The United Illuminating Company

Financial Statements

As of and for the Years Ended December 31, 2022 and 2021

The United Illuminating Company

Index

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

Independent Auditors' Report

The Board of Directors
The United Illuminating Company:

Opinion

We have audited the financial statements of The United Illuminating Company (the Company), which comprise the balance sheets as of December 31, 2022 and 2021, 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.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

Basis for Opinion

We conducted our audits in accordance with auditing standards generally accepted in the United States of America (GAAS). Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with U.S. generally accepted accounting principles, and for 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.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for one year after the date that the financial statements are issued.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

KPMG

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control related matters that we identified during the audit.

KPMG LLP

New York, New York
April 12, 2023

The United Illuminating Company
Statements of Income

Years Ended December 31,		2022		2021
(Thousands)				
Operating Revenues	$	**1,155,867**	$	**1,070,905**
Operating Expenses				
Electricity purchased		395,596		302,133
Operations and maintenance		386,328		390,980
Depreciation and amortization		113,006		111,204
Taxes other than income taxes, net		101,082		102,750
Total Operating Expenses		**996,012**		**907,067**
Operating Income		**159,855**		**163,838**
Other income		21,420		23,134
Other deductions		(9,730)		(3,199)
Earnings from equity method investments		3,579		6,357
Interest expense, net of capitalization		(41,881)		(39,958)
Income Before Income Tax		**133,243**		**150,172**
Income tax expense		20,554		24,795
Net Income	$	**112,689**	$	**125,377**

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

The United Illuminating Company
Statements of Comprehensive Income

Years Ended December 31,		2022		2021
(Thousands)				
Net Income	$	**112,689**	$	**125,377**
Other Comprehensive Income (Loss)				
Amortization of pension cost for non-qualified plans and current year actuarial gain (loss), net of income tax expense of $1,095 for 2022 and tax benefit of ($1,158) for 2021, respectively		2,995		(3,837)
Unrealized loss during the year on derivatives qualifying as cash flow hedges, net of income tax benefit of ($7) for 2021		—		(16)
Reclassification to net income of loss on settled cash flow hedges, net of income tax expense of $7 for 2022		16		—
Other Comprehensive Income (Loss)		**3,011**		**(3,853)**
Comprehensive Income	$	**115,700**	$	**121,524**

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

The United Illuminating Company
Balance Sheets

As of December 31,		2022		2021
(Thousands)				
Assets				
Current Assets				
Cash and cash equivalents	$	1	$	—
Accounts receivable and unbilled revenues, net		170,213		147,782
Accounts receivable from affiliates		1,528		1,165
Notes receivable from affiliates		82,600		64,600
Materials and supplies		8,380		9,792
Derivative assets		489		427
Prepayments and other current assets		5,196		3,822
Regulatory assets		55,984		44,318
Total Current Assets		**324,391**		**271,906**
Utility plant, at original cost		3,642,320		3,485,699
Less accumulated depreciation		(1,046,592)		(958,844)
Net Utility Plant in Service		**2,595,728**		**2,526,855**
Construction work in progress		268,805		216,553
Total Utility Plant		**2,864,533**		**2,743,408**
Operating lease right-of-use assets		12,552		11,339
Equity method investments		82,533		86,557
Other property and investments		13,594		15,655
Regulatory and Other Assets				
Regulatory assets		318,819		370,194
Derivative assets		857		1,284
Other		23,871		22,378
Total Regulatory and Other Assets		**343,547**		**393,856**
Total Assets	**$**	**3,641,150**	**$**	**3,522,721**

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

The United Illuminating Company
Balance Sheets

As of December 31,	2022	2021
(Thousands)		
Liabilities		
Current Liabilities		
Current portion of debt	$ 139,044	$ 162,137
Accounts payable and accrued liabilities	159,724	140,732
Accounts payable to affiliates	68,294	69,991
Interest accrued	10,349	11,166
Taxes accrued	18,714	26,975
Operating lease liabilities	655	1,002
Derivative liabilities	16,580	14,586
Other current liabilities	37,851	37,701
Regulatory liabilities	97,766	45,113
Total Current Liabilities	**548,977**	**509,403**
Regulatory and Other Liabilities		
Regulatory liabilities	347,239	352,021
Other Non-current Liabilities		
Deferred income taxes	406,302	389,550
Pension and other postretirement	121,433	162,445
Operating lease liabilities	16,048	14,644
Derivative liabilities	29,388	45,820
Environmental remediation costs	19,316	22,134
Other	30,968	30,987
Total Regulatory and Other Liabilities	**970,694**	**1,017,601**
Non-current debt	785,140	725,071
Total Liabilities	**2,304,811**	**2,252,075**
Commitments and Contingencies		
Common Stock Equity		
Common stock (no par value, 30,000,000 shares authorized and 100 shares outstanding at December 31, 2022 and December 31, 2021)	1	1
Additional paid-in capital	806,652	806,659
Retained earnings	537,117	474,428
Accumulated other comprehensive loss	(7,431)	(10,442)
Total Common Stock Equity	**1,336,339**	**1,270,646**
Total Liabilities and Equity	**$ 3,641,150**	**$ 3,522,721**

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

The United Illuminating Company
Statements of Cash Flows

Years Ended December 31,	2022	2021
(Thousands)		
Cash Flow from Operating Activities:		
Net income	**$ 112,689**	**$ 125,377**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	113,006	111,204
Regulatory assets/liabilities amortization	(36,343)	(60,670)
Regulatory assets/liabilities carrying cost	(5,316)	(8,489)
Amortization of debt issuance costs	437	613
Deferred taxes	(10,100)	(6,339)
Pension cost	9,027	11,990
Stock-based compensation	45	44
Earnings from equity method investments	(3,569)	(6,441)
Cash distribution from equity method investments	3,578	6,835
Other non-cash Items	(5,886)	(6,818)
Changes in operating assets and liabilities:		
Accounts receivable, from affiliates, and unbilled revenues	(22,794)	37,137
Inventories	1,412	(3,528)
Accounts payable, to affiliates, and accrued liabilities	(9,286)	67,108
Taxes accrued	(8,261)	21,167
Other assets/liabilities	(30,216)	15,341
Regulatory assets/liabilities	113,787	43,117
Net Cash Provided by Operating Activities	**222,210**	**347,648**
Cash Flow from Investing Activities:		
Capital expenditures	(198,444)	(198,531)
Contributions in aid of construction	3,623	881
Notes receivable from affiliates	(18,000)	(49,625)
Proceeds from sale of utility plant	168	—
Cash distribution from equity method investments	4,015	3,852
Net Cash Used in Investing Activities	**(208,638)**	**(243,423)**
Cash Flow from Financing Activities:		
Non-current debt issuance	198,929	—
Repayments of non-current debt	(162,500)	—
Dividends paid	(50,000)	(105,000)
Net Cash Used in Financing Activities	**(13,571)**	**(105,000)**
Net Increase (Decrease) in Cash and Cash Equivalents	**1**	**(775)**
Cash and Cash Equivalents, Beginning of Period	**—**	**775**
Cash and Cash Equivalents, End of Period	**$ 1**	**$ —**

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

The United Illuminating Company
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 Loss		Total Common Stock Equity
Balance, December 31, 2020	**100**	**$**	**1**	**$**	**806,230**	**$**	**454,051**	**$**	**(6,589)**	**$**	**1,253,693**
Net income	—		—		—		125,377		—		125,377
Other comprehensive loss, net of tax	—		—		—		—		(3,853)		(3,853)
Comprehensive income											121,524
Stock-based compensation	—		—		429		—		—		429
Common stock dividends	—		—		—		(105,000)		—		(105,000)
Balance, December 31, 2021	**100**		**1**		**806,659**		**474,428**		**(10,442)**		**1,270,646**
Net income	—		—		—		112,689		—		112,689
Other comprehensive income, net of tax	—		—		—		—		3,011		3,011
Comprehensive income											115,700
Stock-based compensation	—		—		(7)		—		—		(7)
Common stock dividends	—		—		—		(50,000)		—		(50,000)
Balance, December 31, 2022	**100**	**$**	**1**	**$**	**806,652**	**$**	**537,117**	**$**	**(7,431)**	**$**	**1,336,339**

(*) No par value.
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**:** The United Illuminating Company (UI, the company, we, our, us) is a regulated operating electric public utility engaged 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 serves approximately 343,400 customers as of December 31, 2022 in its service territory of approximately 335 square miles in southwestern Connecticut.

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.

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

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

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

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

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

Equity method investments**:** We account for joint ventures and other equity investments that do not meet consolidation criteria using the equity method. We reflect earnings (losses) recognized under the equity method in the statements of income as "Earnings (losses) from equity method investments." We recognize dividends received from equity method investments as a reduction in the carrying amount of the investment and not as dividend income. We assess and record an impairment of our equity method investments in earnings for a decline in value that we determine to be other than temporary.

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

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

We transfer assets from “Construction work in progress” to “Utility plant” when they are available for service.

We determine depreciation expense for utility plant in service using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Consistent with FERC accounting requirements, we charge the original cost of utility plant retired or otherwise disposed of to accumulated depreciation. Our composite rates for depreciation were 2.9% of average depreciable property for both 2022 and 2021. We amortize our capitalized software cost, which is included in other plant, using the straight line method, based on useful lives of 3 to 15 years. Capitalized software costs were approximately $298.8 million as of December 31, 2022, and $290.0 million as of December 31, 2021. Depreciation expense was $95.6 million in 2022 and $93.5 million in 2021. Amortization of capitalized software was $17.4 million in 2022 and $17.7 million in 2021.

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

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

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

Utility Plant	**Estimated useful life range (years)**	**2022**	**2021**
(Thousands)			
Distribution	6-75	$ 2,067,777	$ 1,950,227
Transmission	6-50	1,109,846	1,123,909
Other	6-42	464,697	411,563
Total Utility Plant in Service		**3,642,320**	**3,485,699**
Total accumulated depreciation		(1,046,592)	(958,844)
Total Net Utility Plant in Service		**2,595,728**	**2,526,855**
Construction work in progress		268,805	216,553
Total Utility Plant		**$ 2,864,533**	**$ 2,743,408**

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

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

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

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

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

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

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

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

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

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

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

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

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

Changes in conditions or the occurrence of unforeseen events could require discontinuance of the hedge accounting or could affect the timing of the reclassification of gains or losses on cash flow hedges from OCI into earnings.

***Cash and cash equivalents*:** Cash and cash equivalents include cash, bank accounts, and other highly liquid short-term investments. We consider all highly liquid investments with a maturity date of three months or less when acquired to be cash equivalents and include those investments in “Cash and cash equivalents.” Restricted cash represents cash legally set aside for a specified purpose as part of an agreement with a third party. Restricted cash is included in “Other non-current assets” on our balance sheets. We classify book overdrafts representing outstanding checks in excess of funds on deposit as “Accounts payable and accrued liabilities” on our balance sheets. We report changes in book overdrafts in the operating activities section of the statements of cash flows.

Concentration of risk: We maintain our cash and cash equivalents in accounts with major financial institutions in the form of demand deposits and money market accounts. Deposits in these financial institutions may exceed the amount of federal deposit insurance provided on such deposits.

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

(Thousands)		2022		2021
Cash paid during the year ended December 31:				
Interest, net of amounts capitalized	$	36,633	$	37,475
Income taxes paid, net	$	36,715	$	8,351

Of the income taxes paid, substantially all was paid to AGR under the tax sharing agreement. Interest capitalized was $3.6 million in 2022 and $3.1 million in 2021. Accrued liabilities for utility plant additions were $27.5 million as of December 31, 2022. There were no accrued liabilities for utility plant additions as of December 31, 2021.

***Trade receivables and unbilled revenues, net of allowance for credit losses*:** We record trade receivables at amounts billed to customers and we record unbilled revenues based on an estimate of energy delivered or services provided to customers. The estimates for unbilled revenues are determined based on various assumptions, including current month energy load requirements, billing rates by customer class and delivery loss factors. Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

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

Trade receivables at December 31 include unbilled revenues of $50.8 million for 2022 and $47.5 million for 2021, and are shown net of an allowance for credit losses at December 31 of $13.5 million for 2022 and $12.3 million for 2021. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $34.3 million in 2022 and $33.3 million in 2021.

We establish our allowance for credit losses, including for unbilled revenue (also referred to as contract assets), by using both historical average loss percentages to project future losses, and by establishing a specific allowance for known credit issues or for specific items not considered in the historical average calculation. We also consider whether we need to adjust historical loss rates to reflect the effects of current conditions and forecasted changes considering various economic indicators (e.g., Gross Domestic Product, Personal Income, Consumer Price Index, Unemployment Rate) over the contractual life of the trade receivables. We write off amounts when we have exhausted reasonable collection efforts.

***Variable Interest Entities*:** We have identified GenConn as a variable interest entity (VIE), which is accounted for under the equity method. We are 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 Contracts for Differences (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, our 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 on our balance sheets in the carrying value of our 50% ownership position in GenConn and in our statements of income through "Earnings (losses) from equity method investments." Such exposure to loss cannot be determined at this time.

We have identified the selected capacity resources with which it has CfDs as VIEs and have concluded that we are not the primary beneficiary as we do not have the power to direct any of the significant activities of these capacity resources. As such, we have not consolidated the selected capacity resources. Our maximum exposure to loss through these agreements is limited to the settlement amount under the CfDs as described in Note 11. We have no requirement to absorb additional losses nor have we provided any financial or other support during the periods presented that were not previously contractually required.

We have identified the entities for which we are 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, we have aggregated the contracts based on similar risk characteristics and significance to UI. We are not the primary beneficiary as we do not have the power to direct any of the significant activities of these entities. Our exposure to loss is primarily related to the purchase and resale of the RECs, but, any losses incurred are recoverable through electric rates.

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

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

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

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

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

***Environmental remediation liability*: In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. We record our environmental liabilities on an undiscounted basis. We expect to pay our environmental liability accruals through the year 2030.

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 (PBO). For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. We generally reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in OCI, as management believes it is probable that such items will be recoverable through the ratemaking process. Certain non-qualified plan expenses are not recoverable through the ratemaking process and we present the unrecognized prior service costs and credits and unrecognized actuarial gains and losses in accumulated other comprehensive loss. If a plan meets settlement or curtailment accounting criteria, we recognize a regulatory asset or liability if these costs are probable of recovery from ratepayers. 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 employees active on the date of the amendment. Effective March 31, 2022, the amortization period for prior service cost changes for the UI Pension Plan was updated from average remaining service to future expected lifetime as the plan was frozen, or predominantly frozen, to future accruals. We amortize unrecognized actuarial gains and losses in excess of 5% of the greater of PBO or market-related value of assets (MRVA) related to the pension and other postretirement benefits plans on straight line basis over future working lifetime. Effective March 31, 2022, the amortization period for the UI Pension Plan was updated from future working lifetime to future expected lifetime as the plan was frozen, or predominantly frozen, to future accruals. Our policy is to calculate the expected return on plan assets using the market-related value of assets. We determine that value by recognizing the difference between actual returns and expected returns over a five-year period.

Income taxes**:** In August 2022, the Inflation Reduction Act of 2022 ("IRA") was signed into law in the United States. The IRA created a new corporate alternative minimum tax ("CAMT") of 15% on adjusted financial statement income and an excise tax of 1% on the value of certain stock repurchases. Based on initial guidance, UI currently expects to be subject to the CAMT starting in 2023 but does not expect it to have a material impact on earnings, financial condition, or cash flow. Given the complexity and uncertainty around the applicability of the legislation to our specific facts and circumstances, the company continues to analyze the IRA provisions while waiting on pending Department of Treasury regulatory guidance.

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

The aggregate amount of the related party income tax payable balance due to AGR was $7.4 million at December 31, 2022 and $14.0 million at December 31, 2021.

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

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

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

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

Uncertain tax positions are 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.

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

Adoption of New Accounting Pronouncements

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

There have been no new accounting pronouncements adopted as of December 31, 2022.

Accounting Pronouncements Issued But Not Yet Adopted

There have been no new accounting pronouncements issued but not yet adopted that are expected to have a material effect on our 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 credit losses and unbilled revenues; (2) asset impairments; (3) investments in equity instruments; (4) depreciable lives of assets; (5) income tax valuation allowances; (6) uncertain tax positions; (7) reserves for professional, workers' compensation, and comprehensive general insurance liability risks; (8) contingency and litigation reserves; (9) fair value measurements; (10) earnings sharing mechanism; (11) environmental remediation liabilities; and (12) pension and other postretirement employee benefits. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our financial statements will change as new events occur, as more experience is acquired, as additional information is obtained, and as our operating environment changes. We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside specialists to assist in our evaluations, as considered necessary. Actual results could differ from those estimates.

***Union collective bargaining agreements*:** Approximately 61.7% 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

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 previously approved three-year distribution rate schedules became effective January 1, 2017 through December 31, 2019, and included, among other things, annual tariff increases and an ROE of 9.10% based on a 50.00% 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. Given the expiration of the rate plan, UI has been operating under the 2019 approved rate schedules.

On September 9, 2022, UI filed a distribution revenue requirement case. UI’s filing proposes a three-year rate plan commencing September 1, 2023 through August 31, 2026. The filing is based on a test year ending December 31, 2021, for the rate years beginning September 1, 2023 (“UI Rate Year 1”), September 1, 2024 (“UI Rate Year 2”), and September 1, 2025 (“UI Rate Year 3”). UI is requesting that PURA approve new distribution rates to recover an increase in revenue requirements of approximately $102 million in UI Rate Year 1, an incremental approximately $17 million in UI Rate Year 2, and an incremental approximately $17 million in UI Rate Year 3, compared to total revenues that would otherwise be recovered under UI’s current rate schedules. UI’s Rate Plan also includes several measures to moderate the impact of the proposed rate update for all customers, including, without limitation a rate levelization proposal to spread the proposed total rate increase over the three rate years, which would result in a change in revenue in UI Rate Year 1 of approximately $54 million. Other parties filed direct testimony on December 13, 2022 and UI filed its rebuttal testimony on January 6, 2023. In February and March, 2023, UI attended 15 days of evidentiary hearings in support of its application. Litigation of the case is expected to take approximately one year with new rates expected to go into effect on or around September 2023. We cannot predict the outcome of this matter.

Connecticut Energy Legislation

On October 7, 2020, the Governor of Connecticut signed into law an energy bill that, among other things, instructs PURA to revise the rate-making structure in Connecticut to adopt performance-based rates for each electric distribution company, increases the maximum civil penalties assessable for failures in emergency preparedness, and provides for certain penalties and reimbursements to customers after storm outages greater than 96 hours and extends rate case timelines.

Pursuant to the legislation, on October 30, 2020, PURA re-opened a docket related to new rate designs and review, expanding the scope to consider (a) the implementation of an interim rate decrease; (b) low-income rates; and (c) economic development rates. Separately, UI was due to make its annual RAM filing on March 8, 2021 for the approval of its RAM Rate Components reconciliations: Generation Services Charges, By-passable Federally Mandated Congestion Costs, System Benefits Charge, Transmission Adjustment Charge and RDM.

On March 9, 2021, UI, jointly with the Office of the CT Attorney General, the Office of CT Consumer Counsel, DEEP and PURA’s Office of Education, Outreach, and Enforcement entered into a settlement agreement and filed a motion to approve the settlement agreement, which addressed issues in both dockets.

In an order dated June 23, 2021, PURA approved the as amended settlement agreement in its entirety and it was executed by the parties. The settlement agreement includes a contribution by UI of $5 million and provides customers rate credits of $50 million while allowing UI to collect $52 million in RAM, all over a 22-month period ending April 2023 and also includes a distribution base rate freeze through April 2023.

Pursuant to the legislation, PURA opened a docket to consider the implementation of the associated customer compensation and reimbursement provisions in emergency events where customers were without power for more than 96 consecutive hours. On June 30, 2021, PURA issued a final decision implementing the legislative mandate to create a program pursuant to which residential customers will receive $25 for each day without power after 96 hours and also receive reimbursement of $250 for spoiled food and medicine. The decision emphasizes that no costs incurred in connection with this program are recoverable from customers. The Company is reviewing the requirements of this program and evaluating next steps.

Power Supply Arrangements

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

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

UI has wholesale power supply agreements in place for its entire standard service load for the first half of 2023, 70% of the second half of 2023, and 20% of the first half of 2024. Supplier of last resort service is procured on a quarterly basis and UI is self managing the last resort service for the first quarter of 2023 and has a wholesale power supply agreement in place for the second quarter of 2023.

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. As of December 31, 2022, UI did not hold any supplier cash so it would not have had to post collateral.

New Renewable Source Generation

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

In October of 2018, UI entered into five PPAs totaling approximately 50 MW from developers of offshore wind and fuel cell generation pursuant to state law that provides the net costs of the

PPAs are recoverable through electric rates. On December 19, 2018, PURA approved the PPAs, and approved UI's use of the non-bypassable federally mandated congestion charges for all customers to recover the net costs of the PPAs.

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

In 2020, Pursuant to Connecticut Act Concerning the Procurement of Energy Derived From Offshore Wind, UI entered into a PPA with Vineyard Wind, an affiliate of UI, to provide 804 MW of offshore wind through the development of its Park City Wind Project. Similar to the case with the zero carbon PPAs discussed above, the net costs of the PPAs are recoverable through electric rates.

Revenues are recorded gross from contracts with customers when UI is a principal if it controls a promised good or service before transferring that good or service to the customer. Revenues are recorded net of expenses and regulatory deferrals from contracts with customers when UI is an agent if it arranges for another entity to provide the goods or services.

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 2021, UI's overall allowed weighted-average ROE for its transmission business was 11.25%.

On December 28, 2015, the FERC issued an order instituting section 206 proceedings and establishing hearing and settlement judgement procedures. Pursuant to section 206 of the FPA, the FERC instituted proceedings because it found that ISO-NE Transmission, Markets, and Services Tariff is unjust, unreasonable, and unduly discriminatory or preferential. The FERC stated that ISO-NE's Tariff lacks adequate transparency and challenge procedures with regard to the formula rates for ISO-NE Participating Transmission Owners (PTOs), including UI. The FERC also found that the current Regional Network Service (RNS) and Local Network Service (LNS) formula rates appear to be unjust, unreasonable, unduly discriminatory or preferential or otherwise unlawful as the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates. On June 15, 2020, the PTOs submitted an uncontested formula rate settlement. The FERC approved the uncontested formula rate settlement on December 28, 2020 which made the formula rate tariff sheets effective on January 1, 2022.

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

On October 16, 2014, the FERC issued its decision in Complaint I, setting the base ROE at 10.57% and a maximum total ROE of 11.74% (base plus incentive ROEs) for the October 2011 – December 2012 period as well as prospectively from October 16, 2014. On March 3, 2015, the FERC upheld its decision and further clarified that the 11.74% ROE cap will be applied on a project specific basis and not on a transmission owner's total average transmission return. The complaints were consolidated and the administrative law judge issued an initial decision on March 22, 2016. The initial decision determined that, (1) for the fifteen month refund period in Complaint II, the base ROE should be 9.59% and that the ROE Cap (base ROE plus incentive ROEs) should be 10.42% and (2) for the fifteen month refund period in Complaint III and prospectively, the base ROE should be 10.90% and that the ROE Cap should be 12.19%. The initial decision in Complaints II and III is the administrative law judge's recommendation to the FERC Commissioners.

UI reserved for refunds for Complaints I, II and III consistent with the FERC's March 3, 2015 decision in Complaint I. Refunds were provided to customers for Complaint I. UI's total reserve associated with Complaints II and III is $7.9 million as of December 31, 2022, which has not changed since December 31, 2021, except for the accrual of carrying costs. If adopted as final by the FERC, the impact of the initial decision by the FERC administrative law judge would be an additional aggregate reserve for Complaints II and III of $4.2 million, which is based upon currently available information for these proceedings.

Following various intermediate hearings, orders and appellate decisions, on October 16, 2018, the FERC issued an order directing briefs and proposing a new methodology to calculate the NETOs ROE that is contained in NETOs' transmission formula rate on file at the FERC (the October 2018 Order). Pursuant to the October 2018 Order, the NETOs filed initial briefs on the proposed methodology in all four Complaints on January 11, 2019 and replied to the initial briefs on March 8, 2019.

On November 21, 2019, the FERC issued rulings on two complaints challenging the base return on equity for Midcontinent Independent System Operator, or MISO transmission owners. These rulings established a new zone of reasonableness based on equal weighting of the DCF and capital-asset pricing model for establishing the base return on equity. This resulted in a base return on equity of 9.88% as the midpoint of the zone of reasonableness. Various parties have requested rehearing on this decision, which was granted. On May 21, 2020, FERC issued a ruling, which, among other things, adjusted the methodology to determine the MISO transmission owners' ROE, resulting in an increase in ROE from 9.88% to 10.02% by utilizing the risk premium model in addition to the DCF model and capital-asset pricing model under both prongs of Section 206 of the FPA, and calculated the zone of reasonableness into equal thirds rather than employing the quartile approach. On November 19, 2020, FERC issued an order addressing arguments raised on rehearing of its May 21, 2020 order making minor adjustments to certain typographical errors with regard to some of the case inputs it included in its Risk Premium model analysis. However, those minor adjustments did not affect the outcome of the case, leaving the 10.02% ROE established by the May 21, 2020 order in place. Parties to these orders affecting the MISO transmission owners' base ROE petitioned for their review at the D.C. Circuit Court of Appeals in January 2021. The NETO's submitted an amici curia brief in support of the MISO transmission owners' on March 17, 2021. On August 9, 2022, the D.C. Circuit Court vacated FERC's orders and remanded the matter back to FERC. The D.C. Circuit Court held that FERC failed to offer a reasoned explanation for its decision to reintroduce the RPM after initially, and forcefully, rejecting it and that because FERC adopted that significant portion of its model in an arbitrary and capricious fashion, the new ROE produced by that model cannot stand. We cannot predict the potential impact the MISO transmission owners' ROE proceeding may have in establishing a precedent for the NETO's pending four Complaints.

