			
Statement of Income			
Operating Expenses			
Operation and maintenance	361,219	376,817	(15,598)
Other Income and (Expense), net	(8,304)	7,294	(15,598)

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.

(a) Leases

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

UI adopted the new leases guidance effective January 1, 2019, and has elected the optional transition method under which they will initially apply the standard on that date without adjusting amounts presented for prior periods, and record the cumulative effect of applying the new guidance as an adjustment to beginning retained earnings. UI expects the adjustment to retained earnings will be immaterial. Concerning certain transition and other practical expedients:

- UI did not elect the package of three practical expedients available under the transition provisions, including (i) not reassessing whether expired or existing contracts contain leases, (ii) lease classification, and (iii) not revaluing initial direct costs for existing leases;
- UI elected the land easement practical expedient and did not reassess land easements that we did not account for as leases prior to our adoption of the new leases guidance;
- UI used hindsight for specified determinations and assessments in applying the new leases guidance;
- UI will not recognize lease assets and liabilities for short-term leases (less than one year), for all classes of underlying assets; and
- UI did not separate lease and associated nonlease components for transitioned leases, but will instead account for them together as a single lease component.

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

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

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

(B) CAPITALIZATION

Common Stock

UI had 100 shares of common stock, no par value, outstanding at December 31, 2018 and December 31, 2017.

In December 2018, UI received a $50.0 million equity infusion from UIL 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,		**2018**		**2017**	
(Thousands)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
Senior unsecured debt	2019-2045	$ 847,960	2.80%-6.61%	$ 733,500	2.98%-6.61%
Unamortized debt (costs) premium, net		(5,406)		(4,398)	
Total Debt		**$ 842,554**		**$ 729,102**	
Less: debt due within one year, included in current liabilities		31,000		100,000	
Total Non-current Debt		**$ 811,554**		**$ 629,102**	

The estimated fair value of debt amounted to $905.3 million and $836.2 million as of December 31, 2018 and 2017, respectively. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the natural gas industry and the credit ratings of the borrowers in each case. The fair value hierarchy for the fair value of debt is considered as Level 2. The expenses to issue long-term debt are deferred and amortized over the life of the respective debt issue or the fixed interest-rate period in the case of pollution control revenue bonds.

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

	2019	**2020**	**2021**	**2022**	**2023 & thereafter**	**Total**
			(In Thousands)			
Maturities	$ 31,000	$ 50,000	$ -	$ 162,500	$ 604,460	$ 847,960

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, 2018, UI's debt ratio was 44%.

On October 2, 2018, UI remarketed $64.5 million in aggregate principal amount of Pollution Control Refunding Revenue Bonds, issued through the Business Finance Authority of the State of New Hampshire, with mandatory tender date in 2023 and an interest rate of 2.80%.

In September 2018, UI offered $150 million of debt securities in the private placement market. On October 4, 2018, UI executed a note purchase agreement to issue senior unsecured notes and on October 4, 2018, issued $100 million of senior unsecured notes maturing in 2028 at an interest rate of 4.07%. On December 12, 2018, UI issued an additional $50 million of senior unsecured notes maturing in 2025 at a fixed interest rate of 3.96% under a separate note purchase agreement.

(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 a retail electric supplier and have a maximum demand of less than 500 kilowatts and its customers under supplier of last resort service for those who are not eligible for standard service and who do not choose to purchase electric generation service from a retail electric supplier. The cost of the power is a "pass-through" to those customers through the 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 2018 and the first half of 2019 and for 80% of its standard service load for the second half of 2019, and 20% for the first half of 2020. Supplier of last resort service is procured on a quarterly basis, 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, 2018, UI would have had to post an aggregate of approximately $17.1 million in collateral.

New Renewable Source Generation

Under Connecticut Public Act (PA) 11-80, Connecticut electric utilities are required to enter into long-term contracts to purchase Connecticut Class I RECs from renewable generators located on customer premises. Under this program, UI is required to enter into contracts totaling approximately $200 million in commitments over an approximate 21-year period. The obligations will phase in over a six-year solicitation period, and are expected to peak at an annual commitment level of about $13.6 million per year after all selected projects are online. 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. PA 17-144 and PA18-50 added seventh and eighth years, and up to $48 million in additional commitments by UI, to the program.

On October 23, 2013, PURA approved UI's renewable connections program filed in accordance with PA 11-80, through which UI has developed 10 MW of renewable generation. The costs for this program will be recovered on a cost of service basis. PURA established a base ROE to be calculated as the greater of: (A) the current UI authorized distribution ROE (currently 9.10%) plus 25 basis points and (B) the current authorized distribution ROE for Connecticut Light and Power Company, or CL&P (currently 9.25%), less target equivalent market revenues (reflected as 25 basis points). In addition, UI will retain a percentage of the market revenues from the program, which percentage is expected to equate to approximately 25 basis points on a levelized basis over the life of the program. The cost of this program, a 2.8 MW fuel cell facility in New Haven, solar photovoltaic and fuel cell facilities totaling 5 MW in Bridgeport, and a 2.2 MW fuel cell facility in Woodbridge, all of which are now operational, was approximately $41.5 million.

Pursuant to Connecticut statute, in January 2017, UI entered into a master agreement with the Connecticut Green Bank to procure Connecticut Class I RECs produced by residential solar installations in 15 year tranches, with a final tranche to commence no later than 2022. UI's contractual obligation is to procure 20% of RECs produced by about 255 MW of residential solar installations. Connecticut statutes provides that the net 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.

On May 25, 2017, UI entered into six 20-year power purchase agreements (PPAs) totaling approximately 32 MW with developers of wind and solar generation. These PPAs originated from a three-state Clean Energy RFP, and were entered into pursuant PA 13-303 which provides that the net costs of the PPAs are recoverable through electric rates. The PPAs were approved by PURA on September 13, 2017.

On June 20, 2017, UI entered into twenty-two 20-year PPAs totaling approximately 72 MW with developers of wind and solar generation. These PPAs originated from and RFP issued by the Connecticut Department of Energy and Environmental Protection's (DEEP) PA 15-107 1(b), which provides that the net costs of the PPAs are recoverable through electric rates. The PPAs were approved by PURA on September 7, 2017. One contract was terminated on October 24, 2017, resulting in UI having twenty-one remaining contracts from this solicitation totaling approximately 70 MW.

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

On December 28, 2018, DEEP issued a directive to UI to negotiate and enter into PPAs with twelve projects, totaling approximately 12 million MWh, which were selected as a result of the Zero Carbon RFP issued by DEEP pursuant to PA 17-3, which provides that the net costs of the PPAs are recoverable through electric rates. One of the selected projects is the Millstone nuclear facility located in Waterford, Connecticut and owned by Dominion Energy, Inc. UI completed negotiations, and executed, the PPA with the Millstone nuclear facility which was filed with PURA on March 29, 2019, and regulatory review remains pending. With regard to the other eleven selected projects, DEEP granted UI an extension which allows UI to continue negotiations and file successfully negotiated PPAs with PURA by May 31, 2019.

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 2018, UI's overall allowed weighted-average ROE for its transmission business was 11.31%.

On December 28, 2015, the FERC issued an order instituting section 206 proceedings and establishing hearing and settlement judge procedures. Pursuant to section 206 of the FPA, the FERC instituted proceedings because it found that ISO-NE Transmission, Markets, and Services Tariff is unjust, unreasonable, and unduly discriminatory or preferential. The FERC stated that ISO-NE's Tariff lacks adequate transparency and challenge procedures with regard to the formula rates for ISO-NE Participating Transmission Owners, including UI. The FERC also found that the current Regional Network Service (RNS) and Local Network Service (LNS) formula rates appear to be unjust, unreasonable, unduly discriminatory or preferential or otherwise unlawful as the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates. A settlement judge has been appointed and on August 17, 2018, the PTOs submitted a formula rate settlement opposed by certain parties and supported by the settlement judge. UI is unable to predict the outcome of this proceeding at this time.

On September 30, 2011, the Massachusetts Attorney General, DPU, PURA, New Hampshire Public Utilities Commission, Rhode Island Division of Public Utilities and Carriers, Vermont Department of Public Service, numerous New England consumer advocate agencies and transmission tariff customers collectively filed a joint complaint with the FERC, pursuant to sections 206 and 306 of the Federal Power Act, against several New England Transmission Owners (NETOs), including UI, claiming that the current 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.

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. UI anticipates FERC addressing the Court decision during 2019. UI 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. The FERC is expected to make its final decision in 2019.

UI 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. UI's total reserve associated with Complaints II and III is $6.4 million as of December 31, 2018. If adopted as final, 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. UI cannot predict the outcome of the Complaint II and III proceedings.

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. UI expects FERC to rule on this complaint in 2019. A range of possible outcomes is not able to be determined at this time due to the preliminary state of this matter. UI 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. UI 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 DCF analysis adopted in the FERC order on Complaint I vacated by the Court. The new proposed ROE methodology uses three financial analyses (i.e., DCF, the capital-asset pricing model and the expected earnings analysis) to produce a range of returns to narrow the zone of reasonableness when assessing whether a complainant has met its initial burden of demonstrating that the utility's existing ROE is unjust and unreasonable. The new proposed ROE methodology establishes a range of just and reasonable ROEs of 9.60% to 10.99% and proposes a just and reasonable base ROE of 10.41% with a new ROE cap of 13.08%. Pursuant to the October 2018 Order, the NETOs filed briefs on the proposed methodology in all four Complaints on January 11, 2019. UI cannot predict the outcome of this proceeding.

Equity Investment in Peaking Generation

UI is party to a 50-50 joint venture with Clearway Energy, Inc. in GenConn, which operates two peaking generation plants in Connecticut. The two peaking generation plants, GenConn Devon and GenConn Middletown, are both participating in the ISO-New England markets. PURA has approved revenue requirements for the period from January 1, 2019 through December 31, 2019 of $23.0 million and $28.8 million for GenConn Devon and GenConn Middletown, respectively.

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 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, 2018. There was $24.4 million outstanding under this agreement as of December 31, 2017. UI recorded a $10.9 million note receivable under this arrangement as of December 31, 2018. There was no note receivable as of December 31, 2017.

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, 2018. There was $44.5 million outstanding under this agreement as of December 31, 2017.

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

Under the Avangrid Credit Facility, UI has a maximum sublimit of $400 million. Additionally, under the Avangrid Credit Facility, each of the borrowers, including UI, will pay an annual facility fee that is dependent on their credit rating. The facility fees will range from 12.5 to 17.5 basis points. The maturity date for the Avangrid Credit Facility is June 29, 2023. As of December 31, 2018, UI did not have any outstanding borrowings under the Avangrid Credit Facility. As of December 31, 2017, UI had $100 million of outstanding borrowings under the previous and superseded Avangrid Credit Facility.

(E) INCOME TAXES

	2018	2017
	(In Thousands)	
Income tax expense consists of:		
Income tax provisions (benefits):		
Current		
Federal	$ 30,397	$ 25,557
State	11,480	4,602
Total current	41,877	30,159
Deferred		
Federal	(3,481)	32,804
State	(270)	1,679
Total deferred	(3,751)	34,483
Investment tax credits	(738)	(706)
Total income tax expense	$ 37,388	$ 63,936

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:

	2018	2017
	(In Thousands)	
Book income before income taxes	$ 153,327	$ 169,119
Computed tax at federal statutory rate	$ 32,199	$ 59,192
Increases (reductions) resulting from:		
Property related	(2,314)	(1,194)
State income taxes, net of federal income tax benefits	8,856	4,083
2017 Tax Act deferred tax remeasurement	-	4,336
ITC taken into income	(738)	(706)
Other items, net	(615)	(1,775)
Total income tax expense	$ 37,388	$ 63,936
Effective income tax rates	24.4%	37.8%

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, 2018 and 2017, 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, 2018:

Jurisdiction	*Tax years*
Federal	2013 - 2018
Connecticut	2010 - 2018

The following table summarizes UI's deferred income tax assets and liabilities as of December 31, 2018 and 2017.

	2018	**2017**
	(In Thousands)	
Deferred income taxes:		
Property related	$ (354,061)	$ (338,812)
Unfunded future income taxes	(45,704)	(45,333)
Federal and state tax credits	12,760	15,089
Investment in GenConn	(32,186)	(33,066)
Post-retirement benefits	15,677	5,854
Merger settlement agreement	8,051	8,800
Deferred tax asset on 2017 Tax Act remeasurement	82,561	82,627
Other	(5,267)	(685)
	$ (318,169)	$ (305,526)

As of December 31, 2018, UI had $0.5 million of state tax credit carry forwards that will begin to expire in 2023 and $1.2 million of a state net operating loss carry forward that will begin to expire in 2039. As of December 31, 2017 UI had $2.2 million of state tax credit carry forwards.

(F) PENSION AND OTHER POSTRETIREMENT BENEFITS

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.

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

UI, through Networks, has an investment policy addressing the oversight and management of pension assets and procedures for monitoring and control. State Street Bank is the trustee and NEPC, LLC is the investment advisor that assists in areas of asset allocation and rebalancing, portfolio strategy implementation, and performance monitoring and evaluation.

The goals of the asset investment strategy are to:

- Achieve long-term capital growth while maintaining sufficient liquidity to provide for current benefit payments and pension plan operating expenses.
- Provide a total return that, over the long term, provides sufficient assets to fund pension plan liabilities subject to an appropriate level of risk, contributions and pension expense.
- Optimize the return on assets, over the long term, by investing primarily in a diversified portfolio of equities and additional asset classes with differing rates of return, volatility and correlation.
- Diversify investments within asset classes to maximize preservation of principal and minimize over-exposure to any one investment, thereby minimizing the impact of losses in single investments.

Networks asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. Networks has 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, Liability-Hedging and alternative investments. There is currently a target allocation of 35%-53% in equity securities, 40%-45% for Liability-Hedging assets and 7%-20% for alternative investments. Return-Seeking investments generally consist of domestic, international, global and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking assets also include investments in real estate, absolute return and strategic markets. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The 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, 2018 and 2017. Plan assets and obligations have been measured as of December 31, 2018 and 2017.

	Pension Benefits		Other Post-Retirement Benefits	
	2018	2017	2018	2017
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation at beginning of year	$ 597,466	$ 569,553	$ 63,150	$ 65,519
Service cost	6,420	5,750	930	941
Interest cost	21,841	23,414	2,332	2,700
Participant contributions	-	-	1,144	650
Settlements	188	-	-	-
Actuarial (gain) loss	(22,007)	31,887	(5,234)	(3,882)
Benefits paid (including expenses)	(40,858)	(33,138)	(5,451)	(2,778)
Benefit obligation at end of year	$ 563,050	$ 597,466	$ 56,871	$ 63,150
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 379,212	$ 348,244	$ 27,118	$ 24,583
Actual return on plan assets	(18,955)	52,772	(554)	3,385
Employer contributions	13,357	11,334	-	-
Participant contributions	-	-	1,144	650
Benefits paid (including expenses)	(40,858)	(33,138)	(1,643)	(1,500)
Fair value of plan assets at end of year	$ 332,756	$ 379,212	$ 26,065	$ 27,118
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ 230,294	$ 218,254	$ 30,806	$ 36,032
Amounts Recognized in the Balance Sheet consist of:				
Non-current liabilities	$ 230,294	$ 218,254	$ 30,806	$ 36,032
Amounts Recognized as a Regulatory Asset consist of:				
Prior service cost	-	(4)	(7,204)	(8,741)
Net (gain) loss	215,605	215,735	(8,011)	(5,725)
Total recognized as a regulatory asset	$ 215,605	$ 215,731	$ (15,215)	$ (14,466)
Information on Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:				
Projected benefit obligation	$ 563,050	$ 597,466	N/A	N/A
Accumulated benefit obligation	$ 514,868	$ 540,676	N/A	N/A
Fair value of plan assets	$ 332,756	$ 379,212	N/A	N/A
The following weighted average actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate (Qualified Plans)	4.09%	3.80%	N/A	N/A
Discount rate (Non-Qualified Plans)	4.09%	3.80%	N/A	N/A
Discount rate (Other Post-Retirement Benefits)	N/A	N/A	3.80%	3.80%
Average wage increase	3.80%	3.80%	N/A	N/A
Health care trend rate (current year - pre/post-65)	N/A	N/A	7.50%/5.75%	7.50%/5.75%
Health care trend rate (2030/2025 - pre/post-65)	N/A	N/A	4.50%/4.50%	4.50%/4.50%

N/A – not applicable

UI is allowed to defer as regulatory assets or regulatory liabilities items that would have otherwise been recorded in accumulated OCI pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans. Amounts recognized as regulatory assets or regulatory liabilities for the years ended December 31, 2018 and 2017 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	
	2018	2017	2018	2017
	(In Thousands)			
Components of net periodic benefit cost:				
Service cost	$ 6,420	$ 5,750	$ 930	$ 941
Interest cost	21,840	23,414	2,332	2,700
Expected return on plan assets	(26,826)	(25,163)	(1,650)	(1,451)
Amortization of prior service costs	(4)	(5)	(1,537)	(1,538)
Amortization of actuarial (gain) loss	23,903	25,219	(744)	14
Settlements	188	-	-	-
Net periodic benefit cost	$ 25,521	$ 29,215	$ (669)	$ 666
Other Changes in Plan Assets and Benefit Obligations Recognized as a Regulatory Asset (Liability):				
Net (gain) loss	$ 23,961	$ 4,278	$ (3,030)	$ (5,815)
Amortization of prior service costs	4	5	1,537	1,537
Amortization of actuarial (gain) loss	(23,902)	(25,219)	744	(14)
Settlements	(188)	-	-	-
Total recognized as regulatory asset (liability)	$ (125)	$ (20,936)	$ (749)	$ (4,292)
Total recognized in net periodic benefit costs and regulatory asset (liability)	$ 25,396	$ 8,279	$ (1,418)	$ (3,626)
Estimated Amortizations from Regulatory Assets into Net Periodic Benefit Cost for the next 12 month period:				
Amortization of prior service cost	(2,407)	(4)	(1,537)	(1,537)
Amortization of net (gain) loss	23,177	23,903	(1,099)	(744)
Total estimated amortizations	$ 20,770	$ 23,899	$ (2,636)	$ (2,281)
The following actuarial weighted average assumptions were used in calculating net periodic benefit cost:				
Discount rate	3.80%	4.24%	3.80%	4.24%
Average wage increase	3.80%	3.80%	N/A	N/A
Return on plan assets	7.40%	7.50%	6.25%	6.25%
Health care trend rate (current year - pre/post-65)	N/A	N/A	7.50%/5.75%	6.75%/6.00%
Health care trend rate (2030/2025 - pre/post-65)	N/A	N/A	4.50%/4.50%	4.50%/4.50%

N/A – not applicable

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

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

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

	1% Increase	1% Decrease
Aggregate service and interest cost components	$ 286	$ (237)
Accumulated post-retirement benefit obligation	$ 4,530	$ (3,787)

Contributions

The funding policy for the Plans is to make annual contributions that satisfy the minimum funding requirements of ERISA but that do not exceed the maximum deductible limits of the Internal Revenue Code. These amounts are determined each year as a result of an actuarial valuation of the Plans. UI currently expects to make pension contributions of approximately $19.6 million in 2019. 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)	
2019	$ 35,544	$ 3,655
2020	$ 33,261	$ 3,752
2021	$ 33,713	$ 3,754
2022	$ 34,491	$ 3,748
2023	$ 33,885	$ 3,735
2024-2028	$ 177,645	$ 18,733

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 each of 2018 and 2017 was $5.1 million.

(G) RELATED PARTY TRANSACTIONS

During the years ended December 31, 2018 and 2017, UI received cash distributions from GenConn. See Note (A) Business Organization and Statement of Accounting Policies – Equity Investments.

In December 2018 UI received an equity infusion from UIL Holdings. See Note (B) "Capitalization."

A Director of Avangrid, Inc. holds a beneficial interest in the building located at 157 Church Street, New Haven, Connecticut, where UIL Holdings leases office space, a portion of which is utilized by UI. UI's portion of the lease payments for this office space for each of the years ended December 31, 2018 and 2017 totaled $0.2 million.

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 each of the years ended December 31, 2018 and 2017, UI recorded inter-company expenses of $55.9 million 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.

In the fourth quarter of 2018, UI purchased $105.5 million of corporate assets from UIL Holdings resulting in an increase in net property, plant and equipment.

Dividends/Capital Contributions

UI makes wire transfers to UIL Holdings on a quarterly basis in order to maintain its capitalization structure as allowed per PURA's final decision in UI's 2008 distribution rate proceeding. For the year ended December 31, 2018, UI did not accrue dividends to UIL Holdings. For the year ended December 31, 2017, UI accrued dividends to UIL Holdings of $125 million.

(H) LEASE OBLIGATIONS

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

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

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

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

(I) COMMITMENTS AND CONTINGENCIES

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

Connecticut Yankee Atomic Power Company

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

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

In 2012, the U.S. Court of Appeals issued a favorable decision in Connecticut Yankee's claim for the first six-year-period (Phase I). Connecticut Yankee won on all appellate points in the U.S. Court of Appeals for the Federal Circuit's unanimous decision. In November 2013, the U.S. Court of Claims issued its decision in the Phase II case (the second six-year-period), awarding damages to Connecticut Yankee. In August 2016 the U.S. Court of Claims issued its decision in the Phase III case (the third six-year-period), awarding damages to Connecticut Yankee. In July 2017, Connecticut Yankee filed a Phase IV case (the fourth six-year-period). On February 21, 2019, the U.S. Court of Appeals for the Federal Circuit issued a decision on a motion for partial summary judgment in the Phase IV case awarding Connecticut Yankee approximately $40.7 million in damages. The federal government has 60 days to appeal the decision.

The damage awards will refund past costs and/or reduce the future costs to shareholders of Connecticut Yankee, including UI, upon FERC approval, and will reduce retail customer charges or otherwise as specified by law. UI will receive their proportionate share of the awards that flow through based on percentage ownership. We cannot predict the timing or amount of damage awards that may ultimately flow through to customers.

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.

UI refunds its share of such awards to its customers through the nonbypassable federally mandated congestion charge.

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.

<u>Site Decontamination, Demolition and Remediation Costs</u>

English Station

In January 2012, Evergreen Power, LLC (Evergreen Power) and Asnat Realty LLC (Asnat), then and current 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 against UI seeking, among other things: (i) an order directing UI to reimburse the plaintiffs for costs they have incurred and will incur for the testing, investigation and remediation of hazardous substances at the English Station site and (ii) an order directing UI to investigate and remediate the site. This proceeding had been 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 in Connecticut state court seeking among other things: (i) remediation of the English Station site; (ii) reimbursement of remediation costs; (iii) termination of UI's easement rights; (iv) reimbursement for costs associated with securing the property; and (v) punitive damages. This lawsuit had been stayed in May 2014 pending mediation. Due to lack of activity in the case, the court terminated the stay and scheduled a status conference for July 6, 2017. On July 5, 2017, Asnat filed a pretrial memorandum claiming damages of $10 million for "environmental remediation activities" and lost use of the property. On April 16, 2018, the plaintiffs filed a revised compliant alleging fraud and unjust enrichment against UIL and UI and adding former UIL officers as named defendants alleging fraud. The complaint was further revised on July 3, 2018. UI filed a Motion to Strike the counts in the complaint in August 2018 and oral arguments were held. 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. As to the remaining count, the court declined to strike the claim against UI for unjust enrichment. The court's ruling is subject to appeal by the plaintiffs. 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. Mediation of the matter began in the fourth quarter of 2013 and concluded unsuccessfully in April 2015. 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 the 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, 2018 and 2017, the remaining amount reserved for this matter was $20 million and $25 million, respectively. UI cannot predict the outcome of this matter.

Other

With respect to transmission-related property adjacent to the New Haven Harbor Generating Station, UI performed an environmental analysis that indicated remaining remediation expenses would be approximately $2.7 million. UI has accrued these estimated expenses, which were recovered in transmission rates. As of December 31, 2018 and 2017, the remaining amount reserved for this matter was $1.9 million and $2.7 million, respectively.

(J) FAIR VALUE MEASUREMENTS

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

The following tables set forth the fair value of UI's financial assets and liabilities, other than pension benefits and other postretirement benefits, as of December 31, 2018 and December 31, 2017:

	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, 2018		(In Thousands)		
Assets:				
Derivative assets	$ -	$ -	5,355	$ 5,355
Supplemental retirement benefit trust life insurance policies	-	9,806	-	9,806
	-	9,806	5,355	15,161
Liabilities:				
Derivative liabilities	-	-	79,935	79,935
	-	-	79,935	79,935
Net fair value assets/(liabilities), December 31, 2018	$ -	$ 9,806	$ (74,580)	$ (64,774)
December 31, 2017				
Assets:				
Derivative assets	$ -	$ -	$ 11,647	$ 11,647
Supplemental retirement benefit trust life insurance policies	-	10,416	-	10,416
	-	10,416	11,647	22,063
Liabilities:				
Derivative liabilities	-	-	79,093	79,093
	-	-	79,093	79,093
Net fair value assets/(liabilities), December 31, 2017	$ -	$ 10,416	$ (67,446)	$ (57,030)

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, 2018 or December 31, 2017 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, 2018	Range at December 31, 2017
Risk of non-performance	0.87%-0.88%	0.11% - 0.49%
Discount rate	2.51% - 2.63%	1.89% - 2.40%
Forward pricing ($ per MW)	$4.30 - $9.55	$5.30 - $9.55

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

The determination of the fair value of the supplemental retirement benefit trust life insurance policies was based on quoted prices as of December 31, 2018 and December 31, 2017 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, 2018 and 2017:

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

	December 31, 2017 (In Thousands)	
Net derivative assets/(liabilities), December 31, 2016	$	(75,284)
Unrealized gains and (losses), net		7,838
Net derivative assets/(liabilities), December 31, 2017	$	(67,446)
Change in unrealized gains (losses), net relating to net derivative assets/(liabilities), still held as of December 31, 2017	$	7,838

The following tables set forth the fair values of UI's pension and OPEB assets as of December 31, 2018 and 2017.

	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, 2018	(In Thousands)			
Pension assets				
Mutual funds	$ -	$ 332,756	$ -	$ 332,756
OPEB assets				
Mutual funds	26,065	-	-	26,065
Fair value of plan assets, December 31, 2018	$ 26,065	$ 332,756	$ -	$ 358,821
December 31, 2017				
Pension assets				
Mutual funds	$ -	$ 379,212	$ -	$ 379,212
OPEB assets				
Mutual funds	27,118	-	-	27,118
Fair value of plan assets, December 31, 2017	$ 27,118	$ 379,212	$ -	$ 406,330

The determination of fair value of the Level 2 co-mingled mutual funds were based on the Net Asset Value (NAV) provided by the managers of the underlying fund investments and the unrealized gains and losses. The NAV provided by the managers typically reflect the fair value of each underlying fund investment. Changes in the fair value of pension benefits and OPEB are accounted for in accordance with ASC 715 as discussed in Note (F), "Pension and Other Benefits".

THE SOUTHERN CONNECTICUT GAS COMPANY

AUDITED CONSOLIDATED FINANCIAL STATEMENTS

AS OF AND FOR THE YEARS ENDED

DECEMBER 31, 2018 AND 2017

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

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, 2018 and 2017, 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 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, 2018 and 2017, 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 29, 2019

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

	Year Ended December 31, 2018	Year Ended December 31, 2017
Operating Revenues	$ 390,498	$ 363,832
Operating Expenses		
Natural gas purchased	183,663	169,043
Operation and maintenance	88,146	93,426
Depreciation and amortization	29,574	25,831
Taxes other than income taxes	28,940	27,547
Total Operating Expenses	330,323	315,847
Operating Income	60,175	47,985
Other Income and (Expense), net	(6,402)	(4,270)
Interest Expense, net	15,835	13,508
Income Before Income Tax	37,938	30,207
Income Tax	10,859	2,467
Net Income	$ 27,079	$ 27,740
Less: Net Income Attributable to Noncontrolling Interest	1,769	7,115
Net Income Attributable to The Southern Connecticut Gas Company	$ 25,310	$ 20,625

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

	Year Ended December 31, 2018	Year Ended December 31, 2017
Net Income	$ 27,079	$ 27,740
Other Comprehensive Income, net of income tax	-	841
Comprehensive Income	27,079	28,581
Less: Comprehensive Income attributable to Noncontrolling Interest	1,769	7,115
Comprehensive Income Attributable to The Southern Connecticut Gas Company	$ 25,310	$ 21,466

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

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

	Year Ended December 31, 2018	Year Ended December 31, 2017
Cash Flows From Operating Activities		
Net income	$ 27,079	$ 27,740
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	29,935	26,020
Uncollectible expense	7,235	8,781
Deferred income taxes	493	(1,862)
Pension expense	2,124	4,656
Regulatory assets/liabilities amortization	(1,766)	13,367
Regulatory assets/liabilities carrying cost	801	174
Other non-cash items, net	1,220	(511)
Changes in:		
Accounts receivable and unbilled revenue, net	(6,058)	(14,206)
Gas in storage	(1,914)	(1,204)
Accounts payable and accrued liabilities	8,502	13,511
Taxes accrued/refundable, net	(901)	(10,880)
Interest accrued	573	
Accrued pension and other post-retirement	(2,191)	(691)
Regulatory assets/liabilities	2,314	(12,997)
Other assets	(589)	11,893
Other liabilities	(737)	84
Total Adjustments	39,041	36,135
Net Cash provided by Operating Activities	66,120	63,875
Cash Flows from Investing Activities		
Plant expenditures including AFUDC debt	(86,998)	(54,690)
Notes receivable from affiliates	(2,063)	(1,557)
Net Cash used in Investing Activities	(89,061)	(56,247)
Cash Flows from Financing Activities		
Payment of long-term debt	(50,000)	-
Payment of common stock dividend	(25,000)	(27,000)
Notes payable to affililiates	99,951	19,200
Other	(173)	-
Net Cash provided by (used in) Financing Activities	24,778	(7,800)
Cash, Restricted Cash, and Cash Equivalents:		
Net change for the period	1,837	(172)
Balance at beginning of period	622	794
Balance at end of period	$ 2,459	$ 622
Cash paid during the period for:		
Interest (net of amount capitalized)	$ 13,515	$ 13,515
Non-cash investing activity:		
Plant expenditures included in ending accounts payable	$ 8,968	$ 5,380
Notes receivable from affiliates	$ 6,500	$ -
Non-cash financing activity:		
Payment of noncontrolling interest dividend	$ (6,500)	$ -

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

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

	December 31, 2018	December 31, 2017
Assets		
Current Assets		
Unrestricted cash and temporary cash investments	$ 2,316	$ 622
Accounts receivable and unbilled revenues, net	86,097	80,972
Accounts receivable from affiliates	2,913	8,992
Notes receivable from affiliates	-	4,437
Regulatory assets	32,503	26,240
Gas in storage	29,607	27,693
Materials and supplies	1,695	1,787
Prepayments and other current assets	2,109	1,298
Total Current Assets	157,240	152,041
Other Investments	9,141	10,584
Net Property, Plant and Equipment	773,296	707,093
Regulatory Assets	138,522	140,059
Deferred Charges and Other Assets		
Goodwill	134,931	134,931
Other	143	130
Total Deferred Charges and Other Assets	135,074	135,061
Total Assets	$ 1,213,273	$ 1,144,838

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

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

	December 31, 2018	December 31, 2017
Liabilities		
Current Liabilities		
Notes payable to affiliates	$ 138,727	$ 38,898
Current portion of long-term debt	911	52,517
Accounts payable and accrued liabilities	65,342	57,533
Accounts payable to affiliates	13,975	9,395
Regulatory liabilities	9,080	9,557
Other current liabilities	7,909	8,208
Interest accrued	2,774	2,201
Taxes accrued	6,693	7,594
Total Current Liabilities	245,411	185,903
Deferred Income Taxes	23,676	23,375
Regulatory Liabilities	203,690	197,090
Other Noncurrent Liabilities		
Pension and other postretirement	67,424	59,790
Asset retirement obligations	12,264	12,089
Environmental remediation costs	46,333	46,886
Other	8,736	8,943
Total Other Noncurrent Liabilities	134,757	127,708
Capitalization		
Long-term debt, net of unamortized premium	169,714	170,316
Common Stock Equity		
Common stock	18,761	18,761
Paid-in capital	369,737	369,737
Retained earnings	28,274	27,266
Accumulated other comprehensive income	-	698
Net Common Stock Equity of The Southern Connecticut Gas Company	416,772	416,462
Noncontrolling interest	19,253	23,984
Total Common Stock Equity	436,025	440,446
Total Capitalization	605,739	610,762
Total Liabilities and Capitalization	$ 1,213,273	$ 1,144,838

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

THE SOUTHERN CONNECTICUT GAS COMPANY
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDER'S EQUITY
December 31, 2018
(Thousands of Dollars)

	Common Stock		Paid-in	Retained	Accumulated Other Comprehensive	Noncontrolling	
	Shares	Amount	Capital	Earnings	Income (Loss)	Interest	Total
Balance as of December 31, 2016	1,407,072	$ 18,761	$ 369,737	$ 33,641	$ (143)	$ 16,869	$ 438,865
Net income attributable to The Southern Connecticut Gas Company				20,625			20,625
Net income attributable to Noncontrolling interest						7,115	7,115
Other comprehensive loss, net of income taxes					841		841
Payment of common stock dividend				(27,000)			(27,000)
Balance as of December 31, 2017	1,407,072	$ 18,761	$ 369,737	$ 27,266	$ 698	$ 23,984	$ 440,446
Net income attributable to The Southern Connecticut Gas Company				25,310			25,310
Net income attributable to Noncontrolling interest						1,769	1,769
Adoption of accounting standard				698	(698)		-
Payment of common stock dividend				(25,000)		(6,500)	(31,500)
Balance as of December 31, 2018	1,407,072	$ 18,761	$ 369,737	$ 28,274	$ -	$ 19,253	$ 436,025

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(A) STATEMENT OF ACCOUNTING POLICIES

The Southern Connecticut Gas Company (SCG) engages in natural gas transportation, distribution and sales operations in Connecticut serving approximately 197,000 customers in service areas totaling approximately 522 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.

Certain amounts reported in the Financial Statements in previous periods have been reclassified to conform to the current presentation.

SCG has evaluated subsequent events through the date its financial statements were available to be issued, March 29, 2019.

We consider the following policies to be the most critical in understanding the judgments that are involved in preparing our consolidated 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, owns 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 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 $31.4 million and income of $1.8 million as of and for the year ended December 31, 2018. Intercompany operating revenues and natural gas purchased expenses of $12.1 million and intercompany receivables and payables of $0.1 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, 2018	December 31, 2017
	(In Thousands)	
Assets:		
Current assets	$ 7,554	$ 13,126
Long-term assets	23,826	16,637
Total Assets	$ 31,380	$ 29,763
Liabilities		
Current liabilities	$ 12,271	$ 5,779
Total Liabilities	$ 12,271	$ 5,779

Revenues

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

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

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

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

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

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

Revenues disaggregated by major source are as follows:

		Year Ended December 31, 2018
(Thousands)		
Regulated operations – natural gas	$	380,391
Other (a)		1,466
Revenue from contracts with customers		**381,857**
Leasing revenue		632
Alternative revenue programs		8,009
Total operating revenues	**$**	**390,498**

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

Regulatory Accounting

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

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

Unless otherwise stated below, all of SCG's regulatory assets earn a return. SCG's regulatory assets and liabilities as of December 31, 2018 and 2017 included the following:

	Remaining Period	December 31, 2018	December 31, 2017
		(In Thousands)	
Regulatory Assets:			
Pension and other post-retirement benefit plans	(a)	$ 84,460	$ 81,257
Hardship programs	(b)	6,981	6,184
Deferred purchased gas	(c)	14,247	10,432
Environmental remediation costs	(g)	49,989	50,311
Debt premium	1 to 19 years	9,131	11,647
Other	(e)	6,217	6,468
Total regulatory assets		171,025	166,299
Less current portion of regulatory assets		32,503	26,240
Regulatory Assets, Net		$ 138,522	$ 140,059
Regulatory Liabilities:			
Pension and other post-retirement benefit plans	(a)	4,067	4,984
Asset removal costs	(e)	102,356	98,713
Rate Credits	1 to 9 years	6,750	7,500
Unfunded future income taxes	(d)	24,263	22,471
Tax reform remeasurement	(h)	29,574	24,678
Low income program	(f)	38,109	43,167
Non-firm margin sharing credits	7 years	4,656	4,334
Other	(e)	2,995	800
Total regulatory liabilities		212,770	206,647
Less current portion of regulatory liabilities		9,080	9,557
Regulatory Liabilities, Net		$ 203,690	$ 197,090

(a) Life is dependent upon timing of final pension plan distribution; balance, which is fully offset by a corresponding asset/liability, is recalculated each year in accordance with ASC 715 "Compensation-Retirement Benefits." See Note (F) "Pension and Other Benefits" for additional information.
(b) Hardship customer accounts deferred for future recovery to the extent they exceed the amount in rates.
(c) Deferred purchase gas costs balances at the end of the rate year are normally recorded / returned in the next year.
(d) The balance will be extinguished when the asset, which is fully offset by a corresponding liability, or liability, has been realized or settled, respectively.
(e) Amortization period and/or balance vary depending on the nature, cost of removal and/or remaining life of the underlying assets/liabilities; liability amount as of December 31, 2018 includes decoupling ($0.6 million) that is not currently earning a return.
(f) Various hardship and payment plan programs approved for recovery.
(g) Liability relates to the remediation of the property owned by SCG on Chapel Street in New Haven. See Note (H) "Commitments and Contingencies" for additional information.
(h) Balance includes customer impacts of deferred tax remeasurement as of December 2017, as well as the post 2017 impact of the tax rate decrease related to the passage of the federal Tax Cuts and Jobs Act of 2017 on December 22, 2017. The amount and timing of potential settlement are determined by the regulated utilities' respective rate regulators and IRS Normalization rules.

Goodwill

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

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

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

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

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

SCG had no impairment of goodwill in 2018 and 2017 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 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, 2018 and 2017 were comprised as follows:

	2018	2017
	(In Thousands)	
Gas distribution plant	$ 891,318	$ 842,063
Software	32,892	2,204
Land	3,748	3,748
Building and improvements	26,387	25,725
VIE	22,528	19,911
Other plant	39,056	35,765
Total property, plant & equipment	1,015,929	929,416
Less accumulated depreciation	267,932	234,646
	747,997	694,770
Construction work in progress	25,299	12,323
Net property, plant & equipment	$ 773,296	$ 707,093

Allowance for Funds Used During Construction

In accordance with the uniform systems of accounts, SCG 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 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 2018 and 2017 were 2.16% and 1.28%, respectively. The portion of the allowance applicable to equity funds for 2018 and 2017 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 2018 and 2017 were approximately $29.6 million and $25.8 million, respectively, or approximately 3.1% and 2.8%, 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, 2018, 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 at December 31, 2018 totaled $0.1 million, which primarily relates to its VIE, which have 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 had no restricted cash balances at December 31, 2017.

Accounts receivable and unbilled revenues

Accounts receivable at December 31, 2018 and 2017 include unbilled revenues of $22.6 million and $27.7 million, respectively and are shown net of an allowance for doubtful accounts of $0.8 million and $1.0 million for 2018 and 2017, respectively. Accounts receivable do not bear interest, although late fees may be assessed.

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

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

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.

Accrued removal obligations

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 accrued removal obligations.

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 2018 and 2017 is as follows:

	2018	2017
	(In Thousands)	
Balance as of January 1	$ 12,089	$ 11,910
Liabilities settled during the year	(460)	(447)
Accretion	635	626
Balance as of December 31	$ 12,264	$ 12,089

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. 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, 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 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 Standards Pronouncements

(a) Revenue from contracts with customers

In May 2014, the Financial Accounting Standards Board (FASB) issued ASC 606 replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The FASB further amended ASC 606 through various updates issued thereafter. The core principle is for an entity to recognize revenue to represent the transfer of promised goods or services to customers in amounts that reflect the consideration to which the entity expects to be entitled in exchange for those goods or services. SCG adopted ASC 606 effective January 1, 2018, and applied the modified retrospective method, for which they did not have a cumulative effect adjustment to retained earnings for initial application of the guidance. Refer to 'Revenue' above for further details.

(b) Classifying and measuring financial instruments

In January 2016, the FASB issued final guidance on the classification and measurement of financial instruments. As a result of our adoption, we reclassified $0.7 million from AOCI to retained earnings.

(c) Improving the presentation of net periodic benefit costs

In March 2017, the FASB issued amendments to improve the presentation of net periodic pension cost and net periodic postretirement benefit cost in the financial statements. SCG retrospectively adopted the amendments that require them to present the service cost component separately from the other (non-service) components of net benefit cost, to report the service cost component in the income statement line item where we report the corresponding compensation cost and to present all non-service components outside of operating cost. As a result, the non-service components – interest cost, expected return on plan assets, amortization of prior service cost (benefit), amortization of net loss, and settlement charge – have been reclassified from "Operations and maintenance" to "Other Income and (Expense), net" within the consolidated statement of income. Prospectively, from adoption, SCG capitalizes only the service cost component when applicable (for example, as a cost of a self-constructed asset). SCG elected to apply the practical expedient that allows them to retrospectively apply the amendments on adoption to net benefit costs for comparative periods by using the amounts disclosed in the notes to financial statements for Pension and Other Benefits as the basis for those periods. In addition to those amounts, SCG includes amortization of net benefit costs recorded as regulatory deferrals as a result of purchase accounting in a prior year. In connection with applying the practical expedient, in periods after adoption SCG continues to include in operating income all legacy net benefit costs previously capitalized as a cost of self-constructed assets and other deferred regulatory costs. The adoption of the amendments did not affect prior period net income. Beginning in 2018, non-service cost components incurred are no longer eligible for construction capitalization. The impact of this change was reflected in SCG's new rates effective January 1, 2018.