On April 15, 2021, the FERC issued a supplemental Notice of Proposed Rulemaking (Supplemental NOPR) that proposes to eliminate the 50 basis-point ROE incentive for utilities who join Regional Transmission Organizations after three years of membership. The NETOs submitted initial comments in opposition to the Supplemental NOPR on June 25, 2021 and reply comments on July 26, 2021. If the elimination of the 50 basis-point ROE incentive adder becomes final, we estimate we would have an approximately $2 million reduction in earnings per year. We cannot predict the outcome of this proceeding.

Equity Investment in Peaking Generation

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

GenConn filed its annual revenue requirements request with PURA on June 30, 2022, seeking approval of its 2023 revenue requirements for the period commencing January 1, 2023 for both the GenConn Devon and GenConn Middletown facilities. As required by PURA Order 1 in the 2022 Decision GenConn's calculation for revenue requirements totaled $44.7 million. On October 24, 2022 PURA issued a final decision approving revenue requirement of $44.0 million ($19.2 million for GenConn Devon, and $24.8 million for GenConn Middletown). Additionally, GenConn was granted a 9.85% Return on Equity (ROE) for 2023. PURA disallowed $0.7 million associated with recommended capital and expenses projects and costs associated with Working Capital Facility renewal necessary in 2023. GenConn has filed a 2023 Decision appeal before the CT Superior Court on January 27, 2023. The 2022 Decision appeal before CT Superior Court remains open but stayed pending the outcome of the 2021 Decision Appeal. The 2021 Decision Appeal is awaiting a schedule before CT Supreme Court.

GenConn filed its annual revenue requirements request with PURA on June 15, 2021, seeking approval of its 2022 revenue requirements for the period commencing January 1, 2022 for both the GenConn Devon and GenConn Middletown facilities and totaling $55.8 million. A final decision was received on December 8, 2021, approving 2022 revenue requirements of $44.4 million for GenConn ($19.3 million for GenConn Devon, and $25.1 million for GenConn Middletown). Additionally, GenConn was granted a 9.85% Return on Equity (ROE) for 2022. PURA disallowed $2.9 million from the original 2021 revenue requirements associated with interest expense associated with GenConn's debt, $0.1 million associated with 2013 refinancing amortization, $6.1 million associated with its equity return and $2.3 million associated with the resulting income tax, totaling $11.4 million. On January 21, 2022, GenConn filed an appeal with the CT Superior Court, appealing PURA's disallowance of the $11.4 million. On October 17, 2022 the company filed a brief to Superior Court of the 2022 appeal. A stay of the case was granted on January 6, 2023 pending the decision of the CT Supreme Court case on the 2021 revenue requirements decision. The company cannot predict the outcome of the appeal.

GenConn filed its annual revenue requirements request with PURA on June 12, 2020, seeking approval of its 2021 revenue requirements for the period commencing January 1, 2021 for both the GenConn Devon and GenConn Middletown facilities. A final decision was received on December 23, 2020, approving 2021 revenue requirements of $49.4 million for GenConn ($22.0

million for GenConn Devon, and $27.4 million for GenConn Middletown). Additionally, GenConn was granted a 9.85% Return on Equity (ROE) for 2021. PURA disallowed $3.3 million from the original 2021 revenue requirements request which includes a disallowance of $2.9 million of interest expense associated with GenConn's debt, and $0.4 million related to a proposed expense project to paint Exhaust Stacks at GenConn Devon. On February 4, 2021, GenConn filed an appeal with the CT Superior Court, appealing PURA's disallowance of the $2.9 million interest expense. The appeal was dismissed on January 28, 2022. On February 16, 2022, GenConn initiated an appeal at the Connecticut Appellate Court, which requested transfer to the Connecticut Supreme Court. The high court agreed to hear the case. Oral arguments are expected to be in the spring or fall terms of 2023 and the case remains pending.

PURA had approved revenue requirements for the period from January 1, 2020 through December 31, 2020, however, GenConn filed to reopen the related docket with PURA on April 3, 2020, for the purpose of resetting 2020 revenue requirements after a recalculation of excess deferred income taxes. GenConn received a final decision from PURA on December 23, 2020 approving $1.2 million of the additional $2.1 million requested for 2020 revenue requirements. The $0.9 million difference is due to an acceleration of $0.6 million related to Excess Accumulated Deferred Income Tax (ADIT) associated with Intangible Plant that otherwise would have been refunded over a longer period of time, and $0.3 million is related to actual tangible plant timing differences.

Tax Cuts and Jobs Act

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Tax Act) was signed into law. The Tax Act significantly changed the federal taxation of business entities including, among other things, implementing a federal corporate tax rate decrease from 35% to 21% for tax years beginning after December 31, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates will result in amounts previously and currently collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates.

PURA instituted proceedings in Connecticut to review and address the implications associated with the Tax Act on the utilities providing service in the state and rendered a final decision on January 23, 2019. PURA directed UI to establish a regulatory liability in the amount of the income tax expense to be returned to customers and propose a method of returning such amount to customers in its next rate case filing. On June 28, 2021, PURA approved a multi-docket settlement proposal that required UI to flow $44.7 million of the regulatory liability related to accumulated Tax Act savings back to customers over an accelerated 22-month period, commencing on July 1, 2021 through April 30, 2023.

On December 22, 2021, the FERC issued an order finding that the New England Transmission Owners (NETOs) Regional Network Service proposed revisions partially comply with the requirements of Order 864 and directed the NETOs to submit a further compliance filing within 60 days of the date of the order. The compliance is effective January 27, 2020, consistent with Order 864 and January 1, 2022, to reflect the fact that the NETOs existing transmission formula rates under the ISO-NE Tariff will be replaced by a settled formula rate effective January 1, 2022.

PURA Investigation of the Preparation for and Response to the Tropical Storm Isaias and Connecticut Storm Reimbursement Legislation

On August 6, 2020, PURA opened a docket to investigate the preparation for and response to Tropical Storm Isaias by the electric distribution companies in Connecticut including UI. Following hearings and the submission of testimony, PURA issued a final decision on April 15, 2021, finding that UI “generally met standards of acceptable performance in its preparation and response to Tropical Storm Isaias," subject to certain exceptions noted in the decision, but ordered a 15-basis point reduction to UI's ROE in its next rate case to incentivize better performance and indicated that penalties could be forthcoming in the penalty phase of the proceedings. On June 11, 2021, UI filed an appeal of PURA’s decision with the Connecticut Superior Court.

On May 6, 2021, in connection with its findings in the Tropical Storm Isaias docket, PURA issued a Notice of Violation to UI for allegedly failing to comply with standards of acceptable performance in emergency preparation or restoration of service in an emergency and with orders of the Authority, and for violations of accident reporting requirements. PURA assessed a civil penalty in the total amount of $2 million. PURA held a hearing on this matter and, in an order dated July 14, 2021, reduced the civil penalty to approximately $1 million. UI filed an appeal of PURA’s decision with the Connecticut Superior Court. This appeal and the appeal of PURA’s decision on the Tropical Storm Isaias docket have been consolidated. On October 17, 2022, the court denied UI’s appeal and affirmed PURA’s decisions in their entirety. UI filed a notice of appeal to Connecticut's Appellate court on November 7, 2022. We cannot predict the outcome of this proceeding.

Minimum Equity Requirements for Regulated Subsidiaries

Pursuant to agreements with PURA, UI is restricted from paying dividends if paying such dividend would result in a common equity ratio lower than 300 basis points below the equity percentage used to set rates in the most recent distribution rate proceeding as measured using a trailing 13-month average calculated as of the most recent quarter end. In addition, UI is prohibited from paying dividends to their parent if the utility’s credit rating, as rated by any of the three major credit rating agencies, falls below investment grade, or if the utility’s credit rating, as determined by two of the three major credit rating agencies, falls to the lowest investment grade and there is a negative watch or review downgrade notice.

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 $256.6 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

Details of 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.

Regulatory assets at December 31, 2022 and 2021 consisted of:

As of December 31,	2022	2021
(Thousands)		
Contracts for differences	$ 44,602	$ 58,672
COVID-19 cost recovery	8,759	10,416
Deferred transmission expense	—	13,507
Environmental remediation costs	6,557	6,311
Excess generation service charge	23,889	11,156
Non-bypassable charges	—	4,600
Pension and other postretirement benefit plans	88,795	125,151
Pension and other postretirement benefits cost deferrals	19,880	13,755
Revenue decoupling mechanism	13,288	16,958
Storm costs	26,875	23,135
Unamortized losses on reacquired debt	4,956	5,455
Unfunded future income taxes	118,417	110,501
Other	18,785	14,895
Total regulatory assets	**374,803**	**414,512**
Less: current portion	55,984	44,318
Total non-current regulatory assets	**$ 318,819**	**$ 370,194**

Contracts for differences represent the deferral of unrealized gains and losses on contracts for differences derivative contracts. The balance fluctuates based upon quarterly market analysis performed on the related derivatives. The amounts, which do not earn a return, are fully offset by a corresponding derivative asset/liability.

COVID-19 cost recovery represents deferred COVID-19-related costs in the state of Connecticut based on the order issued by PURA on April 29, 2020, requiring utilities to track COVID-19-related expenses and lost revenue and create a regulatory asset.

Deferred transmission expense represents deferred transmission income or expense and fluctuates based upon actual revenues and revenue requirements.

Environmental remediation costs includes 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.

Excess generation service charge represents deferred generation-related costs or revenues for future recovery from or return to customers. The amount fluctuates based upon timing differences between revenues collected from rates and actual costs incurred.

Non-bypassable charges represent non-bypassable federally mandated congestion costs or revenues for future recovery from or return to customers. The amount fluctuates based upon timing differences between revenues collected from rates and actual costs incurred.

Pension and other postretirement benefit plans 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.

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 for certain of our regulated utilities. The recovery of these amounts will be determined in future proceedings.

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

Storm costs are allowed in rates based on an estimate of the routine costs of service restoration. UI 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. A portion of this balance is amortized through current rates, and the remaining portion will be determined through future rate cases.

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 and are the offset to the unfunded future deferred income tax liability recorded. The income tax benefits or charges for certain plant related timing differences, such as removal costs, are immediately flowed through to, or collected from, customers. This amount is being amortized as the amounts related to temporary differences that give rise to the deferrals are recovered in rates.

Other includes items such as deferred loss on sale of non-utility property.

Regulatory liabilities at December 31, 2022 and 2021 consisted of:

As of December 31,		**2022**		**2021**
(Thousands)				
2017 Tax Act	$	219,439	$	252,016
Accrued removal obligations		76,263		72,165
Accumulated deferred investment tax credits		10,628		11,358
Conservation and load management		3,790		(156)
Deferred transmission expense		11,465		—
Middletown/Norwalk local transmission network service collections		16,242		16,815
Non-bypassable charges		70,308		5,165
Pension and other postretirement benefit plans		22,909		15,538
Pension and other postretirement benefits cost deferrals		1,063		—
Rate refund - FERC ROE proceeding		7,892		7,600
System benefit charge		—		12,049
Other		5,006		4,584
Total regulatory liabilities		**445,005**		**397,134**
Less: current portion		97,766		45,113
Total non-current regulatory liabilities	**$**	**347,239**	**$**	**352,021**

2017 Tax Act 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 and currently collected from utility customers for these deferred taxes to be refundable to such customers.

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

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

Deferred transmission expense represents deferred transmission income or expense and fluctuates based upon actual revenues and revenue requirements.

Middletown/Norwalk local transmission network service collections represents allowance for funds used during construction of the Middletown/Norwalk transmission line, which is being amortized over the useful life of the project.

Non-bypassable charges represent non-bypassable federally mandated congestion costs or revenues for future recovery from or return to customers. The amount fluctuates based upon timing differences between revenues collected from rates and actual costs incurred.

Pension and other postretirement benefit plans represent the actuarial gains on the pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future pension expenses.

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 for certain of our regulated utilities. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases.

Rate refund - FERC ROE proceeding represents the reserve associated with the FERC proceeding around the base return on equity (ROE) reflected in ISO-NE's open access transmission tariff.

Systems benefit charge represents various costs or revenues as defined by Connecticut General Statute 16-2451 deferred for future recovery from or return to customers. The amount fluctuates based upon timing differences between revenues collected from rates and actual costs incurred.

Other includes items such as deferral of CAM gross earnings tax expense collected in base distribution rates for periods subsequent to January 1, 2020.

Note 4. Revenue

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

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

UI derives its revenue primarily from tariff-based sales of electricity service to customers in its Connecticut territory with no defined contractual term. For such revenues, we recognize 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 UI or from another supplier. For customers that receive their electricity from another supplier, UI acts as an agent and delivers the electricity by that supplier. Revenue in those cases is only for providing the service of delivery of the electricity.

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 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 from Alternative Revenue Programs (ARPs), which is not ASC 606 revenue. Such programs represent contracts between UI and their regulators. UI ARPs include revenue decoupling mechanisms, other ratemaking mechanisms, and annual revenue requirement reconciliations.

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, ARPs, or other activities.

Revenues disaggregated by major source for the years ended December 31, 2022 and 2021 are as follows:

Years Ended December 31,	2022	2021
(Thousands)		
Regulated operations – electricity	$ 1,124,779	$ 1,020,219
Other (a)	6,871	5,633
Revenue from contracts with customers	**1,131,650**	**1,025,852**
Leasing revenue	4,114	2,942
Alternative revenue programs	18,346	41,937
Other revenue	1,757	174
Total operating revenues	**$ 1,155,867**	**$ 1,070,905**

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

Note 5. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,	2022	2021
(Thousands)		
Current		
Federal	$ 24,194	$ 26,605
State	6,460	4,529
Current taxes charged to expense	**30,654**	**31,134**
Deferred		
Federal	(13,562)	(5,968)
State	4,192	359
Deferred taxes charged to benefit	**(9,370)**	**(5,609)**
Investment tax credits	(730)	(730)
Total Income Tax Expense	**$ 20,554**	**$ 24,795**

The differences between tax expense per the statements of income and tax expense at the 21% statutory federal tax rate for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,	2022	2021
(Thousands)		
Tax expense at federal statutory rate	$ 27,981	$ 31,536
Depreciation/amortization and other plant differences not normalized	(3,255)	(2,073)
State taxes net of federal benefit	8,415	3,862
Investment tax credit amortization	(730)	(730)
Excess ADIT amortization	(12,524)	(6,906)
Other, net	667	(894)
Total Income Tax Expense	**$ 20,554**	**$ 24,795**

Income tax expense for the year ended December 31, 2022 was $7.4 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to Excess ADIT amortization, and depreciation/amortization and other plant differences not normalized partially offset by state taxes. This resulted in an effective tax rate of 15.4%. Income tax expense for the year ended December 31, 2021 was $6.7 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to Excess ADIT amortization, and depreciation/

amortization and other plant differences not normalized, partially offset by state taxes. This resulted in an effective tax rate of 16.5%

As part of a settlement agreement approved by PURA, UI began refunding previously deferred Distribution Excess ADITS, commencing July 1, 2021. In 2021, UI began refunding previously deferred Transmission Excess ADITS as determined by the FERC.

Deferred tax assets and liabilities as of December 31, 2022 and 2021 consisted of:

December 31,	2022	2021
(Thousands)		
Non-current Deferred Income Tax Liabilities (Assets)		
Property related	$ 426,093	$ 416,992
Unfunded future income taxes	31,899	35,969
Federal and state tax credits	(190)	(16,006)
Investment in GenConn	31,758	31,369
Postretirement benefits	(8,737)	(12,111)
Regulatory liability due to "Tax Cuts and Jobs Act"	(59,084)	(67,864)
Other	(15,437)	1,201
Total Non-current Deferred Income Tax Liabilities	**$ 406,302**	**$ 389,550**
Deferred tax assets	$ 83,448	$ 95,981
Deferred tax liabilities	489,750	485,531
Net Accumulated Deferred Income Tax Liabilities	**$ 406,302**	**$ 389,550**

As of December 31, 2022, UI had $0.2 million of state tax credit carry forwards that will begin to expire in 2027. As of December 31, 2021, UI had $5.8 million of gross state tax credit carry forwards with no valuation allowance offset.

Uncertain tax positions are classified as non-current unless expected to be paid within one year. We net our liability for uncertain tax positions against all same jurisdiction deferred tax assets, net operating losses and tax credit carryforwards. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the statements of income. As of December 31, 2022 and 2021, UI did not have any gross income tax reserves for uncertain tax positions.

There were no additional accruals for interest and penalties on tax reserves as of December 31, 2022 and 2021.

Note 6. Non-current Debt

Long-term debt as of December 31, 2022 and 2021 consisted of:

As of December 31,		2022		2021	
(Thousands)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
Senior unsecured notes	2023 - 2049	$ 929,460	2.02% - 6.51%	$ 891,960	2.02% - 6.51%
Unamortized debt issuance costs and discount		(5,276)		(4,752)	
Total Debt		**924,184**		**887,208**	
Less: debt due within one year, included in current liabilities		139,044		162,137	
Total Non-current Debt		**$ 785,140**		**$ 725,071**	

On January 1, 2022, UI issued $150 million aggregate principal amount of unsecured notes maturing in 2032 at an interest rate of 2.25%.

On December 15, 2022, UI issued $50 million aggregate principal amount of unsecured notes maturing in 2032 at an interest rate of 4.62%.

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

2023	2024	2025	2026	2027	Total
(Thousands)					
$ 139,044	$ —	$ 100,000	$ —	$ —	$ 239,044

We have no debt covenant requirements related to the maintenance of financial ratios in our long-term debt agreements at December 31, 2022 and 2021.

Note 7. Bank Loans and Other Borrowings

UI had no short-term debt outstanding as of December 31, 2022 and December 31, 2021. 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 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. UI has a lending/borrowing limit of $100 million under this agreement. UI had no debt outstanding under this agreement at December 31, 2022 and December 31, 2021.

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. UI had no debt outstanding under this agreement at December 31, 2022 and December 31, 2021.

On November 23, 2021, AGR and its investment-grade rated utility subsidiaries (New York State Electric and Gas Corporation (“NYSEG”), Rochester Gas and Electric Corporation (“RG&E”), Central Maine Power Company (“CMP”), The United Illuminating Company (“UI”), Connecticut Natural Gas Corporation (“CNG”), The Southern Connecticut Gas Company (“SCG”) and The Berkshire Gas Company (“BGC”)) executed a new credit facility with an aggregate limit of $3,575 million and a termination date of November 23, 2026. Under the terms of the Avangrid Credit Facility, each borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit contained in the agreement. NYSEG has a maximum sublimit of $700 million, RG&E has $300 million, CMP has $200 million and UI has a maximum sublimit of $250 million, CNG and SCG have maximum sublimits of $150 million, and BGC has a maximum sublimit of $50 million. Effective on November 23 2021, the AGR Credit Facility was amended to increase AGR's maximum sublimit to $2,500 million and to establish minimum sublimits of $500 million for NYSEG, $200 million for RG&E, $100 million for CMP, $150 million for UI, $50 million for CNG and SCG, and $25 million for BGC. Under the AGR Credit Facility, each of the borrowers are charged a facility fee that is dependent on their credit rating. The facility fees range from 10.0 to 22.5 basis points. UI had no debt outstanding under this agreement at December 31, 2022 and December 31, 2021.

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 0.41 to 1.00 at December 31, 2022. We are not in default as of December 31, 2022.

Note 8. Preferred Stock

At December 31, 2022, UI had 1,119,612 shares of $100 par value preferred stock, 2,400,000 shares of $25 par value preferred stock, and 5,000,000 shares of $25 par value preference stock authorized but unissued.

Note 9. Leases

We have operating leases for land, office buildings, facilities, and certain equipment. We do not have any finance leases. Certain of our lease agreements include rental payments adjusted periodically for inflation or are based on other periodic input measures. Our leases do not contain any material residual value guarantees or material restrictive covenants. Our leases have remaining lease terms of 1 year to 41 years, some of which may include options to extend the leases for up to 40 years, and some of which may include options to terminate the leases within one year. We consider extension or termination options in the lease term if it is reasonably certain we will exercise the option.

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

For the Years Ended December 31,		2022		2021
(Thousands)				
Lease cost				
Operating lease cost	$	4,377	$	2,795
Short-term lease cost		65		69
Variable lease cost		411		751
Intercompany		—		122
Total lease cost	**$**	**4,853**	**$**	**3,737**

Balance sheet and other information for the years ended December 31, 2022 and 2021 was as follows:

As of December 31,		2022		2021
(Thousands, except lease term and discount rate)				
Operating Leases				
Operating lease right-of-use assets	$	12,552	$	11,339
Operating lease liabilities, current		655		1,002
Operating lease liabilities, long-term		16,048		14,644
Total operating lease liabilities	$	16,703	$	15,646
Weighted-average Remaining Lease Term (years)				
Operating leases		21.22		21.52
Weighted-average Discount Rate				
Operating leases		3.72%		3.32%

For the years ended December 31, 2022 and 2021, supplemental cash flow information related to leases was as follows:

For the Years Ended December 31,		2022		2021
(Thousands)				
Cash paid for amounts included in the measurement of lease liabilities:				
Operating cash flows from operating leases	$	1,481	$	1,728
Right-of-use assets obtained in exchange for lease obligations:				
Operating leases	$	2,038	$	2,731

As of December 31, 2022, maturities of lease liabilities were as follows:

		Operating Leases
(Thousands)		
Year ending December 31,		
2023	$	1,168
2024		1,113
2025		948
2026		971
2027		3,306
Thereafter		18,546
Total lease payments		**26,052**
Less: imputed interest		(9,349)
Total	**$**	**16,703**

Most of our leases do not provide an implicit rate in the lease; thus we use our incremental borrowing rate based on the information available at the commencement date in determining the present value of lease payments.

Note 10. 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.

English Station

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

In December 2013, Evergreen Power and Asnat filed a subsequent lawsuit related to the English Station site. On April 16, 2018, the plaintiffs filed a revised complaint alleging fraud and unjust enrichment against UIL and UI and adding former UIL officers as named defendants alleging fraud. On February 21, 2019, the court granted our Motion to Strike with respect to all counts except for the count against UI for unjust enrichment. The counts stricken include all counts against the individual defendants as well as against UIL. The plaintiffs have appealed the court's decision to strike and oral arguments have taken place. On May 4, 2021, the Appeals Court affirmed the court's decision striking the counts. The plaintiffs filed a petition to appeal to the Connecticut Supreme Court, which was denied, leaving only the claim against UI for unjust enrichment. We cannot predict the outcome of this matter.

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

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

The amount reserved related to English Station was $19.4 million as of December 31, 2022 and $21.7 million as of December 31, 2021. We cannot predict the outcome of this matter.

Other

In May 2019, UI obtained an updated remediation evaluation of the property adjacent to the New Haven Harbor Generating Station. As a result, UI recorded an additional $6.0 million reserve in June 2019, the minimum of the range of remediation estimates. As of December 31, 2022 and

December 31, 2021, the amount reserved for this property was $7.9 million and $7.7 million, respectively.

UI also holds a reserve for remediation of 801 Bridgeport Ave, the site of a former operations center. The amount reserved for this site was $0.4 million as of both December 31, 2022 and 2021.

Note 11. Accounting for Derivative Instruments and Hedging Activities

Our operating and financing activities are exposed to certain risks, which are managed by using derivative instruments. All derivative instruments are recognized as either assets or liabilities at fair value on our balance sheets in accordance with the accounting requirements concerning derivative instruments and hedging activities.

Derivatives not designated as hedging instruments

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, 2022, UI has recorded a gross derivative asset of $1.3 million ($0 of which is related to UI's portion of the CfD signed by CL&P), a regulatory asset of $44.6 million, a gross derivative liability of $45.9 million ($44.3 million of which is related to UI's portion of the CfD signed by CL&P), and a regulatory liability of $0. As of December 31, 2021, UI had recorded a gross derivative asset of $1.7 million ($0 of which is related to UI's portion of the CfD signed by CL&P), a regulatory asset of $58.7 million, a gross derivative liability of $60.4 million ($58.2 million of which is related to UI's portion of the CfD signed by CL&P), and a regulatory liability of $0.

The unrealized gains and losses from fair value adjustments to these derivatives, which are recorded in regulatory assets, for the years ended December 31, 2022 and 2021, respectively, were as follows:

	Years Ended December 31,	
	2022	2021
(Thousands)		
Derivative assets	$ (365)	$ (327)
Derivative liabilities	$ 14,435	$ 10,839

Derivatives designated as hedging instruments

The effect of derivatives in cash flow hedging relationships on Other Comprehensive Income (OCI) and income for the years ended December 31, 2022 and 2021, respectively, consisted of:

Year Ended December 31,	Loss Recognized in OCI on Derivatives	Location of Loss Reclassified From Accumulated OCI into Income	Loss Reclassified From Accumulated OCI into Income	Total Amount per Income Statement
(Thousands)				
2022				
Foreign exchange contracts	$ —	Operations and maintenance	$ (23)	$ 386,328
Total	**$ —**		**$ (23)**	
2021				
Foreign exchange contracts	$ (23)	Operations and maintenance	$ —	$ 390,980
Total	**$ (23)**		**$ —**	

Note 12. Fair Value of Financial Instruments and Fair Value Measurements

The estimated fair value of debt amounted to $860 million as of December 31, 2022 and $1,029 million as of December 31, 2021. 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, 2022 and December 31, 2021, consisted of:

As of December 31, 2022	Level 1	Level 2	Level 3	Total
(Thousands)				
Derivative assets				
Contracts for differences	$ —	$ —	$ 1,346	$ 1,346
Equity investments with readily determinable fair values				
Supplemental retirement benefit trust life insurance policies	—	13,360	—	13,360
Total	**$ —**	**$ 13,360**	**$ 1,346**	**$ 14,706**
Derivative liabilities				
Contracts for differences	$ —	$ —	$ (45,948)	$ (45,948)
Foreign exchange contracts	—	(20)	—	(20)
Total	**$ —**	**$ (20)**	**$ (45,948)**	**$ (45,968)**

As of December 31, 2021	Level 1	Level 2	Level 3	Total
(Thousands)				
Derivative assets				
Contracts for differences	$ —	$ —	$ 1,711	$ 1,711
Equity investments with readily determinable fair values				
Supplemental retirement benefit trust life insurance policies	—	15,431	—	15,431
Total	**$ —**	**$ 15,431**	**$ 1,711**	**$ 17,142**
Derivative liabilities				
Contracts for differences	$ —	$ —	$ (60,383)	$ (60,383)
Foreign exchange contracts	—	(23)	—	(23)
Total	**$ —**	**$ (23)**	**$ (60,383)**	**$ (60,406)**

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2022 and 2021. 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 determine the fair value of our derivative assets and liabilities and non-current equity investments utilizing market approach valuation techniques:

- UI enters into CfDs, which are marked-to-market based on a probability-based expected cash flow analysis that is discounted at risk-free interest rates and an adjustment for non-performance risk using credit default swap rates. We include the fair value measurement for these contracts in Level 3 (Refer to Note 11 for further discussion of CfDs).
- We measure the fair value of the supplemental retirement benefit life insurance trust based on quoted prices in the active markets for the various funds within which the assets are held and include the measurement in Level 2.
- We determine the fair value of our foreign currency exchange derivative instruments based on current exchange rates compared to the rates at inception of the hedge. We include the fair value measurement for these contracts in Level 2.

The determination of fair value of the CfDs was based on a probability-based expected cash flow analysis that was discounted at 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 extends over the term of the contracts. We believe this methodology provides the most reasonable estimates of the amount of future discounted cash flows associated with the CfDs. Additionally, on a quarterly basis, we perform analytics to ensure that the fair value of the derivatives is consistent with changes, if any, in the various fair value model inputs. 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. Additional quantitative information about Level 3 fair value measurements of the CfDs is as follows:

Unobservable Input	Range at December 31, 2022	Range at December 31, 2021
Risk of non-performance	0.84% - 0.89%	0.39% - 0.51%
Discount rate	3.99% - 4.22%	0.97% - 1.26%
Forward pricing ($ per MW)	$2.00 - $3.80	$2.00 - $4.80

The reconciliation of changes in the fair value of financial instruments based on Level 3 inputs for the years ended December 31, 2022 and 2021, respectively, is as follows:

Years Ended December 31,		2022		2021
(Thousands)				
Beginning balance	$	(58,672)	$	(69,184)
Unrealized gains, net		14,070		10,512
Ending balance	**$**	**(44,602)**	**$**	**(58,672)**

Note 13. Postretirement and Similar Obligations

The UI pension plan provides benefits under a traditional defined benefit formula and was closed to newly-hired employees in 2005. The plan was amended, effective as of the close of business on December 31, 2020, to freeze benefit accruals for UI Collectively Bargained Group 1 participants and to permit in-service distributions to UI Collectively Bargained Group 1 participants who are at least age 60. The plan was remeasured as of December 9, 2020 as a result of this amendment. On March 31, 2022, the Board approved to freeze benefit accruals for the non-union participants of the UI pension plan, with an effective date of June 30, 2022.

UI employees are eligible to participate in the UIL Holdings Corporation 401(k) Employee Stock Ownership 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 totaled approximately $9.2 million for 2022 and $6.6 million for 2021.

We provide 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.

Non-Qualified Retirement Benefit Plans

We sponsor various unfunded non-qualified pension plans for certain current employees, former employees, and former directors. The total liability for these plans, which is included in Other non-current liabilities on our balance sheets, was $10.2 million and $14.0 million at December 31, 2022 and 2021, respectively. On March 31, 2022, the Board approved to freeze benefit accruals for the non-union participants of the UI supplemental executive retirement plan, with an effective date of June 30, 2022.

Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2022 and 2021 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2022**	**2021**	**2022**	**2021**
(Thousands)				
Change in benefit obligation				
Benefit obligation as of January 1,	**$ 561,934**	**$ 604,221**	**$ 61,916**	**$ 64,178**
Service cost	2,195	3,730	542	621
Interest cost	18,491	15,031	1,708	1,424
Plan amendments	448	—	—	—
Actuarial (gain) loss	(118,557)	(17,813)	(18,041)	1,552
Curtailments	(17,540)	—	—	—
Settlements	(27,706)	—	—	—
Benefits paid	(28,294)	(43,235)	(5,240)	(5,859)
Benefit obligation as of December 31,	**$ 390,971**	**$ 561,934**	**$ 40,885**	**$ 61,916**
Change in plan assets				
Fair value of plan assets at January 1,	**$ 423,172**	**$ 429,238**	**$ 38,233**	**$ 34,257**
Actual return on plan assets	(87,634)	37,169	(5,891)	5,173
Employer contributions	—	—	3,783	4,662
Settlements	(27,706)	—	—	—
Benefits paid	(28,294)	(43,235)	(5,240)	(5,859)
Fair value of plan assets at December 31,	**$ 279,538**	**$ 423,172**	**$ 30,885**	**$ 38,233**
Funded status at December 31,	**$ (111,433)**	**$ (138,762)**	**$ (10,000)**	**$ (23,683)**

During 2022, the pension benefit obligation had an actuarial gain of $118.6 million, primarily due to a $107.5 million gain from increases in discount rates. In 2022, the pension benefit obligation had a reduction of $27.7 million from settlements and $17.5 million from curtailments. The settlements were lump-sum payments made within the pension plan guidelines at the discretion of the plan participants who opted to retire. The curtailments were driven by a Company decision to freeze pension benefit accruals and contribution credits for non-union employees and transition their retirement benefits to a 401(k) plan. During 2022, the postretirement benefit obligation had an actuarial gain of $18.0 million, primarily due to a $10.7 million gain from increases in discount rates.

During 2021, the pension benefit obligation had an actuarial gain of $17.8 million, primarily due to a $29.5 million gain from increases in discount rates, offset by a $9.8 million loss from demographic and other experience and a $1.9 million loss from changes in mortality. The only significant plan change in 2021 was an agreement to freeze the union pension plan. During 2021, the postretirement benefit obligation had an actuarial loss of $1.6 million.

Amounts recognized as of December 31, 2022 and 2021 consisted of:

As of December 31,	Pension Benefits 2022	Pension Benefits 2021	Postretirement Benefits 2022	Postretirement Benefits 2021
(Thousands)				
Non-current liabilities	$ (111,433)	$ (138,762)	$ (10,000)	$ (23,683)

We have determined that we are allowed to defer as regulatory assets or regulatory liabilities items that would otherwise be recorded in accumulated other comprehensive income pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans.

Amounts recognized as regulatory assets or regulatory liabilities for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,	Pension Benefits 2022	Pension Benefits 2021	Postretirement Benefits 2022	Postretirement Benefits 2021
(Thousands)				
Net loss (gain)	$ 83,371	$ 119,004	$ (16,268)	$ (7,356)
Prior service cost (credit)	$ 5,424	$ 6,147	$ (1,056)	$ (2,593)

Our accumulated benefit obligation (ABO) for all qualified defined benefit pension plans was $391.0 million and $538.9 million as of December 31, 2022 and 2021, respectively. Our postretirement benefits were partially funded at December 31, 2022 and 2021.

The PBO and ABO exceeded the fair value of pension plan assets for our qualified plans as of December 31, 2022 and 2021. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets for the relevant periods.

As of December 31,	2022	2021
(Thousands)		
Projected benefit obligation	$ 390,971	$ 561,934
Accumulated benefit obligation	$ 390,971	$ 538,930
Fair value of plan assets	$ 279,538	$ 423,172

As of December 31, 2022 and 2021, the accumulated postretirement benefits obligation for all the qualified plans exceeded the fair value of plan assets.

Components of net periodic benefit cost and other changes in plan assets and benefit obligations recognized in income and regulatory assets and liabilities for the years ended December 31, 2022 and 2021 consisted of:

For the years ended December 31,	Pension Benefits 2022	Pension Benefits 2021	Postretirement Benefits 2022	Postretirement Benefits 2021
(Thousands)				
Net Periodic Benefit Cost:				
Service cost	$ 2,195	$ 3,730	$ 542	$ 621
Interest cost	18,491	15,031	1,708	1,424
Expected return on plan assets	(24,564)	(29,394)	(2,256)	(1,953)
Amortization of prior service cost (credit)	1,171	1,163	(1,537)	(1,537)
Amortization of actuarial loss (gain)	5,826	21,460	(982)	(821)
Settlements	5,908	—	—	—
Net Periodic Benefit Cost	**$ 9,027**	**$ 11,990**	**$ (2,525)**	**$ (2,266)**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities:				
Curtailments	$ (17,540)	$ —	$ —	$ —
Settlements	(5,908)	—	—	—
Current year prior service cost	448	—	—	—
Amortization of prior service (cost) benefit	(1,171)	(1,163)	1,537	1,537
Current year actuarial gain	(6,359)	(25,588)	(9,894)	(1,668)
Amortization of actuarial (loss) gain	(5,826)	(21,460)	982	821
Total Other Changes	**$ (36,356)**	**$ (48,211)**	**$ (7,375)**	**$ 690**
Total Recognized	**$ (27,329)**	**$ (36,221)**	**$ (9,900)**	**$ (1,576)**

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

The weighted-average assumptions used to determine benefit obligations as of December 31, 2022 and 2021 consisted of:

As of December 31,	Pension Benefits 2022	Pension Benefits 2021	Postretirement Benefits 2022	Postretirement Benefits 2021
Discount rate	5.21%	2.96%	5.17%	2.85%
Rate of compensation increase	N/A	3.80%	N/A	N/A
Interest crediting rate	N/A	N/A	N/A	N/A

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

The weighted-average assumptions used to determine net periodic benefit cost for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,	Pension Benefits 2022	2021	Postretirement Benefits 2022	2021
Discount rate	2.96% / 4.15% / 5.00%	2.56%	2.85%	2.29%
Expected long-term return on plan assets	7.00%	7.00%	5.90%	5.70%
Rate of compensation increase	3.80% Non-Union; 3.00% Union / N/A Non-Union; 3.00% Union / N/A	3.80%	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. Our analysis considered current capital market conditions and projected conditions. Our policy is to calculate the expected return on plan assets using the market related value of assets. We amortize unrecognized actuarial gains and losses in excess of 5% of the greater of PBO or MRVA related to the pension and other postretirement benefits plans on straight line basis over future working lifetime. Effective March 31, 2022, the amortization period for the UI Pension Plan was updated from future working lifetime to future expected lifetime as the plan was frozen, or predominantly frozen, to future accruals.

Assumed health care cost trend rates used to determine benefit obligations as of December 31, 2022 and 2021 consisted of:

As of December 31,	2022	2021
Health care cost trend rate assumed for next year	6.00%/5.00%	6.50% / 5.25%
Rate to which cost trend rate is assumed to decline (ultimate trend rate)	4.50%	4.50%
Year that the rate reaches the ultimate trend rate	2029/2025	2029 / 2025

Contributions

We make annual contributions in accordance with our funding policy of not less than the minimum amounts as required by applicable regulations. We do not expect to contribute to our pension plan during 2023. We expect to contribute $2.4 million to our other postretirement benefit plans during 2023.

Estimated future benefit payments

Expected benefit payments and Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) subsidy receipts reflecting expected future service as of December 31, 2022 consisted of:

(Thousands)	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
2023	$ 35,304	$ 3,727	$ —
2024	$ 34,044	$ 3,559	$ —
2025	$ 32,641	$ 3,499	$ —
2026	$ 32,077	$ 3,389	$ —
2027	$ 32,192	$ 3,169	$ —
2028 - 2032	$ 147,525	$ 14,934	$ —

Plan assets

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

The asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets within broad categories of asset classes made up of Return-Seeking and Liability-Hedging investments. We have targets of 25%-60% for Return-Seeking assets and 40%-75% for Liability-Hedging assets. Return-Seeking investments generally consist of domestic, international, global, and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking assets also include investments in real estate, global asset allocation strategies and hedge funds. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS, and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of pension benefits plan assets, by asset category, as of December 31, 2022, consisted of:

As of December 31, 2022		**Fair Value Measurements**		
(Thousands)	**Total**	**Level 1**	**Level 2**	**Level 3**
Asset Category				
Cash and cash equivalents	$ 8,676	$ 33	$ 8,643	$ —
U.S. government securities	15,320	15,320	—	—
Common stocks	12,579	12,579	—	—
Registered investment companies	14,103	14,103	—	—
Corporate bonds	73,112	—	73,112	—
Preferred stocks	76	76	—	—
Common collective trusts	105,861	—	105,861	—
Other, principally annuity, fixed income	1,057	—	1,057	—
	$ 230,784	**$ 42,111**	**$ 188,673**	**$ —**
Other investments measured at net asset value	48,754			
Total	**$ 279,538**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2021, consisted of:

As of December 31, 2021		Fair Value Measurements		
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 8,158	$ 1,909	$ 6,249	$ —
U.S. government securities	24,530	24,530	—	—
Common stocks	18,862	18,862	—	—
Registered investment companies	39,979	39,979	—	—
Corporate bonds	112,211	—	112,211	—
Preferred stocks	121	121	—	—
Common collective trusts	154,514	—	154,514	—
Other, principally annuity, fixed income	2,966	1	2,965	—
	$ 361,341	**$ 85,402**	**$ 275,939**	**$ —**
Other investments measured at net asset value	61,831			
Total	**$ 423,172**			

Valuation Techniques

We value our pension benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities - at the closing price reported in the active market in which the security is traded.
- Common stock - at the closing price reported in the active market in which the security is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks - at the closing price reported in the active market in which the individual investment is traded.
- Registered investment companies - at the closing price reported in the active market in which the individual investment is traded.
- Common collective trusts - the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Other investments measured at net asset value (NAV) - fund shares offered to a limited group of investors and alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

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

We have established a target asset allocation policy within allowable ranges for postretirement benefits plan assets of 49%-69% for equity securities and 31%-51% for fixed income. Equity investments are diversified across U.S. and non-U.S. stocks, investment styles, and market capitalization ranges. Fixed income investments are primarily invested in U.S. bonds and may also include some non-U.S. bonds. Other asset classes, including alternative investments, are used to enhance long-term returns while improving portfolio diversification. We primarily minimize the risk of large losses through diversification but also through monitoring and managing other aspects of risk through quarterly investment portfolio reviews. Systematic rebalancing within target ranges increases the probability that the annualized return on investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of other postretirement benefits plan assets, by asset category, as of December 31, 2022, consisted of:

As of December 31, 2022		**Fair Value Measurements**		
(Thousands)	**Total**	**Level 1**	**Level 2**	**Level 3**
Asset Category				
Cash and cash equivalents	$ 587	$ —	$ 587	$ —
Registered investment companies	30,298	30,298	—	—
Total	**$ 30,885**	**$ 30,298**	**$ 587**	**$ —**

The fair values of pension benefits plan assets, by asset category, as of December 31, 2021, consisted of:

As of December 31, 2021		**Fair Value Measurements**		
(Thousands)	**Total**	**Level 1**	**Level 2**	**Level 3**
Asset Category				
Cash and cash equivalents	$ 1,375	$ —	$ 1,375	$ —
Registered investment companies	36,858	36,858	—	—
Total	**$ 38,233**	**$ 36,858**	**$ 1,375**	**$ —**

Valuation techniques

We value our postretirement benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- Registered investment companies - at the closing price reported in the active market in which the individual investment is traded.

Pension and postretirement plan equity securities did not include any AGR and Iberdrola common stock as of both December 31, 2022 and 2021.

Note 14. Equity Method Investments

UI is a 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 $82.5 million and $86.6 million as of December 31, 2022 and December 31, 2021, respectively.

UI's pre-tax income from its equity investment in GenConn was $3.6 million and $6.3 million for the years ended December 31, 2022 and 2021, 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 statements of cash flows, respectively. UI received cash distributions from GenConn of $7.6 million and $10.7 million during the years ended December 31, 2022 and 2021, respectively.

The following represents summarized financial information of GenConn as of and for the years ended December 31, 2022 and 2021, respectively:

Years Ended December 31,		**2022**		**2021**
(Thousands)				
Current assets	$	39,334	$	37,833
Non-current assets	$	311,195	$	328,069
Current liabilities	$	15,952	$	15,426
Non-current liabilities	$	169,707	$	177,577
Operating revenues	$	50,212	$	54,701
Income	$	7,156	$	12,612

Note 15. Other Income and Other Deductions

Other income and other deductions for the years ended December 31, 2022 and 2021, respectively, consisted of:

Years Ended December 31,		**2022**		**2021**
(Thousands)				
Interest and dividends income	$	5,738	$	3,671
Allowance for funds used during construction		11,433		9,852
Carrying costs on regulatory assets		4,213		9,591
Miscellaneous		36		20
Total other income	**$**	**21,420**	**$**	**23,134**
Pension non-service components	$	(6,968)	$	(1,860)
Miscellaneous		(2,762)		(1,339)
Total other deductions	**$**	**(9,730)**	**$**	**(3,199)**

Note 16. Related Party Transactions

Certain Networks subsidiaries, including UI, borrow from AGR, the parent of Networks, through intercompany revolving credit agreements. For UI, 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 UI, 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 UI by AGR and its affiliates was approximately $73.8 million and $74.9 million for the years ended December 31, 2022 and 2021, respectively. Cost for services includes amounts capitalized in utility plant, which was approximately $6.0 million in 2022 and $5.0 million in 2021, respectively. The remainder was primarily recorded as operations and maintenance expense. The charges for services provided by UI to AGR and its subsidiaries were approximately $8.7 million in 2022 and $6.8 million in 2021, respectively. 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 $68.3 million at December 31, 2022 and $70.0 million at December 31, 2021 is primarily due to UIL Holdings. The balance in accounts receivable from affiliates of $1.5 million at December 31, 2022 is primarily receivable from CMP and the balance of accounts receivable from affiliates of $1.2 million at December 31, 2021 is receivable from various companies.

The balance in notes receivable from affiliates of $82.6 million at December 31, 2022 was due as follows: $16.1 million due from NYSEG, $7.0 million due from CMP, $9.6 million due from BGC, $25.5 million due from CNG, $24.4 million due from SCG. The balance in notes receivable from affiliates of $64.6 million at December 31, 2021 was due from NYSEG. Notes receivable from affiliates relate to the Virtual Money Pool Agreement as discussed in Note 7 of these financial statements.

Note 17. Subsequent Events

The company has performed a review of subsequent events through April 12, 2023, which is the date these financial statements were available to be issued.

The Southern Connecticut Gas Company

Consolidated Financial Statements

As of and for the Years Ended December 31, 2022 and 2021

The Southern Connecticut Gas Company

Index

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

Independent Auditors' Report

The Stockholder and Board of Directors
The Southern Connecticut Gas Company:

Opinion

We have audited the consolidated financial statements of The Southern Connecticut Gas Company and its subsidiaries (the Company), which comprise the consolidated balance sheets as of December 31, 2022 and 2021, and the related consolidated statements of income, comprehensive income, changes in common stock equity, and cash flows for the years then ended, and the related notes to the consolidated financial statements.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

Basis for Opinion

We conducted our audits in accordance with auditing standards generally accepted in the United States of America (GAAS). Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audit of the Consolidated Financial Statements section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with U.S. generally accepted accounting principles, and for 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.

In preparing the consolidated financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for one year after the date that the consolidated financial statements are issued.

Auditors' Responsibilities for the Audit of the Consolidated Financial Statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the consolidated financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.

- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the consolidated financial statements.

- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control related matters that we identified during the audit.

KPMG LLP

New York, New York
March 31, 2023

The Southern Connecticut Gas Company
Consolidated Statements of Income

Years Ended December 31,		2022		2021
(Thousands)				
Operating Revenues	$	**515,861**	$	**412,564**
Operating Expenses				
Natural gas purchased		274,609		180,914
Operations and maintenance		93,370		97,770
Depreciation and amortization		38,835		37,057
Taxes other than income taxes, net		35,431		33,670
Total Operating Expenses		**442,245**		**349,411**
Operating Income		**73,616**		**63,153**
Other income		2,647		2,298
Other deductions		(12,172)		(96)
Interest expense, net of capitalization		(17,709)		(16,503)
Income Before Income Tax		**46,382**		**48,852**
Income tax expense		3,403		11,873
Net Income		**42,979**		**36,979**
Less: net income attributable to noncontrolling interest		3,462		3,348
Net Income Attributable to SCG	$	**39,517**	$	**33,631**

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

The Southern Connecticut Gas Company
Consolidated Statements of Comprehensive Income

Years Ended December 31,		2022		2021
(Thousands)				
Net Income	$	**42,979**	$	**36,979**
Other Comprehensive Income (Loss), Net of Tax				
Amortization of pension cost for non-qualified plans and current year actuarial gain (loss), net of income tax expense of $409 for 2022 and income tax benefit of ($477) for 2021		1,111		(1,295)
Total Other Comprehensive Income (Loss), Net of Tax		**1,111**		**(1,295)**
Comprehensive Income		**44,090**		**35,684**
Less: Comprehensive income attributable to noncontrolling interest		3,462		3,348
Comprehensive Income Attributable to SCG	$	**40,628**	$	**32,336**

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

The Southern Connecticut Gas Company
Consolidated Balance Sheets

As of December 31,	2022	2021
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$ 1,259	$ 473
Accounts receivable and unbilled revenues, net	133,397	103,731
Accounts receivable from affiliates	1,645	1,529
Notes receivable from affiliates	1,660	28,956
Gas in storage	57,789	34,535
Materials and supplies	4,002	3,072
Other current assets	1,106	389
Regulatory assets	48,145	38,738
Total Current Assets	**249,003**	**211,423**
Utility plant, at original cost	1,340,472	1,230,436
Less accumulated depreciation	(375,637)	(347,760)
Net Utility Plant in Service	**964,835**	**882,676**
Construction work in progress	20,303	36,753
Total Utility Plant	**985,138**	**919,429**
Operating lease right-of-use assets	10,418	8,197
Other property and investments	9,372	11,787
Regulatory and Other Assets		
Regulatory assets	159,846	141,733
Goodwill	134,931	134,931
Other	372	372
Total Regulatory and Other Assets	**295,149**	**277,036**
Total Assets	**$ 1,549,080**	**$ 1,427,872**

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

The Southern Connecticut Gas Company
Consolidated Balance Sheets

As of December 31,		2022		2021
(Thousands, except share information)				
Liabilities				
Current Liabilities				
Notes payable to affiliates	$	24,600	$	3,580
Accounts payable and accrued liabilities		96,451		66,704
Accounts payable to affiliates		19,655		20,005
Interest accrued		3,881		3,828
Taxes accrued		11,493		30,376
Operating lease liabilities		781		644
Regulatory liabilities		14,843		9,893
Other		19,792		23,011
Total Current Liabilities		**191,496**		**158,041**
Regulatory and Other Liabilities				
Regulatory liabilities		232,557		220,140
Other Non-current Liabilities				
Deferred income taxes		103,303		85,996
Pension and other postretirement		48,768		50,637
Operating lease liabilities		10,484		7,682
Asset retirement obligation		12,785		12,654
Environmental remediation costs		60,661		60,714
Other		5,007		6,885
Total Regulatory and Other Liabilities		**473,565**		**444,708**
Non-current debt		304,982		305,316
Total Liabilities		**970,043**		**908,065**
Commitments and Contingencies				
Common Stock Equity				
Common stock ($13.33 par value, 2,650,000 shares authorized and 1,407,072 shares outstanding at December 31, 2022 and 2021)		18,761		18,761
Additional paid-in capital		462,737		412,737
Retained earnings		62,315		52,798
Accumulated other comprehensive loss		(5,216)		(6,327)
Total SCG Common Stock Equity		**538,597**		**477,969**
Noncontrolling interest		40,440		41,838
Total Equity		**579,037**		**519,807**
Total Liabilities and Equity	**$**	**1,549,080**	**$**	**1,427,872**