The following table summarizes the impact to the prior period as a result of the adoption of this standard:

Year Ended December 31, 2017 (in thousands)	As previously filed	Reclassifications	As currently reported
Statement of Income			
Operating Expenses			
Operation and maintenance	99,706	(6,280)	93,426
Other Income and (Expense), net	2,010	(6,280)	(4,270)

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 consolidated financial statements.

(a) Leases

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

SCG adopted the new leases guidance effective January 1, 2019, and has elected the optional transition method under which they will initially apply the standard on that date without adjusting amounts presented for prior periods, and record the cumulative effect of applying the new guidance as an adjustment to beginning retained earnings. SCG expects the adjustment to retained earnings will be immaterial. Concerning certain transition and other practical expedients:

- SCG did not elect the package of three practical expedients available under the transition provisions, including (i) not reassessing whether expired or existing contracts contain leases, (ii) lease classification, and (iii) not revaluing initial direct costs for existing leases;
- SCG used hindsight for specified determinations and assessments in applying the new leases guidance;
- SCG will not recognize lease assets and liabilities for short-term leases (less than one year), for all classes of underlying assets; and
- SCG did not separate lease and associated nonlease components for transitioned leases, but will instead account for them together as a single lease component.

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

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

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

(c) Simplifying the test for goodwill impairment

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

B) CAPITALIZATION

Common Stock

SCG had 1,407,072 shares of its common stock, $13.33 par value, outstanding as of December 31, 2018 and 2017.

Long-Term Debt

As of December 31,		**2018**		**2017**	
(Thousands)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
First mortgage bonds [(a)]	2021-2041	$ 164,000	3.88%-7.95%	$ 214,000	3.88%-7.95%
Unamortized debt (costs) premium, net		6,625		8,833	
Total Debt		**170,625**		**222,833**	
Less: debt due within one year,					
included in current liabilities		911		52,517	
Total Long-term Debt		**$ 169,714**		**$ 170,316**	

(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 $197.1 million and $261.2 million as of December 31 2018 and 2017, 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:

	2019	2020	2021	2022	2023 & Thereafter	Total
			(In Thousands)			
Maturities	$ -	$ -	$ 25,000	$ -	$ 139,000	$ 164,000

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, 2018, SCG's debt ratio was 41%.

(C) REGULATORY PROCEEDINGS

Rates

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

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

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

Gas Supply Arrangements

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

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

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

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

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

Tax Cuts and Jobs Act

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

(D) SHORT-TERM CREDIT ARRANGEMENTS

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

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. SCG has a lending/borrowing limit of $100 million under this agreement. There was $55.5 million and $9.8 million outstanding as of December 31, 2018 and 2017, respectively, under this agreement.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $250 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. There was $72.8 million and $29.1 million outstanding under this agreement as of December 31, 2018 and 2017, respectively.

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

Under the Avangrid Credit Facility, SCG has a maximum sublimit of $150 million. Additionally, under the Avangrid Credit Facility, each of the borrowers, including SCG, will pay an annual facility fee that is dependent on their credit rating. The facility fees will range from 12.5 to 17.5 basis points. The maturity date for the Avangrid Credit Facility is June 29, 2023. As of December 31, 2018 and 2017, SCG did not have any outstanding borrowings under the Avangrid Credit Facility.

CNE and TPS each have a current account agreement with Avangrid whereby they can lend excess cash to Avangrid or borrow from Avangrid when they have cash funding needs to meet their obligations. Interest is charged at a rate equal to three month LIBOR plus an applicable margin and is capitalized annually. As of December 31, 2018 TPS had $10.4 million outstanding under its agreement. TPS did not have any amounts outstanding under this agreement as of December 31, 2017. CNE did not have any amounts outstanding under its agreement as of December 31, 2018 and 2017.

(E) INCOME TAXES

	Year Ended December 31, 2018	Year Ended December 31, 2017
	(In Thousands)	
Income tax expense consists of:		
Income tax provisions (benefits):		
Current		
Federal	$ 7,644	$ 2,647
State	2,722	1,682
Total current	10,366	4,329
Deferred		
Federal	(682)	(76)
State	1,175	(1,786)
Total deferred	493	(1,862)
Total Income tax expense	$ 10,859	$ 2,467

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

	Year Ended December 31, 2018	Year Ended December 31, 2017
	(In Thousands)	
Book income before income taxes	$ 37,938	$ 30,207
Computed tax at federal statutory rate	$ 7,967	$ 10,573
Increases (reductions) resulting from:		
Removal costs	-	(1,000)
Uncollectible reserves and programs	-	1,158
State taxes, net of federal income tax benefits	3,078	(103)
2017 Tax Act deferred tax remeasurement	-	(3,262)
Variable interest entity	(476)	(519)
Other items, net	290	(4,380)
Total income tax expense	$ 10,859	$ 2,467
Effective income tax rates	28.6%	8.2%

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, 2018 and 2017, 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, 2018:

Jurisdiction	*Tax years*
Federal	2013 - 2018
Connecticut	2013 - 2018

The following table summarizes SCG's deferred tax assets and liabilities as of December 31, 2018 and 2017:

	2018	**2017**
	(In Thousands)	
Property related	$ (39,984)	$ (37,939)
Unfunded future income taxes	6,228	7,658
Federal and state tax credits	4,780	4,589
Deferred tax asset on 2017 Tax Act remeasurement	7,179	5,037
Federal and state net operating loss	5,383	4,796
Post-retirement benefits, net	(3,260)	(2,429)
Other liabilities	(4,002)	(5,087)
	$ (23,676)	$ (23,375)

As of December 31, 2018, SCG had a net state tax credit carry forward of $4.8 million, a state net operating loss carry forward of $0.5 million and a federal net operating loss carry forward of $4.8 million that will begin to expire in 2032. As of December 31, 2017, SCG had a net state tax credit carry forward of $4.6 million, a state net operating loss carry forward of $0.5 million and a federal net operating loss carry forward of $4.8 million.

(F) PENSION AND OTHER POSTRETIREMENT BENEFITS

Defined Benefit Plans (the Plans)

Pension Plans

SCG has two qualified pension plans covering substantially all of their union and management employees. SCG also has non-qualified supplemental pension plans for certain retirees. The qualified pension plans provide benefits under traditional defined benefit formulas or, for those hired on or after specified dates, cash balance formulas. The Plans are closed to new employees. New employees are eligible for enhanced benefits in the 401(k) plan.

Other Postretirement Benefits Plans

SCG also has plans providing other postretirement benefits for a majority of its employees. These benefits consist primarily of health care, prescription drug and life insurance benefits, for retired employees and their dependents. Effective January 1, 2016, pre-Medicare eligible union retirees are eligible to participate in a multiemployer retiree welfare plan to which SCG provides a subsidy through a Voluntary Employee Benefit Association Trust. For Medicare eligible non-union retirees, SCG 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

SCG, through Networks, has an investment policy addressing the oversight and management of pension assets and procedures for monitoring and control. State Street Bank is the trustee and NEPC, LLC is the investment advisor that assists in areas of asset allocation and rebalancing, portfolio strategy implementation, and performance monitoring and evaluation.

The goals of the asset investment strategy are to:

- Achieve long-term capital growth while maintaining sufficient liquidity to provide for current benefit payments and pension plan operating expenses.
- Provide a total return that, over the long term, provides sufficient assets to fund pension plan liabilities subject to an appropriate level of risk, contributions and pension expense.
- Optimize the return on assets, over the long term, by investing primarily in a diversified portfolio of equities and additional asset classes with differing rates of return, volatility and correlation.
- Diversify investments within asset classes to maximize preservation of principal and minimize over-exposure to any one investment, thereby minimizing the impact of losses in single investments.

Networks asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. Networks has 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, Liability-Hedging and alternative investments. There is currently a target allocation of 35%-53% in equity securities, 40%-45% for Liability-Hedging assets and 7%-20% for alternative investments. Return-Seeking investments generally consist of domestic, international, global and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking assets also include investments in real estate, absolute return and strategic markets. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The following table represents the change in benefit obligation, change in plan assets and the respective funded status of SCG's pension and other postretirement plans as of December 31, 2018 and 2017. Plan assets and obligations have been measured as of December 31, 2018 and 2017.

	Pension Benefits		Other Post-Retirement Benefits	
	Year Ended December 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2018	Year Ended December 31, 2017
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation at beginning of year	$ 180,032	$ 179,453	$ 19,693	$ 21,901
Service cost	2,199	1,925	121	163
Interest cost	6,658	7,417	720	893
Plan participants' contributions	-	-	781	615
Actuarial (gain) loss	(7,376)	377	147	(1,777)
Benefits paid (including expenses)	(10,211)	(9,140)	(2,521)	(2,102)
Benefit obligation at end of year	$ 171,302	$ 180,032	$ 18,941	$ 19,693
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 127,044	$ 118,176	$ 6,065	$ 5,688
Actual return on plan assets	(8,302)	17,354	(312)	700
Plan participants' contributions	-	-	781	615
Employer contributions	2,286	654	-	1,450
Benefits paid (including expenses)	(10,201)	(9,140)	(1,105)	(2,388)
Fair value of plan assets at end of year	$ 110,827	$ 127,044	$ 5,429	$ 6,065
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ 60,475	$ 52,988	$ 13,512	$ 13,628
Amounts Recognized in the Consolidated Balance Sheet consist of:				
Non-current liabilities	$ 60,475	$ 52,988	$ 13,512	$ 13,628
Amounts Recognized as a Regulatory Asset (Liability) consist of:				
Prior service cost	$ 911	$ 1,671	$ 678	$ 1,155
Net (gain) loss	$ 33,903	$ 25,562	(3,030)	(4,463)
Total recognized as a regulatory asset (liability)	$ 34,814	$ 27,233	$ (2,352)	$ (3,308)
Information on Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:				
Projected benefit obligation	$ 171,302	$ 180,032	N/A	N/A
Accumulated benefit obligation	$ 167,269	$ 174,171	N/A	N/A
Fair value of plan assets	$ 110,827	$ 127,044	N/A	N/A
The following weighted average actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate (Qualified Plans)	4.09%	3.80%	N/A	N/A
Discount rate (Non-Qualified Plans)	4.09%	3.80%	N/A	N/A
Discount rate (Other Post-Retirement Benefits)	N/A	N/A	4.09%	3.80%
Average wage increase	3.50%	3.50%	N/A	N/A
Health care trend rate (current year pre/post-65)	N/A	N/A	7.00%/7.75%	7.50%/8.50%
Health care trend rate (2029/2027 - pre/post-65)	N/A	N/A	4.50%/4.50%	4.50%/4.50%

N/A – not applicable

THE SOUTHERN CONNECTICUT GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2018 and 2017 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, 2018	Year Ended December 31, 2017	Year Ended December 31, 2018	Year Ended December 31, 2017
	(In Thousands)			
Components of net periodic benefit cost:				
Service cost	$ 2,199	$ 1,925	$ 121	$ 163
Interest cost	6,658	7,417	720	893
Expected return on plan assets	(9,076)	(8,551)	(418)	(376)
Amortization of prior service cost	759	759	477	489
Amortization of actuarial (gain) loss	1,671	2,791	(555)	(392)
Net periodic benefit cost	$ 2,211	$ 4,341	$ 345	$ 777
Other Changes in Plan Assets and Benefit Obligations Recognized as a Regulatory Asset (Liability):				
Net (gain) loss	$ 10,002	$ (8,424)	$ 878	$ (1,815)
Amortization of current year prior service (credit)/costs	-	-	-	-
Transition obligation (asset)	-	-	-	-
Amortization of prior service cost	(759)	(759)	(477)	(489)
Amortization of actuarial gain (loss)	(1,671)	(2,791)	555	392
Total recognized as regulatory asset (liability)	$ 7,572	$ (11,974)	$ 956	$ (1,912)
Total recognized in net periodic benefit costs and regulatory asset (liability)	$ 9,783	$ (7,633)	$ 1,301	$ (1,135)
Estimated Amortizations from Regulatory Assets (Liabilities) into Net Periodic Benefit Cost for the next 12 month period:				
Amortization of prior service (cost) credit	$ 759	$ 759	N/A	N/A
Amortization of net (gain) loss	2,565	1,671	N/A	N/A
Total estimated amortizations	$ 3,324	$ 2,430	N/A	N/A
The following actuarial weighted average assumptions were used in calculating net periodic benefit cost:				
Discount rate	3.80%	4.24%	3.80%	4.24%
Average wage increase	3.50%	3.50%	N/A	N/A
Return on plan assets	7.40%	7.50%	7.00%	7.00%
Health care trend rate (current year - pre/post-65)	N/A	N/A	7.50%/8.50%	6.75%/8.50%
Health care trend rate (2030/2028 - pre/post-65)	N/A	N/A	4.50%/4.50%	4.50%/4.50%

N/A – not applicable

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

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

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

	1% Increase	1% Decrease
	(In Thousands)	
Aggregate service and interest cost components	$ 41	$ (33)
Accumulated post-retirement benefit obligation	$ 791	$ (649)

Contributions

The funding policy for the Plans is to make annual contributions that satisfy the minimum funding requirements of ERISA but that do not exceed the maximum deductible limits of the Internal Revenue Code. These amounts are determined each year as a result of an actuarial valuation of the Plans. SCG currently expects to make pension contributions of approximately $6.6 million in 2019. 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, 2018 consisted of:

Year	Pension Benefits	Other Post-Retirement Benefits	Medicare Act Subsidy
		(In Thousands)	
2019	$ 10,303	$ 1,677	$ 103
2020	$ 10,351	$ 1,549	$ 109
2021	$ 10,419	$ 1,510	$ 111
2022	$ 10,617	$ 1,463	$ 115
2023	$ 10,747	$ 1,411	$ 118
2024-2028	$ 55,042	$ 6,442	$ 279

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 2018 and 2017 was $0.8 million and $0.9 million, respectively.

(G) RELATED PARTY TRANSACTIONS

Inter-company Transactions

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, 2018, SCG recorded inter-company expenses of $15.0 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.

In the fourth quarter of 2018, SCG purchased $28.1 million of corporate assets from UIL Holdings resulting in an increase in net property, plant and equipment.

Dividends/Capital Contributions

For the years ended December 31, 2018 and 2017, SCG accrued $25 million and $27 million, respectively, in dividends to UIL Holdings. In addition, CNE accrued $6.5 million in dividends to URI for the year ended December 31, 2018 to settle an intercompany loan.

(H) LEASE OBLIGATIONS

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

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

(I) COMMITMENTS AND CONTINGENCIES

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

Environmental Matters

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

Site Decontamination, Demolition and Remediation Costs

SCG owns or has previously owned properties where Manufactured Gas Plants (MGPs) had historically operated. MGP operations have led to contamination of soil and groundwater with petroleum hydrocarbons, benzene and metals, among other things, at these properties, the regulation and cleanup of which is regulated by the federal Resource Conservation and Recovery Act as well as other federal and state statutes and regulations. SCG has or had an ownership interest in one or more such properties contaminated as a result of MGP-related activities. Under the existing regulations, the cleanup of such sites requires state and at times, federal, regulators' involvement and approval before cleanup can commence. In certain cases, such contamination has been evaluated, characterized and remediated. In other cases, the sites have been evaluated and characterized, but not yet remediated. Finally, at some of these sites, the scope of the contamination has not yet been fully characterized; no liability was recorded in respect of these sites as of December 31, 2018 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, 2018, SCG reserved $48.0 million related to the property located in New Haven which was offset by a regulatory asset. Additionally, as of December 31, 2018, SCG has determined that remediation of the properties in Bridgeport is not probable and therefore not reserved.

(J) FAIR VALUE MEASUREMENTS

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

The following tables set forth the fair value SCG's financial assets and liabilities, other than pension benefits and OPEB, as of December 31, 2018 and December 31, 2017.

	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, 2018				
Noncurrent investments	$ 9,141	$ -	$ -	$ 9,141
Total fair value assets, December 31, 2018	$ 9,141	$ -	$ -	$ 9,141
December 31, 2017				
Noncurrent investments	$ 10,584	$ -	$ -	$ 10,584
Total fair value assets, December 31, 2017	$ 10,584	$ -	$ -	$ 10,584

The following tables set forth the fair values of SCG's pension and OPEB assets as of December 31, 2018 and 2017.

	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, 2018		(In Thousands)		
Pension assets				
Mutual funds	$ -	$ 110,827	$ -	$ 110,827
OPEB assets				
Mutual funds	5,429	-	-	5,429
Fair value of plan assets, December 31, 2018	$ 5,429	$ 110,827	$ -	$ 116,256
December 31, 2017				
Pension assets				
Mutual funds	$ -	$ 127,044	$ -	$ 127,044
OPEB assets				
Mutual funds	6,065	-	-	6,065
Fair value of plan assets, December 31, 2017	$ 6,065	$ 127,044	$ -	$ 133,109

The determination of fair values of the Level 2 co-mingled mutual funds were based on the Net Asset Value (NAV) provided by the managers of the underlying fund investments and the unrealized gains and losses. The NAV provided by the managers typically reflect the fair value of each underlying fund investment. Changes in the fair value of pension benefits and OPEB are accounted for in accordance with ASC 715 Compensation – Retirement Benefits as discussed in Note (F) "Pension and Other Benefits".

CONNECTICUT NATURAL GAS CORPORATION

AUDITED FINANCIAL STATEMENTS

AS OF AND FOR THE YEARS ENDED

DECEMBER 31, 2018 AND 2017

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KPMG

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

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, 2018 and 2017, and the related statements of income, changes in shareholder's equity, and cash flows for the years then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

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

Auditors' Responsibility

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

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

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

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Connecticut Natural Gas Corporation as of December 31, 2018 and 2017, 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 29, 2019

CONNECTICUT NATURAL GAS CORPORATION
STATEMENT OF INCOME
(In Thousands)

	Year Ended December 31, 2018	Year Ended December 31, 2017
Operating Revenues	$ 380,671	$ 364,314
Operating Expenses		
Natural gas purchased	184,123	173,312
Operation and maintenance	97,806	98,183
Depreciation and amortization	35,615	33,369
Taxes other than income taxes	25,956	26,271
Total Operating Expenses	343,500	331,135
Operating Income	37,171	33,179
Other Income and (Expense), net	(5,557)	(4,656)
Interest Expense, net	8,381	6,964
Income Before Income Tax	23,233	21,559
Income Tax	4,754	6,517
Net Income	18,479	15,042
Less: Preferred Stock Dividends of Subsidiary, Noncontrolling Interests	20	34
Net Income attributable to Connecticut Natural Gas Corporation	$ 18,459	$ 15,008

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

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

	Year Ended December 31, 2018	Year Ended December 31, 2017
Cash Flows From Operating Activities		
Net Income	$ 18,479	$ 15,042
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	35,700	33,446
Deferred income taxes	(7,188)	6,592
Uncollectible expense	6,767	9,187
Pension expense	3,720	6,528
Regulatory assets/liabilities amortization	3,162	1,864
Regulatory assets/liabiities carrying cost	760	365
Other non-cash items, net	37	(203)
Changes in:		
Accounts receivable and unbilled revenues, net	(11,020)	(14,122)
Natural gas in storage	(4,575)	(631)
Accounts payable and accrued liabilities	8,518	4,948
Interest accrued	383	(643)
Taxes accrued/refundable, net	(1,999)	(1,505)
Accrued pension and other post-retirement	(2,363)	(3,345)
Regulatory assets/liabilities	9,349	(16,384)
Other assets	(412)	142
Other liabilities	1,141	830
Total Adjustments	41,980	27,069
Net Cash provided by Operating Activities	60,459	42,111
Cash Flows from Investing Activities		
Plant expenditures including AFUDC debt	(77,644)	(70,387)
Net Cash used in Investing Activities	(77,644)	(70,387)
Cash Flows from Financing Activities		
Payment of common stock dividend	(2)	(19,000)
Payment of long-term debt	-	(20,000)
Payment of preferred stock dividend	(20)	(34)
Notes payable to affiliates	19,235	67,262
Other	(175)	-
Net Cash provided by Financing Activities	19,038	28,228
Cash, Restricted Cash, and Cash Equivalents:		
Net change for the period	1,853	(48)
Balance at beginning of period	666	714
Balance at end of period	$ 2,519	$ 666
Cash paid during the period for:		
Interest (net of amount capitalized)	$ 6,830	$ 6,937
Non-cash investing activity:		
Plant expenditures included in ending accounts payable	$ 4,730	$ 7,014

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

CONNECTICUT NATURAL GAS CORPORATION
BALANCE SHEET

December 31, 2018 and 2017

ASSETS
(In Thousands)

	2018	2017
Assets		
Current Assets		
Unrestricted cash and temporary cash investments	$ 1,202	$ 666
Accounts receivable and unbilled revenues, net	90,671	85,964
Accounts receivable from affiliates	1,017	1,441
Regulatory assets	31,180	19,143
Gas in storage	27,954	23,379
Materials and supplies	2,024	1,887
Prepayments and other current assets	1,290	1,138
Total Current Assets	155,338	133,618
Other Investments	1,090	1,158
Net Property, Plant and Equipment	701,598	647,486
Deferred Income Taxes	1,979	-
Regulatory Assets	113,735	116,875
Deferred Charges and Other Assets		
Goodwill	79,341	79,341
Other	1,569	130
Total Deferred Charges and Other Assets	80,910	79,471
Total Assets	$ 1,054,650	$ 978,608

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

CONNECTICUT NATURAL GAS CORPORATION
BALANCE SHEET
December 31, 2018 and 2017

LIABILITIES AND CAPITALIZATION
(In Thousands)

	2018	2017
Liabilities		
Current Liabilities		
Notes payable to affiliates	$ 108,375	$ 89,262
Accounts payable and accrued liabilities	68,849	65,011
Accounts payable to affiliates	12,749	10,353
Other current liabilities	3,918	4,098
Regulatory liabilities	9,866	2,880
Interest accrued	1,645	1,262
Taxes accrued	6,064	8,062
Total Current Liabilities	211,466	180,928
Deferred Income Taxes	-	959
Regulatory Liabilities	240,549	224,457
Other Noncurrent Liabilities		
Pension and other postretirement	101,450	90,761
Asset retirement obligations	6,637	6,683
Other	2,724	1,499
Total Other Noncurrent Liabilities	110,811	98,943
Capitalization		
Long-term debt, net of unamortized premium	109,336	109,290
Preferred Stock, not subject to mandatory redemption	340	340
Common Stock Equity		
Common stock	33,233	33,233
Paid-in capital	315,302	315,304
Retained earnings	33,613	15,181
Accumulated other comprehensive income	-	(27)
Net Common Stock Equity	382,148	363,691
Total Capitalization	491,824	473,321
Total Liabilities and Capitalization	$ 1,054,650	$ 978,608

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

CONNECTICUT NATURAL GAS CORPORATION

STATEMENT OF CHANGES IN SHAREHOLDER'S EQUITY

December 31, 2018 and 2017

(Thousands of Dollars)

	Common Stock		Paid-in	Retained Earnings (Accumulated	Accumulated Other Comprehensive	
	Shares	**Amount**	**Capital**	**Deficit)**	**Income (Loss)**	**Total**
Balance as of December 31, 2016	10,634,436	$ 33,233	$ 315,304	$ 19,173	$ (27)	$ 367,683
Net income				15,042		15,042
Payment of commom stock dividend				(19,000)		(19,000)
Payment of preferred stock dividend				(34)		(34)
Balance as of December 31, 2017	10,634,436	$ 33,233	$ 315,304	$ 15,181	$ (27)	$ 363,691
Net income				$ 18,479		18,479
Adoption of accounting standard				(27)	27	-
Payment of common stock dividend			(2)			(2)
Payment of preferred stock dividend				(20)		(20)
Balance as of December 31, 2018	10,634,436	33,233	315,302	33,613	-	$ 382,148

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

CONNECTICUT NATURAL GAS CORPORATION

NOTES TO FINANCIAL STATEMENTS

(A) STATEMENT OF ACCOUNTING POLICIES

Connecticut Natural Gas Corporation (CNG) engages in natural gas transportation, distribution and sales operations in Connecticut serving approximately 177,000 customers in service areas totaling approximately 716 square miles. CNG is regulated by the Connecticut Public Utilities Regulatory Authority (PURA).

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

Accounting Records

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

Basis of Presentation

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

CNG's total comprehensive income is equal to net income for the years ended December 31, 2018 and 2017.

Certain amounts reported in the Financial Statements in previous periods have been reclassified to conform to the current presentation.

CNG has evaluated subsequent events through the date its financial statements were available to be issued, March 29, 2019.

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

Revenues

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

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

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

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

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

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

Revenues disaggregated by major source are as follows:

(Thousands)	Year Ended December 31, 2018
Regulated operations – natural gas	$ 372,204
Other (a)	1,844
Revenue from contracts with customers	**374,048**
Leasing revenue	101
Alternative revenue programs	6,522
Total operating revenues	**$ 380,671**

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

Regulatory Accounting

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

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

Unless otherwise stated below, all of CNG's regulatory assets earn a return. CNG's regulatory assets and liabilities as of December 31, 2018 and 2017 included the following:

	Remaining Period	December 31, 2018	December 31, 2017
		(In Thousands)	
Regulatory Assets:			
Pension and other post-retirement benefit plan:	(a)	$ 112,031	$ 108,979
Hardship programs	(b)	11,746	10,977
Unfunded future income taxes	(c)	3,958	-
Deferred purchased gas	(f)	13,503	10,171
Other	(d)	3,677	5,891
Total regulatory assets		144,915	136,018
Less current portion of regulatory assets		31,180	19,143
Regulatory Assets, Net		$ 113,735	$ 116,875
Regulatory Liabilities:			
Pension and other postretirement benefit plans	(a)	$ 6,105	$ 5,855
Asset removal costs	(d)	187,048	176,113
Asset retirement obligation	(e)	9,058	8,553
Rate credits	1 to 9 years	11,250	12,500
Unfunded future income taxes	(c)	-	829
Tax reform	2 to 32 years	21,574	13,707
Non-firm margin sharing credits	10 years	5,368	5,459
Decoupling	(g)	7,751	3,843
Other	(d)	2,261	478
Total regulatory liabilities		250,415	227,337
Less current portion of regulatory liabilities		9,866	2,880
Regulatory Liabilities, Net		$ 240,549	$ 224,457

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

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

(c) The balance will be extinguished when the asset, which is fully offset by a corresponding liability, or liability has been realized or settled, respectively.
(d) Amortization period and/or balance vary depending on the nature, cost of removal and/or remaining life of the underlying assets/liabilities; asset amount includes certain amounts that are not currently earning a return.
(e) The liability will be extinguished simultaneous with the retirement of the assets and settlement of the corresponding asset retirement obligation.
(f) Deferred purchase gas costs balances at the end of the rate year are normally recorded / returned in the next year.
(g) Decoupling regulatory liability is not currently earning a return. The current portion is being returned to customers in 2018. The return of the long-term portion will be determined in a future proceeding with PURA.

Goodwill

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

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

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

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

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

CNG had no impairment of goodwill in 2018 and 2017 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 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, 2018 and 2017 were comprised as follows:

	2018	2017
	(In Thousands)	
Gas distribution plant	$ 842,745	$ 803,863
Software	30,284	3,093
Land	1,618	1,618
Building and improvements	32,475	31,044
Other plant	98,330	52,978
Total property, plant & equipment	1,005,452	892,596
Less accumulated depreciation	319,083	293,532
	686,369	599,064
Construction work in progress	15,229	48,422
Net property, plant & equipment	$ 701,598	$ 647,486

Allowance for Funds Used During Construction

In accordance with the uniform systems of accounts, CNG 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 historically been recoverable under the ratemaking process over the service lives of the related properties. Weighted-average AFUDC rates for 2018 and 2017 were 2.13% and 1.33%, respectively. The portion of the allowance applicable to equity funds was immaterial for both 2018 and 2017.

Depreciation

Provisions for depreciation on utility plant for book purposes are computed on a straight-line basis using composite rates based on the estimated service lives of the various classes of assets. For utility plant other than software, service lives are determined by independent depreciation consultants and subject to review and approval by PURA. Software service life is based upon management's estimate of useful life. The aggregate annual provisions for depreciation for both 2018 and 2017 were approximately $35.6 million and $33.4 million, respectively, or 3.8% 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 CNG. At December 31, 2018, 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 at December 31, 2018 totaled $1.3 million, which 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. CNG's restricted cash balances are included in other long-term assets on the balance sheet. CNG had no restricted cash balances at December 31, 2017.

Accounts receivable and unbilled revenues

Accounts receivable at December 31, 2018 and 2017 include unbilled revenues of $28.2 million and $31.1 million, respectively and are shown net of an allowance for doubtful accounts of $1.0 million and $1.3 million for 2018 and 2017, respectively. Accounts receivable do not bear interest, although late fees may be assessed.

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

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

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.

Accrued removal obligations

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 accrued removal obligations.

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 2018 and 2017 is as follows:

	2018	2017
	(In Thousands)	
Balance as of January 1	$ 6,683	$ 6,716
Liabilities settled during the year	(397)	(386)
Accretion	351	353
Balance as of December 31	$ 6,637	$ 6,683

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 its recent 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 Standards Pronouncements

(a) Revenue from contracts with customers

In May 2014, the Financial Accounting Standards Board (FASB) issued ASC 606 replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The FASB further amended ASC 606 through various updates issued thereafter. The core principle is for an entity to recognize revenue to represent the transfer of promised goods or services to customers in amounts that reflect the consideration to which the entity expects to be entitled in exchange for those goods or services. CNG adopted ASC 606 effective January 1, 2018, and applied the modified retrospective method, for which they did not have a cumulative effect adjustment to retained earnings for initial application of the guidance. Refer to 'Revenue' above for further details.

(b) Classifying and measuring financial instruments

In January 2016, the FASB issued final guidance on the classification and measurement of financial instruments. As a result of our adoption we reclassified less than $0.1 million from AOCI to retained earnings.

(c) Improving the presentation of net periodic benefit costs

In March 2017, the FASB issued amendments to improve the presentation of net periodic pension cost and net periodic postretirement benefit cost in the financial statements. CNG retrospectively adopted the amendments that require us to present the service cost component separately from the other (non-service) components of net benefit cost, to report the service cost component in the income statement line item where we report the corresponding compensation cost, and to present all non-service components outside of operating cost. As a result, the non-service components – interest cost, expected return on plan assets, amortization of prior service cost (benefit), amortization of net loss, and settlement charge – have been reclassified from Operations and maintenance to Other income/(expense) within the statement of income. Prospectively, from adoption, CNG capitalizes only the service cost component when applicable (for example, as a cost of a self-constructed asset). CNG elected to apply the practical expedient that allows them to retrospectively apply the amendments on adoption to net benefit costs for comparative periods by using the amounts disclosed in the notes to financial statements for Pension and Other Benefits as the basis for those periods. In addition to those amounts, CNG includes amortization of net benefit costs recorded as regulatory deferrals as a result of purchase accounting in a prior year. In connection with applying the practical expedient, in periods after adoption CNG will continue to include in operating income all legacy net benefit costs previously capitalized as a cost of self-constructed assets and other deferred regulatory costs. The adoption of the amendments did not affect prior period net income. Beginning in 2018, non-service cost components incurred are no longer eligible for construction capitalization. For the year ended December 31, 2018, CNG incurred additional immaterial expense as a result of the adoption of this standard. Further, the impact of this change is reflected in CNG's new rates effective January 1, 2019.

The following table summarizes the impact to the prior period as a result of the adoption of this standard:

Year Ended December 31, 2017	As previously filed	Reclassifications	As currently reported
(in thousands)			
Statement of Income			
Operating Expenses			
Operation and maintenance	103,209	(5,026)	98,183
Other Income and (Expense), net	370	(5,026)	(4,656)

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.

(a) Leases

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

CNG adopted the new leases guidance effective January 1, 2019, and has elected the optional transition method under which they will initially apply the standard on that date without adjusting amounts presented for prior periods, and record the cumulative effect of applying the new guidance as an adjustment to beginning retained earnings. CNG expects the adjustment to retained earnings will be immaterial. Concerning certain transition and other practical expedients:

- CNG did not elect the package of three practical expedients available under the transition provisions, including (i) not reassessing whether expired or existing contracts contain leases, (ii) lease classification, and (iii) not revaluing initial direct costs for existing leases;
- CNG used hindsight for specified determinations and assessments in applying the new leases guidance;
- CNG will not recognize lease assets and liabilities for short-term leases (less than one year), for all classes of underlying assets; and
- CNG did not separate lease and associated nonlease components for transitioned leases, but will instead account for them together as a single lease component.

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

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

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

(c) Simplifying the test for goodwill impairment

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

B) CAPITALIZATION

Common Stock

CNG had 10,634,436 shares of its common stock, $3.125 par value, outstanding as of December 31, 2018 and 2017.

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, 2018, there were 108,706 shares issued and outstanding with a value of approximately $0.3 million.

Long-Term Debt

As of December 31,		**2018**		**2017**	
(In Thousands)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
Senior unsecured debt	2028-2043	$ 110,000	4.30%-6.66%	$ 110,000	4.30%-6.66%
Unamortized debt (costs) premium, net		(664)		(710)	
Total Debt		**109,336**		**109,290**	
Less: debt due within one year, included in current liabilities		-		-	
Total Non-current Debt		**$ 109,336**		**$ 109,290**	

The estimated fair value of debt amounted to $128.2 million and $137.7 million as of December 31 2018 and 2017, 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 October 4, 2018, CNG issued a note purchase agreement to issue senior unsecured notes and on January 15, 2019, 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:

	2019	**2020**	**2021**	**2022**	**2023 & Thereafter**	**Total**
			(In Thousands)			
Maturities:	$ -	$ -	$ -	$ -	$ 110,000	$ 110,000

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, 2018, CNG’s debt ratio was 36%.

(C) REGULATORY PROCEEDINGS

Rates

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

On June 29, 2018, CNG filed an application with PURA for new tariffs to become effective January 1, 2019. On August 30, 2018, CNG entered into a settlement agreement with the Office of Consumer Counsel and PURA Prosecutorial Staff that provides for new rates effective January 1, 2019. The settlement agreement was approved by PURA on December 19, 2018. The settlement agreement included an increase in rates of $9.9 million in 2019, an incremental increase of $4.6 million in 2020, and an incremental increase of $5.2 million in 2021, for a total increase of $19.7 million over the three-year rate plan. The settlement agreement is based on an ROE of 9.30%, and an equity ratio of 54% in 2019, 54.50% in 2020, and 55% in 2021 and continues, 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.

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

Gas Supply Arrangements

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

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

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

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

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

Tax Cuts and Jobs Act

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

(D) SHORT-TERM CREDIT ARRANGEMENTS

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

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. CNG has a lending/borrowing limit of $100 million under this agreement. There was $59.8 million and $27.7 million outstanding as of December 31, 2018 and 2017, respectively, under this agreement.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $250 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. There was $48.6 million outstanding under this agreement as of December 31, 2018 and there was $61.6 million outstanding under this agreement as of December 31, 2017.

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

Under the Avangrid Credit Facility, CNG has a maximum sublimit of $150 million. Additionally, under the Avangrid Credit Facility, each of the borrowers, including CNG, will pay an annual facility fee that is dependent on their credit rating. The facility fees will range from 12.5 to 17.5 basis points. The maturity date for the Avangrid Credit Facility is June 29, 2023. As of December 31, 2018 and 2017, CNG did not have any outstanding borrowings under the Avangrid Credit Facility.

(E) INCOME TAXES

	Year Ended December 31, 2018	Year Ended December 31, 2017
	(In Thousands)	
Income tax expense consists of:		
Income tax provisions (benefits):		
Current		
Federal	$ 9,430	$ (539)
State	2,512	464
Total current	11,942	(75)
Deferred		
Federal	(4,918)	9,274
State	(2,270)	(2,682)
Total deferred	(7,188)	6,592
Total income tax expense	$ 4,754	$ 6,517

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

The reasons for the differences are as follows:

	Year Ended December 31, 2018	Year Ended December 31, 2017
	(In Thousands)	
Book income before income taxes	$ 23,233	$ 21,559
Computed tax at federal statutory rate	$ 4,879	$ 7,546
Increases (reductions) resulting from:		
Deferred tax adjustment for prior years	-	(346)
2017 Tax Act deferred tax remeasurement	-	510
State income taxes, net of federal income tax	191	(1,442)
Other items, net	(316)	249
Total income tax expense	$ 4,754	$ 6,517
Effective income tax rates	20.5%	30.2%

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, 2018:

Jurisdiction	*Tax years*
Federal	2013 - 2018
Connecticut	2013 - 2018

The following table summarizes CNG's deferred tax assets and liabilities as of December 31, 2018 and 2017:

	2018	2017
	(In Thousands)	
CT credit carryforward	$ 2,545	$ 2,558
Deferred tax liability on 2017 Tax Act remeasurement	1,732	4,062
Property related	(5,167)	(5,285)
Unfunded future income taxes	3,104	(148)
Goodwill	(3,851)	(3,382)
Pension (net)	(881)	(2,898)
Other assets (liabilities)	4,497	4,134
	$ 1,979	$ (959)

Each of CNG's state tax credit carry forwards will begin to expire in 2020.

(F) PENSION AND OTHER POSTRETIREMENT BENEFITS

Defined Benefit Plans (the Plans)

Pension Plans

CNG has multiple qualified pension plans covering a majority of their union and management employees. CNG also has non-qualified supplemental pension plans for certain retirees. The qualified pension plans provide benefits under a traditional defined benefit formula or cash balance formula depending on date of hire. The plans are closed to new employees hired on or after specified dates.

Employees not participating in a defined benefit plan are eligible for enhanced benefits in the 401(k) plans.

Other Postretirement Benefits Plans

CNG also has plans providing other postretirement benefits for a majority of its employees. 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 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

CNG, through Networks, has an investment policy addressing the oversight and management of pension assets and procedures for monitoring and control. State Street Bank is the trustee and NEPC, LLC is the investment advisor that assists in areas of asset allocation and rebalancing, portfolio strategy implementation, and performance monitoring and evaluation.

The goals of the asset investment strategy are to:

- Achieve long-term capital growth while maintaining sufficient liquidity to provide for current benefit payments and pension plan operating expenses.
- Provide a total return that, over the long term, provides sufficient assets to fund pension plan liabilities subject to an appropriate level of risk, contributions and pension expense.
- Optimize the return on assets, over the long term, by investing primarily in a diversified portfolio of equities and additional asset classes with differing rates of return, volatility and correlation.
- Diversify investments within asset classes to maximize preservation of principal and minimize over-exposure to any one investment, thereby minimizing the impact of losses in single investments.

Networks asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. Networks has 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, Liability-Hedging and alternative investments. There is currently a target allocation of 35%-53% in equity securities, 40%-45% for Liability-Hedging assets and 7%-20% for alternative investments. Return-Seeking investments generally consist of domestic, international, global and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking assets also include investments in real estate, absolute return and strategic markets. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The following table represents the change in benefit obligation, change in plan assets and the respective funded status of CNG's pension and other postretirement plans as of December 31, 2018 and 2017. Plan assets and obligations have been measured as of December 31, 2018 and 2017.

	Pension Benefits		Other Post-Retirement Benefits	
	Year Ended December 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2018	Year Ended December 31, 2017
Change in Benefit Obligation:	(In Thousands)			
Benefit obligation at beginning of year	$ 281,855	$ 270,969	$ 21,006	$ 22,676
Service cost	4,850	4,441	184	228
Interest cost	10,489	11,256	764	922
Participant contributions	-	-	808	715
Amendments	-	-	225	-
Actuarial (gain) loss	(15,263)	6,792	(611)	(687)
Benefits paid (including expenses)	(12,432)	(11,603)	(2,788)	(2,848)
Benefit obligation at end of year	$ 269,499	$ 281,855	$ 19,588	$ 21,006
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 199,896	$ 182,593	$ 11,009	$ 10,331
Actual return on plan assets	(12,846)	27,355	507	691
Employer contributions	402	1,551	-	-
Participant contributions	-	-	808	715
Benefits paid (including expenses)	(12,432)	(11,603)	(842)	(728)
Fair value of plan assets at end of year	$ 175,020	$ 199,896	$ 11,482	$ 11,009
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ 94,479	$ 81,959	$ 8,106	$ 9,997
Amounts Recognized in the Consolidated Balance Sheet consist of:				
Non-current liabilities	$ 94,479	$ 81,959	$ 8,106	$ 9,997
Amounts Recognized as a Regulatory Asset (Liability)				
Prior service cost	$ -	$ 20	$ 798	$ 812
Net (gain) loss	46,750	37,162	(2,625)	(2,331)
Total recognized as a regulatory asset (liability)	$ 46,750	$ 37,182	$ (1,827)	$ (1,519)
Information on Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:				
Projected benefit obligation	$ 269,499	$ 281,855	N/A	N/A
Accumulated benefit obligation	$ 244,948	$ 253,715	N/A	N/A
Fair value of plan assets	$ 175,020	$ 199,896	N/A	N/A
The following weighted average actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate (Qualified Plans)	4.09%	3.80%	N/A	N/A
Discount rate (Non-Qualified Plans)	4.09%	3.80%	N/A	N/A
Discount rate (Other Post-Retirement Benefits)	N/A	N/A	4.09%	3.80%
Average wage increase	3.50%	3.50%	N/A	N/A
Health care trend rate (current year - pre/post-65)	N/A	N/A	7.00%/7.75%	7.50%/8.50%
Health care trend rate (2029/2027 - pre/post-65)	N/A	N/A	4.50%/4.50%	4.50%/4.50%

N/A – not applicable

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, 2018 and 2017 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, 2018	Year Ended December 31, 2017	Year Ended December 31, 2018	Year Ended December 31, 2017
	(In Thousands)			
Components of net periodic benefit cost:				
Service cost	$ 4,850	$ 4,441	$ 184	$ 228
Interest cost	10,489	11,256	764	922
Expected return on plan assets	(14,322)	(13,326)	(591)	(553)
Amortization of prior service costs	20	22	239	247
Amortization of actuarial (gain) loss	2,318	3,446	(233)	(167)
Net periodic benefit cost	$ 3,355	$ 5,839	$ 363	$ 677
Other Changes in Plan Assets and Benefit Obligations Recognized as a Regulatory Asset (Liability):				
Net (gain) loss	$ 11,907	$ (7,237)	$ (527)	$ (824)
Amortization of current year prior service costs	-	-	225	167
Amortization of prior service costs	(20)	(22)	(239)	(247)
Amortization of actuarial gain (loss)	(2,318)	(3,446)	233	-
Total recognized as regulatory asset (liability)	$ 9,569	$ (10,705)	$ (308)	$ (904)
Total recognized in net periodic benefit costs and regulatory asset (liability)	$ 12,924	$ (4,866)	$ 55	$ (227)
Estimated Amortizations from Regulatory Assets (Liabilities) into Net Periodic Benefit Cost for the next 12 month period:				
Amortization of prior service cost	$ -	$ 20	$ 201	$ 239
Amortization of net (gain) loss	3,340	2,318	(262)	(233)
Total estimated amortizations	$ 3,340	$ 2,338	$ (61)	$ 6
The following actuarial weighted average assumptions were used in calculating net periodic benefit cost:				
Discount rate	3.80%	4.24%	3.80%	4.24%
Average wage increase	3.50%	3.50%	N/A	N/A
Return on plan assets	7.40%	7.50%	5.37%	5.37%
Health care trend rate (current year - pre/post-65)	N/A	N/A	7.50%/8.50%	6.75%/8.50%
Health care trend rate (2030/2028 - pre/post-65)	N/A	N/A	4.50%/4.50%	4.50%/4.50%

N/A – not applicable

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

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

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

	1% Increase	1% Decrease
	(In Thousands)	
Aggregate service and interest cost components	$ (7)	$ 7
Accumulated post-retirement benefit obligation	$ (169)	$ 150

Contributions

The funding policy for the Plans is to make annual contributions that satisfy the minimum funding requirements of ERISA but that do not exceed the maximum deductible limits of the Internal Revenue Code. These amounts are determined each year as a result of an actuarial valuation of the Plans. CNG currently expects to make pension contributions of approximately $5.7 million in 2019. 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, 2018 consisted of:

Year	Pension Benefits	Other Post-Retirement Benefits	Medicare Act Subsidy
		(In Thousands)	
2019	$ 12,403	$ 1,847	$ 214
2020	$ 12,429	$ 1,780	$ 220
2021	$ 12,659	$ 1,725	$ 229
2022	$ 13,028	$ 1,685	$ 236
2023	$ 13,324	$ 1,639	$ 241
2024-2028	$ 74,201	$ 7,315	$ 1,215

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 2018 and 2017 was $1.2 million, and $1.3 million, respectively.

(G) RELATED PARTY TRANSACTIONS

Inter-company Transactions

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, 2018, CNG recorded inter-company expenses of $12.7 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.

In the fourth quarter of 2018, CNG purchased $24.5 million of corporate assets from UIL resulting in an increase in net property, plant and equipment.

Dividends/Capital Contributions

For the year ended December 31, 2018, CNG accrued an immaterial amount of dividends to CTG. For the year ended December 31, 2017, CNG accrued $19.0 million in dividends to CTG.

(H) LEASE OBLIGATIONS

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

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

(I) COMMITMENTS AND CONTINGENCIES

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

Environmental Matters

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

Site Decontamination, Demolition and Remediation Costs

CNG owns or has previously owned properties where Manufactured Gas Plants (MGPs) had historically operated. MGP operations have led to contamination of soil and groundwater with petroleum hydrocarbons, benzene and metals, among other things, at these properties, the regulation and cleanup of which is regulated by the federal Resource Conservation and Recovery Act as well as other federal and state statutes and regulations. CNG has or had an ownership interest in one or more such properties contaminated as a result of MGP-related activities. Under the existing regulations, the cleanup of such sites requires state and at times, federal, regulators' involvement and approval before cleanup can commence. In certain cases, such contamination has been evaluated, characterized and remediated. In other cases, the sites have been evaluated and characterized, but not yet remediated. Finally, at some of these sites, the scope of the contamination has not yet been fully characterized; no liability was recorded in respect of these sites as of December 31, 2018 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, 2018, 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, 2018 and December 31, 2017.

	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, 2018		(In Thousands)		
Noncurrent investments	$ 1,090	$ -	$ -	$ 1,090
Total fair value assets, December 31, 2018	$ 1,090	$ -	$ -	$ 1,090
December 31, 2017				
Noncurrent investments	$ 1,158	$ -	$ -	$ 1,158
Total fair value assets, December 31, 2016	$ 1,158	$ -	$ -	$ 1,158

The following tables set forth the fair values of CNG's pension and OPEB assets as of December 31, 2018 and 2017.

	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, 2018		(In Thousands)		
Pension assets				
Mutual funds	$ -	$ 175,020	$ -	$ 175,020
	-	175,020	-	175,020
OPEB assets				
Mutual funds	3,885	7,597	-	11,482
Fair value of plan assets, December 31, 2017	$ 3,885	$ 182,617	$ -	$ 186,502
December 31, 2017				
Pension assets				
Mutual funds	$ -	$ 199,896	$ -	$ 199,896
	-	199,896	-	199,896
OPEB assets				
Mutual funds	3,410	7,599	-	11,009
Fair value of plan assets, December 31, 2016	$ 3,410	$ 207,495	$ -	$ 210,905

The determination of fair values of the Level 2 co-mingled mutual funds were based on the Net Asset Value (NAV) provided by the managers of the underlying fund investments and the unrealized gains and losses. The NAV provided by the managers typically reflect the fair value of each underlying fund investment. Changes in the fair value of pension benefits and OPEB are accounted for in accordance with ASC 715 Compensation – Retirement Benefits as discussed in Note (F) Pension and Other Benefits.

THE BERKSHIRE GAS COMPANY

AUDITED FINANCIAL STATEMENTS

AS OF AND FOR THE YEARS ENDED

DECEMBER 31, 2018 AND 2017

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

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, 2018 and 2017, 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, 2018 and 2017, 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
April 24, 2019

THE BERKSHIRE GAS COMPANY
STATEMENT OF INCOME
(In Thousands)

	Year Ended December 31, 2018	Year Ended December 31, 2017
Operating Revenues	$ 79,674	$ 75,001
Operating Expenses		
Natural gas purchased	28,549	26,360
Operation and maintenance	28,738	26,032
Depreciation and amortization	8,452	8,013
Taxes other than income taxes	4,696	4,036
Total Operating Expenses	70,435	64,441
Operating Income	9,239	10,560
Other Income and (Expense), net	(1,319)	(996)
Interest Expense, net	3,502	3,270
Income Before Income Tax	4,418	6,294
Income Tax	1,410	1,556
Net Income	$ 3,008	$ 4,738

THE BERKSHIRE GAS COMPANY
STATEMENT OF COMPREHENSIVE INCOME
(In Thousands)

	Year Ended December 31, 2018	Year Ended December 31, 2017
Net Income	$ 3,008	$ 4,738
Other Comprehensive Income, net of income tax	-	10
Comprehensive Income	$ 3,008	$ 4,748

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

THE BERKSHIRE GAS COMPANY
STATEMENT OF CASH FLOWS
(In Thousands)

	Year Ended December 31, 2018	Year Ended December 31, 2017
Cash Flows From Operating Activities		
Net income	$ 3,008	$ 4,738
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	8,563	8,121
Deferred income taxes	3,881	6,167
Uncollectible expense	502	524
Pension expense	1,272	1,260
Regulatory assets/liabilities amortization	1,569	1,543
Regulatory assets/liabilities carrying costs	54	-
Other non-cash items, net	75	130
Changes in:		
Accounts receivable and unbilled revenue, net	(1,778)	(1,946)
Natural gas in storage	(559)	10
Accounts payable and accrued liabilities	(1,896)	604
Pension accrued and OPEB	(139)	(2,362)
Environmental liabilities	-	1,000
Regulatory assets/liabilities	(3,955)	(4,852)
Other assets	(2,686)	(1,322)
Other liabilities	(537)	(613)
Total Adjustments	4,366	8,264
Net Cash provided by Operating Activities	7,374	13,002
Cash Flows from Investing Activities		
Plant expenditures including AFUDC debt	(21,862)	(17,778)
Net Cash used in Investing Activities	(21,862)	(17,778)
Cash Flows from Financing Activities		
Payment of long-term debt	(1,455)	(1,455)
Notes payable to affiliates	15,965	6,500
Other	(43)	-
Net Cash provided by Financing Activities	14,467	5,045
Unrestricted Cash and Temporary Cash Investments:		
Net change for the period	(21)	269
Balance at beginning of period	347	78
Balance at end of period	$ 326	$ 347
Cash paid during the period for:		
Interest (net of amount capitalized)	$ 3,312	$ 3,137
Non-cash investing activity:		
Plant expenditures included in ending accounts payable	$ 1,259	$ 797

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

THE BERKSHIRE GAS COMPANY
BALANCE SHEET
ASSETS
(In Thousands)

	December 31, 2018	December 31, 2017
Assets		
Current Assets		
Unrestricted cash and temporary cash investments	$ 326	$ 347
Accounts receivable and unbilled revenues, net	16,103	14,592
Accounts receivable from affiliates	129	323
Regulatory assets	11,531	9,025
Gas in storage	2,447	1,888
Materials and supplies	907	870
Other current assets	4,612	1,944
Total Current Assets	36,055	28,989
Other Investments	2,213	2,331
Net Property, Plant and Equipment	180,150	164,567
Regulatory Assets	32,540	33,281
Deferred Charges and Other Assets		
Goodwill	51,933	51,933
Other	-	21
Total Deferred Charges and Other Assets	51,933	51,954
Total Assets	$ 302,891	$ 281,122

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

THE BERKSHIRE GAS COMPANY
BALANCE SHEET
LIABILITIES AND CAPITALIZATION
(In Thousands)

	December 31, 2018	December 31, 2017
Liabilities		
Current Liabilities		
Notes payable to affiliates	$ 30,730	$ 14,800
Current portion of long-term debt	12,393	2,393
Accounts payable and accrued liabilities	14,204	12,609
Accounts payable to affiliates	3,744	6,809
Other current liabilities	1,351	1,315
Interest accrued	886	852
Regulatory liabilities	61	2,185
Taxes accrued	-	451
Total Current Liabilities	63,369	41,414
Deferred Income Taxes	21,096	17,970
Regulatory Liabilities	52,560	48,846
Other Noncurrent Liabilities		
Pension	20,768	18,285
Environmental remediation costs	3,950	3,950
Other	2,358	2,585
Total Other Noncurrent Liabilities	27,076	24,820
Capitalization		
Long-term debt	25,721	38,011
Common Stock Equity		
Paid-in capital	106,095	106,095
Retained earnings	6,974	3,964
Accumulated other comprehensive income (loss)	-	2
Net Common Stock Equity	113,069	110,061
Total Capitalization	138,790	148,072
Total Liabilities and Capitalization	$ 302,891	$ 281,122

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

THE BERKSHIRE GAS COMPANY

STATEMENT OF CHANGES IN SHAREHOLDER'S EQUITY

December 31, 2018

(Thousands of Dollars)

	Common Stock		Paid-in	Retained	Accumulated Other Comprehensive	
	Shares	Amount	Capital	Earnings	Income (Loss)	Total
Balance as of December 31, 2016	100	$ -	$ 106,095	$ (774)	$ (8)	$ 105,313
Net income				4,738		4,738
Other comprehensive income, net of deferred income taxes					10	10
Balance as of December 31, 2017	100	$ -	$ 106,095	$ 3,964	$ 2	$ 110,061
Net income				3,008		3,008
Adoption of accounting standard				2	(2)	-
Balance as of December 31, 2018	100	$ -	$ 106,095	$ 6,974	$ -	$ 113,069

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

(A) STATEMENT OF ACCOUNTING POLICIES

The Berkshire Gas Company (Berkshire) engages in natural gas transportation, distribution and sales operations serving approximately 40,000 customers in its service area in western Massachusetts, which includes the cities of Pittsfield, North Adams and Greenfield. Berkshire is regulated by the Massachusetts Department of Public Utilities (DPU) as it relates to utility service.

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

Accounting Records

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

Basis of Presentation

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

Certain amounts reported in the Financial Statements in previous periods have been reclassified to conform to the current presentation. Berkshire has evaluated subsequent events through the date its financial statements were available to be issued, April 24, 2019.

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

Revenues

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

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

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

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

Beginning in February 2019, Berkshire will also record 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 will recognize and record 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 will record such amounts as a recovery of the associated regulatory asset or liability. When they owe amounts to customers in connection with ARPs, they will 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, 2018
Regulated operations – natural gas	$ 78,507
Other (a)	31
Revenue from contracts with customers	**78,538**
Leasing revenue	1,136
Total operating revenues	**$ 79,674**

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

Regulatory Accounting

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

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

Unless otherwise stated below, all of Berkshire's regulatory assets earn a return. Berkshire's regulatory assets and liabilities as of December 31, 2018 and 2017 included the following:

	Remaining Period	December 31, 2018	December 31, 2017
		(In Thousands)	
Regulatory Assets:			
Pension and other post-retirement benefit plan	(a)	$ 23,312	$ 22,362
Environmental remediation costs	7 years	7,117	8,290
Debt premium	0 to 3 years	1,159	2,095
Deferred purchased gas	(b)	8,117	6,047
Unfunded future income taxes	(c)	724	622
Other	(d)	3,642	2,890
Total regulatory assets		44,071	42,306
Less current portion of regulatory assets		11,531	9,025
Regulatory Assets, Net		$ 32,540	$ 33,281
Regulatory Liabilities:			
Rate credits	NA	$ -	$ 1,328
Pension and other postretirement benefit plan	(a)	128	-
Asset removal costs	(d)	35,031	33,530
Tax reform	20 years	16,523	15,410
Non-firm margin sharing credits	0 to 2 years	757	-
Other	(d)	182	763
Total regulatory liabilities		52,621	51,031
Less current portion of regulatory liabilities		61	2,185
Regulatory Liabilities, Net		$ 52,560	$ 48,846

(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.

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 2018 and 2017 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 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, 2018 and 2017 were comprised as follows:

	2018	2017
	(In Thousands)	
Gas distribution plant	$ 202,720	$ 190,541
Land	2,304	2,304
Buildings and improvements	28,578	26,707
Other plant	28,451	19,919
Total property, plant & equipment	262,053	239,471
Less accumulated depreciation	86,372	77,297
	175,681	162,174
Construction work in progress	4,469	2,393
Net property, plant & equipment	$ 180,150	$ 164,567

Allowance for Funds Used During Construction

In accordance with the uniform systems of accounts, Berkshire 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 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 2018 and 2017 was 2.15% and 1.31%, respectively. The portion of the allowance applicable to equity funds was immaterial for 2018 and was immaterial for 2017.

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 2018 and 2017 were approximately $8.5 million and $8.0 million, respectively, or 3.4% and 3.5%, 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, 2018, 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, 2018 and 2017 include unbilled revenues of $5.1 million and $6.5 million, respectively and are shown net of an allowance for doubtful accounts of $1.4 million and $1.6 million for 2018 and 2017, 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.

Accrued removal obligations

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 accrued removal obligations.

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 $11.5 million over a 20 year period.

Adoption of New Accounting Standards Pronouncements

(a) Revenue from contracts with customers

In May 2014, the Financial Accounting Standards Board (FASB) issued ASC 606 replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The FASB further amended ASC 606 through various updates issued thereafter. The core principle is for an entity to recognize revenue to represent the transfer of promised goods or services to customers in amounts that reflect the consideration to which the entity expects to be entitled in exchange for those goods or services. Berkshire adopted ASC 606 effective January 1, 2018, and applied the modified retrospective method, for which they did not have a cumulative effect adjustment to retained earnings for initial application of the guidance. Refer to 'Revenue' above for further details.

(b) Classifying and measuring financial instruments

In January 2016, the FASB issued final guidance on the classification and measurement of financial instruments. As a result of our adoption we reclassified immaterial amounts from AOCI to retained earnings.

(c) Improving the presentation of net periodic benefit costs

In March 2017, the FASB issued amendments to improve the presentation of net periodic pension cost and net periodic postretirement benefit cost in the financial statements. Berkshire retrospectively adopted the amendments that require us to present the service cost component separately from the other (non-service) components of net benefit cost, to report the service cost component in the income statement line item where we report the corresponding compensation cost, and to present all non-service components outside of operating cost. As a result, the non-service components – interest cost, expected return on plan assets, amortization of prior service cost (benefit), amortization of net loss, and settlement charge – have been reclassified from Operations and maintenance to Other income/(expense) within the statement of income. Prospectively, from adoption, Berkshire capitalizes only the service cost component when applicable (for example, as a cost of a self-constructed asset). Berkshire elected to apply the practical expedient that allows them to retrospectively apply the amendments on adoption to net benefit costs for comparative periods by using the amounts disclosed in the notes to financial statements for Pension and Other Benefits as the basis for those periods. In addition to those amounts, Berkshire includes amortization of net benefit costs recorded as regulatory deferrals as a result of purchase accounting in a prior year. In connection with applying the practical expedient, in periods after adoption Berkshire continues to include in operating income all legacy net benefit costs previously capitalized as a cost of self-constructed assets and other deferred regulatory costs. The adoption of the amendments did not affect prior period net income. Beginning in 2018, non-service cost components incurred are no longer eligible for construction capitalization. For the year ended December 31, 2018, Berkshire incurred additional immaterial expense as a result of the adoption of this standard. Further, the impact of this change is reflected in Berkshire's new rates effective February 1, 2019.

The following table summarizes the impact to the prior period as a result of the adoption of this standard:

Year Ended December 31, 2017	**As previously filed**	**Reclassifications**	**As currently reported**
(in thousands)			
Statement of Income			
Operating Expenses			
Operation and maintenance	27,178	(1,146)	26,032
Other Income and (Expense), net	150	(1,146)	(996)

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.

(a) Leases

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

Berkshire adopted the new leases guidance effective January 1, 2019, and has elected the optional transition method under which they will initially apply the standard on that date without adjusting amounts presented for prior periods, and record the cumulative effect of applying the new guidance as an adjustment to beginning retained earnings. Berkshire expects the adjustment to retained earnings will be immaterial. Concerning certain transition and other practical expedients:

- Berkshire did not elect the package of three practical expedients available under the transition provisions, including (i) not reassessing whether expired or existing contracts contain leases, (ii) lease classification, and (iii) not revaluing initial direct costs for existing leases;
- Berkshire used hindsight for specified determinations and assessments in applying the new leases guidance;

- Berkshire will not recognize lease assets and liabilities for short-term leases (less than one year), for all classes of underlying assets; and
- Berkshire did not separate lease and associated nonlease components for transitioned leases, but will instead account for them together as a single lease component.

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

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

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

(c) Simplifying the test for goodwill impairment

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

B) CAPITALIZATION

Common Stock

Berkshire had 100 shares of its common stock, $2.50 par value, outstanding as of December 31, 2018 and 2017.

Long-Term Debt

As of December 31, (Thousands)	Maturity Dates	2018 Balances	2018 Interest Rates	2017 Balances	2017 Interest Rates
First mortgage bonds [(a)]	2019	10,000	10.06%	10,000	10.06%
Senior unsecured notes	2020-2043	27,364	5.33%-9.60%	28,818	5.33%-9.60%
Unamortized debt (costs) premium, net		750		1,586	
Total Debt		**38,114**		**40,404**	
Less: debt due within one year, included in current liabilities		12,393		2,393	
Total Non-current Debt		**25,721**		**38,011**	

(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 $40.8 million and $45.9 million as of December 31 2018 and 2017, 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:

	2019	2020	2021	2022	Thereafter	Total
			(In Thousands)			
Maturities:	$ 11,455	$ 9,455	$ 1,454	$ -	$ 15,000	$ 37,364

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, 2018, such ratio was 38%.
- 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, 2018, such ratio was 44.6%.
- A fixed charges coverage ratio of no less than 1.50 to 1.00. As of December 31, 2018, such ratio was 2.25 to 1.00.
- To maintain a tangible net worth greater than $9 million. As of December 31, 2018, Berkshire's tangible net worth was $60.7 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. Berkshire's 10-year rate plan, which was approved by the DPU and included an approved ROE of 10.5%, expired on January 31, 2012. Berkshire continued to charge the rates that were in effect at the end of the rate plan until a rate increase went into effect in the first quarter of 2019.

On May 17, 2018 Berkshire filed a petition with the DPU seeking approval of a distribution rate increase to be effective January 1, 2019. On December 4, 2018, Berkshire and the Massachusetts Attorney General's Office filed a settlement agreement with the DPU. The settlement agreement provides for a $1.7 million distribution base rate increase effective January 1, 2019, or February 1, 2019 if the DPU did not approve the settlement agreement prior to January 1, 2019, and an additional $0.7 million base distribution increase effective December 1, 2019, if certain investments are made by Berkshire. The settlement agreement contained a make-whole provision if the DPU approved the agreement after January 1, 2019. The distribution rate increase is based on a 9.70% ROE and 54% equity ratio. The settlement agreement provides for, among other things, the implementation of a revenue decoupling mechanism and pension expense tracker and also provides that Berkshire will not file to change base distribution to become effective before November 1, 2021. The settlement agreement was approved by the DPU on January 18, 2019.

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, 2018, Berkshire was a party to a 90-day contract expiring on February 28, 2019 for a fixed daily quantity of natural gas. Berkshire's remaining commitment as of December 31, 2018 under this contract was approximately $1.7 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 Connecticut 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 PURA in the second quarter of 2018 and such savings are included in new rates effective January 1, 2019.

(D) SHORT-TERM CREDIT ARRANGEMENTS

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

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. Berkshire has a lending/borrowing limit of $15 million under this agreement. As of December 31, 2018 and 2017, there was no balance outstanding under this agreement.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $50 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. There was $30.7 million and $14.8 million outstanding under this agreement as of December 31, 2018 and 2017, respectively.

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

Under the Avangrid Credit Facility, Berkshire has a maximum sublimit of $40 million. Additionally, under the Avangrid Credit Facility, each of the borrowers, including Berkshire, will pay an annual facility fee that is dependent on their credit rating. The facility fees will range from 12.5 to 17.5 basis points. The maturity date for the Avangrid Credit Facility is June 29, 2023. As of December 31, 2018 and 2017, Berkshire did not have any outstanding borrowings under the Avangrid Credit Facility.

(E) INCOME TAXES

	Year Ended December 31, 2018	Year Ended December 31, 2017
	(In Thousands)	
Income tax expense consists of:		
Income tax provisions:		
Current		
Federal	$ (1,547)	$ (3,990)
State	(924)	(585)
Total current	(2,471)	(4,575)
Deferred		
Federal	2,652	5,064
State	1,229	1,103
Total deferred	3,881	6,167
Investment tax credits	-	(36)
Total income tax expense	$ 1,410	$ 1,556

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

	Year Ended December 31, 2018	Year Ended December 31, 2017
	(In Thousands)	
Book income before income taxes	$ 4,418	$ 6,294
Computed tax at federal statutory rate	$ 928	$ 2,203
Increases (reductions) resulting from:		
State income taxes, net of federal income tax benefits	241	328
2017 Tax Act deferred tax remeasurement	-	171
Other items, net	241	(1,146)
Total income tax expense	$ 1,410	$ 1,556
Effective income tax rates	31.9%	24.7%

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, 2018 and 2017, 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, 2018:

Jurisdiction	*Tax years*
Federal	2013 - 2018
Massachusetts	2013 – 2018

The following table summarizes Berkshire's deferred tax assets and liabilities as of December 31, 2018 and 2017:

	2018	**2017**
	(In Thousands)	
Property related	$ (23,650)	$ (22,536)
Deferred gas and other deferred charges	(2,904)	(1,647)
Deferred tax liability on 2017 Tax Act remeasurement	4,290	4,274
Federal and State net operating losses and other attributes	985	300
Post-retirement benefits, net	(804)	(1,234)
Other assets (liabilities)	987	2,873
	$ (21,096)	$ (17,970)

As of December 31, 2018 and December 31, 2017, Berkshire had a federal net operating loss carry forward of $1.0 million and $0.3 million, respectively, that will begin to expire in 2036.

(F) PENSION AND OTHER POSTRETIREMENT BENEFITS

Defined Benefit Plans (the Plans)

Pension Plans

Berkshire has multiple qualified pension plans covering substantially all of their union and management employees. The Plans provide benefits under a traditional defined benefit formula or a cash balance formula depending on date of hire. The Plans are closed to new employees hired on or after specified dates.

Employees not participating in a defined benefit plan are eligible for enhanced benefits in the 401(k) plans.

Other Postretirement Plans

Berkshire provides other postretirement benefits for certain employees. These benefits consist primarily of health care prescription drug and life insurance benefits for retired employees and their dependents.

Plan Assets

Berkshire, through Networks, has an investment policy addressing the oversight and management of pension assets and procedures for monitoring and control. State Street Bank is the trustee and NEPC, LLC is the investment advisor that assists in areas of asset allocation and rebalancing, portfolio strategy implementation, and performance monitoring and evaluation.

The goals of the asset investment strategy are to:

- Achieve long-term capital growth while maintaining sufficient liquidity to provide for current benefit payments and pension plan operating expenses.
- Provide a total return that, over the long term, provides sufficient assets to fund pension plan liabilities subject to an appropriate level of risk, contributions and pension expense.
- Optimize the return on assets, over the long term, by investing primarily in a diversified portfolio of equities and additional asset classes with differing rates of return, volatility and correlation.
- Diversify investments within asset classes to maximize preservation of principal and minimize over-exposure to any one investment, thereby minimizing the impact of losses in single investments.

Networks asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. Networks has 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, Liability-Hedging and alternative investments. There is currently a target allocation of 35%-53% in equity securities, 40%-45% for Liability-Hedging assets and 7%-20% for alternative investments. Return-Seeking investments generally consist of domestic, international, global and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking assets also include investments in real estate, absolute return and strategic markets. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

THE BERKSHIRE GAS COMPANY

NOTES TO FINANCIAL STATEMENTS

The following table represents the change in benefit obligation, change in plan assets and the respective funded status of Berkshire's pension plans as of December 31, 2018 and 2017. Plan assets and obligations have been measured as of December 31, 2018 and 2017.

	Pension Benefits		Other Post-Retirement Benefits	
	Year Ended December 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2018	Year Ended December 31, 2017
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation at beginning of year	$ 52,591	$ 49,888	$ 3,700	$ 2,890
Service cost	884	578	61	32
Interest cost	1,902	2,010	136	119
Participant contributions	-	-	88	-
Actuarial (gain) loss	(1,918)	2,123	(602)	839
Benefits paid (including expenses)	(2,345)	(2,008)	(189)	(180)
Benefit obligation at end of year	$ 51,114	$ 52,591	$ 3,194	$ 3,700
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 36,512	$ 33,575	$ -	$ -
Actual return on plan assets	(2,266)	4,908	-	-
Participant contributions	-	-	88	-
Employer contributions	145	-	101	180
Benefits paid (including expenses)	(2,243)	(1,971)	(189)	(180)
Fair value of plan assets at end of year	$ 32,148	$ 36,512	$ -	$ -
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ 18,966	$ 16,079	$ 3,194	$ 3,700
Amounts Recognized in the Consolidated Balance Sheet consist of:				
Non-current liabilities	$ 18,966	$ 16,079	$ 3,194	$ 3,700
Amounts Recognized as a Regulatory Asset (Liability) consist of:				
Prior service cost	$ 44	$ 213	$ -	$ -
Net (gain) loss	$ 10,291	$ 7,986	152	839
Total recognized as a regulatory asset (liability)	$ 10,335	$ 8,199	$ 152	$ 839
Information on Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:				
Projected benefit obligation	$ 51,114	$ 52,591	N/A	N/A
Accumulated benefit obligation	$ 45,033	$ 45,667	N/A	N/A
Fair value of plan assets	$ 32,148	$ 36,512	N/A	N/A
The following weighted average actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate (Pension Benefits)	4.09%	3.80%	N/A	N/A
Discount rate (Other Post-Retirement Benefits)	N/A	N/A	4.09%	3.80%
Average wage increase	3.50%	3.50%	N/A	N/A
Health care trend rate (current year - pre/post-65)	N/A	N/A	7.00%/7.75%	7.50%/8.50%
Health care trend rate (2029/2027 - pre/post-65)	N/A	N/A	4.50%/4.50%	4.50%/4.50%

N/A – Not applicable

Berkshire 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, 2018 and 2017 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, 2018	Year Ended December 31, 2017	Year Ended December 31, 2018	Year Ended December 31, 2017
	(In Thousands)			
Components of net periodic benefit cost:				
Service cost	$ 884	$ 578	$ 61	$ 32
Interest cost	1,902	2,010	136	119
Expected return on plan assets	(2,538)	(2,366)	-	-
Amortization of actuarial (gain) loss	580	713	84	-
Amortization of prior service cost	168	169	-	-
Net periodic benefit cost	$ 996	$ 1,104	$ 281	$ 151
Other Changes in Plan Assets and Benefit Obligations Recognized as a Regulatory Asset (Liability):				
Net (gain) loss	$ 2,885	$ (419)	$ (602)	$ 839
Amortization of prior service cost	(168)	(169)	-	-
Amortization of Actuarial gain (loss)	(580)	(713)	(84)	-
Total recognized as regulatory asset (liability)	$ 2,137	$ (1,301)	$ (686)	$ 839
Total recognized in Net Periodic Benefit Costs and Regulatory Asset (Liability):				
	$ 3,133	$ (197)	$ (405)	$ 990
Estimated Amortizations from Regulatory Assets (Liabilities) into Net Periodic Benefit Cost for the next 12 month period:				
Amortization of transition obligation	$ -	$ -	$ -	$ -
Amortization of prior service cost	43	169	-	-
Amortization of net (gain) loss	844	580	16	84
Total estimated amortizations	$ 887	$ 749	$ 16	$ 84
The following actuarial weighted average assumptions were used in calculating net periodic benefit cost:				
Discount rate	3.80%	4.24%	3.80%	4.24%
Average wage increase	3.50%	3.50%	N/A	N/A
Return on plan assets	7.00%	7.00%	N/A	N/A
Health care trend rate (current year - pre/post-65)	N/A	N/A	7.50%/8.50%	6.75%/8.50%
Health care trend rate (2030/2028 - pre/post-65)	N/A	N/A	4.50%/4.50%	4.50%/4.50%

N/A – Not applicable

Berkshire utilizes an alternative method to amortize prior service costs and unrecognized gains and losses. Prior service costs for the Plans are amortized on a straight-line basis over the average remaining service period of participants expected to receive benefits. Unrecognized actuarial gains and losses related to the Plans are amortized over 10 years as required by the DPU. Berkshire does not recognize gains or losses until there is a variance in an amount equal to at least 5% of the greater of the projected benefit obligation or the market-related value of assets.

The expected long-term rate of return on plan assets assumption was developed based on a review of long-term historical returns for the major asset classes, the target asset allocations, and the effect of rebalancing of plan assets. The analysis considered current capital market conditions and projected conditions.

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

	1% Increase	1% Decrease
	(In Thousands)	
Aggregate service and interest cost components	$ 13	$ (11)
Accumulated post-retirement benefit obligation	$ 193	$ (174)

Contributions

The funding policy for the Plans is to make annual contributions that satisfy the minimum funding requirements of ERISA but that do not exceed the maximum deductible limits of the Internal Revenue Code. These amounts are determined each year as a result of an actuarial valuation of the Plans. Berkshire expects to make a pension contribution of approximately $1.6 million in 2019. 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)	
2019	$ 2,243	$ 291
2020	$ 2,318	$ 275
2021	$ 2,438	$ 275
2022	$ 2,618	$ 299
2023	$ 2,662	$ 275
2024-2027	$ 14,777	$ 1,387

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 2018 and 2017 was $0.5 million 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, 2018, 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.

In the fourth quarter of 2018, Berkshire purchased $6.7 million of corporate assets from UIL Holdings resulting in an increase in net property, plant and equipment.

Dividends/Capital Contributions

Berkshire did not accrue any dividends to UIL Holdings during 2018. For the year ended December 31, 2017, Berkshire did not accrue any dividends to UIL Holdings during.

(H) LEASE OBLIGATIONS

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

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

	(In Thousands)	
2019	$	165
2020		23
2021		23
2022		22
2023		18
2024-after		-
	$	251

(I) 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, 2018 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, 2018. 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, 2018, 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.

(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. 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, 2018 and December 31, 2017.

	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, 2018		(In Thousands)		
Noncurrent investments	$ 386	$ -	$ -	$ 386
Total fair value assets, December 31, 2018	$ 386	$ -	$ -	$ 386
December 31, 2017				
Noncurrent investments	$ 564	$ -	$ -	$ 564
Total fair value assets, December 31, 2017	$ 564	$ -	$ -	$ 564

The following tables set forth the fair values of Berkshire's pension assets as of December 31, 2018 and 2017.

	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, 2018		(In Thousands)		
Pension assets				
Mutual funds	$ -	$ 32,148	$ -	$ 32,148
Fair value of plan assets, December 31, 2018	$ -	$ 32,148	$ -	$ 32,148
December 31, 2017				
Pension assets				
Mutual funds	$ -	$ 36,512	$ -	$ 36,512
Fair value of plan assets, December 31, 2017	$ -	$ 36,512	$ -	$ 36,512

The determination of fair value of the Level 2 co-mingled mutual funds was based on the Net Asset Value (NAV) provided by the managers of the underlying fund investments and the unrealized gains and losses. The NAV provided by the managers typically reflect the fair value of each underlying fund investment. Changes in the fair value of pension benefits are accounted for in accordance with ASC 715 Compensation – Retirement Benefits as discussed in Note (F) Pension and Other Benefits.

Central Maine Power Company and Subsidiaries

Consolidated Financial Statements

For the Years Ended December 31, 2018 and 2017

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Consolidated Financial Statements for the Years Ended December 31, 2018 and 2017

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 financial statements of Central Maine Power Company and Subsidiaries, which comprise the consolidated balance sheets as of December 31, 2018 and 2017, 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 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 2018 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, 2018 and 2017, 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 29, 2019

Central Maine Power Company and Subsidiaries
Consolidated Statements of Income

Years Ended December 31,	2018	2017
(Thousands)		
Operating Revenues	**$847,797**	**$822,110**
Operating Expenses		
Electricity purchased	14,543	12,846
Operations and maintenance	415,056	360,517
Depreciation and amortization	107,515	91,842
Taxes other than income taxes, net	64,917	60,621
Total Operating Expenses	**602,031**	**525,826**
Operating Income	**245,766**	**296,284**
Other income	10,318	11,615
Other deductions	(17,150)	(14,907)
Interest expense, net of capitalization	(53,188)	(51,673)
Income Before Income Tax	**185,746**	**241,319**
Income tax expense	53,824	82,166
Net Income	**131,922**	**159,153**
Less: net income attributable to noncontrolling interest	2,205	1,282
Net Income Attributable to CMP	**$129,717**	**$157,871**

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,	2018	2017
(Thousands)		
Net Income	**$131,922**	**$159,153**
Other Comprehensive Income, Net of Tax		
Amortization of pension cost for nonqualified plans, net of income taxes	82	11
Unrealized (loss) during the year on derivatives qualifying as cash flow hedges, net of income taxes:		
Unrealized (loss) during period on derivatives qualifying as hedges	(315)	(101)
Reclassification adjustment for loss included in net income	10	155
Reclassification adjustment for loss on settled cash flow treasury hedges	1,562	1,285
Total Other Comprehensive Income, Net of Tax	**1,339**	**1,350**
Comprehensive Income	**133,261**	**160,503**
Less:		
Comprehensive income attributable to noncontrolling interests	2,205	1,282
Comprehensive Income Attributable to CMP	**$131,056**	**$159,221**

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, (Thousands)	2018	2017
Assets		
Current Assets		
Cash and cash equivalents	$16,126	$15,096
Accounts receivable and unbilled revenues, net	198,935	171,978
Accounts receivable from affiliates	1,776	30,729
Notes receivable from affiliates	12,700	28,336
Materials and supplies	17,103	15,349
Prepayments and other current assets	41,066	63,036
Regulatory assets	31,414	12,689
Total Current Assets	**319,120**	**337,213**
Utility plant, at original cost	4,300,278	4,068,887
Less accumulated depreciation	(1,067,288)	(976,602)
Net Utility Plant in Service	**3,232,990**	**3,092,285**
Construction work in progress	129,985	156,247
Total Utility Plant	**3,362,975**	**3,248,532**
Other Property and Investments	1,222	1,268
Regulatory and Other Assets		
Regulatory assets	393,225	437,461
Goodwill	324,938	324,938
Other	66,964	38,544
Total Regulatory and Other Assets	**785,127**	**800,943**
Total Assets	**$4,468,444**	**$4,387,956**

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, (Thousands, except share information)	2018	2017
Liabilities		
Current Liabilities		
Current portion of debt	$151,800	$1,452
Notes payable to affiliates	172	434
Accounts payable and accrued liabilities	146,065	192,244
Accounts payable to affiliates	38,415	41,072
Interest accrued	17,941	17,828
Taxes accrued	2,953	2,043
Other current liabilities	59,417	55,614
Regulatory liabilities	31,067	44,182
Total Current Liabilities	**447,830**	**354,869**
Regulatory and Other Liabilities		
Regulatory liabilities	419,734	489,276
Other Non-current liabilities		
Deferred income taxes	502,943	401,483
Pension and other postretirement	192,283	207,997
Other	39,245	46,617
Total Regulatory and Other Liabilities	**1,154,205**	**1,145,373**
Non-current debt	949,032	1,040,859
Total Liabilities	**2,551,067**	**2,541,101**
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, 2018 and 2017)	156,057	156,057
Additional paid-in capital	764,087	764,004
Retained earnings	974,709	919,992
Accumulated other comprehensive loss	(3,958)	(5,297)
Total CMP Common Stock Equity	**1,890,895**	**1,834,756**
Noncontrolling interest	25,911	11,528
Total Equity	**1,916,806**	**1,846,284**
Total Liabilities and Equity	**$4,468,444**	**$4,387,956**

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,	2018	2017
(Thousands)		
Cash Flow from Operating Activities:		
Net income	**$131,922**	**$159,153**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	107,515	91,842
Regulatory assets/ liabilities amortization	(2,109)	(16,892)
Regulatory assets/ liabilities carrying cost	1,082	(437)
Amortization of debt issuance costs	602	573
Deferred taxes	32,464	63,926
Pension cost	21,735	18,852
Stock-based compensation	83	(132)
Accretion expenses	45	42
Gain on disposal of assets	(1,376)	(138)
Other non-cash items	(404)	(1,704)
Changes in operating assets and liabilities:		
Accounts receivable, from affiliates, and unbilled revenues	1,995	(39,311)
Inventories	(1,754)	(331)
Accounts payable, to affiliates, and accrued liabilities	(69,904)	23,733
Taxes accrued	29,069	(5,963)
Other assets/liabilities	(37,854)	42,990
Regulatory assets/liabilities	9,232	(30,159)
Net Cash Provided by Operating Activities	**222,343**	**306,044**
Cash Flow from Investing Activities:		
Utility plant additions	(247,616)	(263,465)
Contributions in aid of construction	13,650	14,773
Notes receivable from affiliates	15,636	3,764
Proceeds from sale of utility plant	2,399	1,275
Investments, net	-	29
Net Cash Used in Investing Activities	**(215,931)**	**(243,624)**
Cash Flow from Financing Activities:		
Non-current note issuance	60,000	-
Repayments of non-current debt	(1,183)	(1,183)
Repayments of other short-term debt, net	(454)	-
Repayments of capital leases	(662)	(4,543)
Proceeds of short term debt-affiliates	(261)	434
Contributions from noncontrolling interest	12,178	-
Dividends paid	(75,000)	(50,000)
Net Cash Used in Financing Activities	**(5,382)**	**(55,292)**
Net Increase in Cash and Cash Equivalents	**1,030**	**7,128**
Cash and Cash Equivalents, Beginning of Year	**15,096**	**7,968**
Cash and Cash Equivalents, End of Year	**$16,126**	**$15,096**

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

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

(Thousands, except per share amounts)	CMP Stockholder: Number of shares (*)	Common Stock	Additional Paid in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total CMP Common Stock Equity	Non-controlling Interest	Total Equity
Balances, January 1, 2017	**31,211,471**	**$156,057**	**$764,014**	**$812,121**	**$(6,647)**	**$1,725,545**	**$10,246**	**$1,735,791**
Net income	-	-	-	157,871	-	157,871	1,282	159,153
Other comprehensive income, net of tax	-	-	-	-	1,350	1,350	-	1,350
Comprehensive income								160,503
Stock-based compensation	-	-	(10)	-	-	(10)	-	(10)
Common stock dividends	-	-	-	(50,000)	-	(50,000)	-	(50,000)
Balances, December 31, 2017	**31,211,471**	**156,057**	**764,004**	**919,992**	**(5,297)**	**1,834,756**	**11,528**	**1,846,284**
Net income	-	-	-	129,717	-	129,717	2,205	131,922
Other comprehensive income, net of tax	-	-	-	-	1,339	1,339	-	1,339
Comprehensive income								133,261
Stock-based compensation	-	-	83	-	-	83	-	83
Capital contribution from parent	-	-	-	-	-	-	12,178	12,178
Common stock dividends	-	-	-	(75,000)	-	(75,000)	-	(75,000)
Balances, December 31, 2018	**31,211,471**	**$156,057**	**$764,087**	**$974,709**	**$(3,958)**	**$1,890,895**	**$25,911**	**$1,916,806**

(*) Par value of share amounts is $5

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

Notes to Consolidated Financial Statements

Note 1. Significant Accounting Policies

Background and nature of operations: Central Maine Power Company and subsidiaries (CMP, the company, we, our, us) conduct regulated electricity transmission and distribution operations in Maine serving approximately 627,000 customers as of December 31, 2018, 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) 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 organized on October 9, 1990, under the Maine Uniform Partnership Act.