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

The Southern Connecticut Gas Company
Consolidated Statements of Cash Flows

Years Ended December 31,	2022	2021
(Thousands)		
Cash Flow from Operating Activities:		
Net income	**$ 42,979**	**$ 36,979**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	38,835	37,057
Regulatory assets/liabilities amortization	14,240	13,935
Regulatory assets/liabilities carrying cost	3,493	2,314
Amortization of debt issuance costs	(437)	(2,750)
Deferred taxes	(1,046)	11,166
Pension cost	1,824	(497)
Accretion expenses	649	646
Other non-cash items	3,161	56
Changes in operating assets and liabilities:		
Accounts receivable, from affiliates, and unbilled revenues	(29,782)	(13,388)
Inventories	(24,184)	(10,258)
Accounts payable, to affiliates, and accrued liabilities	20,697	22,677
Taxes accrued	(18,884)	34,892
Other assets/liabilities	10,499	23,283
Regulatory assets/liabilities	(31,928)	(49,012)
Net Cash Provided by Operating Activities	**30,116**	**107,100**
Cash Flow from Investing Activities:		
Capital expenditures	(96,005)	(90,222)
Contributions in aid of construction	3,145	2,864
Proceeds from sale of utility plant	74	43
Notes receivable from affiliates	27,296	(22,427)
Net Cash Used in Investing Activities	**(65,490)**	**(109,742)**
Cash Flow from Financing Activities:		
Non-current debt issuance	—	39,911
Repayment of non-current debt	—	(25,000)
Return of capital	—	(40,000)
Notes payable to affiliates	21,020	(15,448)
Capital contributions	50,000	25,000
Contributions from noncontrolling interest	708	19,431
Dividends paid	(30,000)	—
Payment of noncontrolling interest dividend	(5,568)	(3,798)
Net Cash Provided by Financing Activities	**36,160**	**96**
Net Increase (Decrease) in Cash and Cash Equivalents	**786**	**(2,546)**
Cash and Cash Equivalents, Beginning of Period	**473**	**3,019**
Cash and Cash Equivalents, End of Period	**$ 1,259**	**$ 473**

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

The Southern Connecticut Gas Company
Consolidated 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 Loss	Noncontrolling Interest	Total Common Stock Equity
Balance, December 31, 2020	**1,407,072**	**$ 18,761**	**$ 427,737**	**$ 19,167**	**$ (5,032)**	**$ 22,857**	**$ 483,490**
Net income	—	—	—	33,631	—	—	33,631
Other comprehensive loss, net of tax	—	—	—	—	(1,295)	—	(1,295)
Comprehensive income	—						32,336
Net income attributable to noncontrolling interest	—	—	—	—	—	3,348	3,348
Payment of noncontrolling interest dividend	—	—	—	—	—	(3,798)	(3,798)
Contributions from noncontrolling interest	—	—	—	—	—	19,431	19,431
Capital contributions	—	—	25,000	—	—	—	25,000
Return of capital	—	—	(40,000)	—	—	—	(40,000)
Balance, December 31, 2021	**1,407,072**	**18,761**	**412,737**	**52,798**	**(6,327)**	**41,838**	**519,807**
Net income	—	—	—	39,517	—	—	39,517
Other comprehensive income, net of tax	—	—	—	—	1,111	—	1,111
Comprehensive income							40,628
Net income attributable to noncontrolling interest	—	—	—	—	—	3,462	3,462
Payment of noncontrolling interest dividend	—	—	—	—	—	(5,568)	(5,568)
Contributions from noncontrolling interest	—	—	—	—	—	708	708
Payment of common stock dividend	—	—	—	(30,000)	—	—	(30,000)
Capital contributions	—	—	50,000	—	—	—	50,000
Balance, December 31, 2022	**1,407,072**	**$ 18,761**	**$ 462,737**	**$ 62,315**	**$ (5,216)**	**$ 40,440**	**$ 579,037**

(*) Par value of share amounts is $13.33

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

Notes to Consolidated Financial Statements

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

Background and nature of operations: The Southern Connecticut Gas Company (SCG, the company, we, our, us) engages in natural gas transportation, distribution and sales operations in Connecticut serving approximately 208,000 customers as of December 31, 2022, in its service territory of approximately 555 square miles. SCG is regulated by the Connecticut Public Utilities Regulatory Authority (PURA).

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

Variable Interest Entities: CNE Peaking LLC (CNE) and Total Peaking Services LLC (TPS), both wholly-owned subsidiaries of United Resources, Inc. (URI), which is a wholly-owned subsidiary of UIL Holdings, own a 14.6 million gallon liquefied natural gas (LNG) storage tank operated by SCG and located on property owned by SCG in Milford, Connecticut, and certain equipment, materials and supplies used in or useful for the operation of the storage tank. The assets earn a rate of return equal to SCG's allowed rate of return. CNE and TPS have been identified as Variable Interest Entities (VIEs). SCG has been determined to be the primary beneficiary as SCG has the power to direct significant activities at CNE and TPS with SCG operating the storage tank and all of the revenues at CNE and TPS being derived from SCG. As a result, CNE and TPS have been consolidated into the financial statements of SCG, which include total assets of $41.6 million and income of $3.5 million as of and for the year ended December 31, 2022. Intercompany operating revenues and natural gas purchased expenses and intercompany receivables and payables 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 sheets and consolidated statement of changes in common stock 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:

As of December 31,	**2022**	**2021**
(Thousands)		
Assets		
Current assets	$ 13,076	$ 20,276
Long-term assets	28,493	29,600
Total Assets	**41,569**	**49,876**
Liabilities		
Current liabilities	1,129	8,038
Total Liabilities	**$ 1,129**	**$ 8,038**

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 prepared on a consolidated basis, and therefore include the accounts of SCG and all SCG VIEs where SCG has identified that it is the primary beneficiary. All intercompany transactions and accounts have been eliminated in consolidation in all periods presented. The accounting records of SCG are also maintained in accordance with the uniform system of accounts prescribed by the Federal Energy Regulatory Commission (FERC).

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

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

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

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

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

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

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

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

In assessing goodwill for impairment, we have the option to first perform a qualitative assessment to determine whether a quantitative assessment is necessary. If we determine, based on qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If we bypass the qualitative assessment, or perform the qualitative assessment but determine it is more likely than not that its fair value is less than its carrying amount, we perform a quantitative test to compare the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, we record an impairment loss as a reduction to goodwill and a charge to operating expenses, but the loss recognized would not exceed the total amount of goodwill allocated to the reporting unit.

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

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

We transfer assets from “Construction work in progress” to “Utility plant” when they are available for service.

We determine depreciation expense for utility plant in service using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Consistent with FERC accounting requirements, we charge the original cost of utility plant retired or otherwise disposed of to accumulated depreciation. Our composite rates for depreciation were 2.8% of average depreciable property for 2022 and 2.9% for 2021. We amortize our capitalized software cost using the straight line method, based on useful lives of 3 to 10 years. Depreciation expense was $35.3 million in 2022 and $34.1 million in 2021. Amortization of capitalized software was $3.5 million in 2022 and $3 million in 2021.

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

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

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

Utility Plant	Estimated useful life range (years)	2022	2021
(Thousands)			
Gas distribution plant	6-78	$ 1,198,454	$ 1,093,369
Software	3-10	55,619	51,871
Land	N/A	7,658	7,658
Building and improvements	40-50	29,939	28,788
VIE	10-50	43,419	43,368
Other plant	25-39	5,383	5,382
Total Utility Plant in Service		**1,340,472**	**1,230,436**
Total accumulated depreciation		(375,637)	(347,760)
Total Net Utility Plant in Service		**964,835**	**882,676**
Construction work in progress		20,303	36,753
Total Utility Plant		**$ 985,138**	**$ 919,429**

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

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

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

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

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

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

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

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

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

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

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

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

Concentration of risk: We maintain our cash and cash equivalents in accounts with major financial institutions in the form of demand deposits and money market accounts. Deposits in these financial institutions may exceed the amount of federal deposit insurance provided on such deposits.

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

		2022		2021
(Thousands)				
Cash paid during the years ended December 31:				
Interest, net of amounts capitalized	$	13,204	$	13,637
Income taxes paid (refunded), net	$	23,224	$	(32,138)

Of the income taxes paid (refunded), substantially all was paid (refunded) to AGR under the tax sharing agreement. After completing its 2020 Connecticut income tax return in the fall of 2021, AVANGRID determined that it could not provide a current benefit for loss to SCG for its 2020 stand-alone loss that was settled in March 2021. As a result, SCG reversed a current tax benefit for this loss and replaced it with a $5.1M (tax effected) increase to its CT Net Operating Loss. SCG reimbursed its Parent in March 2022.

Interest capitalized was $0.7 million in 2022 and in $0.4 million in 2021. Accrued liabilities for utility plant additions were $14.2 million and $6.2 million as of December 31, 2022 and 2021, respectively.

***Trade receivables and unbilled revenues, net of allowance for credit losses*:** We record trade receivables at amounts billed to customers and we record unbilled revenues based on an estimate of energy delivered or services provided to customers. The estimates for unbilled revenues are determined based on various assumptions, including current month energy load requirements, billing rates by customer class and delivery loss factors. Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

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

Trade receivables at December 31 include unbilled revenues of $33.3 million for 2022 and $25.8 million for 2021, and are shown net of an allowance for credit losses at December 31 of $8.8 million for 2022 and $9.8 million for 2021. Trade receivable do not bear interest, although late fees may be assessed. Credit loss expense was $6.5 million in 2022 and $9.1 million in 2021.

We establish our allowance for credit losses, including for unbilled revenue (also referred to as contract assets), by using both historical average loss percentages to project future losses, and by establishing a specific allowance for known credit issues or for specific items not considered in the historical average calculation. We also consider whether we need to adjust historical loss rates to reflect the effects of current conditions and forecasted changes considering various economic indicators (e.g., Gross Domestic Product, Personal Income, Consumer Price Index, Unemployment Rate) over the contractual life of the trade receivables. We write off amounts when we have exhausted reasonable collection efforts.

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

Gas in storage*:* We own natural gas that is stored in both self-owned and third-party owned underground storage facilities, which we record as inventory. We price injections of inventory into storage at the market purchase cost at the time of injection, and price withdrawals of working gas from storage at the weighted-average cost in storage. We continuously monitor the weighted-average cost of gas value to ensure it remains at the lower of cost and net realizable value. We report inventories to support gas operations on our consolidated balance sheets within “Gas in storage.”

Materials and supplies: Materials and supplies inventories 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 consolidated balance sheets within “Materials and supplies.” We combine inventory items for the consolidated statement of cash flows presentation purposes.

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

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

There were no government grants recorded as of December 31, 2022 and 2021.

Deferred income: Apart from government grants, we occasionally receive revenues from transactions in advance of the resulting performance obligations arising from the transaction. It is our policy to defer such revenues on our consolidated balance sheets and amortize them into earnings when revenue recognition criteria are met.

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

Notes to Consolidated 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 entity's control. If an entity has sufficient information to reasonably estimate the fair value of the liability for a conditional ARO, it must recognize that liability at the time the liability is incurred.

The following table reconciles the beginning and ending aggregate carrying amount of the ARO for the years ended December 31, 2022 and 2021.

Years ended December 31,		**2022**		**2021**
(Thousands)				
ARO, beginning of year	$	12,654	$	12,599
Liabilities settled during the year		(518)		(591)
Accretion expense		649		646
ARO, end of year	**$**	**12,785**	**$**	**12,654**

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; and costs for abandonment of certain types of gas mains.

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

Environmental remediation liability: In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. We record our environmental liabilities on an undiscounted basis. We expect to pay our environmental liability accruals through the year 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 (PBO). For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan’s assets and the accumulated postretirement benefit obligation. We generally reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in OCI, as management believes it is probable that such items will be recoverable through the ratemaking process. Certain non-qualified plan expenses are not recoverable through the ratemaking process and we present the unrecognized prior service costs and credits and unrecognized actuarial gains and losses in accumulated other comprehensive loss. If a plan meets settlement or curtailment accounting criteria, we recognize a regulatory asset or liability if these costs are probable of recovery from ratepayers. 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 employees active on the date of the amendment. Effective March 31, 2022, the amortization period for prior service cost changes for the SCG Salaried Plan was updated from average remaining service to future expected lifetime as the plan was frozen, or predominantly frozen, to future accruals. We amortize unrecognized actuarial gains and losses in excess of 10% of the greater of PBO or market-related value of assets (MRVA) related to the pension and other postretirement benefits plans on straight line basis over future working lifetime. Effective March 31, 2022, the amortization period for the SCG Salaried Plan was updated from future working lifetime to future expected lifetime as the plan was frozen, or predominantly frozen, to future accruals. Our policy is to calculate the expected return on plan assets using the market-related value of assets. We determine that value by recognizing the difference between actual returns and expected returns over a five-year period.

Income taxes**:** In August 2022, the Inflation Reduction Act of 2022 ("IRA") was signed into law in the United States. The IRA created a new corporate alternative minimum tax (“CAMT”) of 15% on adjusted financial statement income and an excise tax of 1% on the value of certain stock repurchases. Based on initial guidance, SCG currently expects to be subject to the CAMT starting in 2023 but does not expect it to have a material impact on consolidated earnings, financial condition, or cash flow. Given the complexity and uncertainty around the applicability of the legislation to our specific facts and circumstances, the company continues to analyze the IRA provisions while waiting on pending Department of Treasury regulatory guidance.

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

The aggregate amount of the related party income tax payable to AGR is $5.5 million and $24.3 million at December 31, 2022 and 2021, respectively.

We use the asset and liability method of accounting for income taxes. Deferred tax assets and liabilities reflect the expected future tax consequences, based on enacted tax laws, of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts. In accordance with U.S. GAAP for regulated industries, we have established regulatory assets and liabilities for the net revenue requirements to be recovered from or refunded to customers for the related future tax expense or benefit associated with certain of these temporary differences. We defer investment tax credits when earned and amortize them over the estimated lives of the related assets. We also recognize the income tax consequences of intra-entity transfers of assets other than inventory when the transfer occurs. We had no intra-entity transfers of assets other than inventory during the years ended December 31, 2022 and 2021.

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 consolidated balance sheet date. We charge or credit changes in deferred income tax assets and liabilities that are associated with components of OCI directly to OCI. Significant judgment is required in determining income tax provisions and evaluating tax positions. Our tax positions are evaluated under a more-likely-than-not recognition threshold before they are recognized for financial reporting purposes. We record valuation allowances to reduce deferred tax assets when it is more likely than not that we will not realize all or a portion of a tax benefit. We consider the effect of the alternative minimum tax system in determining the need for a valuation allowance for deferred taxes. Deferred tax assets and liabilities are netted and classified as non-current on our consolidated balance sheets.

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

Positions taken or expected to be taken on tax returns, including the decision to exclude certain income or transactions from a return, are recognized in the consolidated 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 consolidated financial statements is disclosed as an unrecognized tax benefit. Changes in assumptions on tax benefits may also impact interest expense or interest income and may result in the recognition of tax penalties. Interest and penalties related to unrecognized tax benefits are recorded within “Interest expense, net of capitalization” and “Other Income” and “Other Deductions” in our consolidated statements of income.

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. 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 consolidated financial statements.

Adoption of New Accounting Pronouncements

Although we are not a public business entity, our parent company is a public business entity; therefore, we adopt new accounting standards based on the effective date for public entities as permitted. There have been no new accounting pronouncements adopted as of December 31, 2022.

Accounting Pronouncements Issued But Not Yet Adopted

There have been no accounting pronouncements issued but not yet adopted that are expected to have a material impact on SCG's consolidated financial statements.

Use of estimates and assumptions: The preparation of our consolidated financial statements in conformity with U.S. GAAP requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the reporting periods. Significant estimates and assumptions are used for, but not limited to: (1) allowance for credit losses and unbilled revenues; (2) asset impairments; (3) investments in equity instruments; (4) depreciable lives of assets; (5) income tax valuation allowances; (6) uncertain tax positions; (7) reserves for professional, workers’ compensation, and comprehensive general insurance liability risks; (8) contingency and litigation reserves; (9) earnings sharing mechanism (ESM); (10) environmental remediation liabilities; (11) pension and other postretirement employee benefits (OPEB); (12) fair value measurements; (13) AROs, and (14) noncontrolling interest balances. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our consolidated financial statements will change as new events occur, as more experience is acquired, as additional information is obtained, and as our operating environment changes. We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside specialists to assist in our evaluations, as considered necessary. Actual results could differ from those estimates.

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

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 Ontario, Canada.

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

Minimum Equity Requirements for Regulated Subsidiaries

Pursuant to an agreement with PURA, SCG is restricted from paying dividends if paying such dividend would result in a common equity ratio lower than 300 basis points below the equity percentage used to set rates in the most recent distribution rate proceeding as measured using a trailing 13-month average calculated as of the most recent quarter end. In addition, SCG is prohibited from paying dividends to their parent if the utility's credit rating, as rated by any of the three major credit rating agencies, falls below investment grade, or if the utility's credit rating, as determined by two of the three major credit rating agencies, falls to the lowest investment grade and there is a negative watch or review downgrade notice.

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 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 $121.6 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

Details of 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.

Regulatory assets at December 31, 2022 and 2021 consisted of:

December 31,		2022		2021
(Thousands)				
Asset retirement obligation	$	3,893	$	3,710
Debt premium		3,514		4,112
Deferred purchased gas		17,214		16,752
Distribution integrity management program		10,161		1,011
Energy efficiency portfolio standard		—		2,279
Environmental remediation costs		67,366		67,366
Pension and other postretirement benefits		62,653		63,501
Revenue decoupling mechanism		7,304		11,973
System expansion		12,464		5,454
Unfunded future income taxes		18,169		—
Other		5,253		4,313
Total regulatory assets		**207,991**		**180,471**
Less: current portion		48,145		38,738
Total non-current regulatory assets	**$**	**159,846**	**$**	**141,733**

Asset retirement obligations represent the differences in timing of the recognition of costs associated with our AROs and the collection of such amounts through rates. This amount is being amortized at the related depreciation and accretion amounts of the underlying liability.

Debt premium represents the regulatory asset recorded to offset the fair value adjustment to the regulatory component of the non-current debt of UIL at the acquisition date. This amount is being amortized to interest expense over the remaining term of the outstanding debt instruments.

Deferred purchased gas costs represents the difference between actual gas costs and gas costs collected in rates. Balances at the end of the rate year are normally recorded/returned in the next year.

Distribution integrity management program (DIMP) represents deferred expenses related to pipeline replacement for cast iron and bare steel mains and services. Balances at the end of each rate year are normally received/returned in the next year.

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.

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.

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

System expansion represents expenses not covered by System expansion rates related to expanding the natural gas system and converting customers to natural gas.

Other includes items such as deferred credit card fees, Environmental defense fund (EDF) legal costs and COVID-19 deferrals.

Regulatory liabilities at December 31, 2022 and 2021 consisted of:

December 31,		**2022**		**2021**
(Thousands)				
Asset removal obligation	$	119,675	$	116,091
Low income program		13,824		20,157
Non-firm margin sharing credits		13,335		6,762
Pension and other postretirement benefits		5,256		5,192
Rate credits		3,750		4,500
Tax reform		68,330		57,596
Unfunded future income taxes		13,578		16,025
Other		9,652		3,710
Total regulatory liabilities		**247,400**		**230,033**
Less: current portion		14,843		9,893
Total non-current regulatory liabilities	**$**	**232,557**	**$**	**220,140**

Asset 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.

Low income program represents various hardship and payment plan programs approved for recovery.

Non-firm margin sharing credits represents the portion of interruptible and off-system sales revenue set aside to fund gas expansion projects.

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.

Rate credits resulted from the acquisition of UIL by Iberdrola. This is being used to moderate increases in rates.

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 amount and timing of potential settlement are determined by the regulated utilities' respective rate regulators and IRS Normalization rules.

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

Other includes items such as Geographical information system (GIS) data conversion and various items subject to reconciliation.

Note 4. Revenue

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

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

SCG derives its revenue primarily from tariff-based sales of natural gas service to customers in Connecticut with no defined contractual term. For such revenues, we recognize 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 determine prices and other terms of service through the ratemaking process. Certain customers have the option to obtain the 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 natural gas provided by that supplier. Revenue in those cases is only for providing the service of delivery of the commodity.

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 SCG delivers or sells the natural gas.

SCG records revenue from Alternative Revenue Programs (ARPs), which is not ASC 606 revenue. This program, a revenue decoupling mechanism (RDM), represent a contract between the utilities and their regulators.

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, ARPs, or other activities.

Revenues disaggregated by major source for the years ended December 31, 2022 and 2021 are as follows:

Years Ended December 31,	**2022**	**2021**
(Thousands)		
Regulated operations – natural gas	$ 506,201	$ 396,739
Other(a)	179	202
Revenue from contracts with customers	**506,380**	**396,941**
Leasing revenue	2	1
Alternative revenue programs	4,205	11,555
Other revenue	5,274	4,067
Total operating revenues	**$ 515,861**	**$ 412,564**

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

Note 5. Goodwill

We do not amortize goodwill, but perform our annual impairment assessment testing at least annually as described in Note 1, in the fourth quarter, as of October 1. Our qualitative assessment involves evaluating key events and circumstances that could affect the fair value of our company, as well as other factors. Events and circumstances evaluated include macroeconomic conditions, industry, regulatory and market considerations, cost factors and their effect on earnings and cash flows, overall financial performance as compared with projected results and actual results of relevant prior periods, other relevant entity-specific events, and events affecting SCG.

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

We had no impairment of goodwill in 2022 and 2021 as a result of our qualitative impairment testing. There were no events or circumstances subsequent to our annual impairment assessment for 2022 or 2021 that required us to update the assessment.

The carrying amount of goodwill was $134.9 million at both December 31, 2022 and 2021, with no accumulated impairment losses and no changes during 2022 and 2021.

Note 6. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,		2022		2021
(Thousands)				
Current				
Federal	$	6,199	$	(844)
State		(1,750)		1,551
Current taxes charged to expense		**4,449**		**707**
Deferred				
Federal		4,215		10,137
State		(5,261)		1,029
Deferred taxes charged to (benefit) expense		**(1,046)**		**11,166**
Total Income Tax Expense	**$**	**3,403**	**$**	**11,873**

The differences between tax expense per the consolidated statements of income and tax expense at the 21% statutory federal tax rate for the years ended December 31, 2022 and 2021, respectively, consisted of:

Years Ended December 31,		2022		2021
(Thousands)				
Tax expense at statutory rate	$	9,740	$	10,259
State tax (benefit) expense, net of federal income tax benefit		(5,539)		2,038
Variable interest entity		(953)		(921)
Other, net		155		497
Total Income Tax Expense	**$**	**3,403**	**$**	**11,873**

Income tax expense for the year ended December 31, 2022 was $6.3 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to state taxes, and AFUDC Equity tax effects. This resulted in an effective tax rate of 7.3%. Income tax expense for the year ended December 31, 2021 was $1.6 million higher than it would have been at the statutory federal income tax rate of 21% due predominately to state taxes, partially offset by AFUDC Equity tax effects. This resulted in an effective tax rate of 24.3%.

Deferred tax assets and liabilities as of December 31, 2022 and 2021 consisted of:

December 31,		2022		2021
(Thousands)				
Non-current Deferred Income Tax Liabilities (Assets)				
Property related	$	117,864	$	104,984
Unfunded future income taxes		1,048		(4,315)
Valuation allowance - state credits		12,074		6,586
Federal and state tax credits		(12,487)		(11,677)
Goodwill		21,780		19,989
Deferred tax asset on 2017 Tax Act remeasurement		(18,398)		(15,507)
Federal and state NOL's		(20,095)		(18,770)
Post-retirement benefits, net		192		2,615
Other		1,325		2,091
Total Non-current Deferred Income Tax Liabilities	**$**	**103,303**	**$**	**85,996**
Deferred tax assets	$	50,980	$	50,269
Deferred tax liabilities		154,283		136,265
Net Accumulated Deferred Income Tax Liabilities	**$**	**103,303**	**$**	**85,996**

SCG has federal net operating losses of $17.1 million, net state net operating losses of $3.0 million and net state credit carryforward of $12.5 million for the year ended December 31, 2022. SCG had federal net operating losses of $13.9 million, net state net operating losses of $4.9 million and net state credit carryforward of $11.7 million for the year ended December 31, 2021.

Valuation allowances are recorded to reduce deferred tax assets when it is more likely than not that all or a portion of a tax benefit will not be realized. As of December 31, 2022, SCG had recorded a valuation allowance on its state tax credit carryforwards of $12.1 million. The company has also recorded a regulatory asset of $17.5 million to recover the associated tax expense of the valuation allowance against the state credits, whose tax benefits were previously shared with customers. As of December 31, 2021, SCG had recorded a valuation allowance on its state credit carryforwards of $6.6 million.

Uncertain tax positions are 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. As of December 31, 2022 and 2021, SCG did not have any gross income tax reserves for uncertain tax positions.

There were no additional accruals for interest and penalties on tax reserves as of December 31, 2022 and 2021.

Note 7. Long-term Debt

Long-term debt as of December 31, 2022 and 2021 consisted of:

As of December 31,		2022		2021	
(Thousands, except interest rates)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
First mortgage bonds (a)	2025-2049	$ 304,000	1.87% - 7.95%	$ 304,000	1.87% - 7.95%
Unamortized debt issuance premium, net		982		1,316	
Total Debt		**304,982**		**305,316**	
Less: debt due within one year, included in current liabilities		—		—	
Total Non-current Debt		**$ 304,982**		**$ 305,316**	

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

On December 15, 2021, SCG issued $40 million of first mortgage bonds maturing in 2031 at an interest rate of 2.05%.

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

	2023	2024	2025	2026	2027	Total
(Thousands)						
	$ —	$ —	$ 25,000	$ 15,000	$ —	$ 40,000

Under various long-term debt agreements, SCG is required to maintain a ratio of indebtedness to capital not to exceed 200% and to limit aggregate dividends paid pursuant specific indenture requirements. As of December 31, 2022 and 2021, SCG was in compliance with long-term debt covenants.

Note 8. Bank Loans and Other Borrowings

Notes payable balances totaled $24.6 million and $3.6 million as of December 31, 2022 and 2021, respectively. 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) and a bank provided credit facility to which SCG 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. SCG has a lending/borrowing limit of $100 million under this agreement. SCG had $24.4 million outstanding under this agreement at December 31, 2022 and no debt outstanding under this agreement at December 31, 2021.

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. SCG had no debt outstanding under this agreement at December 31, 2022 and 2021.

On November 23, 2021, AGR and its investment-grade rated utility subsidiaries (New York State Electric and Gas Corporation ("NYSEG"), Rochester Gas and Electric Corporation ("RG&E"), Central Maine Power Company ("CMP"), The United Illuminating Company ("UI"), Connecticut

Natural Gas Corporation ("CNG"), SCG, and The Berkshire Gas Company ("BGC")) executed a new credit facility with an aggregate limit of $3,575 million and a termination date of November 23, 2026. Under the terms of the Avangrid Credit Facility, each borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit contained in the agreement. NYSEG has a maximum sublimit of $700 million, RG&E has $300 million, CMP has $200 million and UI has a maximum sublimit of $250 million, CNG and SCG have maximum sublimits of $150 million, and BGC has a maximum sublimit of $50 million. Effective on November 23, 2021, the AGR Credit Facility was amended to increase AGR's maximum sublimit to $2,500 million and to establish minimum sublimits of $500 million for NYSEG, $200 million for RG&E, $100 million for CMP, $150 million for UI, $50 million for CNG and SCG, and $25 million for BGC. Under the AGR Credit Facility, each of the borrowers are charged a facility fee that is dependent on their credit rating. The facility fees range from 10.0 to 22.5 basis points. SCG had no outstanding balance as of December 31, 2022 and 2021.

In the AGR Credit Facility we covenant not to permit, without the consent of the lenders, our ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of indebtedness to total capitalization, the facility excludes from net worth the balance of accumulated other comprehensive loss as it appears on the consolidated balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness we may maintain. Continued un-remedied failure to comply with those covenants beyond any applicable cure period, constitutes an event of default, and events of default could result in termination or reduction of lenders' commitments or acceleration of amounts owed under the facility. Our ratio of indebtedness to total capitalization pursuant to the revolving credit facility was 0.36 to 1.00 at December 31, 2022. We are not in default as of December 31, 2022.

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, 2022 and 2021 TPS had $0.2 million and $3.6 million, respectively, outstanding under its agreement. CNE did not have any amounts outstanding under its agreement as of December 31, 2022 and 2021.

Note 9. Preferred Stock

At December 31, 2022, SCG had 200,000 shares of $100 par value preferred stock and 1,600,000 shares of $2 par value preferred stock authorized but unissued.

Note 10. Leases

We have operating leases for office buildings, facilities, vehicles and certain equipment. As of December 31, 2022 and 2021, we had no finance leases. Certain of our lease agreements include rental payments adjusted periodically for inflation or are based on other periodic input measures. Our leases do not contain any material residual value guarantees or material restrictive covenants. Our leases have remaining lease terms of 1 to 51 years, some of which may include options to extend the leases for up to 20 years, and some of which may include options to terminate the leases within one year. We consider extension or termination options in the lease term if it is reasonably certain we will exercise the option.

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

Years Ended December 31,		2022		2021
(Thousands)				
Lease cost				
Operating lease cost	$	1,233	$	16
Short-term lease cost		143		7
Variable lease cost		432		365
Total lease cost	**$**	**1,808**	**$**	**388**

Consolidated balance sheet and other information for the years ended December 31, 2022 and 2021 was as follows:

As of December 31,		2022		2021
(Thousands, except lease term and discount rate)				
Operating Leases				
Operating lease right of use assets	$	10,418	$	8,197
Operating lease liabilities, current		781		644
Operating lease liabilities, long-term		10,484		7,682
Total operating lease liabilities	$	11,265	$	8,326
Weighted-average Remaining Lease Term (years):				
Operating leases		10.87		10.82
Weighted-average Discount Rate:				
Operating leases		3.57 %		1.99 %

Supplemental consolidated cash flows information related to leases was as follows:

Years Ended December 31,		2022		2021
(Thousands)				
Cash paid for amounts included in the measurement of lease liabilities:				
Operating cash flows from operating leases	$	792	$	1,204
Right-of-use assets obtained in exchange for lease obligations:				
Operating leases	$	2,906	$	8,513

Maturities of lease liabilities were as follows:

(Thousands)		Operating
Years Ended December 31,		
2023	$	1,130
2024		1,727
2025		1,096
2026		1,117
2027		1,140
Thereafter		7,664
Total lease payments		**13,874**
Less: imputed interest		(2,609)
Total	**$**	**11,265**

Most of our leases do not provide an implicit rate in the lease, thus we use our incremental borrowing rate based on the information available at the commencement date in determining the present value of lease payments.

Note 11. Environmental Liability

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, 2022 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 and Pine Street 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, 2022 and 2021, SCG reserved $50.7 million and $50.1 million, respectively, related to the property located in New Haven which was offset by a regulatory asset. Additionally, as of December 31, 2022 and 2021, SCG reserved $12.4 million and $12.8 million, respectively, related to the property located on Pine Street in Bridgeport. As of December 31, 2022 and 2021, SCG has determined that remediation of the property on Housatonic Avenue in Bridgeport is not estimable at this time and therefore not reserved.

Note 12. Fair Value of Financial Instruments and Fair Value Measurements

The estimated fair value of debt amounted to $285 million and $369 million as of December 31, 2022 and 2021, 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.

Assets and liabilities measured at fair value on a recurring basis

The financial instruments measured at fair value as of December 31, 2022 and 2021 consisted of:

Description	(Level 1)	(Level 2)	(Level 3)	Total
(Thousands)				
As of December 31, 2022				
Assets				
Non-current investments	$ 9,372	$ —	$ —	$ 9,372
Total	**$ 9,372**	**$ —**	**$ —**	**$ 9,372**
As of December 31, 2021				
Assets				
Non-current investments	$ 11,787	$ —	$ —	$ 11,787
Total	**$ 11,787**	**$ —**	**$ —**	**$ 11,787**

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2022 and 2021. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

Valuation techniques: We measure the fair value of our non-current investments available for sale using quoted market prices in active markets for identical assets and include the measurements in Level 1. The investments which are Rabbi Trusts for deferred compensation plans primarily consist of money market funds.

Note 13. Post-retirement and Similar Obligations

SCG has multiple qualified pension plans covering eligible union and management employees and retirees. The plans are traditional defined benefit plans or cash balance plans depending on date of hire and are closed to new employees hired on or after specified dates. Employees not participating in a defined benefit plan are eligible to receive an enhanced or core 401(k) Company matching contribution. On March 31, 2022, the Board approved to freeze the SCG non-union plan, with an effective date of June 30, 2022.

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 totaled approximately $3.3 million for 2022 and $2.1 million for 2021.

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

Non-Qualified Retirement Benefit Plans

We also sponsor various unfunded non-qualified pension plans for certain current employees, former employees and former directors. The total liability for these plans, which is included in Other non-current liabilities on our consolidated balance sheets, was $4.8 million and $6.1 million at December 31, 2022 and 2021, respectively.

Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2022 and 2021 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2022**	**2021**	**2022**	**2021**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	$ 179,484	$ 194,920	$ 18,423	$ 18,204
Service cost	857	2,132	52	101
Interest cost	5,522	4,436	460	402
Amendments	137	1,777	—	1,189
Actuarial (gain) loss	(32,041)	(9,716)	(1,749)	892
Curtailments	(2,751)	—	—	—
Settlements	(17,605)	—	—	—
Benefits paid	(9,529)	(14,065)	(2,022)	(2,365)
Benefit obligation at December 31	**$ 124,074**	**$ 179,484**	**$ 15,164**	**$ 18,423**
Change in plan assets				
Fair value of plan assets at January 1	$ 142,747	$ 143,821	$ 4,523	$ 4,785
Actual return on plan assets	(29,090)	12,254	(879)	522
Employer & plan participants' contributions	1,010	737	1,315	1,581
Settlements	(17,605)	—	—	—
Benefits paid	(9,529)	(14,065)	(2,022)	(2,365)
Fair value of plan assets at December 31	**$ 87,533**	**$ 142,747**	**$ 2,937**	**$ 4,523**
Funded status	**$ (36,541)**	**$ (36,737)**	**$ (12,227)**	**$ (13,900)**

During 2022, the pension benefit obligation had an actuarial gain of $32.0 million. This gain was primarily driven by a $32.0 million gain from increase in discount rates. In 2022, the pension benefit obligation had a reduction of $17.6 million from settlements and $2.8 million from curtailments. The settlements were lump-sum payments made within the pension plan guidelines at the discretion of the plan participants who opted to retire. The curtailments were driven by a

Notes to Consolidated Financial Statements

Company decision to freeze pension benefit accruals and contribution credits for non-union employees and transition their retirement benefits to a 401(k) plan. There were no significant gains and losses relating to the postretirement benefit obligations.

During 2021, the pension benefit obligation had an actuarial gain of $9.7 million. This gain was primarily driven by a $10.9 million gain from increase in discount rates. There were no significant plan design changes in 2021. There were no significant gains and losses relating to the postretirement benefit obligations.

Amounts recognized in the consolidated balance sheet as of December 31, 2022 and 2021 consisted of:

		Pension Benefits		Postretirement Benefits	
As of December 31,		**2022**	**2021**	**2022**	**2021**
(Thousands)					
Noncurrent liabilities	$	(36,541) $	(36,737) $	(12,227) $	(13,900)

We have determined that we are allowed to defer as regulatory assets or regulatory liabilities items that would otherwise be recorded in accumulated other comprehensive income pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans.

Amounts recognized as regulatory assets or regulatory liabilities consist of:

		Pension Benefits		Postretirement Benefits	
As of December 31,		**2022**	**2021**	**2022**	**2021**
(Thousands)					
Net actuarial loss (gain)	$	21,568 $	22,614 $	(1,542) $	(1,122)
Prior service cost	$	1,813 $	1,777 $	824 $	1,298

Our accumulated benefit obligation for all qualified defined benefit pension plans was $124.1 million and $175.9 million as of December 31, 2022 and 2021, respectively. SCG's postretirement benefits were partially funded as of December 31, 2022 and 2021.

The projected benefit obligation and the accumulated benefit obligation exceeded the fair value of pension plan assets for our qualified plans as of December 31, 2022 and 2021. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets as of December 31, 2022 and 2021.

As of December 31,		**2022**	**2021**
(Thousands)			
Projected benefit obligation	$	124,074 $	179,484
Accumulated benefit obligation	$	124,074 $	175,874
Fair value of plan assets	$	87,533 $	142,747

The postretirement benefits obligation for all the qualified plans exceeded the fair value of plan assets as of December 31, 2022 and 2021.

Components of net periodic benefit cost and other amounts recognized in regulatory assets and regulatory liabilities for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,	Pension Benefits 2022	Pension Benefits 2021	Postretirement Benefits 2022	Postretirement Benefits 2021
(Thousands)				
Net periodic benefit cost				
Service cost	$ 857	$ 2,132	$ 52	$ 101
Interest cost	5,522	4,436	460	402
Expected return on plan assets	(8,698)	(9,904)	(308)	(317)
Amortization of prior service cost	101	—	475	78
Amortization of actuarial loss (gain)	1,037	2,840	(143)	(246)
Settlements	3,005	—	—	—
Net periodic benefit cost	**$ 1,824**	**$ (496)**	**$ 536**	**$ 18**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Curtailments	$ (2,751)	$ —	$ —	$ —
Settlements	(3,005)	—	—	—
Current year prior service costs	137	1,777	—	1,189
Amortization of prior service cost	(101)	—	(475)	(78)
Current year actuarial loss (gain)	5,747	(12,065)	(562)	686
Amortization of actuarial (loss) gain	(1,037)	(2,840)	143	246
Total recognized in regulatory assets and regulatory liabilities	**$ (1,010)**	**$ (13,128)**	**$ (894)**	**$ 2,043**
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$ 814**	**$ (13,624)**	**$ (358)**	**$ 2,061**

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

The weighted-average assumptions used to determine benefit obligations as of December 31, 2022 and 2021 consisted of:

As of December 31,	Pension Benefits 2022	Pension Benefits 2021	Postretirement Benefits 2022	Postretirement Benefits 2021
Discount rate	5.17 %	2.85 %	5.10 %	2.61 %
Rate of compensation increase	N/A	3.50%/ N/A Union	N/A	N/A
Interest crediting rate	4.48% / 4.00%	2.00% / 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 developing a yield curve derived from a portfolio of high grade non-callable bonds with yields that closely matches the duration of the expected cash flows of our benefit obligations.

The weighted-average assumptions used to determine net periodic benefit cost for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,	Pension Benefits 2022	Pension Benefits 2021	Postretirement Benefits 2022	Postretirement Benefits 2021
Discount rate	2.85% /4.08% /4.92%	2.29% / 2.43%	2.61 %	2.29 %
Expected long-term return on plan assets	7.00 %	7.00 %	6.80 %	6.62 %
Rate of compensation increase	3.50% / 3.50% / N/A	3.50% / 2.75%	N/A	N/A

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.

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 in excess of 10% of the greater of PBO or MRVA related to the pension and other postretirement benefits plans on straight line basis over future working lifetime. Effective March 31, 2022, the amortization period for the SCG Salaried Plan was updated from future working lifetime to future expected lifetime as the plan was frozen, or predominantly frozen, to future accruals. For other postretirement benefits, there is no such allowance for a variance in capturing the amortization of unrecognized gains and losses.

Assumed health care cost trend rates to determine benefit obligations as of December 31, 2022 and 2021 consisted of:

As of December 31,	2022	2021
Health care cost trend rate (pre 65/post 65)	6.00%/6.50%	6.25% / 7.00%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	4.50 %	4.50 %
Year that the rate reaches the ultimate trend rate	2029 / 2027	2029 / 2027

Contributions: In accordance with our funding policy, we make annual contributions of not less than the minimum required by applicable regulations. We do not expect to contribute to our pension benefits plan in 2023. We expect to contribute $0.8 million to our postretirement benefits plan in 2023.

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)			
2023	$ 12,028	$ 1,498	$ 93
2024	$ 11,103	$ 1,474	$ 98
2025	$ 10,492	$ 1,440	$ 100
2026	$ 10,946	$ 1,353	$ 105
2027	$ 10,439	$ 1,330	$ 106
2028-2032	$ 49,266	$ 5,707	$ 599

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

The asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets within broad categories of asset classes made up of Return-Seeking and Liability-Hedging investments. We have targets of 25%-60% for Return-Seeking assets and 40%-75% for Liability-Hedging assets. Return-Seeking investments generally consist of domestic, international, global, and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking assets also include investments in real estate, global asset allocation strategies and hedge funds. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS, and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of pension benefits plan assets as of December 31, 2022, by asset category, consisted of:

Asset Category	Total	Fair Value Measurements (Level 1)	(Level 2)	(Level 3)
(Thousands)				
As of December 31, 2022				
Cash and cash equivalents	$ 3,167	$ 10	$ 3,157	$ —
U.S. government securities	4,703	4,703	—	—
Common stocks	3,885	3,885	—	—
Registered investment companies	4,363	4,363	—	—
Corporate bonds	22,807	—	22,807	—
Preferred stocks	24	24	—	—
Common collective trusts	31,791	—	31,791	—
Other, principally annuity, fixed income	320	—	320	—
	$ 71,060	**$ 12,985**	**$ 58,075**	**$ —**
Other investments measured at net asset value	16,473			
Total	**$ 87,533**			

The fair values of pension benefits plan assets as of December 31, 2021, by asset category, consisted of:

Asset Category	Total	Fair Value Measurements (Level 1)	(Level 2)	(Level 3)
(Thousands)				
As of December 31, 2021				
Cash and cash equivalents	$ 2,094	$ 649	$ 1,445	$ —
U.S. government securities	8,401	8,401	—	—
Common stocks	6,350	6,350	—	—
Registered investment companies	12,974	12,974	—	—
Corporate bonds	38,221	—	38,221	—
Preferred stocks	41	41	—	—
Common collective trusts	49,995	—	49,995	—
Other, principally annuity, fixed income	1,019	—	1,019	—
	$ 119,095	**$ 28,415**	**$ 90,680**	**$ —**
Other investments measured at net asset value	23,652			
Total	**$ 142,747**			

Valuation Techniques

We value our pension benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities - at the closing price reported in the active market in which the security is traded.
- Common stocks - at the closing price reported in the active market in which the individual investment is traded.

- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks - at the closing price reported in the active market in which the individual investment is traded.
- Registered investment companies - at the closing price reported in the active market in which the individual investment is traded.
- Common collective trusts – the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Other investments measured at net asset value (NAV) – fund shares offered to a limited group of investors and alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

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

We have established a target asset allocation policy within allowable ranges for postretirement benefits plan assets of 49% - 69% for equity securities, 31%- 51% for fixed income. Equity investments are diversified across U.S. and non-U.S. stocks, investment styles, and market capitalization ranges. Fixed income investments are primarily invested in U.S. bonds and may also include some non-U.S. bonds. Other asset classes, including alternative investments, are used to enhance long-term returns while improving portfolio diversification. We primarily minimize the risk of large losses through diversification but also through monitoring and managing other aspects of risk through quarterly investment portfolio reviews. Systematic rebalancing within target ranges increases the probability that the annualized return on investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair value of other postretirement benefits plan assets, by asset category, as of December 31, 2022 consisted of:

Asset Category	Total	Fair Value Measurements (Level 1)	(Level 2)	(Level 3)
(Thousands)				
As of December 31, 2022				
Cash and cash equivalents	$ 243	$ —	$ 243	$ —
U.S. government securities	145	145	—	—
Common stocks	111	111	—	—
Registered investment companies	179	179	—	—
Corporate bonds	689	—	689	—
Preferred stocks	1	1	—	—
Common collective trusts	1,123	—	1,123	—
Other, principally annuity, fixed income	10	—	10	—
	$ 2,501	**$ 436**	**$ 2,065**	**$ —**
Other investments measured at net asset value	436			
Total	**$ 2,937**			

The fair value of other postretirement benefits plan assets, by asset category, as of December 31, 2021 consisted of:

Asset Category	Total	Fair Value Measurements (Level 1)	(Level 2)	(Level 3)
(Thousands)				
As of December 31, 2021				
Cash and cash equivalents	$ 276	$ 16	$ 260	$ —
U.S. government securities	223	223	—	—
Common stocks	146	146	—	—
Registered investment companies	1,103	1,103	—	—
Corporate bonds	919	—	919	—
Preferred stocks	1	1	—	—
Common collective trusts	1,348	—	1,348	—
Other, principally annuity, fixed income	28	—	28	—
	$ 4,044	**$ 1,489**	**$ 2,555**	**$ —**
Other investments measured at net asset value	479			
Total	**$ 4,523**			

Valuation Techniques

We value our postretirement benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities - at the closing price reported in the active market in which the security is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.

- Common stocks - at the closing price reported in the active market in which the individual investment is traded.
- Preferred stocks - at the closing price reported in the active market in which the individual investment is traded.
- Registered investment companies - at the closing price reported in the active market in which the individual investment is traded.
- Common collective trusts – the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Other investments measured at net asset value (NAV) – fund shares offered to a limited group of investors and alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

Pension and postretirement benefit plan equity securities did not include any AGR and Iberdrola common stock as of both December 31, 2022 and 2021.

Note 14. Other Income and Other Deductions

Other income and deductions for the years ended December 31, 2022 and 2021, consisted of:

Years Ended December 31,		**2022**		**2021**
(Thousands)				
Interest and dividend income	$	765	$	998
Carrying costs on regulatory assets		724		434
Allowance for funds used during construction		1,090		847
Miscellaneous		68		19
Total other income	**$**	**2,647**	**$**	**2,298**
Pension non-service components	$	(10,243)	$	1,926
Miscellaneous		(1,929)		(2,022)
Total other deductions	**$**	**(12,172)**	**$**	**(96)**

Note 15. Related Party Transactions

Certain Networks subsidiaries, including SCG, borrow from AGR, the parent of Networks, through intercompany revolving credit agreements. For SCG, the intercompany revolving credit agreements provide access to supplemental liquidity. See Note 8 for further detail on the credit facility with AGR.

Avangrid Service Company provides administrative and management services to Networks operating utilities, including SCG, 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 SCG by AGR and its affiliates was approximately $17.8 million and $19.1 million for the years ended December 31, 2022 and 2021, respectively. Cost for services includes amounts capitalized in utility plant, which was approximately $0.8 million for 2022 and $0.4 million for 2021. The remainder was primarily recorded as operations and maintenance expense. The charge for services provided by SCG to AGR and its subsidiaries was approximately $5.8 million for 2022 and $4.7 million for 2021. 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 $19.7 million at December 31, 2022 and the balance of $20 million at December 31, 2021 is mostly payable to UIL Holdings. The balance in accounts receivable from affiliates of $1.6 million at December 31, 2022 and the balance of $1.5 million at December 31, 2021 is mostly receivable from CNG.

The balance in notes receivable from affiliates of $1.7 million at December 31, 2022 is receivable from Avangrid. The balance of notes receivable from affiliates of $29 million at December 31, 2021 is receivable from RGE and Avangrid. Notes receivable from affiliates relate to the Virtual Money Pool Agreement as discussed in Note 8 of these consolidated financial statements.

Note 16. Subsequent Events

The company has performed a review of subsequent events through March 31, 2023, which is the date these consolidated financial statements were available to be issued.

Connecticut Natural Gas Corporation
Financial Statements
As of and for the Years Ended December 31, 2022 and 2021

Connecticut Natural Gas Corporation

Index

Financial Statements as of and for the Years Ended December 31, 2022 and 2021

KPMG

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

Independent Auditors' Report

The Stockholders and Board of Directors
Connecticut Natural Gas Corporation:

Opinion

We have audited the financial statements of Connecticut Natural Gas Corporation (the Company), which comprise the balance sheets as of December 31, 2022 and 2021, and the related statements of income, comprehensive income, changes in equity, and cash flows for the years then ended, and the related notes to the financial statements.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

Basis for Opinion

We conducted our audits in accordance with auditing standards generally accepted in the United States of America (GAAS). Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with U.S. generally accepted accounting principles, and for 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.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for one year after the date that the financial statements are issued.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control related matters that we identified during the audit.