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 a 81.5% owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain.

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

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

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

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

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

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

We amortize regulatory assets and liabilities and recognize the related expense or revenue in the 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 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, we have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary (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 we bypass step zero or perform the qualitative assessment, but determine that it is more likely than not that its fair value is less than its carrying amount, 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.

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

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

We determine depreciation expense for utility plant in service using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Our depreciation accruals were equivalent to 2.6% of average depreciable property for 2018 and 2.1% for 2017. 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 $154.6 million as of December 31, 2018, and $142.9 million as of December 31, 2017. Depreciation expense was $99.0 million in 2018 and $85.4 million in 2017. Amortization of capitalized software was $8.5 million in 2018 and $6.4 million in 2017.

Consistent with FERC accounting requirements, we charge the original cost of utility plant retired or otherwise disposed to accumulated depreciation.

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

Allowance for funds used during construction (AFUDC) represents the allowed cost of capital, including a noncash 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 the associated useful lives are shown below as of December 31.

Utility Plant	Estimated useful life (years)	2018	2017
(Thousands)			
Electric			
Transmission	4-70	$2,423,364	$2,255,967
Distribution	20-82	1,429,923	1,388,724
Vehicles	4-10	56,768	61,658
Other	5-54	390,223	362,538
Total Utility Plant in Service		**4,300,278**	**4,068,887**
Total accumulated depreciation		(1,067,288)	(976,602)
Total Net Utility Plant in Service		**3,232,990**	**3,092,285**
Construction work in progress		129,985	156,247
Total Utility Plant		**$3,362,975**	**$3,248,532**

Electric plant includes capital leases of $45.0 million for 2018 and 2017. Related accumulated depreciation at December 31 was $38.4 million for 2018 and $37.9 million for 2017.

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 loss is required to be recognized if the carrying amount of the asset exceeds the undiscounted future net cash flows associated with that asset.

The impairment loss to be recognized is the amount by which the carrying 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.

Fair value measurement: Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants as of the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place in either the principal market for the asset or liability, or, in the absence of a principal market, in the most advantageous market for the asset or liability.

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

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

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

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

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

Derivatives and hedge accounting: Derivatives are recognized on the 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. Changes in the fair value of a derivative contract are recognized in earnings unless specific hedge accounting criteria are met.

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

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 AOCI into earnings. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately.

Cash and cash equivalents: Cash and cash equivalents are comprised of 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 those investments are included 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 the consolidated balance sheets. Changes in book overdrafts are reported in the operating activities section of the consolidated statements of cash flows.

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

(Thousands)	2018	2017
Cash paid during the year ended December 31:		
Interest, net of amounts capitalized	$41,823	$40,611
Income taxes (refunded) paid, net	$(8,743)	$30,059

Of the income taxes paid, substantially all was paid to AGR under the tax sharing agreement. Interest capitalized was $9.2 million in 2018 and $10.4 million in 2017. Accrued liabilities for utility plant additions were $23.7 million in 2018 and $18.3 million in 2017.

***Accounts receivable and unbilled revenues, net*:** We record accounts receivable at amounts billed to customers. Accounts receivable at December 31 include unbilled revenues of 31.8 million for 2018 and $36.0 million for 2017, and are shown net of an allowance for doubtful accounts at December 31 of $7.3 million for 2018 and $3.8 million for 2017. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was $7.4 million in 2018 and $3.8 million in 2017.

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

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

Our accounts receivable include amounts due under deferred payment arrangements (DPAs). When a residential customer becomes delinquent in making payments, the MPUC requires us to allow the customer to enter into a DPA to settle the account balance. A DPA allows the account balance to be paid in installments over an extended period of time by negotiating mutually acceptable payment terms. Generally, we must continue to serve a customer who cannot pay an account balance in full if the customer: (i) pays a reasonable portion of the balance; (ii) agrees to pay the balance in installments; and (iii) agrees to pay future bills within 30 days until the DPA is paid in full or is otherwise considered to be delinquent. We establish provisions for uncollectible accounts by using both historical average loss percentages to project future losses and by establishing specific provisions for known credit issues. Amounts are written off when reasonable collection efforts have been exhausted. The allowance for doubtful accounts for DPAs at December 31 was $4.1 million for 2018 and $1.4 million for 2017. DPA receivable balances at December 31 were $14.8 million for 2018 and $9.1 million for 2017.

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

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

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

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

***Asset retirement obligations*:** We record the fair value of the liability for an asset retirement obligation (ARO) and a conditional ARO in the period in which it is incurred, and capitalize the cost by increasing the carrying amount of the related long-lived asset. We adjust the liability periodically to reflect revisions to either the timing or the 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 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.

Our ARO at December 31, including our conditional ARO, was $0.9 million for 2018 and $0.8 million for 2017. The ARO is associated with our long-lived assets and primarily consists of obligations related to removal or retirement of asbestos and polychlorinated biphenyl-contaminated equipment.

The following table reconciles the beginning and ending aggregate carrying amount of the ARO, which is recorded in Other Non-current Liabilities for the years ended December 31, 2018 and 2017.

Year ended December 31,	**2018**	**2017**
(thousands)		
ARO, beginning of year	$834	$792
Accretion expenses	45	42
ARO, end of year	**$879**	**$834**

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

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

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

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

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

We account for defined benefit pension or other postretirement plans, recognizing an asset or liability for the overfunded or underfunded plan status. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. We reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in other comprehensive income, 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 use the standard amortization methodology under which amounts in excess of 10 percent of the greater of the projected benefit obligation or market related value are amortized over the plan participants' average remaining service to retirement. Our policy is to calculate the expected return on plan assets using the market-related value of assets. We determine that value by recognizing the difference between actual returns and expected returns over a five year period.

Income tax: AGR, the parent company of Networks, files 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, 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 $29.1 million for 2018 and $57.3 million for 2017.

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 investment tax credits when earned and amortize them over the estimated lives of the related assets. We also recognize the income tax consequences of intra-entity transfers of assets other than inventory when the transfer occurs.

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

State franchise tax computed as the higher of a tax based on income or a tax based on capital is recorded in “Taxes other than income taxes” and “Taxes accrued” in the accompanying 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 the consolidated 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 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.

Upon enactment of the “Tax Cuts and Jobs Act” (the Tax Act) on December 22, 2017, we remeasured our existing deferred income tax balances as of December 31, 2017, to reflect the decrease in the corporate income tax rate from 35% to 21%, which resulted in a material decrease to our net deferred income tax liability balances. In connection with the Tax Act, the U.S. Securities and Exchange Commission (SEC) issued guidance in Staff Accounting Bulletin 118, or SAB 118, which clarified accounting for income taxes under Topic 740, Income Taxes, if information was not yet available or complete and provided up to a one year measurement period in which to complete the required analyses and accounting. Following SAB 118 guidance, we recorded provisional income tax amounts as of December 31, 2017, related to the Tax Act based on reasonable estimates that could be determined at that time. As of December 31, 2018, we have completed the measurement and accounting of certain effects of the Tax Act which we have reflected in the December 31, 2018 financial statements.

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

Reclassifications: Certain amounts reported in the financial statements in previous periods have been reclassified to conform to the current year presentation.

New Accounting Standards and Interpretations: New accounting standards issued by the Financial Accounting Standards Board (FASB) that we either adopted or have not yet adopted are explained below. 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.

Adoption of New Accounting Pronouncements

(a) Revenue from contracts with customers

In May 2014 the FASB issued Accounting Standards Codification (ASC), Topic 606, Revenue from Contracts with Customers (Topic 606) replacing the existing accounting standard and industry-specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The FASB further amended Topic 606 through various updates issued thereafter. The core principle is for an entity to recognize revenue to represent the transfer of promised goods or services to customers in amounts that reflect the consideration to which the entity expects to be entitled in exchange for those goods or services. We adopted Topic 606 effective January 1, 2018, and applied the modified retrospective method, for which we did not have a cumulative effect adjustment to retained earnings for initial application of the guidance. Refer to Note 4 for further details.

We also adopted the following standards as of their effective date of January 1, 2018, none of which had a material effect on our consolidated results of operations, financial position, cash flows, and disclosures.

(b) Certain classifications in the statement of cash flows

In August 2016 the FASB issued amendments to address existing diversity in practice concerning the classification of certain cash receipts and payments in the statement of cash flows, which must be applied on a full retrospective basis. Upon adoption, we had no changes to our cash flow classifications and disclosures in our consolidated financial statements.

(c) Improving the presentation of net periodic benefit costs

In March 2017 the FASB issued amendments to improve the presentation of net periodic pension cost and net periodic postretirement benefit cost in the financial statements. We retrospectively adopted the amendments that require us to present the service cost component separately from the other (non-service) components of net benefit cost, to report the service cost component in the income statement line item where we report the corresponding compensation cost, and to present all non-service components outside of operating cost. As a result, we have reclassified the non-service components – interest cost, expected return on plan assets, amortization of prior service cost (benefit), amortization of net loss, and settlement charge – from Operations and maintenance to Other income/(expense) within the statement of income. Prospectively, upon adoption, we will capitalize only the service cost component when applicable (for example, as a cost of a self-constructed asset). We elected to apply the practical expedient that allows us to retrospectively apply the amendments on adoption to net benefit costs for comparative periods by using the amounts disclosed in our notes to financial statements for Post-retirement and Similar Obligations as the basis for those periods. In connection with applying the practical expedient, in periods after adoption we will continue to include in operating income all legacy net benefit costs previously capitalized as a cost of self-constructed assets and other deferred regulatory costs. Our adoption of the amendments did not affect prior period net income. Beginning in 2018, non-service cost components we incur are no longer eligible for construction capitalization, but such costs can be deferred and included as a component of customer rates if permitted by our regulator. For the year ended December 31, 2018, we incurred additional immaterial expense as a result of the adoption of this standard.

The effect of the change in retrospective presentation related to the net periodic cost of our defined benefit pension and other postretirement employee benefits plans on our consolidated statement of income was as follows:

	Year Ended December 31, 2017		
Statement of Income	As Revised	As Previously Reported	Effect of Change Higher/(Lower)
(Thousands)			
Operations and maintenance	$ 360,517	$ 374,603	$ (14,086)
Other Deductions	$ (14,907)	$ (821)	$ (14,086)

(d) Customer accounting for implementation costs incurred in a cloud computing arrangement

The FASB issued amendments in August 2018 to clarify the accounting for implementation costs of a cloud computing arrangement (also referred to as a hosting arrangement) that is a service contract. Implementation costs, which include implementation, setup and other upfront costs, are either to be deferred or expensed as incurred, in accordance with existing internal-use software guidance for similar costs. The amendments require a customer to expense capitalized implementation costs over the contractual term of the arrangement, including any optional renewal periods the customer is reasonably certain it will exercise. An entity is to present deferred implementation costs on the balance sheet, income statement and cash flows consistent with the subscription fees associated with the arrangement. The amendments enhance disclosures to include certain qualitative and quantitative information about implementation costs for internal-use software and all hosting arrangements, not just hosting arrangements that are service contracts. The amendments are effective for public business entities for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted, including adoption in any interim period for which financial statements have not been issued. An entity may apply the amendments either retrospectively or prospectively to all implementation costs incurred after the date of adoption. We early adopted the amendments as of October 1, 2018, and are applying the amendments prospectively to all implementation costs after the date of adoption. Upon adoption, there were no material effects to our consolidated results of operations, financial position, cash flows and disclosures.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements issued as indicated, that we have evaluated or are evaluating to determine their effect on our consolidated financial statements.

(a) Leases

In February 2016 the FASB issued new guidance, and issued subsequent amendments during 2018, that affects all companies and organizations that lease assets, and requires them to record on their balance sheet right-of-use assets and lease liabilities for the rights and obligations created by those leases. Under the new guidance, a lease is an arrangement that conveys the right to control the use of an identified asset for a period of time in exchange for consideration. The amendments retain a distinction between finance leases and operating leases, while requiring both types of leases to be recognized on the balance sheet. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the criteria for distinguishing between capital leases and operating leases in legacy U.S. GAAP. Lessor accounting will remain substantially the same as legacy U.S. GAAP, but with some targeted improvements to align lessor accounting with the lessee accounting model and with the revised revenue recognition guidance under Topic 606. The standard and amendments require new qualitative and quantitative disclosures for both lessees and lessors. The new leases guidance, including the subsequent amendments issued during 2018, is effective for public entities for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, and early application is permitted.

We adopted the new leases guidance effective January 1, 2019, and have elected the optional transition method under which we will initially apply the standard on that date without adjusting amounts presented for prior periods, and record the cumulative effect of applying the new guidance as an adjustment to beginning retained earnings. We expect the adjustment to retained earnings will be immaterial. Concerning certain transition and other practical expedients:

- we did not elect the package of three practical expedients available under the transition provisions, including (i) not reassessing whether expired or existing contracts contain leases, (ii) lease classification, and (iii) not revaluing initial direct costs for existing leases;
- we elected a land easement expedient and did not reassess land easements that we did not account for as leases prior to our adoption of the new leases guidance;
- we used hindsight for specified determinations and assessments in applying the new leases guidance;
- we will not recognize lease assets and liabilities for short-term leases (less than one year), for all classes of underlying assets; and
- we did not separate lease and associated nonlease components for transitioned leases, but will instead account for them together as a single lease component.

(b) Measurement of credit losses on financial instruments

The FASB issued an accounting standards update in June 2016 that requires more timely recording of credit losses on loans and other financial instruments. The amendments affect entities that hold financial assets and net investments in leases that are not accounted for at fair value through net income (loans, debt securities, trade receivables, 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. In November 2018 the FASB issued an update to this new guidance to clarify that receivables arising from operating leases are not within the scope of the credit losses standard. Instead, impairment of receivables arising from operating leases should be accounted for in accordance with the leases standard. The amendments are effective for public entities that are SEC filers for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, with early adoption permitted. Entities are to apply the amendments on a modified retrospective basis for most instruments. We expect our adoption will not materially affect our consolidated results of operations, financial position, and cash flows.

(c) Simplifying the test for goodwill impairment

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

(d) Targeted improvements to accounting for hedging activities

In August 2017 the FASB issued targeted amendments with the objective to better align hedge accounting with an entity's risk management activities in the financial statements, and to simplify the application of hedge accounting. The amendments address concerns of financial statement preparers over difficulties with applying hedge accounting and limitations for hedging both nonfinancial and financial risks, and concerns of financial statement users over how hedging activities are reported in financial statements. Changes to the hedge accounting guidance to address those concerns will: 1) expand hedge accounting for nonfinancial and financial risk components and amend measurement methodologies to more closely align hedge accounting with an entity's risk management activities; 2) eliminate the separate measurement and reporting of hedge ineffectiveness, to reduce the complexity of preparing and understanding hedge results; 3) enhance disclosures and change the presentation of hedge results to align the effects of the hedging instrument and the hedged item in order to enhance transparency, comparability, and understandability of hedge results; and 4) simplify the way assessments of hedge effectiveness may be performed to reduce the cost and complexity of applying hedge accounting. The amendments are effective for public entities for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. For cash flow and net investment hedges existing at the date of adoption, a company must apply a cumulative-effect adjustment related to the separate measurement of ineffectiveness to AOCI with a corresponding adjustment to the opening balance of retained earnings as of the beginning of the fiscal year of adoption. The amended presentation and disclosure guidance is required only prospectively. In October 2018 the FASB issued amendments that are effective concurrently with the above targeted improvements. These additional amendments permit use of the Overnight Index Swap rate based on the Secured Overnight Financing Rate as a U.S. benchmark interest rate for hedge accounting purposes. Use of that rate is in addition to the already eligible benchmark interest rates, which are: interest rates on direct Treasury obligations of the U.S. government, the London Interbank Offered Rate swap rate, the OIS Rate based on the Fed Funds Effective Rate, and the Securities Industry and Financial Markets Association Municipal Swap Rate. Our adoption of the amendments on January 1, 2019, will not materially affect our consolidated results of operations, financial position, or cash flows, but the amendments will ease the administrative burden of hedge documentation requirements and assessing hedge effectiveness going forward.

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

In February 2018 the FASB issued amendments to address a narrow-scope financial reporting issue that arose as a consequence of the Tax Cuts and Jobs Act of 2017 (the Tax Act) enacted on December 22, 2017, by the U.S. federal government. Under current guidance, the adjustment of deferred taxes for the effect of a change in tax laws or rates is required to be included in income from continuing operations, thus the associated tax effects of items within AOCI (referred to as stranded tax effects) do not reflect the appropriate tax rate. The amendments allow a reclassification from AOCI to retained earnings for stranded tax effects resulting from the Tax Act. As a result, the amendments eliminate the stranded tax effects resulting from the Tax Act and will improve the usefulness of information reported to financial statement users. The amendments only relate to the reclassification of the income tax effects of the Tax Act, and do not affect the underlying guidance that requires the effect of a change in tax laws or rates to be included in income from continuing operations. The amendments are effective for all entities for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted including, for public entities, adoption in any interim period for which financial statements have not been issued. An entity has the option to apply the amendments either in the period of adoption or retrospectively to each period (or periods) in which it recognizes the effect of the change in the U.S. federal corporate income tax rate in the Tax Act. An entity is required to disclose its accounting policy election, including its policy for reclassifying material stranded tax effects in AOCI to earnings (specific identification or portfolio method). Our adoption of the amendments on January 1, 2019, will not materially affect our consolidated results of operations, financial position, cash flows, and disclosures.

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

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

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

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

Union collective bargaining agreements: Approximately 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, the Storm proceedings, 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

See Note 10 - Commitments and Contingent Liabilities - for a further discussion of FERC ROE litigation.

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 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 Maine Electric Power Company, Inc. (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. The FERC has not acted on the settlement and we are unable to predict the outcome of this proceeding at this time.

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 has 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 is proposing 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 has established a ten-month process to review CMP's filing and a decision is expected in August of 2019. CMP is planning to use savings from the federal Tax Act to offset the costs of resiliency programs, other investments in infrastructure and cost increases since 2014. CMP's filing proposes to continue the current RDM and storm cost recovery rate mechanisms with certain modifications. We cannot predict the outcome of this investigation.

Under Maine law, the MPUC is authorized to conduct periodic requests for proposals seeking long-term supplies of energy, capacity or Renewable Energy Certificates, or RECs, from qualifying resources. The MPUC is further authorized to order Maine Transmission and Distribution Utilities to enter into contracts with sellers selected from the MPUC's competitive solicitation process. Pursuant to a MPUC Order dated October 8, 2009, CMP entered into a 20-year agreement with Evergreen Wind Power III, LLC, on March 31, 2010, to purchase capacity and energy from Evergreen's 60 MW Rollins wind farm in Penobscot County, Maine. CMP's purchase obligations under the Rollins contract are approximately $7 million per year. In accordance with subsequent MPUC orders, CMP periodically auctions the purchased Rollins energy to wholesale buyers in the New England regional market. Under applicable law, CMP is assured recovery of any differences between power purchase costs and achieved market revenues through a reconcilable component of its retail distribution rates. Although the MPUC has conducted multiple requests for proposals under M.R.S.A §3210-C and has tentatively accepted long-term proposals from other sellers, these selections have not yet resulted in additional currently effective contracts with CMP.

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

On December 19, 2017, the Commission issued a Notice of Investigation regarding utility response to the October 2017 Storm. The wind storm of October 2017 was unprecedented in the number of customers impacted and the magnitude of the damage across the entire Central Maine Power service territory. During the event, thousands of trees were broken or uprooted and many caused damage to the electrical delivery system. The vast majority of tree related damage was from trees that were located outside of the maintenance clearance zone. In an order issued on October 4, 2018, the MPUC found that CMP's actions in preparation for and response to the October wind storm were reasonable. CMP's total incremental restoration costs for the storm event were approximately $69.3 million, of which approximately $24.7 million are capital costs associated with the replacement of damaged infrastructure, including poles, cross arms, transformers and related equipment. Additionally, approximately $744 thousand of the incremental amount is operations and maintenance expense for repairs to CMP transmission facilities. Accordingly, the net incremental operations and maintenance expenses for restoration of the distribution system were approximately $43.9 million. Recovery of the incremental storm restoration costs in CMP distribution rates has been addressed in the Company's 2018 Annual Compliance Filing proceeding pursuant to the applicable provisions of the stipulation approved by the Commission in Docket No. 2013-00168. Total incremental storm recovery in distribution rates (effective July 1, 2018), after consideration for storm reserve treatment, is $28.4M.

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. The Company expects the regulators to address the remaining impacts associated with deferred income taxes in 2019 (included in regulatory liabilities), including how these remaining tax benefits associated with the Tax Act will be returned to customers.

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 $203.8 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.

Current and non-current regulatory assets at December 31, 2018 and 2017 consisted of:

December 31,	**2018**	**2017**
(Thousands)		
Current		
Transmission revenue reconciliation mechanism	$10,865	$7,629
Deferred meter replacement costs	2,163	2,388
Environmental remediation costs	160	1,178
Storm – Tier III	16,720	-
Stranded Costs	1,357	-
Other	149	1,494
Total current regulatory assets	**$31,414**	**$12,689**
Non-current		
Federal tax depreciation normalization adjustment	$13,137	$11,834
Storm costs	14,677	38,541
Unamortized losses on reacquired debt	444	536
Pension and other postretirement benefit costs	201,483	219,764
Unfunded future income taxes	135,120	136,753
Deferred meter replacement costs	26,885	29,110
Other	1,479	923
Total non-current regulatory assets	**$393,225**	**$437,461**

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).

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

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

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 $31.4 million at December 31, 2018 and $38.5 million at December 31, 2017.

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.

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.

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.

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.

Other includes various items subject to reconciliation such as Arrears Forgiveness and Public Advocate Costs.

Current and non-current regulatory liabilities at December 31, 2018 and 2017 consisted of:

December 31,	**2018**	**2017**
(Thousands)		
Current		
Accrued removal obligations	$2,251	$2,251
Transmission revenue reconciliation mechanism	7,028	13,701
Yankee DOE refund	-	3,997
Stranded cost	-	17,000
Revenue decoupling mechanism	7,744	4,098

Tax Act-remeasurement	2,740	-
Energy Efficiency Programs	2,007	372
Scenario B Storm in rates	7,529	-
Other	1,768	2,763
Total current regulatory liabilities	**$31,067**	**$44,182**
Non-current		
Environmental remediation costs	$1,335	$2,246
Rate refund-FERC ROE proceeding	23,448	22,520
Accrued removal obligations	59,502	64,106
Scenario B Storm revenue collection	-	14,617
Tax Act-remeasurement	334,340	385,492
Other	1,109	295
Total non-current regulatory liabilities	**$419,734**	**$489,276**

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.

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).

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.

Yankee DOE refund: CMP has an ownership interest in Maine Yankee Atomic Power Company, Connecticut Yankee Atomic Power Company, and Yankee Atomic Electric Company, (the Yankee Companies), three New England single-unit decommissioned nuclear reactor sites. Every six years, pursuant to the statute of limitations, the Yankee Companies file a lawsuit to recover damages from the Department of Energy (DOE or Government) for breach of the Nuclear Spent Fuel Disposal Contract to remove Spent Nuclear Fuel (SNF) and Greater than Class C Waste (GTCC) 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. CMP’s share of awards associated with Yankee is credited back to customers.

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.

Rate refund-FERC ROE proceeding: see Note 10.

The regulatory liability associated with Scenario B represents the commission approved continuation of the December 2013 storm cost amortization for future rate treatment.

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

Energy efficiency programs 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.

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

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

Note 4. Revenue

On January 1, 2018, we adopted ASC 606 and all related amendments using the modified retrospective method, which we applied only to contracts that were not completed as of January 1, 2018. For reporting periods beginning on January 1, 2018, we present revenue in accordance with ASC 606, and have not adjusted comparative prior period information, which we continue to report under the legacy accounting standards in effect for those prior periods. For the year ended December 31, 2018, the effect of applying ASC 606 to recognize revenue as compared to applying the legacy accounting standards was not material.

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. CMP 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 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. We record revenue for all of those sales based upon the regulatory-approved tariff and the volume delivered or transmitted, which corresponds to the amount that we have a right to invoice. There are no material initial incremental costs of obtaining a contract in any of the arrangements. CMP 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. CMP does not have any material significant payment terms because it receives payment at or shortly after the point of sale.

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 recognizes and records only the initial recognition of "originating" ARP revenues (when the regulatory-specified conditions for recognition have been met). When we subsequently include those amounts in the price of utility service billed to customers, we record such amounts as a recovery of the associated regulatory asset or liability. When we owe amounts to customers in connection with ARPs, we 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.

CMP also has various other sources of revenue including billing, collection, other administrative charges, sundry billings, rent of utility property, and miscellaneous revenue. We classify 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, 2018 are as follows:

Year Ended December 31, 2018: **(Thousands)**		
Regulated operations – electricity	$	789,686
Other[(a)]		20,752
Revenue from contracts with customers		810,438
Leasing revenue		17,212
Alternative revenue programs		18,784
Other revenue		1,363
Total operating revenues	**$**	**847,797**

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

As of December 31, 2018, nearly all of the accounts receivable balances included in "Accounts receivable and unbilled revenues, net" on our condensed balance sheet are related to contracts with customers.

Note 5. Goodwill

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

We had no impairment of goodwill in 2018 and in 2017 as a result of our annual impairment assessment, which we performed as of October 1st. For 2018 as a result of our step one testing and for 2017 as a result of our step zero qualitative analysis, no impairment was indicated within any of the ranges of assumptions analyzed. There were no events or circumstances subsequent to our annual impairment assessment for 2018 or for 2017 that required us to update the assessment.

The carrying amount of goodwill was $325.0 million at both December 31, 2018 and 2017 with no accumulated impairment losses and no changes during 2018 and 2017.

Note 6. Income Taxes

The Tax Act changes significantly the federal taxation of business entities, including among other things, a federal corporate tax rate decrease from 35% to 21% for tax years beginning after December 31, 2017. In connection with the Tax Act, the U.S. Securities and Exchange Commission issued guidance in Staff Accounting Bulletin 118, or SAB 118, which clarified accounting for income taxes under ASC 740, Income Taxes, if information was not yet available or complete and provided up to a one year measurement period in which to complete the required analyses and accounting. Following SAB 118 guidance, the Company recorded provisional income tax amounts as of December 31, 2017 related to the Tax Act based on reasonable estimates that could be determined at that time. As of December 31, 2018, the Company has completed the measurement and accounting of certain effects of the Tax Act which have been reflected in the December 31, 2018 financial statements.

Current and deferred taxes charged to expense for the years ended December 31, 2018 and 2017 consisted of:

Years Ended December 31,	**2018**	**2017**
(Thousands)		
Current		
Federal	$21,762	$17,165
State	(401)	1,075
Current taxes charged to expense	**21,361**	**18,240**
Deferred		
Federal	29,154	53,185
State	3,309	10,741
Deferred taxes charged to expense	**32,463**	**63,926**
Total Income Tax Expense	**$53,824**	**$82,166**

The differences between tax expense per the statements of income and tax expense at the 21% and 35% statutory federal tax rate for the years ended December 31, 2018 and 2017, respectively, consisted of:

Years Ended December 31, (Thousands)	2018	2017
Tax expense at federal statutory rate	$39,007	$84,461
Depreciation and amortization not normalized	(1,711)	(4,737)
Tax reform	-	(613)
Statutory state taxes, net of federal benefit	13,104	7,680
Other, net	3,424	(4,625)
Total Income Tax Expense	**$53,824**	**$82,166**

Income tax expense for the year ended December 31, 2018 was $14.8 million higher than it would have been at the statutory federal income tax rate of 21% due predominately to state taxes, (net of federal benefit), one time discrete items offset by a benefit in depreciation and amortization not normalized. This resulted in an effective tax rate of 28.9%. Income tax expense for the year ended December 31, 2017 was $2.3 million lower than it would have been at the statutory federal income tax rate of 35% due predominately to state taxes, (net of federal benefit). This resulted in an effective tax rate of 37.4%.

Deferred tax assets and liabilities as of December 31, 2018 and 2017 consisted of:

December 31, (Thousands)	2018	2017
Non-current Deferred Income Tax Liabilities (Assets)		
Property related	$571,496	$480,634
Unfunded future income taxes	39,071	38,366
Regulatory liability due to “Tax Cuts and Jobs Act”	(94,567)	(108,149)
Derivative assets	(1,157)	(1,674)
Federal and state tax credits	(8,516)	(9,854)
Federal and state NOL'S	(6,799)	(895)
Pension and other postretirement	7,094	8,198
Other	(4,144)	(5,608)
Non-current Deferred Income Tax Liabilities	**502,478**	**401,018**
Add: Valuation allowance	465	465
Total Non-current Deferred Income Tax Liabilities	**$502,943**	**$401,483**
Deferred tax assets	$115,183	$126,180
Deferred tax liabilities	618,126	527,663
Net Accumulated Deferred Income Tax Liabilities	**$502,943**	**$401,483**

CMP has $8.5 million of federal and state research and development credits offset by $0.4 million of valuation allowance.

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2018, and 2017 consisted of:

Years Ended December 31, (Thousands)	2018	2017
Balance as of January 1	$29,425	$39,794
Reduction for tax positions related to prior years	(3,765)	(10,369)
Balance as of December 31	**$25,660**	**$29,425**

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, 2018 or 2017. If recognized, $25.6 million of the total gross unrecognized tax benefits would affect the effective tax rate as an expense. Gross unrecognized tax benefits decreased $3.7 million in 2018 due to tax positions related to prior years.

Note 7. Non-current debt

At December 31, 2018 and 2017, our non-current debt was:

As of December 31,		**2018**		**2017**	
(Thousands)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
First mortgage bonds [(a)]	2019-2045	$ 960,000	3.07%-5.70%	$ 900,000	3.07%-5.70%
Senior unsecured notes	2025-2037	140,000	5.375%-6.40%	140,000	5.38%-6.40%
Chester: Promissory and Senior Notes[(b)]	2020	2,176	7.05%-10.48%	3,359	7.05%-10.48%
Obligations under capital leases	2019-2036	2,375		2,881	
Unamortized debt issuance costs and discount		(3,719)		(3,929)	
Total Debt		**$1,100,832**		**$ 1,042,311**	
Less: debt due within one year, included in current liabilities		151,800		1,452	
Total Non-current Debt		**$ 949,032**		**$ 1,040,859**	

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

At December 31, 2018, non-current debt, including sinking fund obligations and capital lease payments (in thousands) that will become due during the next five years are:

2019	**2020**	**2021**	**2022**	**2023**
$151,800	$2,107	$150,290	$125,015	$15

We have no debt covenant requirements related to the maintenance of financial ratios in our long-term debt agreements at December 31, 2018 and 2017.

In the AGR Credit Facility we covenant not to permit, without the consent of the lender, our ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of indebtedness to total capitalization, the facility excludes from net worth the balance of accumulated other comprehensive loss as it appears on the balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness we may maintain. Continued un-remedied failure to comply with those covenants for five business days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity. Our ratio of indebtedness to total capitalization pursuant to the revolving credit facility was 0.37 to 1.00 at December 31, 2018. We are not in default as of December 31, 2018.

Note 8. Bank Loans and Other Borrowings

CMP had no short-term debt outstanding at December 31, 2018 or 2017. 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.

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 balances outstanding under this agreement as of both December 31, 2018 and 2017.

On June 29, 2018, AGR and its investment-grade rated utility subsidiaries (New York State Electric & Gas Corporation ("NYSEG"), Rochester Gas and Electric Corporation ("RG&E"), CMP, The United Illuminating Company ("UI"), Connecticut Natural Gas Corporation ("CNG"), The Southern Connecticut Gas Company (SCG) and The Berkshire Gas Company ("BGC")) increased the maximum borrowing terms of the AGR Credit Facility from $1.5 billion to $2.5 billion (in aggregate) and extended the maturity date from April 5, 2021 to June 29, 2023. The lending commitments under the AGR Credit Facility are comprised of a syndicate of banks. Under the terms of the AGR Credit Facility, each joint borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit established by the banks. AGR's maximum sublimit is $2 billion, NYSEG, RG&E, CMP and UI have maximum sublimits of $400 million, CNG, and SCG have maximum sublimits of $150 million and BGC has a maximum sublimit of $40 million. Under the AGR Credit Facility, each of the borrowers will pay an annual facility fee that is dependent on their credit rating. The facility fees range from 10.0 to 17.5 basis points. CMP had not borrowed under this agreement as of both December 31, 2018 and 2017.

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, 2018 and 2017, our redeemable preferred stock was:

Series	Par Value per Share	Redemption Price per Share	Shares Authorized and Outstanding[1]	Amount (Thousands) 2018	2017
CMP, 6% Noncallable	$100	-	5,713	$571	$571
Total				**$571**	**$571**

[1] At December 31, 2018 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. Commitments and Contingent Liabilities

CMP Transmission - ROE Complaint

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 during 2019. 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. The FERC is expected to make its final decision in 2019.

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 $23.5 million, as of December 31, 2018 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 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. CMP expects FERC to rule on this complaint in 2019. 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. We cannot predict the outcome of this proceeding.

Leases

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

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

Power purchase contracts including nonutility generator

We recognized expense of approximately $14.2 million for NUG power in 2018 and $12.0 million in 2017.

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 service.

Waste sites

The EPA and various state environmental agencies, as appropriate, have notified us that we are among the potentially responsible parties that may be liable for costs incurred to remediate certain hazardous substances at six waste sites. The six sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the six sites, five sites are included in Maine's Uncontrolled Sites Program, one is included on the Massachusetts Non-Priority Confirmed Disposal Site list and two sites are also included on the National Priorities list. Any liability may be joint and several for certain of those sites. We have recorded an estimated liability of $1.4 million related to the six sites at December 31, 2018.

We have recorded an estimated liability of $2.3 million at December 31, 2018, related to four additional sites where we believe it is probable that we will incur remediation costs and/or monitoring costs, although we have not been notified that we are among the potentially responsible parties or are regulated under State Resource Conservation and Recovery Act (RCRA) program. It is reasonably possible the ultimate cost to remediate the sites may be significantly more than the accrued amount. Our estimate for costs to remediate the 10 total sites ranges from $2.7 million to $8.9 million as of December 31, 2018. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to us. We recorded a corresponding regulatory asset, net of insurance recoveries, because we expect to recover the net costs in rates.

Manufactured gas plants

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

Our estimate for all costs related to investigation and remediation of the three sites range from $0.2 million to $1.2 million at December 31, 2018. 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, 2018, and 2017. 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 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. 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 $(0.5) million as of December 31, 2018, and $(0.7) million as of December 31, 2017, and are included in current liabilities.

The effect of hedging instruments on OCI and income was:

Year Ended December 31,	(Loss) Gain Recognized in OCI on Derivatives	Location of Gain (Loss) Reclassified from Accumulated OCI into Income	Gain (Loss) Reclassified from Accumulated OCI into Income
Derivatives in Cash Flow Hedging Relationships	**Effective Portion**	**Effective Portion**	
(Thousands)			
2018			
Interest rate contracts	$-	Interest expense	$(2,171)
Commodity contracts:			
Fleet Fuel	$(438)	Other operating expenses	(13)
Total	**$(438)**		**$(2,184)**
2017			
Interest rate contracts	$-	Interest expense	$(2,175)
Commodity contracts:			
Fleet Fuel	$(171)	Other operating expenses	(262)
Total	**$(171)**		**$(2,437)**

The amount in AOCI related to previously settled interest rate hedging contracts at December 31 is a net loss of $3.6 million for 2018 and $5.8 million for 2017. For the year ended December 31, 2018, we recorded $2.2 million in net derivative losses related to discontinued cash flow hedges. We will amortize approximately $1.0 million of discontinued cash flow hedges in 2019.

At December 31, 2018, $0.5 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. There was no ineffective portion of the hedge recognized during the year ended December 31, 2018.

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

Year to settle	Electricity Contracts Mwhs	Natural Gas Contracts Dths	Other Fuel Contracts Gallons
As of December 31, 2018			
2019	-	-	594,700
As of December 31, 2017			
2018	-	-	601,800

Note 13. Fair Value of Financial Instruments and Fair Value Measurements

The estimated fair value of debt amounted to $1,163 million and $1,169 million as of December 31, 2018 and 2017, 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.

Notes to Consolidated Financial Statements

Assets and liabilities measured at fair value on a recurring basis

		Fair Value Measurements at December 31, Using		
Description	**Total**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
(Thousands)				
2018				
Assets				
Noncurrent investments available for sale	$535	$535	$-	$-
Total	**$535**	**$535**	**$-**	**$-**
Liabilities				
Derivatives	$498	$-	$-	$498
Total	**$498**	**$-**	**$-**	**$498**
2017				
Assets				
Noncurrent investments available for sale	$623	$623	$-	$-
Total	**$623**	**$623**	**$-**	**$-**
Liabilities				
Derivatives	$73	$-	$-	$73
Total	**$73**	**$-**	**$-**	**$73**

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2018 and 2017. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

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

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

Instruments measured at fair value on a recurring basis using significant unobservable inputs

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)	
	Derivatives, Net	
Year ended December 31,	**2018**	**2017**
(Thousands)		
Beginning balance	$73	$164
Total gain (loss) for the period		
Included in earnings	(13)	(262)
Included in other comprehensive income	438	171
Ending balance	**$498**	**$73**

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.

Notes to Consolidated Financial Statements

Note 14. Accumulated Other Comprehensive Loss

(Thousands)	Balance January 1, 2017	2017 Change	Balance December 31, 2017	2018 Change	Balance December 31, 2018
Amortization of pension cost for nonqualified plans, net of income tax expense of $8 for 2017 and $32 for 2018	$(1,884)	$11	$(1,873)	$82	$(1,791)
Unrealized (loss) on derivatives qualified as hedges:					
Unrealized (loss) during period on derivatives qualified as hedges, net of income tax expense (benefit) of $(70) for 2017 and $(123) for 2018		(101)		(315)	
Reclassification adjustment for loss included in net income, net of income tax expense of $107 for 2017 and of $3 for 2018		155		10	
Reclassification adjustment for loss on settled cash flow treasury hedge, net of income tax expense of $890 for 2017 and $609 for 2018		1,285		1,562	
Net unrealized (loss) gain on derivatives qualified as hedges	$(4,763)	$1,339	$(3,424)	$1,257	$(2,167)
Accumulated Other Comprehensive Loss	**$(6,647)**	**$1,350**	**$(5,297)**	**$1,339**	**$(3,958)**

No Accumulated Other Comprehensive Loss is attributable to the non-controlling interest for the above periods.

Note 15. Post-Retirement and Similar Obligations

We have funded noncontributory defined benefit pension plans that cover all 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 benefits accumulate 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. CMP union employees covered under the cash balance plans ceased accruals as of December 31, 2014. 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 for 2018 and $2.9 million for 2017.

We also have other postretirement health care benefit plans covering substantially all of our employees. The health care plans are contributory with participants' contributions adjusted annually.

***Obligations and funded status*:**

	Pension Benefits		Postretirement Benefits	
	2018	**2017**	**2018**	**2017**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	$431,986	$396,523	$114,196	$106,979
Service cost	7,654	7,679	642	647
Interest cost	15,339	15,976	4,021	4,269
Plan participants' contributions	-	-	1,038	642
Actuarial loss (gain)	(24,470)	36,141	(12,619)	8,721
Medicare subsidies received	-	-	-	60
Benefits paid	(28,811)	(24,333)	(7,620)	(7,122)
Benefit obligation at December 31	**$401,698**	**$431,986**	**$99,658**	**$114,196**
Change in plan assets				
Fair value of plan assets at January 1	$301,503	$272,645	$36,682	$36,141
Actual return on plan assets	(15,066)	37,492	(1,640)	4,158
Employer contributions	20,000	15,700	2,987	2,801
Employer and plan participants' contributions	-	-	1,038	642
Benefits paid	(28,811)	(24,333)	(7,620)	(7,122)
Medicare subsidies received	-	-	-	60
Fair value of plan assets at December 31	**$277,626**	**$301,503**	**$31,447**	**$36,682**
Funded status at December 31	**$(124,072)**	**$(130,483)**	**$(68,211)**	**$(77,514)**

Amounts recognized in the balance sheet	Pension Benefits		Postretirement Benefits	
December 31,	**2018**	**2017**	**2018**	**2017**
(Thousands)				
Noncurrent liabilities	$(124,072)	$(130,483)	$(68,211)	$(77,514)

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,	**2018**	**2017**	**2018**	**2017**
(Thousands)				
Net loss	$174,427	$182,574	$33,731	$45,878
Prior service cost (credit)	$-	$-	$(6,675)	$(8,688)

Our accumulated benefit obligation for all defined benefit pension plans at December 31 was $373.6 million for 2018 and $394.0 million for 2017.

Our postretirement benefits were partially funded at December 31, 2018 and 2017.

The projected benefit obligation and accumulated benefit obligation exceeded the fair value of pension plan assets for our plans as of December 31, 2018 and 2017. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets for the relevant periods.

December 31,	**2018**	**2017**
(Thousands)		
Projected benefit obligation	$401,698	$431,986
Accumulated benefit obligation	$373,583	$393,959
Fair value of plan assets	$277,626	$301,503

Components of net periodic benefit cost and other amounts recognized in regulatory assets and regulatory liabilities:

	Pension Benefits		Postretirement Benefits	
Years ended December 31,	**2018**	**2017**	**2018**	**2017**
(Thousands)				
Net periodic benefit cost				
Service cost	$7,654	$7,679	$642	$647
Interest cost	15,339	15,976	4,021	4,268
Expected return on plan assets	(21,503)	(20,727)	(2,177)	(2,175)
Amortization of prior service cost (credit)	-	6	(2,013)	(2,013)
Amortization of net loss	20,245	15,918	3,346	2,833
Net periodic benefit cost	**$21,735**	**$18,852**	**$3,819**	**$3,560**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net loss (gain)	$12,099	$19,377	$(8,802)	$6,737
Amortization of net loss	(20,245)	(15,918)	(3,346)	(2,833)
Amortization of prior service (cost) credit	-	(6)	2,013	2,013
Total recognized in regulatory assets and regulatory liabilities	**(8,146)**	**3,453**	**(10,135)**	**5,917**
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$13,589**	**$22,305**	**$(6,316)**	**$9,477**

We include the net periodic benefit cost in other operating expenses. The net periodic benefit cost for postretirement benefits represents the amount expensed for providing health care benefits to retirees and their eligible dependents.

Amounts expected to be amortized from regulatory assets or regulatory liabilities into net periodic benefit cost for the fiscal year ending December 31, 2019	**Pension Benefits**	**Postretirement Benefits**
(Thousands)		
Estimated net loss	$15,531	$2,520
Estimated prior service cost (credit)	$-	$(2,013)

We expect that no pension benefit or postretirement benefit plan assets will be returned to us during the fiscal year ending December 31, 2019.

Weighted-average assumptions used to determine benefit obligations at December 31,	**Pension Benefits**		**Postretirement Benefits**	
	2018	**2017**	**2018**	**2017**
Discount rate	3.93%	3.63%	3.93%	3.63%
Rate of compensation increase	3.70%-4.20%	3.80%-4.20%	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.

Weighted-average assumptions used to determine net periodic benefit cost for	**Pension Benefits**		**Postretirement Benefits**	
Years ended December 31,	**2018**	**2017**	**2018**	**2017**
Discount rate	3.63%	4.12%	3.63%	4.12%
Expected long-term return on plan assets	7.30%	7.30%	-	-
Expected long-term return on plan assets - nontaxable trust	-	-	6.40%	6.50%
Expected long-term return on plan assets - taxable trust	-	-	4.20%	4.25%

Rate of compensation increase (Union/Non-Union	3.70%-4.20%	3.80%-4.20%	N/A	N/A

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations and the effect of rebalancing of plan assets discussed below. That analysis considered current capital market conditions and projected conditions. Our policy is to calculate the expected return on plan assets using the market related value of assets. We amortize unrecognized actuarial gains and losses 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 to determine benefit obligations at December 31,	**2018**	**2017**
Health care cost trend rate (pre 65/post 65)	7.50%/8.50%	6.75%/8.50%
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	2030/2028	2026/2028

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plan. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1% Increase	**1% Decrease**
(Thousands)		
Effect on total of service and interest cost	$189	$(160)
Effect on postretirement benefit obligation	$4,874	$(4,126)

***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 $20 million to our pension benefit plans in 2019.

***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)			
2019	$18,787	$7,038	$188
2020	$19,484	$6,906	$203
2021	$20,392	$6,800	$227
2022	$21,079	$6,774	$250
2023	$21,927	$6,725	$273
2024 - 2028	$120,496	$31,148	$1,572

***Plan assets*:** Our pension benefits plan assets are held in a master trust providing for a single trustee/custodian, a uniform investment manager lineup, and an efficient, cost-effective means of allocating expenses and investment performance to each plan under the master trust. Our primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our tolerance for risk. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. Our primary means for achieving capital preservation is through diversification of the trust’s investments while avoiding significant concentrations of risk in any one area of the securities markets. Within each asset group, further diversification is achieved through utilizing multiple asset managers and systematic allocation to various asset classes; providing broad exposure to different segments of the equity, fixed-income and alternative investment markets.

Networks' asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets within broad categories of asset classes made up of Return-Seeking and Liability-Hedging investments. Within the Return-Seeking category, we have targets of 35%-53% in equity securities, 40%-45% for Liability-Hedging assets and 7%-20% for alternative investments. Return-Seeking investments generally consist of domestic, international, global, and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking assets also include investments in real estate, absolute return, and strategic markets. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS, and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of Networks' pension benefits plan assets at December 31, 2018 and 2017, by asset category are shown in the following table. CMP's share of the total consolidated assets is approximately 11% for 2018 and 2017.

		Fair Value Measurements at December 31, Using		
Asset Category	**Total**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
(Thousands)				
2018				
Cash and cash equivalents	$51,661	$ -	$51,661	$-
U.S. government securities	15,137	15,137	-	-
Common stocks	90	90	-	-
Registered investment companies	216,508	216,508	-	-
Corporate bonds	412,703	-	412,703	-
Preferred stocks	3,512	270	3,242	-
Common collective trusts	813,186	179,510	633,676	-
Other investments, principally annuity and fixed income	71,412	-	71,412	-
	$1,584,209	**$411,515**	**$1,172,694**	**$-**
Other investments measured at net asset value	925,888			
Total	**$2,510,097**			
2017				
Cash and cash equivalents	$17,531	$-	$17,531	$-
U.S. government securities	13,338	13,338	-	-
Common stocks	129,312	129,312	-	-
Registered investment companies	105,037	105,037	-	-
Corporate bonds	447,124	-	447,124	-
Preferred stocks	4,381	299	4,082	-
Equity commingled funds	435,635	185,989	249,646	-
Other investments, principally annuity and fixed income	548,957	-	548,957	-
	$1,701,315	**$433,975**	**$1,267,340**	**$-**
Other investments measured at net asset value	1,126,017			
Total	**$2,827,332**			

Notes to Consolidated Financial Statements

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.

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 twenty-five-percent 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 46%-66% for equity securities, 30%-31% for fixed income, and 3%-23% for all other investment types. The target allocations within allowable ranges are further diversified into 27%-66% large cap domestic equities, 5% small cap domestic equities, 8% international developed market, and 6% emerging market equity securities. Fixed income investment targets and ranges are segregated into core fixed income at 24%-31%, global high yield fixed income at 4%, and international developed market debt at 3%. Other alternative investment targets are 6% for real estate, 6% for tangible assets, and 3%-11% for other funds. 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 Networks' pension and postretirement plan assets, by asset category, as of December 31, 2018 and 2017, by asset category are shown in the following table. CMP's share of the total consolidated assets was approximately 21% for 2018 and 2017.

Asset Category	Total	Fair Value Measurements at December 31, Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(Thousands)				
2018				
Money market funds	$9,197	$4,804	$4,393	$-
Registered investment companies	109,128	107,513	1,615	-
Common collective trusts	21,742	21,742	-	-
Mutual funds, other	7,379	-	7,379	-
Total assets measured at fair value	**$147,446**	**$134,059**	**$13,387**	**$-**
2017				
Money market funds	$3,978	$3,978	$-	$-
Mutual funds, fixed	35,419	35,419	-	-
Government & corporate bonds	1,658	-	1,658	-
Mutual funds, equity	76,444	49,089	27,355	-
Common stocks	19,800	19,800	-	-
Mutual funds, other	27,172	19,573	7,599	-
Total assets measured at fair value	**$164,471**	**$127,859**	**$36,612**	**$-**

Valuation techniques: We value our postretirement benefits plan assets as follows:

- Money market funds and Mutual funds – based upon quoted market prices in active markets, which represent the NAV of the shares held.
- Government bonds, and Common stocks - 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.

Pension and postretirement plan equity securities did not include any AGR and Iberdrola common stock as of both December 31, 2018 and 2017.

Note 16. Other Income and Other Deductions

Years Ended December 31,	2018	2017
(Thousands)		
Gain on sale of property	$1,423	$138
Interest and dividends income	31	777
Allowance for funds used during construction	6,885	7,829
Carrying costs on regulatory assets	1,527	2,457
Equity earnings	43	46
Miscellaneous	409	368
Total other income	**$10,318**	**$11,615**
Pension non-service components	$(16,344)	$(14,086)
Miscellaneous	(806)	(821)
Total other deductions	**$(17,150)**	**$(14,907)**

Note 17. 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 $ 37.2 million and $42.1 million for 2018 and 2017, respectively. Charge for services provided by CMP to AGR and its subsidiaries were approximately $4.0 million for 2018 and $7.2 million for 2017. All charges for services are at cost. The balance in accounts payable to affiliates of $38.4 million at December 31, 2018 and $41.1 million at December 31, 2017 is mostly payable to Avangrid Service Company.

The balance in accounts receivable from affiliates of $1.8 million at December 31, 2018 is mostly from Avangrid Service Company.

The balance in notes receivable from affiliates of $12.7 million at December 31, 2018 and the balance of $28.3 million at December 31, 2017 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 18. Subsequent Events

The company has performed a review of subsequent events through March 29, 2019, which is the date these financial statements were available to be issued, and no subsequent events have occurred from January 1, 2019 through such date.

New York State Electric & Gas Corporation
Financial Statements
For the Years Ended December 31, 2018 and 2017

New York State Electric & Gas Corporation

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Financial Statements As of and for the Years Ended December 31, 2018 and 2017

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

Independent Auditors' Report

Shareholders and The Board of Directors
New York State Electric and Gas Corporation:

We have audited the accompanying financial statements of New York State Electric and Gas Corporation, which comprise the balance sheets as of December 31, 2018 and 2017, 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 and Gas Corporation as of December 31, 2018 and 2017, 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 29, 2019

New York State Electric & Gas Corporation
Statements of Income

Years Ended December 31,	**2018**	**2017**
(Thousands)		
Operating Revenues	**$1,694,292**	**$1,534,821**
Operating Expenses		
Electricity purchased	434,752	313,978
Natural gas purchased	116,227	92,999
Operations and maintenance	614,744	576,293
Depreciation and amortization	133,531	129,023
Taxes other than income taxes, net	147,595	144,281
Total Operating Expenses	**1,446,849**	**1,256,574**
Operating Income	**247,443**	**278,247**
Other income	13,401	15,372
Other deductions	(53,215)	(46,834)
Interest expense, net of capitalization	(62,840)	(62,999)
Income Before Income Tax	**144,789**	**183,786**
Income tax expense	37,883	78,819
Net Income	**$106,906**	**$104,967**

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,	**2018**	**2017**
(Thousands)		
Net Income	**$106,906**	**$104,967**
Other Comprehensive (Loss) Income, Net of Tax		
Amortization of pension cost for nonqualified plans, net of income taxes	131	(74)
Unrealized (loss) during the year on derivatives qualifying as cash flow hedges, net of income taxes:		
Unrealized (loss) during period on derivatives qualifying as hedges	(535)	(164)
Reclassification adjustment for loss included in net income	(34)	228
Reclassification adjustment for loss on settled cash flow treasury hedges	76	63
Total Other Comprehensive (Loss) Income, Net of Tax	**(362)**	**53**
Comprehensive Income	**$106,544**	**$105,020**

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

New York State Electric & Gas Corporation
Balance Sheets

As of December 31,	2018	2017
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$4,943	$3,396
Accounts receivable and unbilled revenues, net	289,751	268,977
Accounts receivable from affiliates	2,505	10,704
Fuel and gas in storage	16,820	15,231
Materials and supplies	16,759	15,813
Derivative assets	3,248	-
Broker margin accounts	5,301	13,334
Income tax receivable	20,896	41,844
Prepaid property taxes	36,400	35,779
Other current assets	5,872	6,060
Regulatory assets	113,210	113,403
Total Current Assets	**515,705**	**524,541**
Utility plant, at original cost	5,950,914	5,588,372
Less accumulated depreciation	(2,173,629)	(2,100,274)
Net Utility Plant in Service	**3,777,285**	**3,488,098**
Construction work in progress	353,440	240,657
Total Utility Plant	**4,130,725**	**3,728,755**
Other Property and Investments	8,081	10,411
Regulatory and Other Assets		
Regulatory assets	897,938	888,255
Other	6,469	1,634
Total Regulatory and Other Assets	**904,407**	**889,889**
Total Assets	**$5,558,918**	**$5,153,596**

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

New York State Electric & Gas Corporation
Balance Sheets

As of December 31,	2018	2017
(Thousands, except share information)		
Liabilities		
Current Liabilities		
Current portion of debt	$20,305	$322
Notes payable	-	150,000
Notes payable to affiliates	40,375	124,643
Accounts payable and accrued liabilities	374,591	287,925
Accounts payable to affiliates	82,366	78,532
Interest accrued	7,382	5,963
Taxes accrued	1,563	1,553
Derivative liabilities	824	39
Environmental remediation costs	38,910	51,758
Customer deposits	12,744	12,532
Regulatory liabilities	91,674	78,298
Other	70,322	77,684
Total Current Liabilities	**741,056**	**869,249**
Regulatory and Other Liabilities		
Regulatory liabilities	1,197,227	1,190,333
Other non-current liabilities		
Deferred income taxes	479,633	466,706
Pension and other postretirement	270,984	224,736
Asset retirement obligation	13,506	14,021
Environmental remediation costs	102,168	105,707
Other	82,484	44,009
Total Regulatory and Other Liabilities	**2,146,002**	**2,045,512**
Non-current debt	1,217,990	1,041,536
Total Liabilities	**4,105,048**	**3,956,297**
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, 2018 and 2017)	430,057	430,057
Additional paid-in capital	418,430	268,403
Retained earnings	606,650	499,744
Accumulated other comprehensive loss	(1,267)	(905)
Total Common Stock Equity	**1,453,870**	**1,197,299**
Total Liabilities and Equity	**$5,558,918**	**$5,153,596**

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,	2018	2017
(Thousands)		
Cash Flow from Operating Activities:		
Net income	**$106,906**	**$104,967**
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	133,531	129,023
Regulatory assets/liabilities amortization	45,790	46,864
Regulatory assets/liabilities carrying cost	1,831	3,269
Amortization of debt issuance costs	1,352	1,745
Deferred taxes	39,125	59,189
Pension cost	70,190	60,825
Stock-based compensation	144	(11)
Accretion expenses	748	774
Gain on disposal of assets	(717)	(1,080)
Other non-cash items	(17,844)	(21,899)
Changes in assets and liabilities		
Accounts receivable, from affiliates, and unbilled revenues	(12,575)	(19,533)
Inventories	(2,535)	(2,803)
Accounts payable, to affiliates, and accrued liabilities	93,727	81,541
Taxes accrued	20,958	345
Taxes receivable	-	(21,326)
Other assets/liabilities	3,078	(75,777)
Regulatory assets/liabilities	(67,932)	57,102
Net Cash Provided by Operating Activities	**415,777**	**403,215**
Cash Flow from Investing Activities:		
Capital expenditures	(529,875)	(377,859)
Contributions in aid of construction	26,505	24,352
Proceeds from sale of utility plant	3,004	2,352
Investments, net	-	(26)
Net Cash Used in Investing activities	**(500,366)**	**(351,181)**
Cash Flow from Financing Activities:		
Non-current debt issuance	172,566	-
Repayments of non-current debt	-	(200,000)
Repayments of capital leases	(1,708)	(21,027)
Notes payable	(150,454)	150,000
Notes payable to affiliates	(84,268)	118,743
Capital contribution	150,000	-
Dividends paid	-	(100,000)
Net Cash Provided by (Used in) Financing Activities	**86,136**	**(52,284)**
Net Increase (Decrease) in Cash and Cash Equivalents	**1,547**	**(250)**
Cash and Cash Equivalents, Beginning of Year	**3,396**	**3,646**
Cash and Cash Equivalents, End of Year	**$4,943**	**$3,396**

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	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stock Equity
Balance, January 1, 2017	**64,508,477**	**$430,057**	**$268,405**	**$494,777**	**$(958)**	**$1,192,281**
Net income	-	-	-	104,967	-	104,967
Other comprehensive income, net of tax	-	-	-	-	53	53
Comprehensive income						105,020
Stock-based compensation	-	-	(2)	-	-	(2)
Common stock dividends	-	-	-	(100,000)	-	(100,000)
Balance, December 31, 2017	**64,508,477**	**430,057**	**268,403**	**499,744**	**(905)**	**1,197,299**
Net income	-	-	-	106,906	-	106,906
Other comprehensive income, net of tax	-	-	-	-	(362)	(362)
Comprehensive income			-	-	-	106,544
Stock-based compensation	-	-	27	-	-	27
Capital contribution	-	-	150,000	-	-	150,000
Balance, December 31, 2018	**64,508,477**	**$430,057**	**$418,430**	**$606,650**	**$(1,267)**	**$1,453,870**

(*) Par value of share amounts is $6.66 2/3

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

Notes to Financial Statements

Note 1. Significant Accounting Policies

Background and nature of operations: New York State Electric & Gas Corporation (NYSEG, the company, we, our, us) conducts regulated electricity transmission and distribution operations and regulated natural gas transportation, storage and distribution operations in upstate New York. It also generates electricity, primarily from its several hydroelectric stations. NYSEG serves approximately 899,000 electricity and 268,000 natural gas customers as of December 31, 2018 in its service territory of approximately 20,000 square miles, which is located in the central, eastern and western parts of the state of New York and has a population of approximately 2.5 million. The larger cities in which NYSEG serves electricity and natural gas customers are Binghamton, Elmira, Auburn, Geneva, Ithaca and Lockport. We operate under the authority of the New York State Public Service Commission (NYPSC) and are also subject to regulation by the Federal Energy Regulatory Commission (FERC).

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

***Basis of presentation*:** The accompanying financial statements have been prepared in accordance with generally accepted accounting principles in the United States (U.S. GAAP).

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

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

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

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

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

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

We determine depreciation expense for utility plant in service using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Our depreciation accruals were equivalent to 2.2% of average depreciable property for 2018 and 2.3% for 2017. 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 $201.1 million as of December 31, 2018 and $184.0 million as of December 31, 2017. Depreciation expense was $126.5 million in 2018 and $123.0 million in 2017. Amortization of capitalized software was $7.1 million in 2018 and $6.0 million in 2017.

Consistent with FERC accounting requirements, we charge the original cost of utility plant retired or otherwise disposed to accumulated depreciation.

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

Allowance for funds used during construction (AFUDC) represents the allowed cost of capital, including a noncash 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)**	**2018**	**2017**
(Thousands)			
Electric	29-75	$4,250,399	$4,022,679
Natural Gas	25-75	1,041,984	1,002,251
Common	7-75	658,531	563,442
Total Utility Plant in Service		**5,950,914**	**5,588,372**
Total accumulated depreciation		(2,173,629)	(2,100,274)
Total Net Utility Plant in Service		**3,777,285**	**3,488,098**
Construction work in progress		353,440	240,657
Total Utility Plant		**$4,130,725**	**$3,728,755**

Electric plant includes capital leases of $45.0 million for 2018 and $31.9 million for 2017. Related accumulated depreciation at December 31 was $7.8 million for 2018 and $5.4 million for 2017.

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 loss is required to be recognized if the carrying amount of the asset exceeds the undiscounted future net cash flows associated with that asset.

The impairment loss to be recognized is the amount by which the carrying 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.

***Fair value measurement*:** Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants as of the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place in either the principal market for the asset or liability, or, in the absence of a principal market, in the most advantageous market for the asset or liability.

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

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

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

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

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

***Derivatives and hedge accounting*:** Derivatives are recognized on the balance sheets at their fair value, except for certain electricity commodity purchases and sales contracts for both capacity and energy (physical contracts) that qualify for, and are elected under, the normal purchases and normal sales exception. To be a derivative under the accounting standards for derivatives and hedging, an agreement would need to have a notional and an underlying, require little or no initial net investment and could be net settled. Changes in the fair value of a derivative contract are recognized in earnings unless specific hedge accounting criteria are met.

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

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 AOCI 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.

Notes to Financial Statements

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 are comprised of 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 those investments are included 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 the balance sheets. Changes in book overdrafts are reported in the operating activities section of the statements of cash flows.

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

(Thousands)	2018	2017
Cash paid during the year ended December 31:		
Interest, net of amounts capitalized	$32,986	$40,861
Income taxes paid, net	$21,662	$28,261

Of the income taxes paid, substantially all was paid to AGR under the tax sharing agreement. Interest capitalized was $7.6 million in 2018 and in $11.4 million in 2017. Accrued liabilities for utility plant additions were $35.4 million in 2018 and $18.8 million in 2017.

Broker margin accounts: We maintain accounts with clearing firms that require initial margin deposits upon the establishment of new positions, primarily related to natural gas and electricity derivatives, as well as maintenance margin deposits in the event of unfavorable movements in market valuation for those positions. We show the amount reflecting those activities as broker margin accounts on our balance sheets.

***Accounts receivable and unbilled revenues, net*:** We record accounts receivable at amounts billed to customers. Accounts receivable at December 31 include unbilled revenues of $90.3 million for 2018 and $99.6 million for 2017, and are shown net of an allowance for doubtful accounts at December 31 of $24.0 million for 2018 and $23.2 million for 2017. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was $17.3 million in 2018 and $12.1 million in 2017.

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

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

Our accounts receivable include amounts due under deferred payment arrangements (DPAs). When a residential customer becomes delinquent in making payments, the NYPSC requires us to allow the customer to enter into a DPA to settle the account balance. A DPA allows the account balance to be paid in installments over an extended period of time by negotiating mutually acceptable payment terms. Generally, we must continue to serve a customer who cannot pay an account balance in full if the customer: (i) pays a reasonable portion of the balance; (ii) agrees to pay the balance in installments; and (iii) agrees to pay future bills within 30 days until the DPA is paid in full or is otherwise considered to be delinquent. We establish provisions for uncollectible accounts by using both historical average loss percentages to project future losses and by establishing specific provisions for known credit issues. Amounts are written off when reasonable collection efforts have been exhausted. The allowance for doubtful accounts for DPAs at December 31 was $13.6 million for 2018 and $14.5 million for 2017. DPA receivable balances at December 31 were $24.3 million for 2018 and $24.0 million for 2017.

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

Inventory*:* Inventory comprises fuel and natural gas in storage and materials and supplies. We own natural gas that is stored in third-party owned underground storage facilities. This gas is recorded as inventory. Injections of inventory into storage are priced at the market purchase cost at the time of injection, and withdrawals of working gas from storage are priced at the weighted-average cost in storage. We continuously monitor the weighted-average cost of gas value to ensure it remains at, or below net realizable value. Inventories to support gas operations are reported on the balance sheet within “Fuel and natural gas in storage.”

We also have materials and supplies inventories that are used for construction of new facilities and repairs of existing facilities. These inventories are carried and withdrawn at the lower of cost and net realizable value and reported on the balance sheets within “Materials and supplies.” Inventory items are combined for the statement of cash flows presentation purposes.

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

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

Deferred income: Apart from government grants, we occasionally receive revenues from transactions in advance of the resulting performance obligations arising from the transaction. It is our policy to defer such revenues on the 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, and capitalize the cost by increasing the carrying amount of the related long-lived asset. We adjust the liability periodically to reflect revisions to either the timing or the 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.

Notes to Financial Statements

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 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.

Our ARO at December 31, including our conditional ARO, was $13.5 million for 2018 and $14.0 million for 2017. The ARO is associated with our long-lived assets and primarily consists of obligations related to removal or retirement of: asbestos, polychlorinated biphenyl contaminated equipment, gas pipeline and cast iron gas mains.

The following table reconciles the beginning and ending aggregate carrying amount of the ARO for the years ended December 31, 2018 and 2017.

Year ended December 31,	**2018**	**2017**
(Thousands)		
ARO, beginning of year	$14,021	$14,478
Liabilities settled during the year	(1,263)	(1,231)
Accretion expense	748	774
ARO, end of year	**$13,506**	**$14,021**

We have AROs for which we have not recognized a liability because the fair value cannot be reasonably estimated due to indeterminate settlement dates, including: the removal of hydroelectric dams due to structural inadequacy or for decommissioning; the removal of property upon termination of an easement, right-of-way or franchise; and costs for abandonment of certain types of gas mains.

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

Environmental remediation liability**:** In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. We record our environmental liabilities on an undiscounted basis. Our environmental liability accruals are expected to be paid through the year 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 reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in other comprehensive income, 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 over 10 years from the time they are incurred as required by the NYPSC. Our policy for the pension plans is to calculate the expected return on plan assets using the market-related value of assets. Our policy for the postretirement health care benefit plans is to calculate the expected return on plan assets using the market value of assets. We determine that value by recognizing the difference between actual returns and expected returns over a five year period.

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

The aggregate amount of the related party income tax receivable balance due from AGR at December 31 is $20.9 million for 2018 and $41.8 million for 2017.

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

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

State franchise tax, computed as the higher of a tax based on income or a tax based on capital, is recorded in “Taxes other than income taxes” and “Taxes accrued” in the accompanying 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” of 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 income tax components of the financial statements.

Upon enactment of the "Tax Cuts and Jobs Act" (the Tax Act) on December 22, 2017, we remeasured our existing deferred income tax balances as of December 31, 2017, to reflect the decrease in the corporate income tax rate from 35% to 21%, which resulted in a material decrease to our net deferred income tax liability balances. In connection with the Tax Act, the U.S. Securities and Exchange Commission (SEC) issued guidance in Staff Accounting Bulletin 118, or SAB 118, which clarified accounting for income taxes under Topic 740, Income Taxes, if information was not yet available or complete and provided up to a one year measurement period in which to complete the required analyses and accounting. Following SAB 118 guidance, we recorded provisional income tax amounts as of December 31, 2017, related to the Tax Act based on reasonable estimates that could be determined at that time. As of December 31, 2018, we have completed the measurement and accounting of certain effects of the Tax Act which we have reflected in the December 31, 2018 financial statements.

Limited voting junior preferred stock: We have a class of preferred stock having one share and a par value of $1, which is issued and outstanding and has voting authority only with respect to whether NYSEG may file a voluntary bankruptcy petition.

Stock-based compensation: Stock-based compensation represents costs related to AGR stock-based awards granted to NYSEG employees. We account for stock-based payment transactions based on the estimated fair value of awards reflecting forfeitures when they occur. The recognition period for these costs begin 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.

Reclassifications: Certain amounts reported in the financial statements in previous periods have been reclassified to conform to the current year presentation.

New Accounting Standards and Interpretations: New accounting standards issued by the Financial Accounting Standards Board (FASB) that we either adopted or have not yet adopted are explained below. 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.

(a) Revenue from contracts with customers

In May 2014 the FASB issued Accounting Standards Codification (ASC), Topic 606, Revenue from Contracts with Customers (Topic 606) replacing the existing accounting standard and industry-specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The FASB further amended Topic 606 through various updates issued thereafter. The core principle is for an entity to recognize revenue to represent the transfer of promised goods or services to customers in amounts that reflect the consideration to which the entity expects to be entitled in exchange for those goods or services. We adopted Topic 606 effective January 1, 2018, and applied the modified retrospective method, for which we did not have a cumulative effect adjustment to retained earnings for initial application of the guidance. Refer to Note 4 for further details.

Notes to Financial Statements

We also adopted the following standards as of their effective date of January 1, 2018, none of which had a material effect on our results of operations, financial position, cash flows, and disclosures.

(b) Certain classifications in the statement of cash flows

In August 2016 the FASB issued amendments to address existing diversity in practice concerning the classification of certain cash receipts and payments in the statement of cash flows, which must be applied on a full retrospective basis. Upon adoption, we had no changes to our cash flow classifications and disclosures in our financial statements.

(c) Improving the presentation of net periodic benefit costs

In March 2017 the FASB issued amendments to improve the presentation of net periodic pension cost and net periodic postretirement benefit cost in the financial statements. We retrospectively adopted the amendments that require us to present the service cost component separately from the other (non-service) components of net benefit cost, to report the service cost component in the income statement line item where we report the corresponding compensation cost, and to present all non-service components outside of operating cost. As a result, we have reclassified the non-service components – interest cost, expected return on plan assets, amortization of prior service cost (benefit), amortization of net loss, and settlement charge – from Operations and maintenance to Other income/(expense) within the statement of income. Prospectively, upon adoption, we will capitalize only the service cost component when applicable (for example, as a cost of a self-constructed asset). We elected to apply the practical expedient that allows us to retrospectively apply the amendments on adoption to net benefit costs for comparative periods by using the amounts disclosed in our notes to financial statements for Post-retirement and Similar Obligations as the basis for those periods. In connection with applying the practical expedient, in periods after adoption we will continue to include in operating income all legacy net benefit costs previously capitalized as a cost of self-constructed assets and other deferred regulatory costs. Our adoption of the amendments did not affect prior period net income. Beginning in 2018, non-service cost components we incur are no longer eligible for construction capitalization, but such costs can be deferred and included as a component of customer rates if permitted by our regulator. For the year ended December 31, 2018, we incurred additional immaterial expense as a result of the adoption of this standard.

The effect of the change in retrospective presentation related to the net periodic cost of our defined benefit pension and other postretirement employee benefits plans on our statement of income was as follows:

	Year Ended December 31, 2017		
Statement of Income	**As Revised**	**As Previously Reported**	**Effect of Change Higher/(Lower)**
(Thousands)			
Operations and maintenance	$ 576,293	$ 621,973	$ (45,680)
Other Deductions	$ (46,834)	$ (1,154)	$ (45,680)

(d) Customer accounting for implementation costs incurred in a cloud computing arrangement

The FASB issued amendments in August 2018 to clarify the accounting for implementation costs of a cloud computing arrangement (also referred to as a hosting arrangement) that is a service contract. Implementation costs, which include implementation, setup and other upfront costs, are either to be deferred or expensed as incurred, in accordance with existing internal-use software guidance for similar costs. The amendments require a customer to expense capitalized implementation costs over the contractual term of the arrangement, including any optional renewal periods the customer is reasonably certain it will exercise. An entity is to present deferred implementation costs on the balance sheet, income statement and cash flows consistent with the subscription fees associated with the arrangement. The amendments enhance disclosures to include certain qualitative and quantitative information about implementation costs for internal-use software and all hosting arrangements, not just hosting arrangements that are service contracts. The amendments are effective for public business entities for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted, including adoption in any interim period for which financial statements have not been issued. An entity may apply the amendments either retrospectively or prospectively to all implementation costs incurred after the date of adoption. We early adopted the amendments as of October 1, 2018, and are applying the amendments prospectively to all implementation costs after the date of adoption. Upon adoption, there were no material effects to our results of operations, financial position, cash flows and disclosures.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements issued as indicated, that we have evaluated or are evaluating to determine their effect on our financial statements.

(a) Leases

In February 2016 the FASB issued new guidance, and issued subsequent amendments during 2018, that affects all companies and organizations that lease assets, and requires them to record on their balance sheet right-of-use assets and lease liabilities for the rights and obligations created by those leases. Under the new guidance, a lease is an arrangement that conveys the right to control the use of an identified asset for a period of time in exchange for consideration. The amendments retain a distinction between finance leases and operating leases, while requiring both types of leases to be recognized on the balance sheet. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the criteria for distinguishing between capital leases and operating leases in legacy U.S. GAAP. Lessor accounting will remain substantially the same as legacy U.S. GAAP, but with some targeted improvements to align lessor accounting with the lessee accounting model and with the revised revenue recognition guidance under Topic 606. The standard and amendments require new qualitative and quantitative disclosures for both lessees and lessors. The new leases guidance, including the subsequent amendments issued during 2018, is effective for public entities for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, and early application is permitted.

We adopted the new leases guidance effective January 1, 2019, and have elected the optional transition method under which we will initially apply the standard on that date without adjusting amounts presented for prior periods, and record the cumulative effect of applying the new guidance as an adjustment to beginning retained earnings. We expect the adjustment to retained earnings will be immaterial. Concerning certain transition and other practical expedients:

- we did not elect the package of three practical expedients available under the transition provisions, including (i) not reassessing whether expired or existing contracts contain leases, (ii) lease classification, and (iii) not revaluing initial direct costs for existing leases;
- we elected a land easement expedient and did not reassess land easements that we did not account for as leases prior to our adoption of the new leases guidance;
- we used hindsight for specified determinations and assessments in applying the new leases guidance;
- we will not recognize lease assets and liabilities for short-term leases (less than one year),

for all classes of underlying assets; and
- we did not separate lease and associated nonlease components for transitioned leases, but will instead account for them together as a single lease component.

(b) Measurement of credit losses on financial instruments

The FASB issued an accounting standards update in June 2016 that requires more timely recording of credit losses on loans and other financial instruments. The amendments affect entities that hold financial assets and net investments in leases that are not accounted for at fair value through net income (loans, debt securities, trade receivables, 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. In November 2018 the FASB issued an update to this new guidance to clarify that receivables arising from operating leases are not within the scope of the credit losses standard. Instead, impairment of receivables arising from operating leases should be accounted for in accordance with the leases standard. The amendments are effective for public entities that are SEC filers for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, with early adoption permitted. Entities are to apply the amendments on a modified retrospective basis for most instruments. We expect our adoption will not materially affect our results of operations, financial position, and cash flows.

(c) Targeted improvements to accounting for hedging activities

In August 2017 the FASB issued targeted amendments with the objective to better align hedge accounting with an entity’s risk management activities in the financial statements, and to simplify the application of hedge accounting. The amendments address concerns of financial statement preparers over difficulties with applying hedge accounting and limitations for hedging both nonfinancial and financial risks, and concerns of financial statement users over how hedging activities are reported in financial statements. Changes to the hedge accounting guidance to address those concerns will: 1) expand hedge accounting for nonfinancial and financial risk components and amend measurement methodologies to more closely align hedge accounting with an entity’s risk management activities; 2) eliminate the separate measurement and reporting of hedge ineffectiveness, to reduce the complexity of preparing and understanding hedge results; 3) enhance disclosures and change the presentation of hedge results to align the effects of the hedging instrument and the hedged item in order to enhance transparency, comparability, and understandability of hedge results; and 4) simplify the way assessments of hedge effectiveness may be performed to reduce the cost and complexity of applying hedge accounting. The amendments are effective for public entities for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. For cash flow and net investment hedges existing at the date of adoption, a company must apply a cumulative-effect adjustment related to the separate measurement of ineffectiveness to AOCI with a corresponding adjustment to the opening balance of retained earnings as of the beginning of the fiscal year of adoption. The amended presentation and disclosure guidance is required only prospectively. In October 2018 the FASB issued amendments that are effective concurrently with the above targeted improvements. These additional amendments permit use of the Overnight Index Swap rate based on the Secured Overnight Financing Rate as a U.S. benchmark interest rate for hedge accounting purposes. Use of that rate is in addition to the already eligible benchmark interest rates, which are: interest rates on direct Treasury obligations of the U.S. government, the London Interbank Offered Rate swap rate, the OIS Rate based on the Fed Funds Effective Rate, and the Securities Industry and Financial Markets Association Municipal Swap Rate. Our adoption of the amendments on January 1, 2019, will not materially affect our results of operations, financial position, or cash flows, but the amendments will ease the administrative burden of hedge documentation requirements and assessing hedge effectiveness going forward.

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

In February 2018 the FASB issued amendments to address a narrow-scope financial reporting issue that arose as a consequence of the Tax Cuts and Jobs Act of 2017 (the Tax Act) enacted on December 22, 2017, by the U.S. federal government. Under current guidance, the adjustment of deferred taxes for the effect of a change in tax laws or rates is required to be included in income from continuing operations, thus the associated tax effects of items within AOCI (referred to as stranded tax effects) do not reflect the appropriate tax rate. The amendments allow a reclassification from AOCI to retained earnings for stranded tax effects resulting from the Tax Act. As a result, the amendments eliminate the stranded tax effects resulting from the Tax Act and will improve the usefulness of information reported to financial statement users. The amendments only relate to the reclassification of the income tax effects of the Tax Act, and do not affect the underlying guidance that requires the effect of a change in tax laws or rates to be included in income from continuing operations. The amendments are effective for all entities for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted including, for public entities, adoption in any interim period for which financial statements have not been issued. An entity has the option to apply the amendments either in the period of adoption or retrospectively to each period (or periods) in which it recognizes the effect of the change in the U.S. federal corporate income tax rate in the Tax Act. An entity is required to disclose its accounting policy election, including its policy for reclassifying material stranded tax effects in AOCI to earnings (specific identification or portfolio method). Our adoption of the amendments on January 1, 2019, will not materially affect our results of operations, financial position, cash flows, and disclosures.

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

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

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

Notes to Financial Statements

Use of estimates and assumptions: The preparation of our financial statements in conformity with U.S. GAAP requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Significant estimates and assumptions are used for, but not limited to: (1) allowance for doubtful accounts and unbilled revenues; (2) asset impairments; (3) depreciable lives of assets; (4) income tax valuation allowances; (5) uncertain tax positions; (6) reserves for professional, workers' compensation, and comprehensive general insurance liability risks; (7) contingency and litigation reserves; (8) earnings sharing mechanism (ESM); (9) environmental remediation liabilities; (10) pension and other postretirement employee benefits (OPEB); (11) fair value measurements and (12) AROs. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our financial statements will change as new events occur, as more experience is acquired, as additional information is obtained, and as our operating environment changes. We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside specialists to assist in our evaluations, as considered necessary. Actual results could differ from those estimates.

Union collective bargaining agreements: Approximately 76% of our employees are covered by a collective bargaining agreement. We have no agreements that will expire within the coming year.

Note 2. Industry Regulation

Electricity and Natural Gas Distribution

Our revenues are regulated, being based on tariffs established in accordance with administrative procedures set by the NYPSC. The tariffs applied to regulated activities are approved by the NYPSC and are based on the cost of providing service. Our revenues are set to be sufficient to cover all of our operating costs, including energy costs, finance costs, and the costs of equity, the last of which reflect our capital ratio and a reasonable return on equity (ROE).

Energy costs that are set on the New York wholesale markets are passed on to consumers. The difference between energy costs that are budgeted and those that are actually incurred is offset by applying reconciliation procedures that result in either immediate or deferred tariff adjustments. Reconciliation procedures apply to other costs, which are in many cases exceptional, such as the effects of extreme weather conditions, environmental factors, regulatory and accounting changes, and treatment of vulnerable customers. Any revenues that allow us to exceed target returns, usually the result of better than expected cost efficiency, are generally shared with customers, resulting in future tariff reductions.

NYSEG Rate Plans

On May 20, 2015, NYSEG and Rochester Gas and Electric Corporation ("RG&E") (together, "the companies") filed electric and gas rate cases with the NYPSC. We requested rate increases for NYSEG electric and NYSEG gas.