KPMG LLP

New York, New York
March 31, 2023

Connecticut Natural Gas Corporation
Statements of Income

Years Ended December 31,		2022		2021
(Thousands)				
Operating Revenues	$	**523,673**	$	**419,074**
Operating Expenses				
Natural gas purchased		283,662		185,342
Operations and maintenance		100,300		102,744
Depreciation and amortization		47,226		45,837
Taxes other than income taxes, net		34,594		32,676
Total Operating Expenses		**465,782**		**366,599**
Operating Income		**57,891**		**52,475**
Other income		2,344		2,106
Other deductions		(5,823)		(3,558)
Interest expense, net of capitalization		(9,093)		(9,817)
Income Before Income Tax		**45,319**		**41,206**
Income tax expense		11,206		8,343
Net Income	$	**34,113**	$	**32,863**

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

Connecticut Natural Gas Corporation
Statements of Comprehensive Income

Years Ended December 31,		2022		2021
(Thousands)				
Net Income	$	**34,113**	$	**32,863**
Other Comprehensive Income (Loss), Net of Tax				
Amortization of pension cost for nonqualified plans and current year actuarial gain (loss), net of income tax expense (benefit) of $78 for 2022 and ($47) for 2021		212		(128)
Total Other Comprehensive Income (Loss), Net of Tax		**212**		**(128)**
Comprehensive Income	$	**34,325**	$	**32,735**

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

Connecticut Natural Gas Corporation
Balance Sheets

As of December 31,		2022		2021
(Thousands)				
Assets				
Current Assets				
Cash and cash equivalents	$	1,070	$	—
Accounts receivable and unbilled revenues, net		149,398		107,019
Accounts receivable from affiliates		535		706
Gas in storage		54,803		30,118
Materials and supplies		4,809		4,653
Other current assets		1,899		2,179
Regulatory assets		57,875		51,867
Total Current Assets		**270,389**		**196,542**
Utility plant, at original cost		1,214,513		1,142,558
Less accumulated depreciation		(399,929)		(374,307)
Net Utility Plant in Service		**814,584**		**768,251**
Construction work in progress		15,370		19,823
Total Utility Plant		**829,954**		**788,074**
Operating lease right-of-use assets		2,432		542
Other property and investments		764		833
Regulatory and Other Assets				
Regulatory assets		62,376		84,532
Goodwill		79,341		79,341
Other		136		128
Total Regulatory and Other Assets		**141,853**		**164,001**
Total Assets	**$**	**1,245,392**	**$**	**1,149,992**

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

Connecticut Natural Gas Corporation
Balance Sheets

As of December 31,	2022	2021
(Thousands, except share information)		
Liabilities		
Current Liabilities		
Notes payable to affiliates	$ 25,450	$ 8,700
Accounts payable and accrued liabilities	98,916	63,248
Accounts payable to affiliates	19,880	19,338
Interest accrued	2,614	2,501
Taxes accrued	13,165	19,397
Operating lease liabilities	177	607
Regulatory liabilities	5,230	4,844
Other	16,687	17,664
Total Current Liabilities	**182,119**	**136,299**
Regulatory and Other Liabilities		
Regulatory liabilities	297,201	276,003
Other Non-current Liabilities		
Deferred income taxes	44,724	38,702
Pension and other postretirement	53,429	71,389
Operating lease liabilities	2,323	100
Asset retirement obligation	6,279	6,398
Other	1,121	2,429
Total Regulatory and Other Liabilities	**405,077**	**395,021**
Non-current debt	189,072	188,939
Total Liabilities	**776,268**	**720,259**
Commitments and Contingencies		
Preferred Stock	**340**	**340**
Common Stock Equity		
Common stock ($3.125 par value, 20,000,000 shares authorized and 10,634,436 shares outstanding at December 31, 2022 and 2021)	33,233	33,233
Additional paid-in capital	396,791	366,698
Retained earnings	39,008	29,922
Accumulated other comprehensive loss	(248)	(460)
Total Common Stock Equity	**468,784**	**429,393**
Total Liabilities and Equity	**$ 1,245,392**	**$ 1,149,992**

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

Connecticut Natural Gas Corporation
Statements of Cash Flows

Years Ended December 31,	2022	2021
(Thousands)		
Cash Flow from Operating Activities:		
Net income	**$ 34,113**	**$ 32,863**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	47,226	45,837
Regulatory assets/liabilities amortization	22,377	12,463
Regulatory assets/liabilities carrying cost	(615)	39
Amortization of debt issuance costs	67	48
Deferred taxes	3,427	2,747
Pension cost	(1,101)	879
Stock-based compensation	122	94
Accretion expenses	328	333
Other non-cash items	719	(101)
Changes in operating assets and liabilities:		
Accounts receivable, from affiliates, and unbilled revenues	(42,208)	(16,509)
Inventories	(24,841)	(9,804)
Accounts payable, to affiliates, and accrued liabilities	29,589	19,534
Taxes accrued	(6,233)	16,570
Other assets/liabilities	(12,836)	7,039
Regulatory assets/liabilities	(5,492)	(29,113)
Net Cash Provided by Operating Activities	**44,642**	**82,919**
Cash Flow from Investing Activities:		
Capital expenditures	(66,754)	(68,287)
Contributions in aid of construction	1,332	792
Proceeds from sale of utility plant	127	22
Notes receivable from affiliates	—	5,050
Net Cash Used in Investing Activities	**(65,295)**	**(62,423)**
Cash Flow from Financing Activities:		
Return of capital	—	(40,000)
Notes payable to affiliates	16,750	8,700
Capital contribution	30,000	20,000
Dividends paid	(25,027)	(10,027)
Net Cash Provided by (Used in) Financing Activities	**21,723**	**(21,327)**
Net Increase (Decrease) in Cash and Cash Equivalents	**1,070**	**(831)**
Cash and Cash Equivalents, Beginning of Period	**—**	**831**
Cash and Cash Equivalents, End of Period	**$ 1,070**	**$ —**

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

Connecticut Natural 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 Loss	Total Common Stock Equity
Balances, December 31, 2020	**10,634,436**	**$ 33,233**	**$ 386,302**	**$ 7,086**	**$ (332)**	**$ 426,289**
Net income	—	—	—	32,863	—	32,863
Other comprehensive income, net of tax	—	—	—	—	(128)	(128)
Comprehensive income						32,735
Stock-based compensation	—	—	396	—	—	396
Common stock dividends	—	—	—	(10,000)	—	(10,000)
Preferred stock dividends	—	—	—	(27)	—	(27)
Capital contribution	—	—	20,000	—	—	20,000
Return of capital	—	—	(40,000)	—	—	(40,000)
Balances, December 31, 2021	**10,634,436**	**33,233**	**366,698**	**29,922**	**(460)**	**429,393**
Net income	—	—	—	34,113	—	34,113
Other comprehensive income, net of tax	—	—	—	—	212	212
Comprehensive income						34,325
Stock-based compensation	—	—	93	—	—	93
Common stock dividends	—	—	—	(25,000)	—	(25,000)
Preferred stock dividends	—	—	—	(27)	—	(27)
Capital contribution	—	—	30,000	—	—	30,000
Balances, December 31, 2022	**10,634,436**	**$ 33,233**	**$ 396,791**	**$ 39,008**	**$ (248)**	**$ 468,784**

(*) Par value of share amounts is $3.125

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

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

Background and nature of operations: Connecticut Natural Gas Corporation (CNG) engages in natural gas transportation, distribution and sales operations in Connecticut serving approximately 184,679 customers as of December 31, 2022, in service areas totaling approximately 724 square miles. CNG is regulated by the Connecticut Public Utilities Regulatory Authority (PURA).

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

Basis of presentation: The accompanying financial statements have been prepared in accordance with generally accepted accounting principles in the United States (U.S. GAAP). The accounting records of CNG are also maintained in accordance with the uniform system of accounts prescribed by the Federal Energy Regulatory Commission (FERC).

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

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

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

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

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

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

In assessing goodwill for impairment, we have the option to first perform a qualitative assessment to determine whether a quantitative assessment is necessary. If we determine, based on qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If we bypass the qualitative assessment, or perform the qualitative assessment but determine it is more likely than not that its fair value is less than its carrying amount, we perform a quantitative test to compare the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, we record an impairment loss as a reduction to goodwill and a charge to operating expenses, but the loss recognized would not exceed the total amount of goodwill allocated to the reporting unit.

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

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

We transfer assets from “Construction work in progress” to “Utility plant” when they are available for service.

We determine depreciation expense for utility plant in service using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Consistent with FERC accounting requirements, we charge the original cost of utility plant retired or otherwise disposed of to accumulated depreciation. Our composite rates for depreciation were 3.8% and 3.9% of average depreciable property for 2022 and 2021, respectively. We amortize our capitalized software cost using the straight line method, based on useful lives of 3 to 10 years. Depreciation expense was $44.3 million in 2022 and $42.8 million in 2021. Amortization of capitalized software was $2.9 million in 2022 and $3.0 million in 2021.

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

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

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

Utility Plant	Estimated useful life range (years)	2022	2021
(Thousands)			
Gas distribution plant	5-75	$ 1,063,928	$ 994,356
Software	3-10	42,924	41,984
Land	N/A	1,618	1,618
Building and improvements	35-50	37,848	36,428
Other plant	45-90	68,195	68,172
Total Utility Plant in Service		**1,214,513**	**1,142,558**
Total accumulated depreciation		(399,929)	(374,307)
Total Net Utility Plant in Service		**814,584**	**768,251**
Construction work in progress		15,370	19,823
Total Utility Plant		**$ 829,954**	**$ 788,074**

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

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

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

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

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

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

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

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

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

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

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

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

Concentration of risk: We maintain our cash and cash equivalents in accounts with major financial institutions in the form of demand deposits and money market accounts. Deposits in these financial institutions may exceed the amount of federal deposit insurance provided on such deposits.

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

		2022		2021
(Thousands)				
Cash paid during the year ended December 31:				
Interest, net of amounts capitalized	$	8,605	$	8,697
Income taxes paid, net	$	14,301	$	7,211

Of the income taxes paid, substantially all was paid to AGR under the tax sharing agreement. Interest capitalized was $0.4 million in 2022 and $0.3 million in 2021. Accrued liabilities for utility plant additions were $7.5 million and $1.3 million as of December 31, 2022 and 2021, respectively.

***Trade receivables and unbilled revenues, net of allowance for credit losses*:** We record trade receivables at amounts billed to customers and we record unbilled revenues based on an estimate of energy delivered or services provided to customers. The estimates for unbilled revenues are determined based on various assumptions, including current month energy load requirements, billing rates by customer class and delivery loss factors. Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

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

Trade receivables at December 31 include unbilled revenues of $49.2 million for 2022 and $31.3 million for 2021, and are shown net of an allowance for credit losses at December 31 of $7.0 million for 2022 and $6.8 million for 2021. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $9.0 million in 2022 and $8.6 million in 2021.

We establish our allowance for credit losses, including for unbilled revenue (also referred to as contract assets), by using both historical average loss percentages to project future losses, and by establishing a specific allowance for known credit issues or for specific items not considered in the historical average calculation. We also consider whether we need to adjust historical loss rates to reflect the effects of current conditions and forecasted changes considering various economic indicators (e.g., Gross Domestic Product, Personal Income, Consumer Price Index, Unemployment Rate) over the contractual life of the trade receivables. We write off amounts when we have exhausted reasonable collection efforts.

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

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. We continuously monitor 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. These inventories are carried and withdrawn at the lower of cost and net realizable value and reported on the balance sheets within "Materials and supplies." We combine inventory items for the statement of cash flows presentation purposes.

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

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

There were no government grants recorded as of December 31, 2022 and 2021.

Deferred income: Apart from government grants, we occasionally receive revenues from transactions in advance of the resulting performance obligations arising from the transaction. It is our policy to defer such revenues on our balance sheets and amortize them into earnings when revenue recognition criteria are met.

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

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

The following table reconciles the beginning and ending aggregate carrying amount of the ARO, including our conditional ARO, which is recorded in Other Non-current Liabilities for the years ended December 31, 2022 and 2021.

Years Ended December 31,	2022	2021
(Thousands)		
ARO, beginning of year	$ 6,398	$ 6,499
Liabilities settled during the year	(447)	(434)
Accretion expenses	328	333
ARO, end of year	**$ 6,279**	**$ 6,398**

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.

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

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

We account for defined benefit pension or other postretirement plans, recognizing an asset or liability for the overfunded or underfunded plan status. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. We generally reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in OCI, as management believes it is probable that such items will be recoverable through the ratemaking process. Certain nonqualified plan expenses are not recoverable through the ratemaking process and we present the unrecognized prior service costs and credits and unrecognized actuarial gains and losses in accumulated other comprehensive loss. If a plan meets settlement or curtailment accounting criteria, we recognize a regulatory asset or liability if these costs are probable of recovery from ratepayers. 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 employees active on the date of the amendment. Effective March 31, 2022, the amortization period for prior service cost changes for the CNG Pension Plan was updated from average remaining service to future expected lifetime as the plan was frozen, or predominantly frozen, to future accruals. Effective April 1, 2022, the amortization period for prior service cost changes for CNG Pension Plan B was updated from average remaining service to future expected lifetime as the plan was frozen to future accruals. Effective December 10, 2022, the amortization period for prior service cost changes for the CNG

Retirement Plan was updated from average remaining service to future expected lifetime as the plan was frozen to future accruals. We amortize unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans in excess of 10% of the greater of periodic benefit obligation or market-related value of assets on a straight-line basis over future working lifetime. Effective March 31, 2022, the amortization period for the CNG Pension Plan was updated from future working lifetime to future expected lifetime as the plan was frozen, or predominantly frozen, to future accruals. Effective April 1, 2022, the amortization period for CNG Pension Plan B was updated from future working lifetime to future expected lifetime as the plan was frozen to future accruals. Effective December 10, 2022, the amortization period for the CNG Retirement Plan was updated from future working lifetime to future expected lifetime as the plan was frozen to future accruals. Our policy is to calculate the expected return on plan assets using the market-related value of assets. We determine that value by recognizing the difference between actual returns and expected returns over a five-year period.

Income taxes: In August 2022, the Inflation Reduction Act of 2022 ("IRA") was signed into law in the United States. The IRA created a new corporate alternative minimum tax ("CAMT") of 15% on adjusted financial statement income and an excise tax of 1% on the value of certain stock repurchases. Based on initial guidance, CNG currently expects to be subject to the CAMT starting in 2023 but does not expect it to have a material impact on earnings, financial condition, or cash flow. Given the complexity and uncertainty around the applicability of the legislation to our specific facts and circumstances, the company continues to analyze the IRA provisions while waiting on pending Department of Treasury regulatory guidance.

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

The aggregate amount of the related party income tax payable balance due to AGR was $4.7 million and $11.2 million at December 31, 2022 and 2021, respectively.

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

Deferred tax assets and liabilities are measured at the expected tax rate for the period in which the asset or liability will be realized or settled, based on legislation enacted as of the balance sheet date. We charge or credit changes in deferred income tax assets and liabilities that are associated with components of OCI directly to OCI. Significant judgment is required in determining income tax provisions and evaluating tax positions. Our tax positions are evaluated under a more-likely-than-not recognition threshold before they are recognized for financial reporting purposes. We record valuation allowances to reduce deferred tax assets when it is more likely than not that we will not realize all or a portion of a tax benefit. Deferred tax assets and liabilities are netted and classified as non-current on our balance sheets. We had no intra-entity transfers of assets other than inventory during the years ended December 31, 2022 and 2021.

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

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

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. 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.

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

Adoption of New Accounting Pronouncements

Although we are not a public business entity, our parent company is a public business entity; therefore, we adopt new accounting standards based on the effective date for public entities as permitted. There have been no new accounting pronouncements adopted as of December 31, 2022.

Accounting Pronouncements Issued But Not Yet Adopted

There have been no accounting pronouncements issued but not yet adopted that are expected to have a material impact on CNG's 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 credit losses and unbilled revenues; (2) asset impairments, including goodwill; (3) depreciable lives of assets; (4) income tax valuation allowances; (5) uncertain tax positions; (6) reserves for professional, workers’ compensation and comprehensive general insurance liability risks; (7) contingency and litigation reserves; (8) fair value measurements; (9) environmental remediation liabilities; (10) AROs; (11) pension and other postretirement employee benefits

(OPEB); (12) investments in equity instruments; and (13) earnings sharing mechanisms. 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 79% 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

Rates

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

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

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

Gas Supply Arrangements

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

CNG purchases the majority of our 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 and Algonquin 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 Ontario, Canada.

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

Minimum Equity Requirements for Regulated Subsidiaries

Pursuant to an agreement with PURA, CNG is restricted from paying dividends if paying such dividend would result in a common equity ratio lower than 300 basis points below the equity percentage used to set rates in the most recent distribution rate proceeding as measured using a trailing 13-month average calculated as of the most recent quarter end. In addition, CNG is prohibited from paying dividends to its parent if the utility's credit rating, as rated by any of the three major credit rating agencies, falls below investment grade, or if the utility's credit rating, as determined by two of the three major credit rating agencies, falls to the lowest investment grade and there is a negative watch or review downgrade notice.

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 regulated 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 $56.0 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.

Regulatory assets at December 31, 2022 and 2021 consisted of:

As of December 31,	2022	2021
(Thousands)		
Pension and other postretirement benefit plan	$ 52,574	$ 77,219
Hardship programs	—	2,914
Unfunded future income taxes	6,375	4,266
Deferred purchased gas	24,428	22,646
Revenue decoupling mechanism	20,311	20,008
System expansion reconciliation	8,871	5,308
Other	7,692	4,038
Total regulatory assets	**120,251**	**136,399**
Less: current portion	57,875	51,867
Total non-current regulatory assets	**$ 62,376**	**$ 84,532**

Pension and other postretirement represents 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.

Hardship programs represent customer accounts deferred for recovery to the extent they exceed the amount 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.

Deferred purchased gas represents the difference between actual gas costs and gas costs collected in rates. Balances at the end of the rate year are normally recorded/returned in the following year.

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

System expansion reconciliation represents expenses not covered by system expansion rates related to expanding the natural gas system and converting customers to natural gas.

Other includes various items subject to reconciliation such as Distribution Integrity Management Program and Environmental Defense Fund legal fees.

Regulatory liabilities at December 31, 2022 and 2021 consisted of:

As of December 31,	2022	2021
(Thousands)		
Pension and other postretirement benefit plan	$ 2,128	$ 4,783
Asset removal costs	247,523	230,235
Asset retirement obligation	10,409	10,327
Rate credits	6,250	7,500
Tax reform	13,167	13,575
Non-firm margin sharing credits	14,150	7,901
Hardship programs	5,018	5,366
Other	3,786	1,160
Total regulatory liabilities	**302,431**	**280,847**
Less: current portion	5,230	4,844
Total non-current regulatory liabilities	**$ 297,201**	**$ 276,003**

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.

Asset retirement obligation represents the fair value of the liability for an asset retirement which we are legally committed to remove.

Rate credits resulted from the acquisition of UIL by Iberdrola. This is being used to moderate increases in rates.

Tax reform represents the impact from re-measurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates from 35% to 21% under the provisions of the Tax Act will result in amounts previously collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates. A portion of this balance is amortized through current rates; the remaining portion will be refunded in future periods through future rate cases.

Non-firm margin sharing credits represents the portion of interruptible and off-system sales revenue set aside to fund gas expansion projects.

Other includes various items subject to reconciliation such as Geographic Information System Data Conversion expense deferral.

Note 4. Revenue

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

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

CNG derives its revenue primarily from tariff-based sales of natural gas delivered to customers. For such revenues, we recognize 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.

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

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 for the year ended December 31, 2022 and 2021 are as follows:

Years Ended December 31,	**2022**	**2021**
(Thousands)		
Regulated operations – natural gas	$ 509,967	$ 402,429
Other (a)	12	95
Revenue from contracts with customers	**509,979**	**402,524**
Alternative revenue programs	11,850	15,525
Other revenue	1,844	1,025
Total operating revenues	**$ 523,673**	**$ 419,074**

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

Note 5. Goodwill

We do not amortize goodwill, but perform our annual impairment assessment testing at least annually as described in Note 1, in the fourth quarter, as of October 1. Our qualitative assessment involves evaluating key events and circumstances that could affect the fair value of our company, as well as other factors. Events and circumstances evaluated include macroeconomic conditions, industry, regulatory and market considerations, cost factors and their effect on earnings and cash flows, overall financial performance as compared with projected results and actual results of relevant prior periods, other relevant entity-specific events, and events affecting CNG.

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

We had no impairment of goodwill in 2022 and 2021 as a result of our qualitative impairment testing. There were no events or circumstances subsequent to our annual impairment assessment for 2022 or 2021 that required us to update the assessment.

The carrying amount of goodwill, which resulted from the purchase of CNG by UIL Holdings in 2010, was $79.3 million at both December 31, 2022 and 2021, with no accumulated impairment losses and no changes during 2022 and 2021.

Note 6. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,	**2022**	**2021**
(Thousands)		
Current		
Federal	$ 6,589	$ 3,502
State	1,190	2,094
Current taxes charged to expense	**7,779**	**5,596**
Deferred		
Federal	2,258	4,901
State	1,169	(2,154)
Deferred taxes charged to expense	**3,427**	**2,747**
Total Income Tax Expense	**$ 11,206**	**$ 8,343**

The differences between tax expense per the statements of income and tax expense at the 21% statutory federal tax rate for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,	**2022**	**2021**
(Thousands)		
Tax expense at federal statutory rate	$ 9,517	$ 8,653
Tax return related adjustments	15	310
State taxes, net of federal income tax	1,864	(47)
Other, net	(190)	(573)
Total Income Tax Expense	**$ 11,206**	**$ 8,343**

Income tax expense for the year ended December 31, 2022 was $1.7 million higher than it would have been at the statutory federal income tax rate of 21% due predominately to state taxes. This resulted in an effective tax rate of 24.7%. Income tax expense for the year ended December 31, 2021 was $0.3 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to state taxes which are partially offset by tax benefits from Excess ADIT amortization and AFUDC flow through adjustments. This resulted in an effective tax rate of 20.2%.

Deferred tax assets and liabilities as of December 31, 2022 and 2021 consisted of:

December 31,		2022		2021
(Thousands)				
Non-current Deferred Income Tax Liabilities (Assets)				
CT credit carryforward	$	(6,412)	$	(6,551)
Valuation allowance - State Credits		1,304		482
Deferred tax liability on 2017 Tax Act remeasurement		(3,482)		(3,718)
Property related		47,633		38,268
Unfunded future income taxes		1,629		1,148
Goodwill		5,727		5,258
Pension (net)		(1,288)		343
Other		(387)		3,472
Total Non-current Deferred Income Tax Liabilities	**$**	**44,724**	**$**	**38,702**
Deferred tax assets	$	11,569	$	10,269
Deferred tax liabilities		56,293		48,971
Net Accumulated Deferred Income Tax Liabilities	**$**	**44,724**	**$**	**38,702**

As of December 31, 2022, CNG had a state net credit carry forward of $6.4 million and a net state net operating loss carry forward of $1.1 million. As of December 31, 2021, CNG had a state net credit carry forward of $6.6 million and a net state net operating loss carry forward of $1.4 million. CNG's state tax credit carry forwards will begin to expire for the 2022 tax year.

Valuation allowances are recorded to reduce deferred tax assets when it is more likely than not that all or a portion of a tax benefit will not be realized. At December 31, 2022, CNG has recorded a valuation allowance of $1.3 million against its CT tax credits. The company also recorded a regulatory asset of $1.8 million to recover the associated tax expense of the valuation allowance against the state credits whose tax benefits were previously shared with customers.

Uncertain tax positions are classified as non-current unless expected to be paid within one year. We net our liability for uncertain tax positions against all same jurisdiction deferred tax assets, net operating losses and tax credit carryforwards. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the statements of income. As of December 31, 2022 and 2021, CNG did not have any gross income tax reserves for uncertain tax positions.

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. CNG had no unrecognized income tax benefits as of December 31, 2022 or 2021.

There were no additional accruals for interest and penalties on tax reserves as of December 31, 2022 or 2021.

Note 7. Non-current Debt

Long-term debt as of December 31, 2022 and 2021 consisted of:

As of December 31,		2022		2021	
(Thousands, except interest rates)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
Senior unsecured debt	2028-2049	$ 190,000	2.02%-6.66%	$ 190,000	2.02%-6.66%
Unamortized debt issuance costs and discount		(928)		(1,061)	
Total Debt		**189,072**		**188,939**	
Less: debt due within one year, included in current liabilities		—		—	
Total Non-current Debt		**$ 189,072**		**$ 188,939**	

We have no long-term debt, including sinking fund obligations, due during the next five years through 2027.

We have no debt covenant requirements related to the maintenance of financial ratios in our long-term debt agreements at December 31, 2022 and 2021.

Note 8. Bank Loans and Other Borrowings

CNG had $25.5 million of notes payable at December 31, 2022 and $8.7 million at December 31, 2021. 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 "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. CNG has a lending/borrowing limit of $100 million under this agreement. CNG had $25.5 million outstanding under this agreement at December 31, 2022 and no debt outstanding under this agreement at December 31, 2021.

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. CNG had no debt outstanding under this agreement at December 31, 2022 and $8.7 million outstanding at December 31, 2021.

On November 23, 2021, AGR and its investment-grade rated utility subsidiaries (New York State Electric & Gas Corporation ("NYSEG"), Rochester Gas and Electric Corporation ("RG&E"), Central Maine Power Company ("CMP"), The United Illuminating Company ("UI"), CNG, The Southern Connecticut Gas Company ("SCG") and The Berkshire Gas Company ("BGC")) executed a new credit facility with an aggregate limit of $3,575 million and a termination date of November 23, 2026. Under the terms of the Avangrid Credit Facility, each borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit contained in the agreement. NYSEG has a maximum sublimit of $700 million, RG&E has $300 million, CMP has $200 million, UI has $250 million, CNG and SCG have maximum sublimits of $150 million and BGC has a maximum sublimit of $50 million. Effective on November 23, 2021, the AGR Credit Facility was amended to increase AGR's maximum sublimit to $2,500 million and to establish minimum sublimits of $500 million for NYSEG, $200 million for RG&E, $100 million for CMP, $150 million for UI, $50 million for CNG and SCG and $25 million for BGC. Under the AGR Credit Facility, each of the borrowers are charged a facility fee that is dependent on their credit rating. The facility fees range from 10 to 22.5 basis points. CNG had not borrowed under this agreement as of both December 31, 2022 and 2021.

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 0.31 to 1.00 at December 31, 2022. We are not in default as of December 31, 2022.

Note 9. Redeemable Preferred Stock

At December 31, 2022 and 2021, our redeemable preferred stock was:

Series	Par Value per Share	Redemption Price per Share	Shares Authorized and Outstanding(1)	Amount (Thousands) 2022	Amount (Thousands) 2021
CNG, 8% Non-callable	$ 3.125	$ —	108,706	$ 340	$ 340
Total				**$ 340**	**$ 340**

(1) At December 31, 2022 CNG had 884,315 shares of $3.125 par value preferred stock authorized.