On February 19, 2016, NYSEG and the other signatory parties filed a Joint Proposal (Proposal) with the NYPSC for a three-year rate plan for electric and gas service at NYSEG commencing May 1, 2016. The Proposal, which was approved on June 15, 2016, balanced the varied interests of the signatory parties including but not limited to maintaining the company's credit quality and mitigating the rate impacts to customers. The Proposal reflects many customer benefits including: acceleration of the company's natural gas leak prone main replacement programs and enhanced electric vegetation management to provide continued safe and reliable service. The delivery rate increase in the Proposal can be summarized as follows:

	May 1, 2016		May 1, 2017		May 1, 2018	
	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %
Electric	$29.6	4.10%	$29.9	4.10%	$30.3	4.10%
Gas	$13.1	7.30%	$13.9	7.30%	$14.8	7.30%

The allowed rate of return on common equity for NYSEG Electric and NYSEG Gas is 9.00%. The equity ratio for each company is 48%; however, the equity ratio is set at the actual up to 50% for earnings sharing calculation purposes. The customer share of any earnings above allowed levels increases as the ROE increases, with customers receiving 50%, 75% and 90% of earnings over 9.5%, 10.0% and 10.5% ROE, respectively, in the first rate year covering the period May 1, 2016 - April 30, 2017. The earnings sharing levels increased in rate year two (May 1, 2017 - April 30, 2018) to 9.65%, 10.15% and 10.65% ROE, respectively. The earnings sharing levels have further increased in rate year three (May 1, 2018 - April 30, 2019) to 9.75%, 10.25% and 10.75% ROE, respectively. The rate plans also include the implementation of a rate adjustment mechanism ("RAM") designed to return or collect certain defined reconciled revenues and costs, implementation of new depreciation rates, and continuation of the existing Revenue Decoupling Mechanism ("RDM") for each business.

The Proposal reflects the recovery of deferred NYSEG Electric storm costs of approximately $262 million, of which $123 million will be amortized over ten years and the remaining $139 million will be amortized over five years. The Proposal also continues reserve accounting for qualifying Major Storms ($21.4 million annually). Incremental maintenance costs incurred to restore service in qualifying divisions will be chargeable to the Major Storm Reserve provided they meet certain thresholds for each storm event.

The Proposal maintains current electric reliability performance measures (and associated potential negative revenue adjustments for failing to meet established performance levels) which include the system average interruption frequency index (SAIFI) and the customer average interruption duration index (CAIDI). The Proposal also modifies certain gas safety performance measures at the company, including those relating to the replacement of leak prone main, leak backlog management, emergency response, and damage prevention. The Proposal establishes threshold performance levels for designated aspects of customer service quality and continues and expands bill reduction and arrears forgiveness Low Income Programs with increased funding levels. The Proposal provides for the implementation of NYSEG's Energy Smart Community ("ESC") Project in the Ithaca region which will serve as a test-bed for implementation and deployment of Reforming the Energy Vision (REV) initiatives. The ESC Project will be supported by NYSEG's planned Distribution Automation upgrades and Advanced Metering Infrastructure (AMI) implementation for customers on circuits in the Ithaca region. Other REV-related incremental costs and fees will be included in the RAM to the extent cost recovery is not provided for elsewhere. Under the Proposal, we will implement the RAM, which will be applicable to all customers, to return or collect RAM Eligible Deferrals and Costs, including: (1) property taxes; (2) Major Storm deferral balances; (3) gas leak prone pipe replacement; (4) REV costs and fees which are not covered by other recovery mechanisms; and (5) Electric Pole Attachment revenues.

The Proposal provides for partial or full reconciliation of certain expenses including, but not limited to: pension and other postretirement benefits; property taxes; variable rate debt and new fixed rate debt; gas research and development; environmental remediation costs; Major Storms; nuclear electric insurance limited credits; economic development; and Low Income Programs. The Proposal also includes a downward-only Net Plant reconciliation. In addition, the Proposal includes downward-only reconciliations for the costs of: electric distribution and gas vegetation management; pipeline integrity; and other incremental maintenance programs. The Proposal provides that we continue the electric RDMs on a total revenue per class basis and the gas RDMs on a revenue per customer basis.

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 in the first quarter of 2017, was suspended in the second quarter of 2017, and was resumed in the first quarter of 2018. The companies also filed their first bi-annual update of the DSIP on July 31, 2018.

Other various proceedings have also been initiated by the NYPSC which are REV related, and each proceeding has its own schedule. These proceedings include the Clean Energy Standard, Value of Distributed Energy Resources (VDER) and Net Energy Metering, Demand Response Tariffs, and Community Choice Aggregation. As part of the Clean Energy Standard proceeding, all electric utilities were ordered to begin payments to New York State Energy Research and Development Authority (NYSERDA) for Renewable Energy Credits ("RECs") and Zero Emissions Credits beginning in 2017. A separate Offshore Wind was ordered by the NYPSC in July 2018.

Track 2 of the REV initiative is also underway, and through a NYPSC 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.

In March, 2017, the NYPSC issued three separate REV-related orders. These orders created a series of filing requirements for NYSEG beginning in March 2017 and extending through the end of 2018. The three orders involve: 1) modifications to the electric utilities' proposed interconnection earnings adjustment mechanism framework; 2) further DSIP requirements, including confirmation of the filing of an updated DSIP plan by mid-2018 and implementing two energy storage projects at NYSEG by the end of 2018; and 3) Net Energy Metering Transition including implementation of Phase One of VDER. In September 2017, the NYPSC issued another order related to VDER, requiring tariff filings, changes to Standard Interconnection Requirements, and planning for the implementation of automated consolidated billing. NYSEG has participated with the other NY state electric utilities in jointly filing updates to the interconnection earnings adjustment mechanism, has implemented two energy storage projects, and has participated with the other NY state electric utilities in the VDER transition effort, including tariff updates and application of VDER principles.

The March 2017 Order in the VDER proceeding approved a transition from traditional Net Energy Metering (NEM) towards a more values-based approach (Value Stack) for compensating Distributed Energy Resources (DER). The March 2017 Order approved an interim methodology for more precise DER valuation and compensation for NEM-eligible technologies. The interim methodology approved by the NYPSC provides for a market transition consistent with the principles of gradualism and predictability, and established a tranche system to manage impacts on non-participants.

The March 2017 Order also directed a Phase Two of the VDER proceding. 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 disucss, review and analyze several issues regarding each subject. The working groups culminated with a series of whitepapers developed by NYPSC 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. A Staff whitepaper on rate design for mass market on-site DER projects interconnected after January 1, 2020 is scheduled to be submitted in 2019.

New York State Department of Public Service Investigation of the Preparation for and Response to the March 2017 Windstorm

On March 11, 2017, the New York State Department of Public Service (the Department) commenced an investigation of NYSEG’s preparation for and response to the March 2017 windstorm, which affected more than 219,000 customers at NYSEG and RG&E. The Department investigation included a comprehensive review of NYSEG’s preparation for and response to the windstorm, including all aspects of the company’s filed and approved emergency plan. The Department held public hearings on April 12 and 13, 2017.

On November 16, 2017, the NYPSC announced that the Department Staff had completed their investigation into the March 2017 Windstorm and the NYPSC issued an Order Instituting Proceeding and to Show Cause. The Staff’s investigation found that NYSEG had allegedly violated certain parts of its emergency response plan, which makes the Company subject to possible financial penalties. NYSEG responded to the order in a timely manner and has conducted settlement discussions with the Department of Public Service Staff and other parties. These settlement discussions culminated with the filing of two Joint Proposals for settling the issues raised by the Department in June 2018, with several parties signing on to the Joint Proposals. These Joint Proposals have NYSEG and RG&E implementing a combined $3.9 million of storm resiliency and restoration projects which will not be paid for by ratepayers. The Joint Proposals are currently before the Commission, and a ruling is expected in 2019.

New York State Department of Public Service Investigation of the Preparation for and Response to the March 2018 Winter Storms

On March 13, 2018, the New York State Department of Public Service (the Department) commenced an investigation of NYSEG's preparation for and response to the March 1 and March 8, 2018 winter storms, which affected more than 300,000 customers at NYSEG and RG&E. The Department investigation will include a comprehensive review of NYSEG's preparation for and response to the winter storms, including all aspects of the company's filed and approved emergency plan. The Department held 21 public hearings between April 16 and April 26, 2018. The companies received and responded to numerous data requests and have participated in dozens of interviews related to the investigation over the last several months. We cannot predict the outcome of this regulatory action.

Tax Cuts and Jobs Act

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Tax Act) was signed into law. The Tax Act contains significant changes to the federal tax structure, including among other things, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017. The NYPSC has instituted proceedings in New York to review and address the implications associated with the Tax Act on the utilities providing service in state of New York. The Department of Public Service (DPS) Staff, on March 29, 2018, submitted a proposal to the NYPSC indicating that any companies which have not included the impacts from the Tax Act in a recent rate proceeding should submit a filing to initiate a surcredit beginning October 1, 2018 to pass back benefits to customers. The proposal invited all companies to comment on the proposal prior to June 29, 2018, and to include comments about alternative mechanisms to return the benefits to customers. NYSEG has submitted comments in response to the DPS Staff proposal, identifying that it would be premature to begin a surcredit which could cause rate volatility when major expenditures may be forthcoming. On August 9, 2018, the NYPSC issued an order in case 17-M-0815 and as part of that order instituted surcredits for NYSEG customers beginning October 1, 2018. The surcredits include the annual 2018 tax expense savings for both electric and gas businesses and include an amortization of previously deferred tax savings through September 30, 2018 for NYSEG Gas business. The annual amounts of the surcredits beginning October 1, 2018 for NYSEG are approximately $31 million.

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 $535.4 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

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

On June 15, 2016, the NYPSC approved the Proposal in connection with a three-year rate plan for electric and gas service at NYSEG effective May 1, 2016. Following the approval of the proposal most of these items related to NYSEG are amortized over a five-year period, except the portion of storm costs to be recovered over ten years, and plant related tax items which are amortized over the life of associated plant. Annual amortization expense for NYSEG is approximately $16.5 million per rate year.

Current and non-current regulatory assets at December 31, 2018 and 2017 consisted of:

December 31,	**2018**	**2017**
(Thousands)		
Current		
Environmental remediation costs	$5,705	$5,705
Electric supply reconciliation	1,744	144
Property tax	-	9,766
Revenue decoupling mechanism	5,919	12,447
Pension and other postretirement benefits cost deferrals	23,886	23,887
Unamortized loss on re-acquired debt	1,968	2,037
Storm cost	58,226	40,129
Low income programs	1,826	1,826
Hedge gains/losses	-	1,155
Rate change levelization	4,657	8,252
Other	9,279	8,055
Total current regulatory assets	**$113,210**	**$113,403**
Non-current		
Federal tax depreciation normalization adjustment	$90,405	$92,988
Asset retirement obligation	13,577	14,055
Property tax deferrals	2,135	14,370
Pension and other retirement benefits cost deferrals	71,108	71,949
Merger capital expenditure	983	1,720
Low income programs	5,547	7,487
Unamortized loss on re-acquired debt	14,499	12,047
Pension and other postretirement benefits	393,787	398,341
Environmental remediation costs	85,014	93,155
Storm costs	209,085	165,623
Other	11,798	16,520
Total non-current regulatory assets	**$897,938**	**$888,255**

Notes to Financial Statements

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.

Merger capital expense target customer credit account was created as a result of NYSEG not meeting certain capital expenditure requirements established in the order approving the purchase of Energy East by Iberdrola. The amortization period is five years following the approval of the proposal by the NYPSC.

Low income programs represent deferrals related to over/under spending on Low-Income customer assistance programs.

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.

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 deferral, including carrying costs was $267.3 million at December 31, 2018 and $205.8 million at December 31, 2017. Pursuant to the most recent Joint Proposal approved by the Commission, which began May 1, 2016, NYSEG will recover $139.0 million of the balance over five years for non-super-storms and the super-storm balance of $123.0 million over 10 years.

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

Asset retirement obligations represents 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.

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.

Other includes items such as post-term amortization.

Deferred income taxes regulatory: see Note 1.

Current and non-current regulatory liabilities at December 31, 2018 and 2017 consisted of:

December 31, (Thousands)	2018	2017
Current		
Energy efficiency programs	$25,315	$15,368
Non by-passable charges	3,456	4,515
Gas supply charge and deferred natural gas cost	2,751	3,654
Carrying costs on deferred income tax depreciation	18,107	18,107
Pension and other postretirement benefits cost deferral	13,601	13,601
Economic development	3,487	3,487
Theoretical reserve flow through impact	5,367	5,367
Reliability support services	-	26
Debt rate reconciliation	2,825	2,825
Positive benefit adjustment	2,685	2,685
NYS excess DIT – in rates	2,676	2,676
Hedge gains/losses	3,248	-
Other	8,156	5,987
Total current regulatory liabilities	**$91,674**	**$78,298**
Non-current		
Carrying costs on deferred income tax bonus depreciation	$13,248	$26,183
Economic development	5,596	12,919
Positive benefit adjustment	3,579	6,264
Debt rate reconciliation	25,987	17,295
Unfunded future income taxes	23,424	21,484
New York State tax rate change	-	1,738
Tax Act-remeasurement	496,381	476,855
Pension and other postretirement benefits	29,841	12,180
Pension and other postretirement benefits cost deferral	21,520	33,646
Accrued removal obligation	521,175	516,905
Other	56,476	64,864
Total non-current regulatory liabilities	**$1,197,227**	**1,190,333**

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.

Energy efficiency portfolio standard represents the difference between revenue billed to customers through an energy efficiency charge and the costs of our energy efficiency programs as approved by the state authorities. This may be refunded to customers within the next year.

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

Carrying costs on deferred income tax bonus depreciation represent the carrying costs benefit of increased accumulated deferred income taxes created by the change in tax law allowing bonus depreciation. The amortization period is five years following the approval of the proposal by the NYPSC.

Notes to Financial Statements

Pension and other postretirement benefits represent the actuarial gains on pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future expenses. Because no funds have yet been received for this a regulatory liability is not reflected within rate base. They also represent the difference between actual expense for pension and other postretirement benefits and the amount provided for in rates. Recovery of these amounts will be determined in future proceedings.

Positive benefit adjustment resulted from Iberdrola's 2008 acquisition of Energy East. This is being used to moderate increases in rates. The amortization period is five years following the approval of the proposal by the NYPSC and included in the Ginna RSSA settlement.
Variable Rate Debt represents the over/under collection of costs related to variable rate debt instruments identified in the rate case. Costs include interest, commissions and fees versus amounts included in rates.

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 percent to 6.5 percent. Amounts previously collected from utility customers for these deferred taxes are refundable to such customers, generally through reductions in rates.

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.

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.

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.

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.

New York State tax rate change represents excess funded accumulated deferred income tax balance caused by the 2014 New York state tax rate change from 7.1% to 6.5%. The amortization period is five years following the approval of the proposal by the NYPSC.

Tax Act - remeasurement represents the impact from remeasurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates from 35% to 21% under the provisions of the Tax Act will result in amounts previously collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates. The NYPSC has instituted separate proceedings to review and address the implications associated with the Tax Act on the utilities providing service in state of New York.

Other includes various items subject to reconciliation including low income, earnings sharing provision and asset retirement obligations.

Note 4. Revenue

On January 1, 2018, we adopted ASC 606 and all related amendments using the modified retrospective method, which we applied only to contracts that were not completed as of January 1, 2018. For reporting periods beginning on January 1, 2018, we present revenue in accordance with ASC 606, and have not adjusted comparative prior period information, which we continue to report under the legacy accounting standards in effect for those prior periods. For the year ended December 31, 2018, the effect of applying ASC 606 to recognize revenue as compared to applying the legacy accounting standards was not material.

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. NYSEG 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 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 NYSEG delivers or sells the electricity or natural gas or provides the transmission service. We record revenue for all of those sales based upon the regulatory-approved tariff and the volume delivered or transmitted, which corresponds to the amount that we have a right to invoice. There are no material initial incremental costs of obtaining a contract in any of the arrangements. NYSEG 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. NYSEG does not have any material significant payment terms because it receives payment at or shortly after the point of sale. NYSEG assesses its deferred payment arrangements at each balance sheet date for the existence of significant financing components, but has had no material adjustments as a result.

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 recognizes and records only the initial recognition of “originating” ARP revenues (when the regulatory-specified conditions for recognition have been met). When we subsequently include those amounts in the price of utility service billed to customers, we record such amounts as a recovery of the associated regulatory asset or liability. When we owe amounts to customers in connection with ARPs, we 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.

NYSEG also has various other sources of revenue including billing, collection, other administrative charges, sundry billings, rent of utility property, and miscellaneous revenue. We classify 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, which we receive payment for 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 $8.8 million at December 31, 2018, and $8.0 million at January 1, 2018, and are presented in "Other current liabilities." We recognized $16.5 million as revenue during 2018, of which $7.8 million was included in contract liabilities at January 1, 2018.

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 year ended December 31, 2018 are as follows:

Year Ended December 31, 2018: **(Thousands)**	
Regulated operations – electricity	$ 1,323,626
Regulated operations – natural gas	318,344
Other[(a)]	29,589
Revenue from contracts with customers	**1,671,559**
Leasing revenue	12,335
Alternative revenue programs	10,647
Other revenue	(249)
Total operating revenues	**$ 1,694,292**

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

As of December 31, 2018, nearly all of the accounts receivable balances included in "Accounts receivable and unbilled revenues, net" on our condensed balance sheet are related to contracts with customers.

Note 5. Income Taxes

The Tax Act changes significantly the federal taxation of business entities, including among other things, a federal corporate tax rate decrease from 35% to 21% for tax years beginning after December 31, 2017. In connection with the Tax Act, the U.S. Securities and Exchange Commission issued guidance in Staff Accounting Bulletin 118, or SAB 118, which clarified accounting for income taxes under ASC 740, Income Taxes, if information was not yet available or complete and provided up to a one year measurement period in which to complete the required analyses and accounting. Following SAB 118 guidance, the Company recorded provisional income tax amounts as of December 31, 2017 related to the Tax Act based on reasonable estimates that could be determined at that time. As of December 31, 2018, the Company has completed the measurement and accounting of certain effects of the Tax Act which have been reflected in the December 31, 2018 financial statements.

Current and deferred taxes charged to expense for the years ended December 31, 2018 and 2017 consisted of:

Years Ended December 31,	**2018**	**2017**
(Thousands)		
Current		
Federal	$5,707	$15,456
State	(6,440)	4,684
Current taxes charged to (benefit)/expense	**(733)**	**20,140**
Deferred		
Federal	23,762	51,821
State	15,364	7,368
Deferred taxes charged to expense	**39,126**	**59,189**
Investment tax credit adjustments	(510)	(510)
Total Income Tax Expense	**$37,883**	**$78,819**

The differences between tax expense per the statements of income and tax expense at the 21% and 35% statutory federal tax rate for the years ended December 31, 2018 and 2017, respectively, consisted of:

Years Ended December 31,	**2018**	**2017**
(Thousands)		
Tax expense at statutory rate	$31,492	$64,325
Investment tax credit amortization	(510)	(510)
Statutory state taxes net of federal benefit	7,701	7,834
Other, net	(800)	7,170
Total Income Tax Expense	**$37,883**	**$78,819**

Income tax expense for the year ended December 31, 2018 was $6.4 million higher than it would have been at the statutory federal income tax rate of 21% due predominately to state taxes, (net of federal benefit). This resulted in an effective tax rate of 26.2%. Income tax expense for the year ended December 31, 2017 was $14.4 million higher than it would have been at the statutory federal income tax rate of 35% due predominately to tax return and related adjustments, and state taxes, (net of federal benefit). This resulted in an effective tax rate of 42.9%.

Notes to Financial Statements

Deferred tax assets and liabilities as of December 31, 2018 and 2017 consisted of:

December 31, (Thousands)	2018	2017
Non-current Deferred Income Tax Liabilities (Assets)		
Property related	$573,148	$530,396
Storm costs	69,938	53,773
Federal and state tax credits	(49,148)	(2,665)
Accumulated deferred investment tax credits	(1,020)	(510)
Pension and other postretirement benefits	55,570	28,933
Regulatory liability due to "Tax Cuts and Jobs Act"	(130,399)	(124,626)
Federal and state NOL's	(738)	(738)
Environmental	(36,911)	(15,317)
Power tax DIT	24,329	-
Other	(25,136)	(2,540)
Total Non-current Deferred Income Tax Liabilities	**$479,633**	**$466,706**
Deferred tax assets	$243,352	$146,396
Deferred tax liabilities	722,985	613,102
Net Accumulated Deferred Income Tax Liabilities	**$479,633**	**$466,706**

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2018 and 2017 consisted of:

Years Ended December 31, (Thousands)	2018	2017
Balance as of January 1	$17,861	$16,994
Increases for tax positions related to prior years	46,484	867
Reduction for tax positions related to prior years	(19,076)	-
Balance as of December 31	**$45,269**	**$17,861**

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, 2018. Accruals for interest and penalties on tax reserves were $0.4 million as of December 31, 2017. Gross unrecognized tax benefits increased by $27.5 million in 2018 primarily due to NY State tax credits claimed for open tax years.

Note 6. Long-term Debt

At December 31, 2018 and 2017, our long-term debt was:

As of December 31,		2018		2017	
(Thousands)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
Senior unsecured debt	2022-2042	$ 850,000	3.24%-5.75%	$ 850,000	3.24%-5.75%
Unsecured pollution control notes – fixed	2020-2029	374,000	2.00%-3.50%	200,000	2.00%-2.375%
Obligations under capital leases	2019-2036	25,659		7,348	
Unamortized debt issuance costs and discount		(11,364)		(15,490)	
Total Debt		**$1,238,295**		**$1,041,858**	
Less: debt due within one year, included in current liabilities		20,305		322	
Total Non-current Debt		**$1,217,990**		**$1,041,536**	

On June 29, 2018, NYSEG remarketed $174 million in aggregate principal amount of Pollution Control Revenue Bonds, issued through the New York State Energy Research and Development Authority, with mandatory tender dates ranging from 2023 to 2029 and interest rates ranging 2.625% - 3.50%.

At December 31, 2018, long-term debt, including sinking fund obligations and capital lease payments (in thousands) that will become due during the next five years are:

2019	2020	2021	2022	2023
$20,305	$201,437	$397	$75,332	$300,332

Note 7. Bank Loans and Other Borrowings

NYSEG had a total of $40.4 million and $274.6 million of notes payable at December 31, 2018 and 2017, 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 $14.6 million outstanding under this agreement at December 31, 2018 and $5.9 million outstanding at December 31, 2017.

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 was $25.8 million and $118.7 million outstanding under this agreement as of December 31, 2018 and December 31, 2017, 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")) increased the maximum borrowing terms of the facility from $1.5 billion to $2.5 billion (in aggregate) and extended the maturity date from April 5, 2021 to June 29, 2023. The revolving credit facility is comprised of a syndicate of banks. Under the terms of the AGR Credit Facility, each joint borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit established by the banks. AGR's maximum sublimit is $2 billion, NYSEG, RG&E, CMP and UI have maximum sublimits of $400 million, CNG and SCG have maximum sublimits of $150 million and BGC has a maximum sublimit of $40 million. Under the AGR Credit Facility, each of the borrowers will pay an annual facility fee that is dependent on their credit rating. The facility fees will range from 10.0 to 17.5 basis points. The maturity date for the AGR Credit Facility is June 29, 2023. NYSEG had no outstanding balance as of December 31, 2018 and borrowed $150.0 million under this agreement as of December 31, 2017.

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 0.47 to 1.00 at December 31, 2018. We are not in default as of December 31, 2018.

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

At December 31, 2018, 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. Commitments and Contingencies

New York State Department of Public Service Investigation of the Preparation for and Response to the March 2017 Windstorm

On March 11, 2017, the New York State Department of Public Service (the Department) commenced an investigation of NYSEG's preparation for and response to the March 2017 windstorm, which affected more than 219,000 customers at NYSEG and RG&E. The Department investigation included a comprehensive review of NYSEG's preparation for and response to the windstorm, including all aspects of the company's filed and approved emergency plan. The Department held public hearings on April 12 and 13, 2017.

On November 16, 2017, the NYPSC announced that the Department Staff had completed their investigation into the March 2017 Windstorm and the NYPSC issued an Order Instituting Proceeding and to Show Cause. The Staff's investigation found that NYSEG had allegedly violated certain parts of its emergency response plan, which makes the Company subject to possible financial penalties. NYSEG responded to the order in a timely manner and has conducted settlement discussions with the Department of Public Service Staff and other parties. These settlement discussions culminated with the filing of two Joint Proposals for settling the issues raised by the Department in June 2018, with several parties signing on to the Joint Proposals. These Joint Proposals have NYSEG and RG&E implementing a combined $3.9 million of storm resiliency and restoration projects which will not be paid for by ratepayers. The Joint Proposals are currently before the Commission, and a ruling is expected in 2019.

Leases

On January 16, 2014, as required by its regulator, NYSEG renewed a Reliability Support Services Agreement (RSS Agreement) with Cayuga Operating Company, LLC (Cayuga) for Cayuga to provide reliability support services to maintain necessary system reliability through June 2017. Cayuga owns and operates the Cayuga Generating Facility (Facility), a coal-fired generating station that includes two generating units. Cayuga operated and maintained the RSS units and managed and complied with scheduling deadlines and requirements for maintaining the Facility and the RSS units as eligible energy and capacity providers and complied with dispatch instructions. NYSEG paid Cayuga a monthly fixed price and also paid for capital expenditures for specified capital projects. NYSEG was entitled to a share of any capacity and energy revenues earned by Cayuga. We accounted for this arrangement as an operating lease. The net expense incurred under this operating lease was $17.6 million for the year ended December 31, 2017.

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

Year	Operating Leases	Capital Leases	Total
(Thousands)			
2019	$1,696	$21,951	$23,647
2020	1,520	1,437	2,957
2021	998	397	1,395
2022	894	332	1,226
2023	930	332	1,262
Thereafter	6,688	2,614	9,302
Total	**$12,726**	**$27,063**	**$39,789**

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 $80.6 million for Normal Purchase Normal Sale (NPNS) purchase power and natural gas contracts including non-utility generators in 2018 and $87.9 million in 2017.

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 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, eleven sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites and four 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 $5.4 million as of December 31, 2018, related to the twelve sites. We have paid remediation costs related to the twelve sites. 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 $5.3 million to $5.9 million as of December 31, 2018. 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 $114.6 million to $232.9 million at December 31, 2018. 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 $135.7 million at December 31, 2018 and $152.1 million at December 31, 2017. 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 2050.

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 $20 million. This amount is being treated as a contingent asset and has not been recorded as either a receivable or a decrease to the environmental provision. Any recovery will be flowed through to NYSEG ratepayers.

Century Indemnity and OneBeacon

On August 14, 2013, NYSEG filed suit in federal court against two excess insurers, Century Indemnity and OneBeacon, who provided excess liability coverage to NYSEG. NYSEG seeks payment for clean-up costs associated with contamination at twenty-two former manufactured gas plants. Based on estimated clean-up costs of $282 million, the carriers' allocable share is approximately $89 million, excluding pre-judgment interest, although this amount may change substantially depending upon the determination of various factual matters and legal issues during the case.

Century Indemnity and OneBeacon have answered admitting issuance of the excess policies, but contesting coverage and providing documentation proving they received notice of the claims in the 1990s. On March 31, 2017, the District Court granted motions filed by Century Indemnity and One Beacon dismissing all of NYSEG's claims against both defendants on the grounds of late notice. NYSEG filed a motion with the District Court on April 14, 2017 seeking reconsideration of the Court's decision. On March 27, 2018, the District Court denied NYSEG's request for reconsideration; NYSEG filed a notice of appeal on April 9, 2018. We cannot predict the outcome of this matter.

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. At December 31, 2018 and 2017, the amount recognized in regulatory assets/liabilities for electricity derivatives was a gain of $3.4 million and a loss of $0.4 million, respectively. For the years ended December 31, 2018 and 2017, the amount reclassified from regulatory assets/liabilities into income, which is included in electricity purchased, was a gain of $5.1 million and a loss of $24.3 million, respectively.

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. At December 31, 2018 and 2017, the amount recognized in regulatory assets/liabilities for natural gas hedges was a gain of $0.1 million and a loss of $0.7 million, respectively. For the years ended December 31, 2018 and 2017, the amount reclassified from regulatory assets/liabilities into income, which is included in natural gas purchased, was a gain of $0.3 million and a loss of $0.1 million, respectively.

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

Year to settle	Electricity Contracts Mwhs	Natural Gas Contracts Dths	Other Fuel Contracts Gallons
As of December 31, 2018			
2019	2,597,550	2,120,000	1,061,900
2020	761,600	350,000	-
As of December 31, 2017			
2018	2,381,125	1,580,000	1,043,400
2019	219,000	330,000	-

The offsetting of derivatives, location in the balance sheet and amounts of derivatives as of December 31, 2018 and 2017, respectively, consisted of:

December 31, 2018	Derivative Assets - Current	Derivative Assets - Noncurrent	Derivative Liabilities - Current	Derivative Liabilities - Noncurrent
(In thousands)				`
Not designated as hedging instruments				
Derivative assets	$9,991	$2,467	$6,743	$2,267
Derivative liabilities	(6,743)	(2,267)	(6,743)	(2,267)
	3,248	200	-	-

Designated as hedging instruments				
Derivative assets	-	-	-	-
Derivative liabilities	-	-	(824)	-
	-	-	(824)	-
Total derivatives before offset of cash collateral	3,248	200	(824)	-
Cash collateral receivable	-	-	-	-
Total derivatives as presented in the balance sheet	**$3,248**	**$200**	**$(824)**	**$-**

December 31, 2017	**Derivative Assets – Current**	**Derivative Assets - Noncurrent**	**Derivative Liabilities - Current**	**Derivative Liabilities – Noncurrent**
(In thousands)				`
Not designated as hedging instruments				
Derivative assets	$8,859	$515	$8,859	$405
Derivative liabilities	(8,859)	(405)	(10,015)	(456)
	-	110	(1,156)	(51)
Designated as hedging instruments				
Derivative assets	36	-	36	-
Derivative liabilities	(36)	-	(75)	-
	-	-	(39)	-
Total derivatives before offset of cash collateral	-	110	(1,195)	51
Cash collateral receivable	-	-	1,156	(51)
Total derivatives as presented in the balance sheet	**$-**	**$110**	**$(39)**	**$-**

As of both December 31, 2018 and 2017, the derivative assets – noncurrent are presented within other non-current assets of the balance sheet.

The effect of hedging instruments on OCI and income was:

Year Ended December 31,	**(Loss) Gain Recognized in OCI on Derivatives**	**Location of (Loss) Gain Reclassified From Accumulated OCI into Income**	**Loss Reclassified From Accumulated OCI into Income**
Derivatives in Cash Flow Hedging Relationships	**Effective Portion**	**Effective Portion**	
(Thousands)			
2018			
Interest rate contracts	$-	Interest expense	$(105)
Commodity contracts:			
Other	(738)	Other operating expenses	47
Total	**($738)**		**$(58)**

2017			
Interest rate contracts	$-	Interest expense	$(105)
Commodity contracts:			
Other	(271)	Other operating expenses	(377)
Total	**$(271)**		**$(482)**

The amounts in AOCI related to previously settled forward starting swaps, and accumulated amortization, as of December 31, 2018, is a net loss of $0.5 million as compared to a net loss of $0.6 million for 2017. For the year ended December 31, 2018, we recorded $0.1 million in net derivative losses related to discontinue cash flow hedges. We will amortize approximately $0.1 million of discontinued cash flow hedges in 2019.

As of December 31, 2018, $0.8 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, 2018.

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, 2018 is $5.3 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 $1,249 million and $1,095 million as of December 31, 2018 and 2017, 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, consist of:

Notes to Financial Statements

Description (Thousands)	(Level 1)	(Level 2)	(Level 3)	Netting	Total
2018					
Assets					
Noncurrent investments available for sale, primarily money market funds	$8,081	$-	$-	$-	$8,081
Derivatives					
Commodity contracts:					
Electricity	12,045	-	-	(8,676)	3,369
Natural Gas	413	-	-	(334)	79
Other	-	-	-	-	-
Total	**$20,539**	**$-**	**$-**	**$(9,010)**	**$11,529**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	($8,676)	$-	$-	$8,676	$-
Natural gas	(334)	-	-	334	-
Other	-	-	(824)	-	(824)
Total	**$(9,010)**	**$-**	**$(824)**	**$9,010**	**$(824)**
2017					
Assets					
Noncurrent investments available for sale, primarily money market funds	$10,411	$-	$-	$-	$10,411
Derivatives					
Commodity contracts:					
Electricity	9,356	-	-	(9,246)	110
Natural Gas	19	-	-	(19)	-
Other	-	-	36	(36)	-
Total	**$19,786**	**$-**	**$36**	**$(9,301)**	**$10,521**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	$(9,726)	$-	-	$9,726	-
Natural gas	(744)	-	-	744	-
Other	-	-	(75)	36	(39)
Total	**$(10,470)**	**$-**	**$(75)**	**$10,506**	**$(39)**

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2018 and 2017. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

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

We determine the fair value of our derivative assets and liabilities utilizing market approach valuation techniques:

- We enter into electric energy derivative contracts to hedge the forecasted purchases required to serve their electric load obligations. We hedge our electric load obligations using derivative contracts that are settled based upon Locational Based Marginal Pricing published by the NYISO. We hedge approximately 70% of their electric load obligations using contracts for a NYISO location where an active market exists. The forward market prices used to value the companies' open electric energy derivative contracts are based on quoted prices in active markets for identical assets or liabilities with no adjustment required and therefore we include the fair value in Level 1.
- We enter into natural gas derivative contracts to hedge the forecasted purchases required to serve our natural gas load obligations. The forward market prices used to value our open natural gas derivative contracts are exchange-based prices for the identical derivative contracts traded actively on the New York Mercantile Exchange. Because we use prices quoted in an active market, we include those fair value measurements in Level 1.
- We enter into fuel derivative contracts to hedge our unleaded and diesel fuel requirements for our fleet vehicles. Exchange based forward market prices are used but because a basis adjustment is added to the forward prices, we include the fair value measurement for these contracts in Level 3.

Instruments measured at fair value on a recurring basis using significant unobservable inputs

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3) Derivatives, Net	
Year Ended December 31,	**2018**	**2017**
(Thousands)		
Beginning balance	$39	$145
Total gains (losses) (realized/unrealized)		
Included in earnings	47	(377)
Included in other comprehensive income	738	271
Ending balance	**$824**	**$39**

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

	Balance January 1, 2017	2017 Change	Balance December 31, 2017	2018 Change	Balance December 31, 2018
(Thousands)					
Amortization of pension cost for nonqualified plans, net of income tax (benefit)/expense of $(48) for 2017 and $50 for 2018	$(471)	$(74)	$(545)	$131	$(414)
Unrealized (loss) on derivatives qualified as hedges:					
Unrealized (loss) during period on derivatives qualified as hedges, net of income tax expense (benefit) of $(107) for 2017 and $(203) for 2018		(164)		(535)	
Reclassification adjustment for loss included in net income, net of income tax expense (benefit) of $150 for 2017 and $(13) for 2018		228		(34)	

Reclassification adjustment for loss on settled cash flow treasury hedges, net of income tax expense of $42 for 2017 and $29 for 2018		63		76	
Net unrealized gain (loss) on derivatives qualified as hedges	(487)	127	(360)	(493)	(853)
Accumulated Other Comprehensive Loss	**$(958)**	**$53**	**$(905)**	**$(362)**	**$(1,267)**

Note 14. Post-retirement and Similar Obligations

We have funded noncontributory defined benefit pension plans that cover all of 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 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.

The company maintains a 401(k) Savings and Retirement Plan (the Plan) for all eligible employees as defined in the Plan agreement. Participants in the Plan may contribute a percentage of their compensation and the company may match a predetermined percentage of the participant contributions. Expenses under the Plan for the Company totaled approximately $6.3 million for 2018 and $6.0 million for 2017.

We also have pension and other postretirement health care benefit plans covering substantially all of our employees. The health care plans are contributory with participants' contributions adjusted annually.

Obligations and funded status:

	Pension Benefits		**Postretirement Benefits**	
	2018	**2017**	**2018**	**2017**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	$1,601,569	$1,531,453	$181,111	$186,093
Service cost	16,516	16,718	1,836	2,180
Interest cost	56,498	61,280	6,354	7,402
Plan participants' contributions	-	-	3,993	3,399
Actuarial loss/(gain)	(69,054)	85,229	(26,404)	(185)
Benefits paid	(97,447)	(93,111)	(15,732)	(17,793)
Federal subsidy on benefits paid	-	-	-	15
Benefit obligation at December 31	**$1,508,082**	**$1,601,569**	**$151,158**	**$181,111**
Change in plan assets				
Fair value of plan assets at January 1	$1,474,106	$1,370,779	$83,838	$83,595
Actual return on plan assets	(61,675)	196,438	(3,287)	7,243
Employer & plan participants' contributions	-	-	8,453	10,778
Federal subsidy on benefits paid	-	-	-	15
Benefits paid	(97,447)	(93,111)	(15,732)	(17,793)
Fair value of plan assets at December 31	**$1,314,984**	**$1,474,106**	**$73,272**	**$83,838**
Funded status	**$(193,098)**	**$(127,463)**	**$(77,886)**	**$(97,273)**

Amounts recognized in the balance sheet December 31,	Pension Benefits 2018	 2017	Postretirement Benefits 2018	 2017
(Thousands)				
Noncurrent liabilities	$(193,098)	$(127,463)	$(77,886)	$(97,273)

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:

December 31,	Pension Benefits 2018	 2017	Postretirement Benefits 2018	 2017
(Thousands)				
Net loss	$389,296	$392,773	$(16,071)	$7,186
Prior service cost (credit)	$4,491	$5,568	$(13,770)	$(19,367)

Our accumulated benefit obligation for all defined benefit pension plans was $1.4 billion as of both December 31, 2018 and 2017. NYSEG's postretirement benefits were partially funded as of December 31, 2018 and 2017.

The projected benefit obligation and the accumulated benefit obligation exceeded the fair value of pension plan assets for our plans as of both December 31, 2018 and 2017. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets as of December 31, 2018 and 2017.

December 31,	2018	2017
(Thousands)		
Projected benefit obligation	$1,508,082	$1,601,569
Accumulated benefit obligation	$1,445,266	$1,531,218
Fair value of plan assets	$1,314,984	$1,474,106

Components of net periodic benefit cost and other amounts recognized in regulatory assets and regulatory liabilities:

Years Ended December 31,	Pension Benefits 2018	 2017	Postretirement Benefits 2018	 2017
(Thousands)				
Net periodic benefit cost				
Service cost	$16,516	$16,718	$1,836	$2,180
Interest cost	56,498	61,280	6,354	7,402
Expected return on plan assets	(103,271)	(103,106)	(3,521)	(3,553)
Amortization of prior service cost (credit)	1,077	1,201	(5,597)	(5,596)
Amortization of net loss	99,370	84,732	3,661	3,320
Net periodic benefit cost	**$70,190**	**$60,825**	**$2,733**	**$3,753**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net loss (gain)	$95,892	$(8,103)	$(19,596)	$(3,875)
Amortization of net (loss)	(99,370)	(84,732)	(3,661)	(3,320)
Amortization of prior service (cost) credit	(1,077)	(1,201)	5,597	5,596
Total recognized in regulatory assets and regulatory liabilities	**$(4,555)**	**$(94,036)**	**$(17,660)**	**$(1,599)**
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$65,635**	**$(33,211)**	**$(14,927)**	**$2,154**

We include the net periodic benefit cost in other operating expenses. The net periodic benefit cost for postretirement benefits represents the amount expensed for providing health care benefits to retirees and their eligible dependents.

Amounts expected to be amortized from regulatory assets or regulatory liabilities into net periodic benefit cost for the fiscal year ending December 31, 2019	Pension Benefits	Postretirement Benefits
(Thousands)		
Estimated net loss	$78,769	$(796)
Estimated prior service cost (credit)	$919	$(5,597)

We expect that no pension benefit or postretirement benefit plan assets will be returned to us during the fiscal year ending December 31, 2019.

Weighted-average assumptions used to determine benefit obligations at December 31,	Pension Benefits 2018	Pension Benefits 2017	Postretirement Benefits 2018	Postretirement Benefits 2017
Discount rate	3.93%	3.63%	3.93%	3.63%
Rate of compensation increase	3.80%	3.90%	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 above median yields that closely matches the duration of the expected cash flows of our benefit obligations.

Weighted-average assumptions used to determine net periodic benefit cost for Years ended December 31,	Pension Benefits 2018	Pension Benefits 2017	Postretirement Benefits 2018	Postretirement Benefits 2017
Discount rate	3.63%	4.12%	3.63%	4.12%
Expected long-term return on plan assets	7.30%	7.30%	-	-
Expected long-term return on plan assets - nontaxable trust	-	-	6.40%	6.50%
Expected long-term return on plan assets - taxable trust	-	-	4.20%	4.25%
Rate of compensation increase	3.90%	3.90%	N/A	N/A

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations and the effect of rebalancing of plan assets discussed below. That analysis considered current capital market conditions and projected conditions. Our policy is to calculate the expected return on plan assets using the market related value of assets. We amortize unrecognized actuarial gains and losses over 10 years from the time they are incurred.

Assumed health care cost trend rates to determine benefit obligations at December 31,	2018	2017
Health care cost trend rate (pre 65/post 65)	7.00%/7.75%	6.75%/8.50%
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	2026/2028

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
(Thousands)		
Effect on total of service and interest cost	$1	$-
Effect on postretirement benefit obligation	$60	$(41)

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 plans in 2019.

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)			
2019	$89,590	$12,056	-
2020	$91,849	$11,484	-
2021	$93,844	$11,289	-
2022	$95,751	$11,087	-
2023	$97,294	$10,877	-
2024-2028	$495,991	$50,928	-

***Plan assets*:** Our pension benefits plan assets are held in a master trust providing for a single trustee/custodian, a uniform investment manager lineup, and an efficient, cost-effective means of allocating expenses and investment performance to each plan under the master trust. Our primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our tolerance for risk. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. Our primary means for achieving capital preservation is through diversification of the trust's investments while avoiding significant concentrations of risk in any one area of the securities markets. Within each asset group, further diversification is achieved through utilizing multiple asset managers and systematic allocation to various asset classes; providing broad exposure to different segments of the equity, fixed-income and alternative investment markets.

Networks' asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets within broad categories of asset classes made up of Return-Seeking and Liability-Hedging investments. Within the Return-Seeking category, we have targets of 35%-53% in equity securities, 40%-45% for Liability-Hedging assets and 7%-20% for alternative investments. Return-Seeking investments generally consist of domestic, international, global, and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking assets also include investments in real estate, absolute return, and strategic markets. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS, and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of Networks' pension benefits plan assets at December 31, 2018 and 2017, by asset category are shown in the following table. NYSEG's share of the total consolidated assets is approximately 52% for 2018 and 2017:

Asset Category	Total	Fair Value Measurements at December 31, Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(Thousands)				
2018				
Cash and cash equivalents	$51,661	$ -	$51,661	$-
U.S. government securities	15,137	15,137	-	-
Common stocks	90	90	-	-
Registered investment companies	216,508	216,508	-	-
Corporate bonds	412,703	-	412,703	-
Preferred stocks	3,512	270	3,242	-
Common collective trusts	813,186	179,510	633,676	-
Other investments, principally annuity and fixed income	71,412	-	71,412	-
	$1,584,209	**$411,515**	**$1,172,694**	**$-**
Other investments measured at net asset value	925,888			
Total	**$2,510,097**			
2017				
Cash and cash equivalents	$17,531	$-	$17,531	$-
U.S. government securities	13,338	13,338	-	-
Common stocks	129,312	129,312	-	-
Registered investment companies	105,037	105,037	-	-
Corporate bonds	447,124	-	447,124	-
Preferred stocks	4,381	299	4,082	-
Equity commingled funds	435,635	185,989	249,646	-
Other investments, principally annuity and fixed income	548,957	-	548,957	-
	$1,701,315	**$433,975**	**$1,267,340**	**$-**
Other investments measured at net asset value	1,126,017			
Total	**$2,827,332**			

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.

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 twenty-five-percent 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 46%-66% for equity securities, 30%-31% for fixed income, and 3%-23% for all other investment types. The target allocations within allowable ranges are further diversified into 27%-66% large cap domestic equities, 5% small cap domestic equities, 8% international developed market, and 6% emerging market equity securities. Fixed income investment targets and ranges are segregated into core fixed income at 24%-31%, global high yield fixed income at 4%, and international developed market debt at 3%. Other alternative investment targets are 6% for real estate, 6% for tangible assets, and 3%-11% for other funds. 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, 2018 consisted and 2017 are shown in the following table. NYSEG's share of the total assets is approximately 50% for 2018 and 51% for 2017:

		Fair Value Measurements at December 31, Using		
Asset Category	**Total**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
(Thousands)				
2018				
Money market funds	$9,197	$4,804	$4,393	$-
Registered investment companies	109,128	107,513	1,615	-
Common collective trusts	21,742	21,742	-	-
Mutual funds, other	7,379	-	7,379	-
Total assets measured at fair value	**$147,446**	**$134,059**	**$13,387**	**$-**

2017				
Money market funds	$3,978	$3,978	$-	$-
Mutual funds, fixed	35,419	35,419	-	-
Government & corporate bonds	1,658	-	1,658	-
Mutual funds, equity	76,444	49,089	27,355	-
Common stocks	19,800	19,800	-	-
Mutual funds, other	27,172	19,573	7,599	-
Total assets measured at fair value	**$164,471**	**$127,859**	**$36,612**	**$-**

Valuation Techniques

We value our postretirement benefits plan assets as follows:

- Money market funds and mutual funds - based upon quoted market prices in active markets.
- Government bonds, and common stocks - 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.

Pension and postretirement benefit plan equity securities did not include any AGR and Iberdrola common stock as of both December 31, 2018 and 2017.

Note 15. Other Income and Other Deductions

Years Ended December 31, (Thousands)	2018	2017
Interest and dividend income	$67	$37
Carrying costs on regulatory assets	9,316	4,809
Allowance for funds used during construction	3,006	7,315
Gain on sale of property	899	1,080
Miscellaneous	113	2,131
Total other income	**$13,401**	**$15,372**
Pension non-service components	$(52,058)	$(45,680)
Miscellaneous	(1,157)	(1,154)
Total other deductions	**$(53,215)**	**$(46,834)**

Note 16. 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 $102.4 million for 2018 and $89.8 million for 2017 and charge for services provided by NYSEG to AGR and its subsidiaries were approximately $11.0 million for 2018 and $22.2 million for 2017. All charges for services are at cost. The balance in accounts payable to affiliates of $82.4 million at December 31, 2018 and $78.5 million at December 31, 2017 is mostly payable to Avangrid Service Company.

Networks holds an approximate 20% ownership interest in the regulated New York TransCo. Through New York TransCo, Networks has formed a partnership with Central Hudson Gas and Electric Corporation, Consolidated Edison, Inc., National Grid, plc and Orange and Rockland Utilities, Inc. to develop a portfolio of interconnected transmission lines and substations to fulfill the objectives of the New York energy highway initiative, which is a proposal to install up to 3,200 MW of new electric generation and transmission capacity in order to deliver more power generated from upstate New York power plants to downstate New York. In 2016 NYSEG received approximately $67 million from New York TransCo in the form of $43 million for assets constructed and transferred to the New York TransCo, $22 million in contributions in aid of construction and approximately $2 million in advanced lease payments for a 99 year lease of land and attachment rights. The amount receivable from New York TransCo was $1.0 million at December 31, 2018 and $6.3 million at December 31, 2017.

Note 17. Subsequent Events

The company has performed a review of subsequent events through March 29, 2019, which is the date these financial statements were available to be issued, and no subsequent events have occurred from January 1, 2019 through such date.

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, 2018 and 2017, 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, 2018 and 2017, 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 29, 2019

Rochester Gas and Electric Corporation
Statements of Income

Years Ended December 31,	2018	2017
(Thousands)		
Operating Revenues	**$923,768**	**$850,679**
Operating Expenses		
Electricity purchased and fuel used in generation	128,817	102,169
Natural gas purchased	116,169	85,124
Operations and maintenance	271,177	261,087
Depreciation and amortization	84,744	71,470
Taxes other than income taxes, net	122,920	121,243
Total Operating Expenses	**723,827**	**641,093**
Operating Income	**199,941**	**209,586**
Other income	20,638	15,498
Other deductions	(24,406)	(19,708)
Interest expense, net of capitalization	(71,322)	(62,642)
Income Before Tax	**124,851**	**142,734**
Income tax expense	30,722	59,505
Net Income	**$94,129**	**$83,229**

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

Rochester Gas and Electric Corporation
Statements of Comprehensive Income

Years ended December 31,	2018	2017
(Thousands)		
Net Income	**$94,129**	**$83,229**
Other Comprehensive Income, Net of Tax		
Amortization of pension for nonqualified plans, net of income taxes	323	(61)
Unrealized (loss) during the year on derivatives qualifying as cash flow hedges, net of income taxes:		
Unrealized (loss) during period on derivatives qualifying as hedges	(212)	(94)
Reclassification adjustment for loss included in net income	1	98
Reclassification adjustment for loss on settled cash flow treasury hedges	4,260	3,505
Total Other Comprehensive Income, Net of Tax	**4,372**	**3,448**
Comprehensive Income	**$98,501**	**$86,677**

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

Rochester Gas and Electric Corporation
Balance Sheets

As of December 31,	2018	2017
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$170	$631
Accounts receivable and unbilled revenues, net	175,409	160,303
Accounts receivable from affiliates	2,674	4,318
Notes receivable from affiliates	106,350	39,727
Fuel and gas in storage	10,927	9,302
Materials and supplies	11,824	11,005
Derivative assets	1,717	-
Broker margin accounts	2,661	6,848
Income tax receivable	1,591	16,589
Prepaid property taxes	36,708	35,120
Other current assets	2,622	3,555
Regulatory assets	51,876	63,627
Total Current Assets	**404,529**	**351,025**
Utility plant, at original cost	3,711,126	3,423,287
Less accumulated depreciation	(1,008,290)	(948,638)
Net Utility Plant in Service	**2,702,836**	**2,474,649**
Construction work in progress	312,111	332,457
Total Utility Plant in Service	**3,014,947**	**2,807,106**
Other Property and Investments	2,662	3,781
Regulatory and Other Assets		
Regulatory assets	446,997	486,398
Other	2,032	1,021
Total Regulatory and Other Assets	**449,029**	**487,419**
Total Assets	**$3,871,167**	**$3,649,331**

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

Rochester Gas and Electric Corporation
Balance Sheets

As of December 31,	2018	2017
(Thousands, except share information)		
Liabilities		
Current Liabilities		
Current portion of debt	$150,532	$1,434
Accounts payable and accrued liabilities	203,480	166,062
Accounts payable to affiliates	42,739	41,685
Interest accrued	13,379	12,329
Taxes accrued	1,449	1,692
Environmental remediation costs	3,633	2,435
Other	43,885	37,579
Regulatory liabilities	55,531	33,463
Total Current Liabilities	**514,628**	**296,679**
Regulatory and Other Liabilities		
Regulatory liabilities	712,258	694,751
Other Non-current Liabilities		
Deferred income taxes	244,260	295,264
Nuclear plant obligations	125,930	123,622
Pension and other postretirement	169,888	175,394
Asset retirement obligations	2,846	3,214
Environmental remediation costs	127,943	131,367
Other	68,610	22,501
Total Regulatory and Other Liabilities	**1,451,735**	**1,446,113**
Non-current debt	898,652	958,911
Total Liabilities	**2,865,015**	**2,701,703**
Commitments and Contingencies		
Common Stock Equity		
Common stock ($5 par value, 50,000,000 shares authorized, 38,885,813 shares outstanding at December 31, 2018 and 2017)	194,429	194,429
Additional paid-in capital	604,998	604,975
Retained earnings	359,003	304,820
Accumulated other comprehensive loss	(35,040)	(39,358)
Treasury stock, at cost (4,379,300 shares at December 31, 2018 and 2017)	(117,238)	(117,238)
Total Common Stock Equity	**1,006,152**	**947,628**
Total Liabilities and Equity	**$3,871,167**	**$3,649,331**

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

Rochester Gas and Electric Corporation
Statements of Cash Flows

Years Ended December 31,	2018	2017
(Thousands)		
Cash Flow from Operating Activities:		
Net income	**$94,129**	**$83,229**
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	84,744	71,470
Regulatory assets/liabilities amortization	11,165	5,515
Regulatory assets/liabilities carrying cost	5,932	12,468
Amortization of debt issuance costs	1,572	1,251
Deferred taxes	(12,944)	93,981
Pension cost	25,794	22,756
Stock-based compensation	(154)	(70)
Accretion expenses	155	159
Gain on disposal of assets	(60)	(20)
Other non-cash items	(7,822)	(8,054)
Changes in operating assets and liabilities		
Accounts receivable, from affiliates, and unbilled revenues	(13,462)	(12,540)
Inventories	(2,444)	(3,964)
Accounts payable, to affiliates, and accrued liabilities	34,756	(36,267)
Taxes accrued	14,754	(228)
Other assets/liabilities	35,167	(1,310)
Regulatory assets/liabilities	17,446	(10,034)
Net Cash Provided by Operating Activities	**288,728**	**218,342**
Cash Flow from Investing Activities:		
Capital expenditures	(278,650)	(301,811)
Contributions in aid of construction	8,265	4,783
Proceeds from sale of utility plant	826	561
Notes receivable from affiliates	(66,623)	(39,727)
Investments, net	-	(17)
Net Cash Used in Investing Activities	**(336,182)**	**(336,211)**
Cash Flow from Financing Activities:		
Non-current note issuance	151,031	294,012
Repayments of non-current debt	(62,150)	-
Repayments of other short-term debt, net	(454)	-
Repayments of capital leases	(1,434)	(1,354)
Notes payable to affiliates	-	(249,167)
Capital contributions from parent	-	75,000
Dividends paid	(40,000)	-
Net Cash Provided by Financing Activities	**46,993**	**118,491**
Net (Decrease) Increase in Cash and Cash Equivalents	**(461)**	**622**
Cash and Cash Equivalents, Beginning of Year	**631**	**9**
Cash and Cash Equivalents, End of Year	**$170**	**$631**

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	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock	Total Common Stock Equity
Balance, January 1, 2017	**38,885,813**	**$194,429**	**$530,018**	**$221,591**	**$(42,806)**	**$(117,238)**	**$785,994**
Net income	-	-	-	83,229	-	-	83,229
Other comprehensive income, net of tax	-	-	-	-	3,448	-	3,448
							86,677
Capital contribution	-	-	75,000	-	-	-	75,000
Stock-based compensation	-	-	(43)	-	-	-	(43)
Balance, December 31, 2017	**38,885,813**	**194,429**	**604,975**	**304,820**	**(39,358)**	**(117,238)**	**947,628**
Net income	-	-	-	94,129	-	-	94,129
Other comprehensive income, net of tax	-	-	-	-	4,372	-	4,372
							98,501
Stock-based compensation	-	-	23	-	-	-	23
Common stock dividends	-	-	-	(40,000)	-	-	(40,000)
Adoption of accounting standards	-	-	-	54	(54)	-	-
Balance, December 31, 2018	**38,885,813**	**$194,429**	**$604,998**	**$359,003**	**$(35,040)**	**$(117,238)**	**$1,006,152**

(*) Par value of share amounts is $5

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

Notes to Financial Statements

Note 1. Significant Accounting Policies

Background and nature of operations: Rochester Gas and Electric Corporation's (RG&E, the company, we, our, us), principal business consists of its 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 381,000 electricity and 316,000 natural gas customers as of December 31, 2018 in its service territory of approximately 2,700 square miles. The service territory contains a substantial suburban area and a large agricultural area in parts of nine counties including and surrounding the city of Rochester, New York with a population of approximately one million people. We operate under the authority of the New York State Public Service Commission (NYPSC) and are also subject to regulation by the Federal Energy Regulatory Commission (FERC).

RG&E is a subsidiary of Avangrid Networks, Inc. (Networks), which is a wholly-owned subsidiary of Avangrid, Inc. (AGR) which is an 81.5% owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain.

Basis of presentation: The accompanying financial statements have been prepared in accordance with generally accepted accounting principles in the United States (U.S. GAAP).

We consider the following policies to be the most critical 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 and services. Refer to Note 4 for further details.

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

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

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

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

We determine depreciation expense for utility plant in service using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Our depreciation accruals were equivalent to 2.4% of average depreciable property for 2018 and 2.1% for 2017. 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 $123.9 million as of December 31, 2018 and $116.0 million as of December 31, 2017. Depreciation expense was $81.8 million in 2018 and $69.0 million in 2017. Amortization of capitalized software was $3.0 million in 2018 and $2.0 million in 2017.

Consistent with FERC accounting requirements, we charge the original cost of utility plant retired or otherwise disposed to accumulated depreciation.

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

Allowance for funds used during construction (AFUDC) represents the allowed cost of capital, including a noncash 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)**	**2018**	**2017**
(Thousands)			
Electric	29-75	$2,441,300	$2,219,220
Natural Gas	30-80	911,350	874,581
Common	7-55	358,476	329,486
Utility plant at original cost		**3,711,126**	**3,423,287**
Less accumulated depreciation		(1,008,290)	(948,638)
Net Utility Plant in Service		**2,702,836**	**2,474,649**
Construction work in progress		312,111	332,457
Total Utility Plant		**$3,014,947**	**$2,807,106**

Electric plant includes capital leases of $13.7 million in 2018 and 2017. Accumulated depreciation related to these leases was $3.3 million in 2018 and $2.9 million in 2017.

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 loss is required to be recognized if the carrying amount of the asset exceeds the undiscounted future net cash flows associated with that asset.

The impairment loss to be recognized is the amount by which the carrying 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.

***Fair value measurement*:** Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants as of the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place in either the principal market for the asset or liability, or, in the absence of a principal market, in the most advantageous market for the asset or liability.

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

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

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

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

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

Equity investments with readily determinable fair values: We measure equity investments with readily determinable fair values at fair value, with changes in fair value reported in net income.

Derivatives and hedge accounting**:** Derivatives are recognized on the balance sheets at their fair value, except for certain electricity commodity purchases and sales contracts for both capacity and energy (physical contracts) that qualify for, and are elected under, the normal purchases and normal sales exception. To be a derivative under the accounting standards for derivatives and hedging, an agreement would need to have a notional and an underlying, require little or no initial net investment and could be net settled. Changes in the fair value of a derivative contract are recognized in earnings unless specific hedge accounting criteria are met.

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

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 AOCI 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 are comprised of 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 those investments are included 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 the balance sheets. Changes in book overdrafts are reported in the operating activities section of the statements of cash flows.

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

(Thousands)	2018	2017
Cash paid during the year ended December 31:		
Interest, net of amounts capitalized	$35,763	$29,491
Income taxes paid (refunded), net	$28,669	$(58,091)

Of the income taxes paid (refunded), substantially all was received from AGR under the tax sharing agreement. Interest capitalized was $20.1 million in 2018 and $20.5 million in 2017. Accrued liabilities for utility plant additions were $27.0 million in 2018 and $17.9 million in 2017.

Broker margin accounts: We maintain accounts with clearing firms that require initial margin deposits upon the establishment of new positions, primarily related to natural gas and electricity derivatives, as well as maintenance margin deposits in the event of unfavorable movements in market valuation for those positions. We show the amount reflecting those activities as broker margin accounts on our balance sheets.

Accounts receivable and unbilled revenues, net: We record accounts receivable at amounts billed to customers. Accounts receivable at December 31 include unbilled revenues of $62.3 million for 2018 and $64.2 million for 2017, and are shown net of an allowance for doubtful accounts at December 31 of $24.0 million for 2018 and $23.1 million for 2017. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was $14.7 million in 2018 and $15.4 million in 2017.

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

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

Our accounts receivable include amounts due under deferred payment arrangements (DPAs). When a residential customer becomes delinquent in making payments, the NYPSC requires us to allow the customer to enter into a DPA to settle the account balance. A DPA allows the account balance to be paid in installments over an extended period of time by negotiating mutually acceptable payment terms. Generally, we must continue to serve a customer who cannot pay an account balance in full if the customer: (i) pays a reasonable portion of the balance; (ii) agrees to pay the balance in installments; and (iii) agrees to pay future bills within 30 days until the DPA is paid in full or is otherwise considered to be delinquent. We establish provisions for uncollectible accounts by using both historical average loss percentages to project future losses and by establishing specific provisions for known credit issues. Amounts are written off when reasonable collection efforts have been exhausted. The allowance for doubtful accounts for DPAs at December 31 was $14.4 million in 2018 and 2017. DPA receivable balances at December 31 were $23.3 million in 2018 and $21.8 million in 2017.

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

Inventory: Inventory comprises natural gas in storage and materials and supplies. We own natural gas that is stored in third-party owned underground storage facilities. This gas is recorded as inventory. Injections of inventory into storage are priced at the market purchase cost at the time of injection, and withdrawals of working gas from storage are priced at the weighted-average cost in storage. We continuously monitor the weighted-average cost of gas value to ensure it remains at, or below net realizable value. Inventories to support gas operations are reported on the balance sheet within “Natural gas in storage.”

We also have materials and supplies inventories that are used for construction of new facilities and repairs of existing facilities. These inventories are carried and withdrawn at the lower of cost and net realizable value and reported on the balance sheets within “Materials and supplies.” Inventory items are combined for the statement of cash flows presentation purposes.

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

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

Deferred income: Apart from government grants, we occasionally receive revenues from transactions in advance of the resulting performance obligations arising from the transaction. It is our policy to defer such revenues on the 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, and capitalize the cost by increasing the carrying amount of the related long-lived asset. We adjust the liability periodically to reflect revisions to either the timing or the 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 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.

Our ARO at December 31, including our conditional ARO, was $2.8 million for 2018 and $3.2 million for 2017. The ARO is associated with our long-lived assets and primarily consists of obligations related to removal or retirement of: asbestos, polychlorinated biphenyl contaminated equipment, gas pipeline and cast iron gas mains.

The following table reconciles the beginning and ending aggregate carrying amount of the ARO for the years ended December 31, 2018 and 2017.

Year ended December 31,	**2018**	**2017**
(Thousands)		
ARO, beginning of year	$3,214	$3,004
Liabilities settled during the year	(244)	(228)
(Decrease) increase to provision	(279)	279
Accretion expense	155	159
ARO, end of year	**$2,846**	**$3,214**

We have AROs for which we have not recognized a liability because the fair value cannot be reasonably estimated due to indeterminate settlement dates, including: the removal of hydroelectric dams due to structural inadequacy or for decommissioning; the removal of property upon termination of an easement, right-of-way or franchise; and costs for abandonment of certain types of gas mains.

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

Environmental remediation liability**:** In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. We record our environmental liabilities on an undiscounted basis. Our environmental liability accruals are expected to be paid through the year 2046.

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

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

We account for defined benefit pension or other postretirement plans, recognizing an asset or liability for the overfunded or underfunded plan status. For a pension plan, the asset or liability is the difference between the fair value of the plan’s assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. We reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in other comprehensive income, 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 over 10 years from the time they are incurred as required by the NYPSC. Our policy for the pension plans is to calculate the expected return on plan assets using the market-related value of assets. Our policy for the postretirement health care benefit plans is to calculate the expected return on plan assets using the market value of assets. We determine that value by recognizing the difference between actual returns and expected returns over a five year period.

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

The aggregate amount of the related party income tax receivable balance due (to)/from AGR at December 31 is $1.6 million for 2018 and $16.6 million for 2017.

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

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

State franchise tax, computed as the higher of a tax based on income or a tax based on capital, is recorded in "Taxes other than income taxes" and "Taxes accrued" in the accompanying 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.

Upon enactment of the “Tax Cuts and Jobs Act” (the Tax Act) on December 22, 2017, we remeasured our existing deferred income tax balances as of December 31, 2017, to reflect the decrease in the corporate income tax rate from 35% to 21%, which resulted in a material decrease to our net deferred income tax liability balances. In connection with the Tax Act, the U.S. Securities and Exchange Commission (SEC) issued guidance in Staff Accounting Bulletin 118, or SAB 118, which clarified accounting for income taxes under Topic 740, Income Taxes, if information was not yet available or complete and provided up to a one year measurement period in which to complete the required analyses and accounting. Following SAB 118 guidance, we recorded provisional income tax amounts as of December 31, 2017, related to the Tax Act based on reasonable estimates that could be determined at that time. As of December 31, 2018, we have completed the measurement and accounting of certain effects of the Tax Act which we have reflected in the December 31, 2018 financial statements.

Limited voting junior preferred stock: We have a class of preferred stock having one share and a par value of $1, which is issued and outstanding and has voting authority only with respect to whether RG&E may file a voluntary bankruptcy petition.

Stock-based compensation: Stock-based compensation represents costs related to AGR stock-based awards granted to RG&E employees. We account for stock-based payment transactions based on the estimated fair value of awards reflecting forfeitures when they occur. The recognition period for these costs begin 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.

Reclassifications: Certain amounts reported in the financial statements in previous periods have been reclassified to conform to the current year presentation.

New Accounting Standards and Interpretations: New accounting standards issued by the Financial Accounting Standards Board (FASB) that we either adopted or have not yet adopted are explained below. 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.

(a) Revenue from contracts with customers

In May 2014 the FASB issued Accounting Standards Codification (ASC), Topic 606, Revenue from Contracts with Customers (Topic 606) replacing the existing accounting standard and industry-specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The FASB further amended Topic 606 through various updates issued thereafter. The core principle is for an entity to recognize revenue to represent the transfer of promised goods or services to customers in amounts that reflect the consideration to which the entity expects to be entitled in exchange for those goods or services. We adopted Topic 606 effective January 1, 2018, and applied the modified retrospective method, for which we did not have a cumulative effect adjustment to retained earnings for initial application of the guidance. Refer to Note 4 for further details.

We also adopted the following standards as of their effective date of January 1, 2018, none of which had a material effect on our results of operations, financial position, cash flows, and disclosures.

(b) Classifying and measuring financial instruments
In January 2016 the FASB issued final guidance on the classification and measurement of financial instruments. As a result of our adoption we reclassified immaterial amounts from accumulated other comprehensive income (AOCI) to retained earnings.

(c) Certain classifications in the statement of cash flows
In August 2016 the FASB issued amendments to address existing diversity in practice concerning the classification of certain cash receipts and payments in the statement of cash flows, which must be applied on a full retrospective basis. Upon adoption, we had no changes to our cash flow classifications and disclosures in our financial statements.

(d) Improving the presentation of net periodic benefit costs

In March 2017 the FASB issued amendments to improve the presentation of net periodic pension cost and net periodic postretirement benefit cost in the financial statements. We retrospectively adopted the amendments that require us to present the service cost component separately from the other (non-service) components of net benefit cost, to report the service cost component in the income statement line item where we report the corresponding compensation cost, and to present all non-service components outside of operating cost. As a result, we have reclassified the non-service components – interest cost, expected return on plan assets, amortization of prior service cost (benefit), amortization of net loss, and settlement charge – from Operations and maintenance to Other income/(expense) within the statement of income. Prospectively, upon adoption, we will capitalize only the service cost component when applicable (for example, as a cost of a self-constructed asset). We elected to apply the practical expedient that allows us to retrospectively apply the amendments on adoption to net benefit costs for comparative periods by using the amounts disclosed in our notes to financial statements for Post-retirement and Similar Obligations as the basis for those periods. In connection with applying the practical expedient, in periods after adoption we will continue to include in operating income all legacy net benefit costs previously capitalized as a cost of self-constructed assets and other deferred regulatory costs. Our adoption of the amendments did not affect prior period net income. Beginning in 2018, non-service cost components we incur are no longer eligible for construction capitalization, but such costs can be deferred and included as a component of customer rates if permitted by our regulator. For the year ended December 31, 2018, we incurred additional immaterial expense as a result of the adoption of this standard.

The effect of the change in retrospective presentation related to the net periodic cost of our defined benefit pension and other postretirement employee benefits plans on our statement of income was as follows:

	Year Ended December 31, 2017		
Statement of Income	As Revised	As Previously Reported	Effect of Change Higher/(Lower)
(Thousands)			
Operations and maintenance	$ 261,087	$ 280,310	$ (19,223)
Other deductions	$ (19,708)	$ (485)	$ (19,223)

(e) Customer accounting for implementation costs incurred in a cloud computing arrangement

The FASB issued amendments in August 2018 to clarify the accounting for implementation costs of a cloud computing arrangement (also referred to as a hosting arrangement) that is a service contract. Implementation costs, which include implementation, setup and other upfront costs, are either to be deferred or expensed as incurred, in accordance with existing internal-use software guidance for similar costs. The amendments require a customer to expense capitalized implementation costs over the contractual term of the arrangement, including any optional renewal periods the customer is reasonably certain it will exercise. An entity is to present deferred implementation costs on the balance sheet, income statement and cash flows consistent with the subscription fees associated with the arrangement. The amendments enhance disclosures to include certain qualitative and quantitative information about implementation costs for internal-use software and all hosting arrangements, not just hosting arrangements that are service contracts. The amendments are effective for public business entities for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted, including adoption in any interim period for which financial statements have not been issued. An entity may apply the amendments either retrospectively or prospectively to all implementation costs incurred after the date of adoption. We early adopted the amendments as of October 1, 2018, and are applying the amendments prospectively to all implementation costs after the date of adoption. Upon adoption, there were no material effects to our results of operations, financial position, cash flows and disclosures.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements issued as indicated, that we have evaluated or are evaluating to determine their effect on our financial statements.

(a) Leases

In February 2016 the FASB issued new guidance, and issued subsequent amendments during 2018, that affects all companies and organizations that lease assets, and requires them to record on their balance sheet right-of-use assets and lease liabilities for the rights and obligations created by those leases. Under the new guidance, a lease is an arrangement that conveys the right to control the use of an identified asset for a period of time in exchange for consideration. The amendments retain a distinction between finance leases and operating leases, while requiring both types of leases to be recognized on the balance sheet. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the criteria for distinguishing between capital leases and operating leases in legacy U.S. GAAP. Lessor accounting will remain substantially the same as legacy U.S. GAAP, but with some targeted improvements to align lessor accounting with the lessee accounting model and with the revised revenue recognition guidance under Topic 606. The standard and amendments require new qualitative and quantitative disclosures for both lessees and lessors. The new leases guidance, including the subsequent amendments issued during 2018, is effective for public entities for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, and early application is permitted.

We adopted the new leases guidance effective January 1, 2019, and have elected the optional transition method under which we will initially apply the standard on that date without adjusting amounts presented for prior periods, and record the cumulative effect of applying the new guidance as an adjustment to beginning retained earnings. We expect the adjustment to retained earnings will be immaterial. Concerning certain transition and other practical expedients:

- we did not elect the package of three practical expedients available under the transition provisions, including (i) not reassessing whether expired or existing contracts contain leases, (ii) lease classification, and (iii) not revaluing initial direct costs for existing leases;
- we elected a land easement expedient and did not reassess land easements that we did not account for as leases prior to our adoption of the new leases guidance;
- we used hindsight for specified determinations and assessments in applying the new leases guidance;
- we will not recognize lease assets and liabilities for short-term leases (less than one year), for all classes of underlying assets; and
- we did not separate lease and associated nonlease components for transitioned leases, but will instead account for them together as a single lease component.

(b) Measurement of credit losses on financial instruments

The FASB issued an accounting standards update in June 2016 that requires more timely recording of credit losses on loans and other financial instruments. The amendments affect entities that hold financial assets and net investments in leases that are not accounted for at fair value through net income (loans, debt securities, trade receivables, 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. In November 2018 the FASB issued an update to this new guidance to clarify that receivables arising from operating leases are not within the scope of the credit losses standard. Instead, impairment of receivables arising from operating leases should be accounted for in accordance with the leases standard. The amendments are effective for public entities that are SEC filers for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, with early adoption permitted. Entities are to apply the amendments on a modified retrospective basis for most instruments. We expect our adoption will not materially affect our results of operations, financial position, and cash flows.

(c) Targeted improvements to accounting for hedging activities

In August 2017 the FASB issued targeted amendments with the objective to better align hedge accounting with an entity’s risk management activities in the financial statements, and to simplify the application of hedge accounting. The amendments address concerns of financial statement preparers over difficulties with applying hedge accounting and limitations for hedging both nonfinancial and financial risks, and concerns of financial statement users over how hedging activities are reported in financial statements. Changes to the hedge accounting guidance to address those concerns will: 1) expand hedge accounting for nonfinancial and financial risk components and amend measurement methodologies to more closely align hedge accounting with an entity's risk management activities; 2) eliminate the separate measurement and reporting of hedge ineffectiveness, to reduce the complexity of preparing and understanding hedge results; 3) enhance disclosures and change the presentation of hedge results to align the effects of the hedging instrument and the hedged item in order to enhance transparency, comparability, and understandability of hedge results; and 4) simplify the way assessments of hedge effectiveness may be performed to reduce the cost and complexity of applying hedge accounting. The amendments are effective for public entities for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. For cash flow and net investment hedges existing at the date of adoption, a company must apply a cumulative-effect adjustment related to the separate measurement of ineffectiveness to AOCI with a corresponding adjustment to the opening balance of retained earnings as of the beginning of the fiscal year of adoption. The amended presentation and disclosure guidance is required only prospectively. In October 2018 the FASB issued amendments that are effective concurrently with the above targeted improvements. These additional amendments permit use of the Overnight Index Swap rate based on the Secured Overnight Financing Rate as a U.S. benchmark interest rate for hedge accounting purposes. Use of that rate is in addition to the already eligible benchmark interest rates, which are: interest rates on direct Treasury obligations of the U.S. government, the London Interbank Offered Rate swap rate, the OIS Rate based on the Fed Funds Effective Rate, and the Securities Industry and Financial Markets Association Municipal Swap Rate. Our adoption of the amendments on January 1, 2019, will not materially affect our results of operations, financial position, or cash flows, but the amendments will ease the administrative burden of hedge documentation requirements and assessing hedge effectiveness going forward.

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

In February 2018 the FASB issued amendments to address a narrow-scope financial reporting issue that arose as a consequence of the Tax Cuts and Jobs Act of 2017 (the Tax Act) enacted on December 22, 2017, by the U.S. federal government. Under current guidance, the adjustment of deferred taxes for the effect of a change in tax laws or rates is required to be included in income from continuing operations, thus the associated tax effects of items within AOCI (referred to as stranded tax effects) do not reflect the appropriate tax rate. The amendments allow a reclassification from AOCI to retained earnings for stranded tax effects resulting from the Tax Act. As a result, the amendments eliminate the stranded tax effects resulting from the Tax Act and will improve the usefulness of information reported to financial statement users. The amendments only relate to the reclassification of the income tax effects of the Tax Act, and do not affect the underlying guidance that requires the effect of a change in tax laws or rates to be included in income from continuing operations. The amendments are effective for all entities for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted including, for public entities, adoption in any interim period for which financial statements have not been issued. An entity has the option to apply the amendments either in the period of adoption or retrospectively to each period (or periods) in which it recognizes the effect of the change in the U.S. federal corporate income tax rate in the Tax Act. An entity is required to disclose its accounting policy election, including its policy for reclassifying material stranded tax effects in AOCI to earnings (specific identification or portfolio method). Our adoption of the amendments on January 1, 2019, will not materially affect our results of operations, financial position, cash flows, and disclosures.

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

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

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

Use of estimates and assumptions: The preparation of our financial statements in conformity with U.S. GAAP requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Significant estimates and assumptions are used for, but not limited to: (1) allowance for doubtful accounts and unbilled revenues; (2) asset impairments; (3) depreciable lives of assets; (4) income tax valuation allowances; (5) uncertain tax positions; (6) reserves for professional, workers' compensation, and comprehensive general insurance liability risks; (7) contingency and litigation reserves; (8) earnings sharing mechanism (ESM); (9) environmental remediation liabilities; (10) pension and other postretirement employee benefits (OPEB); (11) fair value measurements and (12) AROs. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our financial statements will change as new events occur, as more experience is acquired, as additional information is obtained, and as our operating environment changes. We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside specialists to assist in our evaluations, as considered necessary. Actual results could differ from those estimates.

Union collective bargaining agreements: Approximately 45% of our employees are covered by a collective bargaining agreement. We have no agreements that will expire within the coming year.

Note 2. Industry Regulation

Electricity and Natural Gas Distribution

Our revenues are regulated, being based on tariffs established in accordance with administrative procedures set by the New York State Public Service commission (NYPSC). The tariffs are applied to regulated activities and are approved by the NYPSC and are based on the cost of providing service. Our revenues are set to be sufficient to cover all operating costs, including energy costs, finance costs, and the costs of equity, the last of which reflects our capital ratio and a reasonable return on equity (ROE).

Energy costs that are set on the New York wholesale markets are passed on to consumers. The difference between energy costs that are budgeted and those that are actually incurred by the utilities is offset by applying reconciliation procedures that result in either immediate or deferred tariff adjustments. Reconciliation procedures apply to other costs, which are in many cases exceptional, such as the effects of extreme weather conditions, environmental factors, regulatory and accounting changes, and treatment of vulnerable customers. Revenues that allow us to exceed target returns, usually the result of better than expected cost efficiency, are generally shared with our customers, resulting in future tariff reductions.

RG&E Rate Plan

On May 20, 2015, RG&E filed electric and gas rate cases with the NYPSC. We requested a rate increase for RG&E gas. RG&E electric proposed a rate decrease.

On February 19, 2016, RG&E and New York State Electric & Gas Corporation (NYSEG) (together, "the companies") and other signatory parties filed a Joint Proposal (Proposal) with the NYPSC for a three-year rate plan for electric and gas service at RG&E commencing May 1, 2016. The Proposal, which was approved by the NYPSC on June 15, 2016, balanced the varied interests of the signatory parties including but not limited to maintaining the companies' credit quality and mitigating the rate impacts to customers. The Proposal reflects many customer benefits including: acceleration of the companies' natural gas leak prone main replacement programs and increased funding for electric vegetation management to provide continued safe and reliable service. The delivery rate increase in the Proposal can be summarized as follows:

	May 1, 2016		May 1, 2017		May 1, 2018	
	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %
Electric	$3.0	0.7%	$21.6	5.0%	$25.9	5.7%
Gas	$8.8	5.2%	$7.7	4.4%	$9.5	5.2%

The allowed rate of return on common equity for RG&E Electric and RG&E Gas is 9.00%. The equity ratio for each company is 48%; however, the equity ratio is set at the actual up to 50% for earnings sharing calculation purposes. The customer share of any earnings above allowed levels increases as the ROE increases, with customers receiving 50%, 75% and 90% of earnings over 9.5%, 10.0% and 10.5% of ROE, respectively, in the first rate year covering the period May 1, 2016 – April 30, 2017. The earnings sharing levels increase in rate year two (May 1, 2017 – April 30, 2018) to 9.65%, 10.15% and 10.65% ROE, respectively. The earnings sharing levels further increase in rate year three (May 1, 2018 – April 30, 2019) to 9.75%, 10.25% and 10.75% ROE, respectively. The rate plans also include the implementation of a rate adjustment mechanism ("RAM") designed to return or collect certain defined reconciled revenues and costs, implementation of new depreciation rates, and continuation of the existing Revenue Decoupling Mechanism ("RDM") for each business.

The Proposal continues reserve accounting for qualifying Major Storms ($2.5 million annually for RG&E Electric). Incremental maintenance costs incurred to restore service in qualifying divisions will be chargeable to the Major Storm Reserve provided they meet certain thresholds for each storm event.

The Proposal maintains current electric reliability performance measures (and associated potential negative revenue adjustments for failing to meet established performance levels) which include the system average interruption frequency index (SAIFI) and the customer average interruption duration index (CAIDI). The Proposal also modifies certain gas safety performance measures at the companies, including those relating to the replacement of leak prone main, leak backlog management, emergency response, and damage prevention. The Proposal establishes threshold performance levels for designated aspects of customer service quality and continues and expands RG&E's bill reduction and arrears forgiveness Low Income

Programs with increased funding levels included in the Proposal. Reforming the Energy Vision (REV) related incremental costs and fees will be included in the RAM to the extent cost recovery is not provided for elsewhere. Under the Proposal, the Company will implement the RAM, which will be applicable to all customers, to return or collect RAM Eligible Deferrals and Costs, including: (1) property taxes; (2) Major Storm deferral balances; (3) gas leak prone pipe replacement; and (4) REV costs and fees which are not covered by other recovery mechanisms.

The Proposal provides for partial or full reconciliation of certain expenses including, but not limited to: pensions, pension and other postretirement benefits; property taxes; variable rate debt and new fixed rate debt; gas research and development; environmental remediation costs; Major Storms; nuclear electric insurance limited credits; economic development; and Low Income Programs. The Proposal also includes a downward-only Net Plant reconciliation. In addition, the Proposal includes downward-only reconciliations for the costs of: electric distribution and gas vegetation management; pipeline integrity; and other incremental maintenance programs. The Proposal provides that we continue the electric RDMs on a total revenue per class basis and the gas RDMs on a revenue per customer basis.

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 and was resumed in the first quarter of 2018. The companies also filed their first bi-annual update of the DSIP on July 31, 2018.

Other various proceedings have also been initiated by the NYPSC which are REV related, and each proceeding has its own schedule. These proceedings include the Clean Energy Standard, Value of Distributed Energy Resources (VDER) and Net Energy Metering, Demand Response Tariffs, and Community Choice Aggregation. As part of the Clean Energy Standard proceeding, all electric utilities were ordered to begin payments to New York State Energy Research and Development Authority (NYSERDA) for Renewable Energy Credits ("RECs") and Zero Emissions Credits beginning in 2017. A separate Offshore Wind was ordered by the NYPSC in July 2018.

Track 2 of the REV initiative is also underway, and through a NYPSC 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.

In March, 2017, the NYPSC issued three separate REV-related orders. These orders created a series of filing requirements for NYSEG beginning in March 2017 and extending through the end of 2018. The three orders involve: 1) modifications to the electric utilities' proposed interconnection earnings adjustment mechanism framework; 2) further DSIP requirements, including confirmation of the filing of an updated DSIP plan by mid-2018 and implementing two energy storage projects at RG&E by the end of 2018; and 3) Net Energy Metering Transition including implementation of Phase One of the VDER. In September 2017, the NYPSC issued another order related to the VDER, requiring tariff filings, changes to Standard Interconnection Requirements, and planning for the implementation of automated consolidated billing. RG&E has participated with the other NY state electric utilities in jointly filing updates to the interconnection earnings adjustment mechanism, has implemented two energy storage projects, and has participated with the other NY state electric utilities in the VDER transition effort, including tariff updates and application of VDER principles.