Note 10. Leases

We have operating leases for land, office buildings, facilities, and certain equipment. CNG does not have any finance leases. Certain of our lease agreements include rental payments adjusted periodically for inflation or are based on other periodic input measures. Our leases do not contain any material residual value guarantees or material restrictive covenants. Our leases have remaining lease terms of 1 year to 10 years, some of which may include options to extend the leases for up to 10 years, and some of which may include options to terminate the leases within one year. We consider extension or termination options in the lease term if it is reasonably certain we will exercise the option.

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

For the Years Ended December 31,	2022	2021
(Thousands)		
Lease cost		
Operating lease cost	$ 291	$ 276
Short-term lease cost	38	8
Variable lease cost	44	102
Total lease cost	**$ 373**	**$ 386**

Balance sheet and other information for the years ended December 31, 2022 and 2021 was as follows:

As of December 31,		2022		2021
(Thousands, except lease term and discount rate)				
Operating Leases				
Operating lease right-of-use assets	$	2,432	$	542
Operating lease liabilities, current		177		607
Operating lease liabilities, long-term		2,323		100
Total operating lease liabilities	$	2,500	$	707
Weighted-average Remaining Lease Term (years)				
Operating leases		2.20		2.79
Weighted-average Discount Rate				
Operating leases		3.53 %		1.29 %

For the years ended December 31, 2022 and 2021, supplemental cash flow information related to leases was as follows:

For the Years Ended December 31,		2022		2021
(Thousands)				
Cash paid for amounts included in the measurement of lease liabilities:				
Operating cash flows from operating leases	$	305	$	586
Right-of-use assets obtained in exchange for lease obligations:				
Operating leases	$	2,445	$	442

As of December 31, 2022, maturities of lease liabilities were as follows:

		Operating Leases
(Thousands)		
Year ending December 31,		
2023	$	532
2024		353
2025		317
2026		323
2027		270
Thereafter		1,094
Total lease payments		**2,889**
Less: imputed interest		(389)
Total	**$**	**2,500**

Most of our leases do not provide an implicit rate in the lease; thus we use our incremental borrowing rate based on the information available at the commencement date in determining the present value of lease payments.

Note 11. 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 natural gas service.

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, 2022 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, 2022, CNG has determined that remediation of the property in Hartford is not probable and therefore no amounts have been reserved.

Note 12. Fair Value of Financial Instruments and Fair Value Measurements

The estimated fair value of debt amounted to $178 million and $237 million as of December 31, 2022 and 2021, 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.

Assets and liabilities measured at fair value on a recurring basis

The financial instruments measured at fair value as of December 31, 2022 and 2021 consist of:

Description	Total	(Level 1)	(Level 2)	(Level 3)
(Thousands)				
2022				
Assets				
Noncurrent investments	$ 764	$ 764	$ —	$ —
Total	**$ 764**	**$ 764**	**$ —**	**$ —**
2021				
Assets				
Noncurrent investments	$ 833	$ 833	$ —	$ —
Total	**$ 833**	**$ 833**	$ —	$ —

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2022 and 2021. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

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

Note 13. Post-Retirement and Similar Obligations

CNG has multiple qualified pension plans covering eligible union and management employees and retirees. The union plans are all closed to new hires, and the non-union plans were closed as of December 31, 2017. The plans are traditional defined benefit plans or cash balance plans depending on date of hire and are closed to new employees hired on or after specified dates. Employees not participating in a defined benefit plan are eligible to receive an enhanced or core 401(k) Company matching contribution.

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 expenses under the Plan for the Company totaled approximately $2.2 million for 2022 and $1.7 million for 2021.

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

Non-Qualified Retirement Benefit Plans

We also sponsor various unfunded non-qualified pension plans for certain current employees, former employees and former directors. The total liability for these plans, which is included in Other current and Other non-current liabilities on our balance sheets, was $1.0 million and $1.3 million at December 31, 2022 and 2021, respectively.

Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2022 and 2021 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2022**	**2021**	**2022**	**2021**
(Thousands)				
Change in benefit obligation				
Benefit obligation as of January 1,	**$ 295,866**	**$ 319,796**	**$ 17,528**	**$ 19,090**
Service cost	3,827	4,935	120	166
Interest cost	9,340	8,227	436	366
Actuarial (gain) loss	(65,217)	(15,619)	1,416	156
Curtailments/Settlements	(29,024)	(1,113)	—	—
Benefits paid	(12,945)	(20,360)	(2,103)	(2,250)
Benefit obligation as of December 31,	**$ 201,847**	**$ 295,866**	**$ 17,397**	**$ 17,528**
Change in plan assets				
Fair value of plan assets at January 1,	**$ 229,768**	**$ 228,737**	**$ 12,237**	**$ 12,398**
Actual return on plan assets	(46,939)	19,824	(762)	539
Employer contributions	855	2,680	1,953	1,550
Curtailments/settlements	(16,249)	(1,113)	—	—
Benefits paid	(12,945)	(20,360)	(2,103)	(2,250)
Fair value of plan assets at December 31,	**$ 154,490**	**$ 229,768**	**$ 11,325**	**$ 12,237**
Funded status at December 31,	**$ (47,357)**	**$ (66,098)**	**$ (6,072)**	**$ (5,291)**

During 2022, the pension benefit obligation had an actuarial gain of $65.2 million, primarily due to a gain from discount rate increases of $57.4 million. The pension benefit obligation had a reduction of $16.2 million from settlements and $12.8 million from curtailments. The settlements were lump-sum payments made within the pension plan guidelines at the discretion of the plan participants who opted to retire. The curtailments were driven by a Company decision to freeze pension benefit accruals and contribution credits for non-union employees and transition their retirement benefits to a 401(k) plan. There were no significant gains and losses relating to the postretirement benefit obligations.

During 2021, the pension benefit obligation had an actuarial gain of $15.6 million, primarily due to a $15.5 million gain from decreases in discount rates. There were no significant plan design changes in 2021. There were no significant gains and losses relating to the postretirement benefit obligations.

Amounts recognized as of December 31, 2022 and 2021 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2022**	**2021**	**2022**	**2021**
(Thousands)				
Non-current liabilities	$ (47,357)	$ (66,098)	$ (6,072)	$ (5,291)

We have determined that we are allowed to defer as regulatory assets or regulatory liabilities items that would otherwise be recorded in accumulated other comprehensive income pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans.

Amounts recognized as regulatory assets or regulatory liabilities for the years ended December 31, 2022 and 2021 consisted of:

	Pension Benefits		Postretirement Benefits	
Years Ended December 31,	**2022**	**2021**	**2022**	**2021**
(Thousands)				
Net loss (gain)	$ 10,783	$ 27,568	$ 1,070	$ (1,696)
Prior service cost	$ —	$ —	$ —	$ 195

Our accumulated benefit obligation (ABO) for all qualified defined benefit pension plans was $201.8 million and $276.3 million as of December 31, 2022 and 2021. Our postretirement benefits were partially funded at December 31, 2022 and 2021.

The projected benefit obligation (PBO) and ABO exceeded the fair value of pension plan assets for our qualified plans as of December 31, 2022 and 2021. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets for the relevant periods.

As of December 31,	**2022**	**2021**
(Thousands)		
Projected benefit obligation	$ 201,847	$ 295,866
Accumulated benefit obligation	$ 201,847	$ 276,311
Fair value of plan assets	$ 154,490	$ 229,768

As of December 31, 2022 and 2021, the accumulated postretirement benefits obligation for all the qualified plans exceeded the fair value of plan assets.

Components of net periodic benefit cost and other changes in plan assets and benefit obligations recognized in income and regulatory assets and liabilities for the years ended December 31, 2022 and 2021 consisted of:

	Pension Benefits		Postretirement Benefits	
For the years ended December 31,	**2022**	**2021**	**2022**	**2021**
(Thousands)				
Net Periodic Benefit Cost:				
Service cost	$ 3,827	$ 4,935	$ 120	$ 166
Interest cost	9,340	8,227	436	366
Expected return on plan assets	(14,469)	(15,892)	(419)	(367)
Amortization of prior service cost	—	—	195	201
Curtailment charge	(1,774)	—	—	—
Settlement charge	1,237	63	—	—
Amortization of net loss (gain)	738	3,546	(169)	(187)
Net Periodic Benefit Cost	**$ (1,101)**	**$ 879**	**$ 163**	**$ 179**

Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities:				
Net (gain) loss	$ (3,809)	$ (19,551)	$ 2,596	$ (15)
Settlements	(1,237)	(63)	—	—
Amortization of net (loss) gain	(738)	(3,546)	169	187
Effect of curtailments on gain	(11,001)	—	—	—
Amortization of prior service cost	—	—	(195)	(201)
Total Other Changes	**(16,785)**	**(23,160)**	**2,570**	**(29)**
Total Recognized	**$ (17,886)**	**$ (22,281)**	**$ 2,733**	**$ 150**

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

The weighted-average assumptions used to determine benefit obligations as of December 31, 2022 and 2021 consisted of:

	Pension Benefits		**Postretirement Benefits**	
	2022	**2021**	**2022**	**2021**
Discount rate	5.17% / 5.25%	2.96% / 3.06% / 2.85%	5.13%	2.61%
Rate of compensation increase	N/A	3.50% / 3.00% / 2.90%	N/A	N/A
Interest crediting rate	4.48%	2.00% / 4.00% / 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 rates by developing yield curves derived from a portfolio of high grade non-callable bonds with yields that closely match the duration of the expected cash flows of our benefit obligations.

The weighted-average assumptions used to determine net periodic benefit cost for the years ended December 31, 2022 and 2021 consisted of:

	Pension Benefits		**Postretirement Benefits**	
Years Ended December 31,	**2022**	**2021**	**2022**	**2021**
Discount rate	2.85% - 5.02%	2.56% / 2.70% / 2.43%	2.61 %	2.00 %
Expected long-term return on plan assets	7.00 %	7.00 %	3.42 %	2.96 %
Rate of compensation increase (Union/Non-Union)	3.50% / 3.00% / 2.90%	3.50% / 3.00% / 2.90%	N/A	N/A

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.

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations, and the effect of rebalancing of plan assets discussed below. Our analysis considered current capital market conditions and projected conditions. Our policy is to calculate the expected return on plan assets using the market related value of assets. We amortize unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans in excess of 10% of the greater of periodic benefit obligation or market-related value of assets on a straight-line basis over future working lifetime. Effective March 31, 2022, the amortization period for the CNG Pension Plan was updated from future working lifetime to future expected lifetime as the plan was frozen, or predominantly frozen, to future accruals. Effective April 1, 2022, the amortization period for CNG Pension Plan B was updated from future working lifetime to future expected lifetime as the plan was frozen to future accruals. Effective December 10, 2022, the amortization period for the CNG Retirement Plan was updated from future working lifetime to future expected lifetime as the plan was frozen to future accruals.

Assumed health care cost trend rates used to determine benefit obligations as of December 31, 2022 and 2021 consisted of:

As of December 31,	2022	2021
Health care cost trend rate assumed for next year	6.25% / 7.00%	N/A
Rate to which cost trend rate is assumed to decline (ultimate trend rate)	4.50% / 4.50%	N/A
Year that the rate reaches the ultimate trend rate	2029 / 2027	N/A

Contributions

We make annual contributions in accordance with our funding policy of not less than the minimum amounts as required by applicable regulations. We do not expect to contribute to our pension plans during 2023. We expect to contribute $0.6 million to our other postretirement benefit plans during 2023.

Estimated future benefit payments

Expected benefit payments and Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) subsidy receipts reflecting expected future service as of December 31, 2022 consisted of:

(Thousands)	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
2023	$ 15,565	$ 1,567	$ 156
2024	$ 15,406	$ 1,522	$ 162
2025	$ 17,019	$ 1,451	$ 167
2026	$ 16,321	$ 1,438	$ 171
2027	$ 16,166	$ 1,418	$ 173
2028 - 2032	$ 79,941	$ 6,617	$ 984

Plan assets

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

The asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets within broad categories of asset classes made up of Return-Seeking and Liability-Hedging investments. We currently have target allocations ranging from 25%-60% for Return-Seeking assets and 40%-75% for Liability-Hedging assets. Return-Seeking assets include investments in domestic, international and emerging equity, real estate, global asset allocation strategies and hedge funds. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of pension benefits plan assets, by asset category, as of December 31, 2022, consisted of:

As of December 31, 2022		**Fair Value Measurements**		
(Thousands)	**Total**	**Level 1**	**Level 2**	**Level 3**
Asset Category				
Cash and cash equivalents	$ 5,373	$ 17	$ 5,356	$ —
U.S. government securities	8,190	8,190	—	—
Common stocks	6,539	6,539	—	—
Registered investment companies	7,665	7,665	—	—
Corporate bonds	40,769	—	40,769	—
Preferred stocks	43	43	—	—
Common collective trusts	55,867	—	55,867	—
Other, principally annuity, fixed income	545	—	545	—
	$ 124,991	**$ 22,454**	**$ 102,537**	**$ —**
Other investments measured at net asset value	29,499			
Total	**$ 154,490**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2021, consisted of:

As of December 31, 2021	Fair Value Measurements			
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 5,186	$ 1,028	$ 4,158	$ —
U.S. government securities	13,314	13,314	—	—
Common stocks	10,078	10,078	—	—
Registered investment companies	22,086	22,086	—	—
Corporate bonds	60,480	—	60,480	—
Preferred stocks	65	65	—	—
Common collective trusts	83,418	—	83,418	—
Other, principally annuity, fixed income	1,616	1	1,615	—
	$ 196,243	**$ 46,572**	**$ 149,671**	**$ —**
Other investments measured at net asset value	33,525			
Total	**$ 229,768**			

Valuation Techniques

We value our pension benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities - at the closing price reported in the active market in which the security is traded.
- Common stocks - at the closing price reported in the active market in which the individual investment is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks - at the closing price reported in the active market in which the individual investment is traded.
- Common collective trusts/Registered investment companies - Level 1: at the closing price reported in the active market in which the individual investment is traded. Level 2: the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Other investments measured at net asset value (NAV) - fund shares offered to a limited group of investors and alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

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 25% 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 49%-69% for equity securities and 31%-51% for fixed income investments. Equity investments are diversified across U.S. and non-U.S. stocks, investment styles, and market capitalization ranges. Fixed income investments are primarily invested in U.S. bonds and may also include some non-U.S. bonds. We primarily minimize the risk of large losses through diversification but also through monitoring and managing other aspects of risk through quarterly investment portfolio reviews. Systematic rebalancing within target ranges increases the probability of increasing the projected expected return, while mitigating risk, should any asset categories drift outside their specified ranges.

The fair values of other postretirement benefits plan assets, by asset category, as of December 31, 2022, consisted of:

As of December 31, 2022		**Fair Value Measurements**		
(Thousands)	**Total**	**Level 1**	**Level 2**	**Level 3**
Asset Category				
Cash and cash equivalents	$ 261	$ —	$ 261	$ —
U.S. government securities	147	147	—	—
Common stocks	108	108	—	—
Registered investment companies	172	172	—	—
Corporate bonds	665	—	665	—
Preferred stocks	1	1	—	—
Common collective trusts	1,063	—	1,063	—
Other, principally annuity, fixed income	8,465	—	8,465	—
	$ 10,882	**$ 428**	**$ 10,454**	**$ —**
Other investments measured at net asset value	443			
Total	**$ 11,325**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2021, consisted of:

As of December 31, 2021	Fair Value Measurements			
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 185	$ 15	$ 170	$ —
U.S. government securities	229	229	—	—
Common stocks	141	141	—	—
Registered investment companies	319	319	—	—
Corporate bonds	885	—	885	—
Preferred stocks	1	1	—	—
Common collective trusts	1,295	—	1,295	—
Other, principally annuity, fixed income	8,700	—	8,700	—
	$ 11,755	**$ 705**	**$ 11,050**	**$ —**
Other investments measured at net asset value	482			
Total	**$ 12,237**			

Valuation techniques

We value our postretirement benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities - at the closing price reported in the active market in which the security is traded.
- Common stocks and registered investment companies - at the closing price reported in the active market in which the individual investment is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Common collective trusts – the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income – based on yields currently available on comparable securities of issuers with similar credit ratings.
- Other investments measured at net asset value (NAV) – fund shares offered to a limited group of investors and alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

Pension and postretirement plan equity securities did not include any AGR and Iberdrola common stock as of both December 31, 2022 and 2021.

Note 14. Other Income and Other Deductions

Other income and deductions for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,		2022		2021
(Thousands)				
Interest and dividends income	$	825	$	480
Allowance for funds used during construction		603		1,161
Carrying costs on regulatory assets		850		446
Miscellaneous		66		19
Total other income	**$**	**2,344**	**$**	**2,106**
Pension non-service components	$	(3,641)	$	(2,678)
Miscellaneous		(2,182)		(880)
Total other deductions	**$**	**(5,823)**	**$**	**(3,558)**

Note 15. Related Party Transactions

Certain Networks subsidiaries, including CNG, borrow from AGR, the parent of Networks, through intercompany revolving credit agreements. For CNG, the intercompany revolving credit agreements provide access to supplemental liquidity. See Note 8 for further detail on the credit facility with AGR.

Avangrid Service Company provides administrative and management services to Networks operating utilities, including CNG, 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 services provided to CNG by AGR and its affiliates was approximately $24.3 million and $21.3 million for the years ended December 31, 2022 and 2021, respectively. Cost for services includes amounts capitalized in utility plant, which was approximately $0.5 million in 2022 and $0.6 million in 2021. The remainder was primarily recorded as operations and maintenance expense. The charge for services provided by CNG to AGR and its subsidiaries were approximately $4.5 million for 2022 and $3.0 million for 2021. 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 $19.9 million at December 31, 2022 and $19.3 million at December 31, 2021 is mostly payable to UIL Holdings Corporation. The balance in accounts receivable from affiliates of $0.5 million at December 31, 2022 and $0.7 million at December 31, 2021 is mostly receivable from SCG.

There were no notes receivable from affiliates at December 31, 2022 and December 31, 2021. Notes receivable from affiliates relate to the Virtual Money Pool Agreement as discussed in Note 8 of these financial statements.

Note 16. Subsequent Events

The company has performed a review of subsequent events through March 31, 2023, which is the date these financial statements were available to be issued.

Central Maine Power Company and Subsidiaries

Consolidated Financial Statements

As of and for the Years Ended December 31, 2022 and 2021

Central Maine Power Company
and Subsidiaries

Index

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

Independent Auditors' Report

The Shareholder and Board of Directors
Central Maine Power Company:

Opinion

We have audited the consolidated financial statements of Central Maine Power Company and its subsidiaries (the Company), which comprise the consolidated balance sheets as of December 31, 2022 and 2021, and the related consolidated statements of income, comprehensive income, cash flows, and changes in equity for the years then ended, and the related notes to the consolidated financial statements.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

Basis for Opinion

We conducted our audits in accordance with auditing standards generally accepted in the United States of America (GAAS). Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audit of the Consolidated Financial Statements section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with U.S. generally accepted accounting principles, and for 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.

In preparing the consolidated financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for one year after the date that the consolidated financial statements are issued.

Auditors' Responsibilities for the Audit of the Consolidated Financial Statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the consolidated financial statements.

KPMG

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the consolidated financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control related matters that we identified during the audit.

KPMG LLP

New York, New York
March 24, 2023

Central Maine Power Company and Subsidiaries
Consolidated Statements of Income

Years Ended December 31,		2022		2021
(Thousands)				
Operating Revenues	$	1,051,204	$	978,399
Operating Expenses				
Electricity purchased		50,052		29,518
Operations and maintenance		562,255		486,685
Depreciation and amortization		133,573		127,761
Taxes other than income taxes, net		78,394		76,252
Total Operating Expenses		**824,274**		**720,216**
Operating Income		**226,930**		**258,183**
Other income		15,877		19,197
Other deductions		(14,457)		(17,355)
Interest expense, net of capitalization		(47,760)		(46,347)
Income Before Income Tax		**180,590**		**213,678**
Income tax expense		20,753		30,790
Net Income		**159,837**		**182,888**
Less: net income attributable to noncontrolling interest		3,227		3,055
Net Income Attributable to CMP	$	**156,610**	$	**179,833**

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,		2022		2021
(Thousands)				
Net Income	$	159,837	$	182,888
Other Comprehensive Income, Net of Tax				
Amortization of pension cost for nonqualified plans and current year actuarial gain, net of income tax		224		83
Unrealized gain during period on derivatives qualifying as cash flow hedges, net of income tax		551		203
Reclassification to net income of gain on cash flow hedges, net of income tax		(578)		(121)
Reclassification to net income of loss on settled cash flow treasury hedges, net of income tax		130		85
Other Comprehensive Income, Net of Tax		**327**		**250**
Comprehensive Income		**160,164**		**183,138**
Less:				
Comprehensive income attributable to noncontrolling interest		3,227		3,055
Comprehensive Income Attributable to CMP	$	**156,937**	$	**180,083**

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,	2022	2021
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$ 28,463	$ 24,407
Accounts receivable and unbilled revenues, net	290,523	246,793
Accounts receivable from affiliates	6,931	63,855
Notes receivable from affiliates	240	—
Materials and supplies	40,132	35,726
Prepayments and other current assets	27,809	17,896
Income tax receivable	13,302	—
Regulatory assets	60,653	49,860
Total Current Assets	**468,053**	**438,537**
Utility plant, at original cost	5,226,485	4,949,841
Less accumulated depreciation	(1,481,045)	(1,368,654)
Net Utility Plant in Service	**3,745,440**	**3,581,187**
Construction work in progress	240,411	243,817
Total Utility Plant	**3,985,851**	**3,825,004**
Operating lease right-of-use assets	15,125	14,774
Other property and investments	959	901
Regulatory and Other Assets		
Regulatory assets	404,329	396,121
Goodwill	324,938	324,938
Other	159,613	158,230
Total Regulatory and Other Assets	**888,880**	**879,289**
Total Assets	**$ 5,358,868**	**$ 5,158,505**

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,	2022	2021
(Thousands)		
Liabilities		
Current Liabilities		
Current portion of debt	$ —	$ 124,578
Notes payable to affiliates	46,000	1,146
Accounts payable and accrued liabilities	322,586	192,853
Accounts payable to affiliates	40,892	38,263
Interest accrued	18,393	19,948
Taxes accrued	3,300	15,349
Operating lease liabilities	1,071	1,161
Other current liabilities	110,324	85,151
Regulatory liabilities	86,937	37,912
Total Current Liabilities	**629,503**	**516,361**
Regulatory and Other Liabilities		
Regulatory liabilities	328,080	356,608
Other Non-current liabilities		
Deferred income taxes	691,858	646,330
Pension and other postretirement	59,461	110,920
Operating lease liabilities	15,359	14,791
Other	152,980	163,209
Total Regulatory and Other Liabilities	**1,247,738**	**1,291,858**
Non-current debt	1,285,269	1,161,019
Total Liabilities	**3,162,510**	**2,969,238**
Commitments and Contingencies		
Redeemable Preferred Stock	**571**	**571**
CMP Common Stock Equity		
Common stock ($5 par value, 80,000,000 shares authorized and 31,211,471 shares outstanding at December 31, 2022 and 2021)	156,057	156,057
Additional paid-in capital	1,027,439	950,478
Retained earnings	977,063	1,050,487
Accumulated other comprehensive loss	(3,216)	(3,543)
Total CMP Common Stock Equity	**2,157,343**	**2,153,479**
Noncontrolling interest	38,444	35,217
Total Equity	**2,195,787**	**2,188,696**
Total Liabilities and Equity	**$ 5,358,868**	**$ 5,158,505**

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,	2022	2021
(Thousands)		
Cash Flow from Operating Activities:		
Net income	**$ 159,837**	**$ 182,888**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	133,573	127,761
Regulatory assets/liabilities amortization	(8,671)	16,052
Regulatory assets/liabilities carrying cost	(886)	(4,030)
Amortization of debt issuance costs	588	493
Deferred taxes	684	24,065
Pension cost	13,673	17,459
Stock-based compensation	931	572
Accretion expenses	54	52
Gain on disposal of assets	(408)	(29)
Other non-cash items	(6,188)	(8,231)
Changes in operating assets and liabilities:		
Accounts receivable, from affiliates, and unbilled revenues	13,194	(67,833)
Inventories	(4,406)	(11,052)
Accounts payable, to affiliates, and accrued liabilities	98,755	24,580
Taxes accrued	(25,300)	10,964
Other assets/liabilities	77,462	59,994
Regulatory assets/liabilities	(75,617)	(42,840)
Net Cash Provided by Operating Activities	**377,275**	**330,865**
Cash Flow from Investing Activities:		
Utility plant additions	(297,127)	(236,790)
Contributions in aid of construction	33,207	57,060
Notes receivable from affiliates	(240)	—
Proceeds from sale of utility plant	1,361	814
Net Cash Used in Investing Activities	**(262,799)**	**(178,916)**
Cash Flow from Financing Activities:		
Non-current note issuance	123,569	199,644
Repayments of non-current debt	(125,000)	(150,000)
Payments for finance leases	39	(254)
Notes payable to affiliates	44,854	(71,828)
Capital contribution	76,152	126,076
Dividends paid	(230,034)	(255,035)
Net Cash Used in Financing Activities	**(110,420)**	**(151,397)**
Net Increase in Cash and Cash Equivalents	**4,056**	**552**
Cash and Cash Equivalents, Beginning of Year	**24,407**	**23,855**
Cash and Cash Equivalents, End of Year	**$ 28,463**	**$ 24,407**

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 Loss	Total CMP Common Stock Equity	Non-controlling Interest	Total Common Stock Equity
Balances, December 31, 2020	**31,211,471**	**$ 156,057**	**$ 824,039**	**$1,125,689**	**$ (3,793)**	**$ 2,101,992**	**$ 32,162**	**$ 2,134,154**
Net income	—	—	—	179,833	—	179,833	3,055	182,888
Other comprehensive income, net of tax	—	—	—	—	250	250	—	250
Comprehensive income								183,138
Stock-based compensation	—	—	363	—	—	363	—	363
Capital contribution from parent	—	—	126,076	—	—	126,076	—	126,076
Preferred stock dividends	—	—	—	(35)	—	(35)	—	(35)
Common stock dividends	—	—	—	(255,000)	—	(255,000)	—	(255,000)
Balances, December 31, 2021	**31,211,471**	**156,057**	**950,478**	**1,050,487**	**(3,543)**	**2,153,479**	**35,217**	**2,188,696**
Net income	—	—	—	156,610	—	156,610	3,227	159,837
Other comprehensive income, net of tax	—	—	—	—	327	327	—	327
Comprehensive income								160,164
Stock-based compensation	—	—	809	—	—	809	—	809
Capital contribution from parent	—	—	76,152	—	—	76,152	—	76,152
Preferred stock dividends	—	—	—	(34)	—	(34)	—	(34)
Common stock dividends	—	—	—	(230,000)	—	(230,000)	—	(230,000)
Balances, December 31, 2022	**31,211,471**	**$ 156,057**	**$ 1,027,439**	**$ 977,063**	**$ (3,216)**	**$ 2,157,343**	**$ 38,444**	**$ 2,195,787**

(*) Par value of share amounts is $5

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

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

Background and nature of operations: Central Maine Power Company and subsidiaries (CMP, the company, we, our, us) conduct regulated electricity transmission and distribution operations in Maine serving approximately 659,948 customers as of December 31, 2022, 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 Versant Power (Versant). Versant is wholly-owned by ENMAX Corp. 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 Versant, 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 an 81.5% owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain.