The March 2017 Order in the VDER proceeding approved a transition from traditional Net Energy Metering (NEM) towards a more values-based approach (Value Stack) for compensating Distributed Energy Resources (DER). The March 2017 Order approved an interim methodology for more precise DER valuation and compensation for NEM-eligible technologies. The interim methodology approved by the NYPSC provides for a market transition consistent with the principles of gradualism and predictability, and established a tranche system to manage impacts on non-participants.

The March 2017 Order also directed a Phase Two of the VDER proceding. 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 disucss, review and analyze several issues regarding each subject. The working groups culminated with a series of whitepapers developed by NYPSC 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. A Staff whitepaper on rate design for mass market on-site DER projects interconnected after January 1, 2020 is scheduled to be submitted in 2019.

New York State Department of Public Service Investigation of the Preparation for and Response to the March 2017 Windstorm

On March 11, 2017, the New York State Department of Public Service (the Department) commenced an investigation of RG&E's preparation for and response to the March 2017 windstorm, which affected more than 219,000 customers at NYSEG and RG&E. The

Department investigation included a comprehensive review of RG&E’s preparation for and response to the windstorm, including all aspects of the companies’ filed and approved emergency plan. The Department held public hearings on April 12 and 13, 2017.

On November 16, 2017, the NYPSC announced that the Department Staff had completed their investigation into the March 2017 Windstorm and the NYPSC issued an Order Instituting Proceeding and to Show Cause. The Staff’s investigation found that RG&E had allegedly violated certain parts of its emergency response plan, which makes the Company subject to possible financial penalties. RG&E responded to the order in a timely manner and has conducted settlement discussions with the Department of Public Service Staff and other parties. These settlement discussions culminated with the filing of two Joint Proposals for settling the issues raised by the Department in May 2018, with several parties signing on to the Joint Proposals. These Joint Proposals have NYSEG and RG&E implementing a combined $3.9 million of storm resiliency and restoration projects which will not be paid for by ratepayers. The Joint Proposals are currently before the Commission, and a ruling is expected in 2019.

New York State Department of Public Service Investigation of the Preparation for and Response to the March 2018 Winter Storms

On March 13, 2018, the New York State Department of Public Service (the Department) commenced an investigation of RG&E’s preparation for and response to the March 1 and March 8, 2018 winter storms, which affected more than 300,000 customers at NYSEG and RG&E. The Department investigation will include a comprehensive review of RG&E’s preparation for and response to the winter storms, including all aspects of the company’s filed and approved emergency plan. The Department held 21 public hearings between April 16 and April 26, 2018. The companies received and responded to numerous data requests and have participated in dozens of interviews related to the investigation over the last several months. We cannot predict the outcome of this regulatory action.

Tax Cuts and Jobs Act

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Tax Act) was signed into law. The Tax Act contains significant changes to the federal tax structure, including among other things, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017. The NYPSC has instituted proceedings in New York to review and address the implications associated with the Tax Act on the utilities providing service in state of New York. The Department of Public Service (DPS) Staff, on March 29, 2018, submitted a proposal to the NYPSC indicating that any companies which have not included the impacts from the Tax Act in a recent rate proceeding should submit a filing to initiate a surcredit beginning October 1, 2018 to pass back benefits to customers. The proposal invited all companies to comment on the proposal prior to June 29, 2018, and to include comments about alternative mechanisms to return the benefits to customers. RG&E has submitted comments in response to the DPS Staff proposal, identifying that it would be premature to begin a surcredit which could cause rate volatility when major expenditures may be forthcoming.

On August 9, 2018, the NYPSC issued an order in case 17-M-0815 and as part of that order instituted surcredits for RG&E customers beginning October 1, 2018. The surcredits include the annual 2018 tax expense savings for both electric and gas businesses, and include an amortization of previously deferred tax savings through September 30, 2018 for both businesses. The annual amount of the surcredits beginning October 1, 2018 for RG&E is approximately $29 million.

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.

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 $185.4 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

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

On June 15, 2016, the NYPSC approved the proposal in connection with a three-year rate plan for electric and gas service at RG&E effective May 1, 2016. Following the approval of the Proposal RG&E's plant related tax items are amortized over the life of associated plant, and unfunded deferred taxes being amortized over a period of fifty years. A majority of the other items related to RG&E, which net to a regulatory liability, remains deferred and will not be amortized until future proceedings or will be used to recover costs of the Ginna RSSA. Following the approval of the proposal by the NYPSC, unfunded future income taxes were adjusted for the amount of $123 million to reflect the change from a flow through to normalization method, which has been recorded as an increase to income tax expense and an offsetting increase to revenue, during the year ended December 31, 2016. The amounts will be collected over a period of fifty years.

Current and non-current regulatory assets at December 31, 2018 and 2017 consisted of:

December 31, (Thousands)	**2018**	**2017**
Current		
Revenue decoupling mechanism	$1,320	$8,249
Decommissioning	6,471	6,471
Storm costs	-	6,086
Reliability support services	12,775	27,000
Hedge losses	-	1,658
Environmental remediation costs	6,363	6,363
Rate Adjustment Mechanism (RAM)	18,436	-
Other	6,511	7,800
Total current regulatory assets	**$51,876**	**$63,627**
Non-current		
Asset retirement obligation	3,181	3,153
Unamortized losses on re-acquired debt	5,605	4,814
Decommissioning	4,827	8,655
Pension and other postretirement benefits cost deferrals	46,018	37,615
Federal tax depreciation normalization adjustment	48,076	50,211

Environmental remediation costs	77,794	86,288
Pension and other postretirement benefits	78,955	95,940
Unfunded future income taxes	119,588	130,336
Reliability support services	-	10,234
Storm costs	47,136	49,544
Other	15,817	9,608
Total non-current regulatory assets	**$446,997**	**$486,398**

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

Environmental remediation costs include spending that has occurred and is eligible for future recovery in customer rates. Environmental costs are currently recovered through a reserve mechanism whereby projected spending is included in rates with any variance recorded as a regulatory asset or a regulatory liability. The amortization period will be established in future proceedings and will depend upon the timing of spending for the remediation costs. It also includes the anticipated future rate recovery of costs that are recorded as environmental liabilities since these will be recovered when incurred. Because no funds have yet been expended for the regulatory asset related to future spending, it does not accrue carrying costs and is not included within rate base.

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.

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.

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.

Decommissioning represents amounts to be collected in rates for the decommissioning of shut down plants.

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.

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.

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.

Reliability support services represent the deferral of costs associated with keeping units available and capable of being committed for reliability purposes as requested by the utility or the NYISO.

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.

Other includes items such as deferred purchased gas.

Deferred income taxes regulatory: see Note 1.

Current and non-current regulatory liabilities at December 31, 2018 and 2017 consisted of:

December 31,	**2018**	**2017**
(Thousands)		
Current		
Energy efficiency programs	$28,466	$21,300
Carrying costs on deferred income tax bonus depreciation	10,000	8,333
Tax Act – remeasurement	6,439	-
Rate Adjustment Mechanism (RAM)	5,976	-
Other	4,650	3,830
Total current regulatory liabilities	**$55,531**	**$33,463**
Non-current		
Asset gain sale account	10,851	10,851
Earnings sharing	10,294	12,483
Economic development	19,330	18,846
Merger capital expense	5,953	5,953
Deferred transmission congestion contracts	21,339	19,117
Net plant reconciliation	18,657	9,690
Accrued removal obligations	180,224	175,175
Positive benefit adjustment	32,639	32,639
Deferred property taxes	24,800	19,406
Carrying costs on deferred income tax bonus depreciation	35,769	45,769
Tax Act – remeasurement	290,051	288,190
Debt rate reconciliations	20,356	16,016
Low income programs	-	4,466
NEIL (Nuclear Electric Insurance Limited) credits	4,420	-
Theoretical reserve flow through impact	6,279	6,279
Other	31,296	29,871
Total non-current regulatory liabilities	**$712,258**	**$694,751**

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

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

Carrying costs on deferred income tax bonus depreciation represent the carrying costs benefit of increased accumulated deferred income taxes created by the change in tax law allowing bonus depreciation. The amortization period is five years following the approval of the proposal by the NYPSC.

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.

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.

Deferred transmission congestion contracts represent the deferral of the right to collect day-ahead market congestions rents going forward in time.

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.

Tax Act - remeasurement represents the impact from remeasurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates from 35% to 21% under the provisions of the Tax Act will result in amounts previously collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates. The NYPSC has instituted separate proceedings to review and address the implications associated with the Tax Act on the utilities providing service in state of New York. The NYPSC has required RG&E to institute surcredits to customers as of October 1, 2018. The surcredits include the annual tax expense savings as well as an amortization of previously deferred tax savings through September 30, 2018.

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.

Other includes items such as asset retirement obligations and New York State tax rate change.

Note 4. Revenue

On January 1, 2018, we adopted ASC 606 and all related amendments using the modified retrospective method, which we applied only to contracts that were not completed as of January 1, 2018. For reporting periods beginning on January 1, 2018, we present revenue in accordance with ASC 606, and have not adjusted comparative prior period information, which we continue to report under the legacy accounting standards in effect for those prior periods. For the year ended December 31, 2018, the effect of applying ASC 606 to recognize revenue as compared to applying the legacy accounting standards was not material.

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. RG&E 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 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. We record revenue for all of those sales based upon the regulatory-approved tariff and the volume delivered or transmitted, which corresponds to the amount that we have a right to invoice. There are no material initial incremental costs of obtaining a contract in any of the arrangements. RG&E 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. RG&E does not have any material significant payment terms because it receives payment at or shortly after the point of sale. RG&E assesses its deferred payment arrangements at each balance sheet date for the existence of significant financing components, but has had no material adjustments as a result.

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 recognizes and records only the initial recognition of "originating" ARP revenues (when the regulatory-specified conditions for recognition have been met). When we subsequently include those amounts in the price of utility service billed to customers, we record such amounts as a recovery of the associated regulatory asset or liability. When we owe amounts to customers in connection with ARPs, we 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.

RG&E also has various other sources of revenue including billing, collection, other administrative charges, sundry billings, rent of utility property, and miscellaneous revenue. We classify 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, which we receive payment for 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 $0.5 million at December 31, 2018, and $0.3 million at January 1, 2018, and are presented in "Other current liabilities." We recognized $0.6 million as revenue during 2018, of which $0.3 million was included in contract liabilities at January 1, 2018.

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 year ended December 31, 2018 are as follows:

Year Ended December 31, 2018: **(Thousands)**		
Regulated operations – electricity	$	603,219
Regulated operations – natural gas		296,873
Other[(a)]		13,131
Revenue from contracts with customers		**913,223**
Leasing revenue		1,452
Alternative revenue programs		6,950
Other revenue		2,143
Total operating revenues	**$**	**923,768**

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

As of December 31, 2018, nearly all of the accounts receivable balances included in “Accounts receivable and unbilled revenues, net” on our condensed balance sheet are related to contracts with customers.

Note 5. Income Taxes

The Tax Act changes significantly the federal taxation of business entities, including among other things, a federal corporate tax rate decrease from 35% to 21% for tax years beginning after December 31, 2017. In connection with the Tax Act, the U.S. Securities and Exchange Commission issued guidance in Staff Accounting Bulletin 118, or SAB 118, which clarified accounting for income taxes under ASC 740, Income Taxes, if information was not yet available or complete and provided up to a one year measurement period in which to complete the required analyses and accounting. Following SAB 118 guidance, the Company recorded provisional income tax amounts as of December 31, 2017 related to the Tax Act based on reasonable estimates that could be determined at that time. As of December 31, 2018, the Company has completed the measurement and accounting of certain effects of the Tax Act which have been reflected in the December 31, 2018 financial statements.

Current and deferred taxes charged to expense for the years ended December 31, 2018 and 2017 consisted of:

Years Ended December 31,	**2018**	**2017**
(Thousands)		
Current		
Federal	$42,017	$(37,205)
State	1,649	2,729
Current taxes charged to expense/(benefit)	**43,666**	**(34,476)**
Deferred		
Federal	(17,467)	86,186
State	4,523	7,795
Deferred taxes charged to (benefit)/expense	**(12,944)**	**93,981**
Total Income Tax Expense	**$30,722**	**$59,505**

The differences between tax expense per the statements of income and tax expense at the 21% and 35% statutory federal tax rate for the years ended December 31, 2018 and 2017, respectively, consisted of:

Years Ended December 31,	**2018**	**2017**
(Thousands)		
Tax expense at federal statutory rate	$26,219	$49,957
Statutory state taxes, net of federal benefit	6,411	6,845
Other, net	(1,908)	2,703
Total Income Tax Expense	**$30,722**	**$59,505**

Income tax expense for the year ended December 31, 2018 was $4.5 million higher than it would have been at the statutory federal income tax rate of 21% due predominately to state taxes, net of federal benefit. This resulted in an effective tax rate of 24.6%. Income tax expense for the year ended December 31, 2017 was $9.5 million higher than it would have been at the statutory federal income tax rate of 35% due predominately to state taxes, net of federal benefit. This resulted in an effective tax rate of 41.7%.

Deferred tax assets and liabilities as of December 31, 2018 and 2017 consisted of:

December 31,	**2018**	**2017**
(Thousands)		
Non-current Deferred Income Tax Liabilities (Assets)		
Property related	$426,645	$397,810
Unfunded FIT normalization amortization	31,970	37,794
Derivative assets	(15,824)	(17,257)
Non-cash return – bonus depreciation	(11,962)	(11,091)
Pension and other postretirement benefits	(12,441)	(10,288)
Positive benefits adjustment merger order	(8,530)	(8,530)
Environmental	(12,393)	(10,755)
Regulatory liability due to “Tax Cuts and Jobs Act”	(77,488)	(75,318)
Federal and state tax credits	(48,622)	(1,386)
Federal and state NOLs	(17,610)	(2,509)
Other	(9,485)	(3,206)
Total Non-current Deferred Income Tax Liabilities	**$244,260**	**$295,264**
Deferred tax assets	$214,355	$140,340
Deferred tax liabilities	458,615	435,604
Net Accumulated Deferred Income Tax Liabilities	**$244,260**	**$295,264**

RG&E has gross federal net operating losses of $76.4 million, federal research and development credits of $1.4 million, gross NY state net operating losses of $30.5 million and claims for NY state tax credits of $47.2 million.

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2018 and 2017 consisted of:

Years Ended December 31,	**2018**	**2017**
(Thousands)		
Balance as of January 1	$2,526	$2,905
Increases for tax positions related to prior years	47,737	271
Reduction for tax positions related to prior years	(302)	(650)
Balance as of December 31	**$49,961**	**$2,526**

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, 2018 and December 31, 2017. Gross unrecognized tax benefits increased $47.7 million in 2018 primarily due to NY state tax credits claimed for open tax years.

Note 6. Long-term Debt

At December 31, 2018 and 2017, our long-term debt was:

As of December 31,	**2018**			**2017**	
(Thousands)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
First mortgage bonds [(a)]	2019-2033	$ 900,000	3.10%-8.00%	$ 900,000	3.10%-8.00%
Unsecured pollution control notes – fixed	2025	152,400	2.875%-3.00%	-	-
Unsecured pollution control notes - variable	2032	-	-	62,150	1.94%
Obligations under capital leases	2019-2023	8,778		9,818	
Unamortized debt issuance costs and discount		(11,994)		(11,623)	
Total Debt		**$ 1,049,184**		**$ 960,345**	
Less: debt due within one year, included in current liabilities		150,532		1,434	
Total Non-current Debt		**$ 898,652**		**$ 958,911**	

(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 May 24, 2017, RG&E issued $300 million in aggregate principal amount of 3.10% First Mortgage Bonds maturing in 2027. Proceeds of the offering were used to reduce short-term debt, to fund capital expenditures and for general corporate purposes. Net proceeds of the offering after the price discount and issuance-related expenses were $294 million.

On June 29, 2018, RG&E remarketed $152 million in aggregate principal amount of Pollution

Control Revenue Bonds, issued through the New York State Energy Research and Development Authority, with mandatory tender and maturity date of 2025 and interest rates ranging 2.875% - 3.00%.

At December 31, 2018, long-term debt, including lease obligations (in thousands), that will become due during the next five years are:

2019	2020	2021	2022	2023
$150,532	$1,961	$126,961	$1,961	$1,798

We have no financial debt covenant requirements related to our long-term debt at December 31, 2018 and 2017.

Note 7. Bank Loans and Other Borrowings

RG&E had no short-term debt outstanding at December 31, 2018 and December 31, 2017. RG&E funds short-term liquidity needs through an agreement among Avangrid's regulated utility subsidiaries (the Virtual Money Pool Agreement), a bi-lateral intercompany credit agreement with Avangrid (the Bi-Lateral Intercompany Facility) and a bank provided credit facility to which RG&E is a party (the AGR Credit Facility), each of which are described below.

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. RG&E has a lending/borrowing limit of $100 million under this agreement. On June 29, 2018, the RG&E Board approved the amendment to RG&E's borrowing and lending limit, increasing it temporarily from $100 million to $200 million. The amendment shall terminate on December 31, 2018, and all terms and conditions of the amendment shall revert back to the original terms and conditions provided for in the Agreement. There was no debt outstanding as of December 31, 2018 and December 31, 2017 under this agreement.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $500 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. There was no balance outstanding under this agreement as of December 31, 2018 and December 31, 2017.

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

December 31, 2017.

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 0.51 to 1.00 at December 31, 2018. We are not in default as of December 31, 2018.

Note 8. Commitments and Contingencies

New York State Department of Public Service Investigation of the Preparation for and Response to the March 2017 Windstorm

On March 11, 2017, the New York State Department of Public Service (the Department) commenced an investigation of RG&E's preparation for and response to the March 2017 windstorm, which affected more than 219,000 customers at NYSEG and RG&E. The Department investigation included a comprehensive review of RG&E's preparation for and response to the windstorm, including all aspects of the companies' filed and approved emergency plan. The Department held public hearings on April 12 and 13, 2017.

On November 16, 2017, the NYPSC announced that the Department Staff had completed their investigation into the March 2017 Windstorm and the NYPSC issued an Order Instituting Proceeding and to Show Cause. The Staff's investigation found that RG&E had allegedly violated certain parts of its emergency response plan, which makes the Company subject to possible financial penalties. RG&E responded to the order in a timely manner and has conducted settlement discussions with the Department of Public Service Staff and other parties. These settlement discussions culminated with the filing of two Joint Proposals for settling the issues raised by the Department in May 2018, with several parties signing on to the Joint Proposals. These Joint Proposals have NYSEG and RG&E implementing a combined $3.9 million of storm resiliency and restoration projects which will not be paid for by ratepayers. The Joint Proposals are currently before the Commission, and a ruling is expected in 2019.

Leases

On October 21, 2015, RG&E, GNPP and multiple intervenors filed a joint proposal with the regulator for approval of the modified RSS Agreement for the continued operation of the Ginna Facility. On February 23, 2016, the NYPSC unanimously adopted the joint proposal, which provided for a term of the RSSA from April 1, 2015, through March 31, 2017 and RG&E monthly payments to GNPP in the amount of $15.4 million. RG&E was entitled to 70% of revenues from GNPP's sales into the energy and capacity markets, while GNPP was entitled to 30% of such revenues. We accounted for this arrangement as an operating lease. The net expense incurred under this operating lease was $5.6 million for the year ended December 31, 2017.

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

Year	Operating Leases	Capital Leases	Total
(Thousands)			
2019	$1,524	$2,397	$3,921

2020	1,638	1,961	3,599
2021	1,417	1,961	3,378
2022	1,402	1,961	3,363
2023	3,510	1,798	5,308
Thereafter	2,915	-	2,915
Total	**$12,406**	**$10,078**	**$22,484**

Purchase power and natural gas contracts, including nonutility generators

RG&E is the provider of last resort for customers. As a result, the company buys physical energy and capacity from the NYISO. In accordance with the NYPSC's February 26, 2008 Order, RG&E is required to hedge on behalf of non-demand billed customers. The physical electric capacity purchases we make from parties other than the NYISO are to comply with the hedge requirement for electric capacity. The company enters into financial swaps to comply with the hedge requirement for physical electric energy purchases. RG&E also makes purchases from other independent power producers and New York Power Authority (NYPA) under existing contracts or long-term supply agreements in order to comply with the company’s Public Utility Regulatory Policies Act (PURPA) purchase obligation.

RG&E satisfies its natural gas supply requirements through purchases from various producers and suppliers, withdrawals from natural gas storage, capacity contracts and winter peaking supplies and resources. The company operates diverse portfolios of gas supply, firm transportation capacity, gas storage and peaking resources. Actual gas costs incurred by each of the companies are passed through to customers through state regulated purchased gas adjustment mechanisms, subject to regulatory review.

The company purchases the majority of its natural gas supply at market prices under seasonal, monthly or mid-term supply contracts and the remainder is acquired on the spot market. The company acquires firm transportation capacity on interstate pipelines under long-term contracts and utilizes that capacity to transport both natural gas supply purchased and natural gas withdrawn from storage to the local distribution system. The company acquires firm underground natural gas storage capacity using long-term contracts and fills the storage facilities with gas in the summer months for subsequent withdrawal in the winter months.

We recognized expenses of approximately $47.7 million for Normal Purchase Normal Sale (NPNS) purchase power and natural gas contracts including nonutility generators in 2018 and $47.9 million in 2017.

Note 9. 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, six 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 recorded an estimated liability of $161 thousand at December 31, 2018, related to the nine sites. We have recorded an estimated liability of $4.1 million related to another seven sites where we believe it is probable that we will incur remediation costs and/or monitoring costs, although we have not been notified that we are among the potentially responsible parties. It is possible the ultimate cost to remediate the sites may be significantly more than the accrued amount. Our estimate for costs to remediate these sites ranges from $3.9 million to $6.4 million as of December 31, 2018. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to us. Any cost will be flowed through to RG&E ratepayers.

Manufactured gas plants

We have a program to investigate and perform necessary remediation at our twelve sites where gas was manufactured in the past. In 1994 and 1996 we entered into orders on consent with the NYSDEC. Those orders require us to investigate and, where necessary, remediate all of our eleven sites. All eleven sites are included in the New York Voluntary Clean-up Program.

Our estimate for all costs related to investigation and remediation of the twelve sites ranges from $77.9 million to $194.2 million at December 31, 2018. 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 $127.3 million at December 31, 2018, and $129.5 million at December 31, 2017. 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 2046.

Note 10. 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. At December 31, 2018 and 2017, the amount recognized in regulatory assets/liabilities was a gain of $1.4 million and $0.1 million, respectively, for electricity derivatives. For the years ended December 31, 2018 and 2017, the amount reclassified from regulatory assets/liabilities into income, which is included in electricity purchased, was a gain of $4.6 million and a loss of $12.5 million, respectively.

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. At December 31, 2018 and 2017, the amount recognized in regulatory assets/liabilities for natural gas hedges was a gain of $0.2 million and a loss of $1.8 million, respectively. For the years ended December 31, 2018 and 2017 the amount reclassified from regulatory assets/liabilities into income, which is included in natural gas purchased, was a gain of $0.5 million and a loss of $0.2 million, respectively.

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

Year to settle	Electricity Contracts Mwhs	Natural Gas Contracts Dths	Fleet Fuel Contracts Gals
As of December 31, 2018			
2019	1,313,375	4,560,000	397,100
2020	219,600	730,000	-
As of December 31, 2017			
2018	1,286,375	3,490,000	412,100
2019	-	680,000	-

The offsetting of derivatives, location in the balance sheet and amounts of derivatives as of December 31, 2018 and 2017, respectively, consisted of:

December 31, 2018	Derivative Assets - Current	Derivative Assets – Noncurrent	Derivative Liabilities - Current	Derivative Liabilities - Noncurrent
(In thousands)				`
Not designated as hedging instruments				
Derivative assets	$5,347	$625	$3,630	$591
Derivative liabilities	(3,630)	(591)	(3,630)	(714)
	1,717	**34**	**-**	**(123)**
Designated as hedging instruments				
Derivative assets	-	-	-	-

Derivative liabilities	-	-	(327)	-
	-	**-**	**(327)**	**-**
Total derivatives before offset of cash collateral	1,717	34	(327)	(123)
Cash collateral receivable (payable)	-	-	-	123
Total derivatives as presented in the balance sheet	**$1,717**	**$34**	**$(327)**	**$-**

December 31, 2017	Derivative Assets – Current	Derivative Assets – Noncurrent	Derivative Liabilities - Current	Derivative Liabilities – Noncurrent
(In thousands)				
Not designated as hedging instruments				
Derivative assets	$4,271	$-	$4,129	$-
Derivative liabilities	(4,129)	-	(5,787)	(104)
	142	**-**	**(1,658)**	**(104)**
Designated as hedging instruments				
Derivative assets	8	-	8	-
Derivative liabilities	(8)	-	(49)	-
	-	**-**	**(41)**	**-**
Total derivatives before offset of cash collateral	142		(1,699)	(104)
Cash collateral receivable (payable)	-	-	1,658	104
Total derivatives as presented in the balance sheet	**$142**	**$-**	**$(41)**	**$-**

As of both December 31, 2018 and 2017, the derivative assets - noncurrent and derivative liabilities are presented within other current and non-current assets and liabilities of the balance sheet, respectively.

The effect of hedging instruments on other comprehensive income (OCI) and income was:

Year Ended December 31,	(Loss) Gain Recognized in OCI on Derivatives	Location of (Loss) Gain Reclassified from Accumulated OCI into Income	Loss Reclassified from Accumulated OCI into Income
Derivatives in Cash Flow Hedging Relationships	**Effective Portion**	**Effective Portion**	
(Thousands)			
2018			
Interest rate contracts	$-	Interest expense	$(5,768)
Commodity contracts:			
Other	(287)	Other operating expenses	(1)
Total	**$(287)**		**$(5,769)**

2017			
Interest rate contracts	$-	Interest expense	$(5,768)
Commodity contracts:			
Other	(155)	Other operating expenses	(160)
Total	**$(155)**		**$(5,928)**

The amount in AOCI related to previously settled forward starting interest rate swaps and accumulated amortization, at December 31, 2018 is a net loss of $56.7 million as compared to $62.5 million at December 31, 2017. For the year ended December 31, 2018, we recorded $5.8 million in net derivative losses related to discontinue cash flow hedges. We will amortize approximately $4.7 million of discontinued cash flow hedges in 2019.

As of December 31, 2018, $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, 2018.

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, 2018, is $2.7 million for which we have posted collateral.

Note 11. Fair Value of Financial Instruments and Fair Value Measurements

The estimated fair value of debt amounted to $1,176 million as of December 31, 2018 and $1,129 million as of December 31, 2017. 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, except for unsecured pollution control notes-variable with a fair value of $61.0 million as of December 31, 2017, which were repaid in 2018 and were are considered Level 3. The fair value of these unsecured pollution control notes-variable are determined using unobservable interest rates as the market for these notes is inactive.

Assets and liabilities measured at fair value on a recurring basis

The financial instruments measured at fair value as of December 31, consist of:

Description (Thousands)	**(Level 1)**	**(Level 2)**	**(Level 3)**	**Netting**	**Total**
2018					
Assets					
Noncurrent investments primarily money market funds	$2,662	$-	$-	$-	$2,662
Derivatives					
Commodity contracts:					
Electricity	5,082	-	-	(3,526)	1,556
Gas	890	-	-	(695)	195
Other	-	-	-	-	-
Total	**$8,634**	**$-**	**$-**	**$(4,221)**	**$4,413**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	(3,650)	-	-	3,650	-
Natural gas	(694)	-	-	694	-
Other	-	-	(327)	-	(327)
Total	**$(4,344)**	**$-**	**$(327)**	**$4,344**	**$(327)**
2017					
Assets					
Noncurrent investments primarily money market funds	$3,781	$-	$-	$-	$3,781
Derivatives					
Commodity contracts:					
Electricity	4,236	-	-	(4,094)	142
Gas	35	-	-	(35)	-
Other	-	-	8	(8)	-
Total	**$8,052**	**$-**	**$8**	**$(4,137)**	**$3,923**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	(4,094)	-	-	4,094	-
Natural gas	(1,798)	-	-	1,798	-
Other	-	-	(49)	8	(41)
Total	**$(5,892)**	**$-**	**$(49)**	**$5,900**	**$(41)**

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

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

We determine the fair value of our 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.

Instruments measured at fair value on a recurring basis using significant unobservable inputs

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)	
	Derivatives, Net	
Year ended December 31,	**2018**	**2017**
(Thousands)		
Beginning balance	$41	$46
Total (losses) gains (realized/unrealized)		
Included in earnings	(1)	(160)
Included in other comprehensive income	287	155
Ending balance	**$327**	**$41**

The gains and losses included in earnings for the periods above are reported in Operations and maintenance of the statements of income.

Note 12. Accumulated Other Comprehensive Loss

	Balance January 1, 2017	**2017 Change**	**Balance December 31, 2017**	**Adoption of new accounting standard**	**2018 Change**	**Balance December 31, 2018**
(Thousands)						
Net unrealized holding gain on investments, net of income tax expense of $0 for 2017 and 2018	$39	$-	$39	$-	$-	$39
Amortization of pension cost for nonqualified plans, net of tax (benefit)/ expense of $(40) for 2017 and $114 for 2018	(1,641)	(61)	(1,702)	-	323	(1,379)
Loss for nonqualified pension plans				(54)		

Unrealized (loss) on derivatives qualified as hedges:						
Unrealized (loss) during period on derivatives qualified as hedges, net of income tax expense (benefit) of $(61) for 2017 and $(75) for 2018		(94)			(212)	
Reclassification adjustment for loss included in net income, net of income tax expense of $62 for 2017 and $0 for 2018		98			1	
Reclassification adjustment for loss on settled cash flow treasury hedges, net of income tax expense of $2,263 for 2017 and $1,508 for 2018		3,505			4,260	
Net unrealized (loss) gain on derivatives qualified as hedges	**(41,204)**	**3,509**	**(37,695)**	**-**	**4,049**	**(33,646)**
Accumulated Other Comprehensive Loss	**$(42,806)**	**$3,448**	**$(39,358)**	**$(54)**	**$4,372**	**$(35,040)**

Note 13. Post-retirement and Similar Obligations

We have funded noncontributory defined benefit pension plans that cover the eligible employees. For most employees, generally those hired before 2002, the plans provide defined benefits based on years of service and final average salary. Employees hired in 2002 or later are covered under a cash balance plan or formula where their benefit accumulates based on a percentage of annual salary and credited interest. During 2013 the company announced that we would freeze the benefits for all non-union employees covered under the cash balance plans effective December 31, 2013. Their earned balances would continue to accrue interest, but would no longer be increased by a percentage of earnings. In place of the pension benefit for these employees, they will receive a minimum contribution to their account under their respective company's defined contribution plan. There was no change to the defined benefit plans for employees covered under the plans that provide defined benefits based on years of service and final average salary.

The company maintains a 401(k) Savings and Retirement Plan (the Plan) for all eligible employees as defined in the Plan agreement. Participants in the Plan may contribute a percentage of their compensation and the company may match a predetermined percentage of the participant contributions. Expenses under the Plan for the Company totaled approximately $3.1 million in 2018 and 2017.

We also have pension and other postretirement health care benefit plans covering substantially all of our employees. The health care plans are contributory with participants' contributions adjusted annually.

***Obligations and funded status*:**

	Pension Benefits		**Postretirement Benefits**	
	2018	**2017**	**2018**	**2017**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	$414,289	$417,532	$75,425	$76,344
Service cost	5,457	5,728	278	326
Interest cost	14,084	16,313	2,644	3,038
Plan participants' contributions	-	-	664	684
Amendments	-	-	(3,442)	-
Actuarial loss/(gain)	(15,000)	20,478	(5,739)	102
Benefits paid	(41,610)	(45,762)	(5,184)	(5,069)

Benefit obligation at December 31	**$377,220**	**$414,289**	**$64,646**	**$75,425**
Change in plan assets				
Fair value of plan assets at January 1	$309,048	$308,374	$-	**$-**
Actual return on plan assets	(13,681)	40,236	-	**-**
Employer and plan participants' contributions	12,977	6,200	5,184	5,069
Benefits paid	(41,610)	(45,762)	(5,184)	(5,069)
Fair value of plan assets at December 31	**266,734**	**309,048**	**$-**	**$-**
Funded status at December 31	**$(110,486)**	**$(105,241)**	**$(64,646)**	**$(75,425)**

Amounts recognized in the balance sheet	**Pension Benefits**		**Postretirement Benefits**	
December 31,	**2018**	**2017**	**2018**	**2017**
(Thousands)				
Other current liabilities	$-	$-	$(5,244)	$(5,272)
Pension and other postretirement benefits	(110,486)	(105,241)	(59,402)	(70,153)
Total	**$(110,486)**	**$(105,241)**	**$(64,646)**	**$(75,425)**

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,	**2018**	**2017**	**2018**	**2017**
(Thousands)				
Net loss	$87,928	$95,279	$(3,825)	$3,228
Prior service cost (credit)	$-	$223	$(5,149)	$(2,789)

Our accumulated benefit obligation for all defined benefit pension plans was $349.5 million at December 31, 2018 and $387.6 million at December 31, 2017.

The projected benefit obligation and the accumulated benefit obligation exceeded the fair value of pension plan assets as of both December 31, 2018 and 2017. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets as of December 31, 2018 and 2017.

December 31	**2018**	**2017**
(Thousands)		
Projected benefit obligation	$377,220	$414,289
Accumulated benefit obligation	$349,547	$387,627
Fair value of plan assets	$266,734	$309,049

***Components of net periodic benefit cost and other amounts recognized in regulatory assets and regulatory liabilities*:**

	Pension Benefits		**Postretirement Benefits**	
Years Ended December 31,	**2018**	**2017**	**2018**	**2017**
(Thousands)				
Net periodic benefit cost				
Service cost	$5,457	$5,728	$278	$326
Interest cost	14,084	16,313	2,644	3,038
Expected return on plan assets	(21,028)	(22,571)	-	-
Amortization of prior service cost (credit)	222	403	(1,082)	(1,409)
Amortization of net loss	27,059	22,883	1,314	566
Net periodic benefit cost	**$25,794**	**$22,756**	**$3,154**	**$2,521**

Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net (gain) loss	$19,708	$2,813	(5,739)	$102
Amortization of net (loss) gain	(27,059)	(22,883)	(1,314)	(566)
Prior service cost	-	-	(3,442)	-
Amortization of prior service (cost) credit	(223)	(403)	1,082	1,409
Total recognized in regulatory assets and regulatory liabilities	(7,574)	(20,473)	(9,413)	945
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$18,220**	**$2,283**	**$(6,259)**	**$3,466**

We include the net periodic benefit cost in other operating expenses. The net periodic benefit cost for postretirement benefits represents the amount expensed for providing health care benefits to retirees and their eligible dependents.

Amounts expected to be amortized from regulatory assets or regulatory liabilities into net periodic benefit cost for the fiscal year ending December 31, 2019	Pension Benefits	Postretirement Benefits
(Thousands)		
Estimated net loss	$14,062	$663
Estimated prior service cost (credit)	$-	$(1,390)

We expect that no pension benefit or postretirement benefit plan assets will be returned to us during the fiscal year ending December 31, 2019.

Weighted-average assumptions used to determine benefit obligations at December 31,	Pension Benefits		Postretirement Benefits	
	2018	2017	2018	2017
Discount rate	3.93%	3.63%	3.93%	3.63%
Rate of compensation increase	3.90%	4.00%	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.

Weighted-average assumptions used to determine net periodic benefit cost for the years ended December 31,	Pension Benefits		Postretirement Benefits	
	2018	2017	2018	2017
Discount rate	3.63%	4.12%	3.63%	4.12%
Expected long-term return on plan assets	7.30%	7.30%	N/A	N/A
Rate of compensation increase	4.00%	4.00%	N/A	N/A

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations and the effect of rebalancing of plan assets discussed below. That analysis considered current capital market conditions and projected conditions. Our policy is to calculate the expected return on plan assets using the market related value of assets. We amortize unrecognized actuarial gains and losses over 10 years from the time they are incurred.

Assumed health care cost trend rates to determine benefit obligations at December 31,	2018	2017
Health care cost trend rate (pre 65/post 65)	7.00%-7.75%	6.75%-8.50%
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	2026/2028

The assumed health care cost trend rates can have a significant effect on the amounts reported for the health care plans. Due to the RG&E retirees having moved into a different program, it is no longer sensitive to medical trend changes. The company is limited to a specific dollar amount and will not change in the future.

***Contributions*:** In accordance with our funding policy, we make annual contributions of not less than the minimum required by applicable regulations. We expect to contribute $12.3 million to our pension benefit plans in 2019.

***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)			
2019	$36,504	$5,150	-
2020	$36,268	$5,063	-
2021	$35,568	$5,008	-
2022	$35,562	$4,940	-
2023	$34,543	$4,872	-
2024 – 2028	$153,535	$22,440	-

Plan assets: Our pension benefits plan assets are held in a master trust providing for a single trustee/custodian, a uniform investment manager lineup, and an efficient, cost-effective means of allocating expenses and investment performance to each plan under the master trust. Our primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our tolerance for risk. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. Our primary means for achieving capital preservation is through diversification of the trust's investments while avoiding significant concentrations of risk in any one area of the securities markets. Within each asset group, further diversification is achieved through utilizing multiple asset managers and systematic allocation to various asset classes; providing broad exposure to different segments of the equity, fixed-income and alternative investment markets.

Networks' asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets within broad categories of asset classes made up of Return-Seeking and Liability-Hedging investments. Within the Return-Seeking category, we have targets of 35%-53% in equity securities, 40%-45% for Liability-Hedging assets and 7%-20% for alternative investments. Return-Seeking investments generally consist of domestic, international, global, and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking assets also include investments in real estate, absolute return, and strategic markets. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS, and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of Network's pension benefits plan assets at December 31, 2018 and 2017, by asset category are shown in the following table. RG&E's share of the total consolidated assets is approximately 11% for 2018 and 2017.

Notes to Financial Statements

Asset Category	Total	Fair Value Measurements at December 31, Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(Thousands)				
2018				
Cash and cash equivalents	$51,661	$-	$51,661	$-
U.S. government securities	15,137	15,137	-	-
Common stocks	90	90	-	-
Registered investment companies	216,508	216,508	-	-
Corporate bonds	412,703	-	412,703	-
Preferred stocks	3,512	270	3,242	-
Equity commingled funds	813,186	179,510	633,676	-
Other investments, principally annuity and fixed income	71,412	-	71,412	-
	$1,584,209	**$411,515**	**$1,172,694**	**$-**
Other investments measured at net asset value	925,888			
Total	**$2,510,097**			
2017				
Cash and cash equivalents	$17,531	$-	$17,531	$-
U.S. government securities	13,338	13,338	-	-
Common stocks	129,312	129,312	-	-
Registered investment companies	105,037	105,037	-	-
Corporate bonds	447,124	-	447,124	-
Preferred stocks	4,381	299	4,082	-
Equity commingled funds	435,635	185,989	249,646	-
Other investments, principally annuity and fixed income	548,957	-	548,957	-
	$1,701,315	**$433,975**	**$1,267,340**	**$-**
Other investments measured at net asset value	1,126,017			
Total	**$2,827,332**			

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, 2018 and 2017.

Note 14. Other Income and Other Deductions

Years Ended December 31,	**2018**	**2017**
(Thousands)		
Interest and dividend income	$1,781	$528
Allowance for funds used during construction	11,533	11,199
Gain on sale of property	60	20
Carrying costs on regulatory assets	7,175	3,684
Miscellaneous	89	67
Total other income	**$20,638**	**$15,498**
Pension non-service components	$(23,817)	$(19,223)
Miscellaneous	(589)	(485)
Total other deductions	**$(24,406)**	**$(19,708)**

Note 15. Related Party Transactions

Certain Networks subsidiaries borrow from AGR, the parent of Networks, through intercompany revolving credit agreements, including RG&E. For RG&E the intercompany revolving credit agreements provide access to supplemental liquidity. See Note 7 for further detail on the credit facility with AGR.

Avangrid Service Company provides some administrative and management services to Networks operating utilities, including RG&E, pursuant to service agreements. The cost of those services is allocated in accordance with methodologies set forth in the service agreements. The cost allocation methodologies vary depending on the type of service provided. Management believes such allocations are reasonable. The cost for services provided to RG&E by AGR and its affiliates were approximately $52.8 million in 2018 and $66.9 million for 2017 and the charge for services provided by RG&E to AGR and its subsidiaries were approximately $14.6 million in 2018 and $12.8 million for 2017. 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 $42.7 million at December 31, 2018 and $41.6 million at December 31, 2017 is mostly payable to Avangrid Service Company.

Of the balance in notes receivable from affiliates of $106.4 million at December 31, 2018, $91.8 million is from the UIL companies and $14.6 million is from NYSEG. The balance of $39.7 million at December 31, 2017 is from the UIL companies. 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 16. Subsequent Events

The company has performed a review of subsequent events through March 29, 2019, which is the date these financial statements were available to be issued, and no subsequent events have occurred from January 1, 2019 through such date.