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

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

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

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

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

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

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

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

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

In assessing goodwill for impairment, we have the option to first perform a qualitative assessment to determine whether a quantitative assessment is necessary. If we determine, based on qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If we bypass the qualitative assessment, or perform the qualitative assessment but determine it is more likely than not that its fair value is less than its carrying amount, we perform a quantitative test to compare the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, we record an impairment loss as a reduction to goodwill and a charge to operating expenses, but the loss recognized would not exceed the total amount of goodwill allocated to the reporting unit.

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

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

We transfer assets from “Construction work in progress” to “Utility plant” when they are available for service.

We determine depreciation expense for utility plant in service using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Consistent with FERC accounting requirements, we charge the original cost of utility plant retired or otherwise disposed of to accumulated depreciation. Our composite rates for depreciation were 2.5% of average depreciable property for both 2022 and 2021. 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 $181.2 million as of December 31, 2022, and $171.3 million as of December 31, 2021. Depreciation expense was $124.1 million in 2022 and $118.3 million in 2021. Amortization of capitalized software was $9.5 million in both 2022 and 2021.

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

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

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

Utility Plant	**Estimated useful life range (years)**	**2022**	**2021**
(Thousands)			
Electric			
Transmission	4-70	$ 2,814,733	$ 2,719,219
Distribution	15-82	1,813,459	1,695,279
Vehicles	4-20	70,987	64,730
Other	5-52	527,306	470,613
Total Utility Plant in Service		**5,226,485**	**4,949,841**
Total accumulated depreciation		(1,481,045)	(1,368,654)
Total Net Utility Plant in Service		**3,745,440**	**3,581,187**
Construction work in progress		240,411	243,817
Total Utility Plant		**$ 3,985,851**	**$ 3,825,004**

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

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

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

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

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

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

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

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

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

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

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

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

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

Changes in conditions or the occurrence of unforeseen events could require discontinuance of the hedge accounting or could affect the timing of the reclassification of gains or losses on cash flow hedges from OCI into earnings.

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

Concentration of risk: We maintain our cash and cash equivalents in accounts with major financial institutions in the form of demand deposits and money market accounts. Deposits in these financial institutions may exceed the amount of federal deposit insurance provided on such deposits.

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

(Thousands)		2022		2021
Cash paid during the year ended December 31:				
Interest, net of amounts capitalized	$	46,729	$	48,146
Income taxes paid (refunded), net	$	45,224	$	(10,222)

Of the income taxes paid (refunded), substantially all was paid to (refunded by) AGR under the tax sharing agreement. Interest capitalized was $3.6 million in 2022 and $4.3 million in 2021. Accrued liabilities for utility plant additions were $35.2 million and $3.6 million as of December 31, 2022 and 2021, respectively.

***Trade receivables and unbilled revenues, net of allowance for credit losses*:** We record trade receivables at amounts billed to customers and we record unbilled revenues based on an estimate of energy delivered or services provided to customers. The estimates for unbilled revenues are determined based on various assumptions, including current month energy load requirements, billing rates by customer class and delivery loss factors. Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

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

Trade receivables at December 31 include unbilled revenues of $41.0 million for 2022 and $41.6 million for 2021, and are shown net of an allowance for credit losses at December 31 of $16.9 million for 2022 and $19.0 million for 2021. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $6.1 million in 2022 and $7.8 million in 2021.

Trade receivables include amounts due under deferred payment arrangements (DPAs). When a residential customer becomes delinquent in making payments, the MPUC requires us to allow the customer to enter into a DPA to settle the account balance. A DPA allows the account balance to be paid in installments over an extended period without interest, which generally exceeds one year, by negotiating mutually acceptable payment terms. Generally, we must continue to serve a customer who cannot pay an account balance in full if the customer: (i) pays a reasonable portion of the balance; (ii) agrees to pay the balance in installments; and (iii) agrees to pay future bills within 30 days until the DPA is paid in full. Failure to make payments on a DPA results in the full amount of a receivable under a DPA being due. These accounts are part of the regular operating cycle and we classify them as short term.

We establish our allowance for credit losses, including for unbilled revenue (also referred to as contract assets), by using both historical average loss percentages to project future losses, and by establishing a specific allowance for known credit issues or for specific items not considered in the historical average calculation. We consider whether we need to adjust historical loss rates to reflect the effects of current conditions and forecasted changes considering various economic indicators (e.g., Gross Domestic Product, Personal Income, Consumer Price Index, Unemployment Rate) over the contractual life of the trade receivables. We write off amounts when we have exhausted reasonable collection efforts. The allowance for credit losses for DPAs at December 31 was $9.7 million for 2022 and $11.4 million for 2021. DPA receivable balances at December 31 were $28.0 million for 2022 and $32.1 million for 2021.

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

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

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

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

The changes in government grants recorded as a reduction to the related utility plant as of December 31, 2022 and 2021 consisted of:

(Thousands)	Government grants	Total
As of December 31, 2020	**$ 37,525**	**$ 37,525**
Disposals	—	—
Recognized in income	(3,495)	(3,495)
As of December 31, 2021	**34,030**	**34,030**
Disposals	—	—
Recognized in income	(3,578)	(3,578)
As of December 31, 2022	**$ 30,452**	**$ 30,452**

We are required to comply with certain terms and conditions applicable to each grant and, if a disqualifying event should occur as specified in the grant's terms and conditions, we are required to repay the grant funds to the government. We believe we are in compliance with each grant's terms and conditions as of December 31, 2022 and 2021.

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

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

The following table reconciles the beginning and ending aggregate carrying amount of the ARO, including our conditional ARO, which is recorded in Other Non-current Liabilities for the years ended December 31, 2022 and 2021.

Years Ended December 31,		**2022**		**2021**
(Thousands)				
ARO, beginning of year	$	1,027	$	975
Liabilities settled during the year		(109)		—
Accretion expenses		54		52
ARO, end of year	**$**	**972**	**$**	**1,027**

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

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

Environmental remediation liability**:** In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. We record our environmental liabilities on an undiscounted basis. We expect to pay our environmental liability accruals through the year 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 generally reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in OCI, as management believes it is probable that such items will be recoverable through the ratemaking process. Certain nonqualified plan expenses are not recoverable through the ratemaking process and we present the unrecognized prior service costs and credits and unrecognized actuarial gains and losses in accumulated other comprehensive loss. If a plan meets settlement or curtailment accounting criteria, we recognize a regulatory asset or liability if these costs are probable of recovery from ratepayers. We use a December 31st measurement date for our benefits plans.

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

Income taxes: In August 2022, the Inflation Reduction Act of 2022 ("IRA") was signed into law in the United States. The IRA created a new corporate alternative minimum tax (“CAMT”) of 15% on adjusted financial statement income and an excise tax of 1% on the value of certain stock repurchases. Based on initial guidance, CMP currently expects to be subject to the CAMT starting in 2023 but does not expect it to have a material impact on earnings, financial condition, or cash flow. Given the complexity and uncertainty around the applicability of the legislation to our specific facts and circumstances, the company continues to analyze the IRA provisions while waiting on pending Department of Treasury regulatory guidance.

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

The aggregate amount of the related party income tax receivable balance due from AGR at December 31, 2022 was $13.3 million. The aggregate amount of the related party income tax payable balance due to AGR at December 31, 2021 was $12.3 million which is recorded in Taxes accrued in our consolidated balance sheets.

We use the asset and liability method of accounting for income taxes. Deferred tax assets and liabilities reflect the expected future tax consequences, based on enacted tax laws, of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts. In accordance with U.S. GAAP for regulated industries, we have established regulatory assets and liabilities for the net revenue requirements to be recovered from or refunded to customers for the related future tax expense or benefit associated with certain of these temporary differences. We defer investment tax credits when earned and amortize them over the estimated lives of the related assets. We also recognize the income tax consequences of intra-entity transfers of assets other than inventory when the transfer occurs. We had no intra-entity transfers of assets other than inventory during the years ended December 31, 2022 and 2021.

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

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

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

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the consolidated statements of income.

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

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

Adoption of New Accounting Pronouncements

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

(a) Disclosures by business entities about government assistance

In November 2021, the FASB issued guidance that requires an entity to provide certain annual disclosures about government assistance received and accounted for by applying a grant or contribution accounting model by analogy. As the guidance is disclosure only, it did not have an impact to the consolidated financial results

Accounting Pronouncements Issued But Not Yet Adopted

There have been no accounting pronouncements issued but not yet adopted that are expected to have a material impact on CMP's consolidated financial statements.

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

Union collective bargaining agreements: Approximately 66% 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 and the FERC Transmission Return on Equity (ROE) case 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 and full reconciliation of exceptional costs as identified in CMP's rate plan.

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 Other FERC Matters

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

On September 30, 2011, the Massachusetts Attorney General, Massachusetts Department of Public Utilities, Connecticut Public Utilities Regulatory Authority, New Hampshire Public Utilities Commission, Rhode Island Division of Public Utilities and Carriers, Vermont Department of Public

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

On October 16, 2014, the FERC issued its final decision in Complaint I, setting the base ROE at 10.57% and a maximum total ROE of 11.74% (base plus incentive ROEs) for the October 2011 - December 2012 period as well as prospectively from October 16, 2014. On March 3, 2015, the FERC upheld its decision and further clarified that the 11.74% ROE cap will be applied on a project specific basis and not on a transmission owner's total transmission return. The complaints were consolidated and the administrative law judge issued an initial decision on March 22, 2016. The initial decision determined that, (1) for the fifteen month refund period in Complaint II, the base ROE should be 9.59% and that the ROE Cap (base ROE plus incentive ROEs) should be 10.42% and (2) for the fifteen month refund period in Complaint III and prospectively, the base ROE should be 10.90% and that the ROE Cap should be 12.19%. The initial decision in Complaints II and III is the administrative law judge’s recommendation to the FERC Commissioners.

CMP reserved for refunds for Complaints I, II and III consistent with the FERC’s Mach 3, 2015 decision in Complaint I. Refunds were provided to customers for Complaint I. The CMP total reserve associated with Complaints II and III is $27.9 million as of December 31, 2022, which has not changed since December 31, 2021, except for the accrual of carrying costs. If adopted as final by the FERC, the impact of the initial decision by the FERC administrative law judge would be an additional aggregate reserve for Complaints II and III of $12.8 million, which is based upon currently available information for these proceedings.

Following various intermediate hearings, orders and appellate decisions, on October 16, 2018, the FERC issued an order directing briefs and proposing a new methodology to calculate the NETOs ROE that is contained in NETOs' transmission formula rate on file at the FERC (the October 2018 Order). Pursuant to the October 2018 Order, the NETOs filed initial briefs on the proposed methodology in all four Complaints on January 11, 2019 and replied to the initial briefs on March 8, 2019.

On November 21, 2019, the FERC issued rulings on two complaints challenging the base return on equity for Midcontinent Independent System Operator, or MISO transmission owners. These rulings established a new zone of reasonableness based on equal weighting of the DCF and capital-asset pricing model for establishing the base return on equity. This resulted in a base return on equity of 9.88% as the midpoint of the zone of reasonableness. Various parties have requested rehearing on this decision, which was granted. On May 21, 2020, FERC issued a ruling, which, among other things, adjusted the methodology to determine the MISO transmission owners’ ROE, resulting in an increase in ROE from 9.88% to 10.02% by utilizing the risk premium model in addition to the DCF model and capital-asset pricing model under both prongs of Section 206 of the FPA, and calculated the zone of reasonableness into equal thirds rather than employing the quartile approach. Parties to these orders affecting the MISO transmission owners' base ROE petitioned for their review at the D.C. Circuit Court of Appeals in January 2021. The NETO's submitted an amici curia brief in support of the MISO transmission owners on March 17, 2021. On August 9, 2022, the D.C. Circuit Court vacated FERC's orders and remanded the matter back to FERC. The D.C. Circuit Court held that FERC failed to offer a reasoned explanation for its decision to reintroduce the Risk Premium model after initially, and forcefully, rejecting it and that because FERC adopted the significant portion of its model in an arbitrary and capricious fashion, the new ROE produced by that model cannot stand. We cannot predict the potential impact the MISO transmission owners' ROE proceeding may have in establishing a precedent for the NETO's pending four Complaints.

On April 15, 2021, the FERC issued a supplemental Notice of Proposed Rulemaking (Supplemental NOPR) that proposes to eliminate the 50 basis-point ROE incentive for utilities who join Regional Transmission Organizations after three years of membership. The NETOs submitted initial comments in opposition to the Supplemental NOPR on June 25, 2021 and reply comments on July 26, 2021. If the elimination of the 50 basis-point ROE incentive adder becomes final, we estimate we would have an approximately $1 million reduction in earnings per year. We cannot predict the outcome of this proceeding.

CMP Distribution Rate Stipulation and New Renewable Source Generation

In an order issued on February 19, 2020, the MPUC authorized an increase in CMP's distribution revenue requirement of $17.4 million, or approximately 6.9%, based on an allowed ROE of 9.25% and a 50.00% equity ratio. The rate increase was effective March 1, 2020. Commencing on March 1, 2020, the MPUC also imposed a 1.00% ROE reduction (to 8.25%) for management efficiency associated with CMP’s customer service performance following the implementation of its new billing system in 2017 which would be removed after demonstrating satisfactory customer service performance. In September 2021, CMP met the 18-month required rolling average satisfactory customer service benchmarks and filed with the MPUC a request for removal of the management efficiency adjustment, which was approved by the MPUC effective as of its February 18, 2022 order.

The Order provided additional funding for staffing increases, vegetation management programs and storm restoration costs, while retaining the basic tiered structure for storm cost recovery implemented in the 2014 stipulation. The MPUC Order also retained the RDM implemented in 2014. The Order denied CMP’s request to increase rates for higher costs associated with services provided by its affiliates and ordered the initiation of a management audit to evaluate whether CMP's current management structure, and the management and other services from its affiliates, are appropriate and in the interest of Maine customers. The management audit was commenced in July 2020 by the MPUC's consultants and culminated with a report issued by the MPUC’s consultants in July 2021. On February 18, 2022, the MPUC opened a narrowly tailored follow-on investigation examining how CMP and its customers are affected by decisions made at the CMP corporate parent level about earnings, capital budgeting, and planning. In this context, the investigation will also examine regulatory approaches and structures including ratemaking and performance mechanisms. We cannot predict the outcome of this investigation.

In accordance with Chapter 120 of MPUC Rules, on May 26, 2022, CMP filed a nonbinding notice of intent to file a distribution rate case on or after sixty days from the issuance of the letter. In the notice, CMP signaled its intent to propose a three-year rate plan, which includes a multi-year capital investment plan to fund investments needed to improve reliability and resiliency, as well as to continue to improve the customer experience and cost-effectively advance clean energy transformation. CMP’s notice estimated a revenue change in the range of $45 to $50 million in the first year of the rate plan followed by increases in the range of $25 to $30 million in the second year and $20 to $25 million in the third year. We cannot predict the outcome of this matter.

On August 11, 2022, CMP filed a three-year rate plan, with adjustments to the distribution revenue requirement in each year. In its filing, CMP has set the three rate years as August 1, 2023 to July 31, 2024 (“Rate Year 1”); August 1, 2024 to July 31, 2025 (“Rate Year 2”); and August 1, 2025 to July 31, 2026 (“Rate Year 3”). The requested Rate Year revenue requirement increases for the rate years are $48 million, $28 million and $23 million, respectively. The revenue requirement adjustments are based on a test year ending December 31, 2021. The requested revenue changes for each rate year of the proposal are subject to a number of adjustment mechanisms most significantly including: (1) an annual review of plant additions with potential downward reconciliation in the event of an underspend, (2) a capital adjustment mechanism for certain incremental pole replacements, broadband work, electric vehicle work, energy storage projects, and metering system upgrades, (3) a symmetrical inflation reconciliation adjustment, and (4) symmetrical reconciliation of the Company's tax basis repair deduction. New rates are expected to take effect on or around August 2023. We cannot predict the outcome of this matter.

Pursuant to Maine law, the MPUC is authorized to conduct periodic requests for proposals seeking long-term supplies of energy, capacity or Renewable Energy Certificates, or RECs, from qualifying resources. The MPUC is further authorized to order Maine Transmission and Distribution Utilities to enter into contracts with sellers selected from the MPUC’s competitive solicitation process. Pursuant to a MPUC Order dated October 8, 2009, CMP entered into a 20-year agreement with Evergreen Wind Power III, LLC, on March 31, 2010, to purchase capacity and energy from Evergreen’s 60 MW Rollins wind farm in Penobscot County, Maine. CMP’s purchase obligations under the Rollins contract are approximately $7 million per year. Pursuant to a MPUC Order dated December 18, 2017, CMP entered into a 20-year agreement with Dirigo Solar, LLC on September 10, 2018, to purchase capacity and energy from multiple Dirigo solar facilities throughout CMP's service territory. CMP's purchase obligations under the Dirigo contract will increase as additional solar facilities are brought on line, eventually reaching a level of approximately $4 million per year. Pursuant to a MPUC Order dated November 6, 2019, CMP entered into a 20-year agreement with Maine Aqua Ventus I GP LLC on December 9, 2019, to purchase capacity and energy from an off-shore wind farm under development near Monhegan Island, Maine. CMP's purchase obligations under the Maine Aqua Ventus contract will be approximately $12 million per year once the facility begins commercial operation. On September 11, 2020 the project was assigned to New England Aqua Ventus, LLC. Pursuant to Maine law, the MPUC conducted two competitive solicitation processes to procure, in the aggregate, an amount of energy or RECs from Class 1A resources that is equal to 14% of retail electricity sales in the State during calendar year 2018, or 1.715 Million MWh. Of that 14% total, the MPUC must acquire at least 7%, but not more than 10%. Through contracts approved in December 2020 (Tranche 1), CMP was ordered to execute 13 contracts, 2 contracts terminated in 2022 prior to achieving Commercial Operations. In October 2021 CMP executed contracts with 6 additional facilities (Tranche 2), 1 contract terminated in 2023 prior to achieving Commercial Operations. Each of the Tranche 1 and Tranche 2 are for 20-year terms. In accordance with MPUC orders, CMP either sells the purchased energy, or in one case the RECs, from these facilities in the ISO New England markets, through periodically auctioning the purchased output to wholesale buyers in the New England regional market, or through a sale to a third party for the RECs. Under Maine 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 Maine law, and has tentatively accepted term sheet proposals for long-term contracts from other sellers, these selections have not yet resulted in additional currently effective contracts with CMP.

Summary Investigation into Security Limits Litigation

On December 13, 2021, the MPUC issued a Notice initiating a summary investigation of certain allegations with respect to the recovery of capital expenditure costs contained in the lawsuit filed by Security Limits, Inc. and Paul Silva against the Company, Networks and Iberdrola, S.A. and several other entities and individuals in the United States District Court Southern District of New York. CMP filed a report describing any costs described in the complaint that are currently being recovered or will be recovered in rates on January 18, 2022 as directed by the Notice of Summary Investigation. In the report, CMP noted that the plaintiffs’ had not yet served the complaint upon Networks or the Company. The MPUC directed CMP to submit notification to the MPUC when the

Complaint has been served or when the procedural deadline for serving the Complaint has passed. On February 9, 2022, Security Limits, Inc. and Paul Silva dismissed their complaint. On February 10, 2022, CMP notified the MPUC of the dismissal and requested that the proceeding be closed. Subsequently on March 8, 2022, the MPUC issued an Order closing the investigation.

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 $212.7 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

Details of 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.

Regulatory assets at December 31, 2022 and 2021 consisted of:

As of December 31, (Thousands)		2022		2021
Transmission revenue reconciliation mechanism	$	10,890	$	15,369
Deferred meter replacement costs		21,043		22,906
Environmental remediation costs		318		380
Energy efficiency programs		—		4,732
Federal tax depreciation normalization adjustment		13,087		13,523
Storm costs		121,388		80,933
Unamortized losses on reacquired debt		166		258
Pension and other postretirement benefits costs		90,907		122,690
Unfunded future income taxes		189,008		173,834
Asset retirement obligation		965		1,032
Other		17,210		10,324
Total regulatory assets		**464,982**		**445,981**
Less: current portion		60,653		49,860
Total non-current regulatory assets	**$**	**404,329**	**$**	**396,121**

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

Energy efficiency programs 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.

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

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

Pension and other postretirement represents 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. As of 2022, this also includes pension deferral which represents the distribution related portion of lump-sum pension settlement expense to be amortized in future rates.

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 $121.4 million at December 31, 2022 and $80.9 million at December 31, 2021.

Transmission revenue reconciliation mechanism reflects any differences in actual costs in the rate year from those used to set rates. The ATU (Annual Transmission True Up) portion 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).

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

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

Other includes various items subject to reconciliation such as CRM&B (Billing System Costs), 2021 Pension Deferral, OPA Assessment for Non-Wire Alternatives, Net Energy Billing, Low-Income Bill Credit, 100 BP Recovery, Non-bypassable charges and Public Advocate.

Regulatory liabilities at December 31, 2022 and 2021 consisted of:

As of December 31,		**2022**		**2021**
(Thousands)				
Accrued removal obligations	$	32,434	$	41,356
Transmission revenue reconciliation mechanism		63,775		9,117
Revenue decoupling mechanism		13,314		12,603
Tax Act - remeasurement		274,691		301,520
Environmental remediation costs		1,228		795
Rate refund - FERC ROE proceeding		27,852		26,907
Other		1,723		2,222
Total regulatory liabilities		**415,017**		**394,520**
Less: current portion		86,937		37,912
Total non-current regulatory liabilities	**$**	**328,080**	**$**	**356,608**

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

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

Rate refund - FERC ROE proceedings: see Note 2.

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

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

Transmission revenue reconciliation mechanism reflects any differences in actual costs in the rate year from those used to set rates. The ATU is recovered over the subsequent June to May period.

When the ATU is known we record it as a regulatory asset (regulatory liability), with an offset to revenues, and amortize it over the twelve-month period as the related revenues are collected (refunded).

Other includes various items subject to reconciliation such as Electric Lifeline Program (ELP), removal of Disconnect Penalty, Demand Side Management and Vegetation Management.

Note 4. Revenue

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

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

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

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

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

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

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

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

Revenues disaggregated by major source for the years ended December 31, 2022 and 2021 are as follows:

Years Ended December 31,	2022	2021
(Thousands)		
Regulated operations – electricity	$ 975,064	$ 922,320
Other (a)	42,832	23,254
Revenue from contracts with customers	**1,017,896**	**945,574**
Leasing revenue	1,574	1,529
Alternative revenue programs	4,516	14,740
Other revenue	27,218	16,556
Total operating revenues	**$ 1,051,204**	**$ 978,399**

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

Note 5. Goodwill

We do not amortize goodwill, but perform our annual impairment assessment testing at least annually as described in Note 1, in the fourth quarter, as of October 1. Our qualitative assessment involves evaluating key events and circumstances that could affect the fair value of our company, as well as other factors. Events and circumstances evaluated include macroeconomic conditions, industry, regulatory and market considerations, cost factors and their effect on earnings and cash flows, overall financial performance as compared with projected results and actual results of relevant prior periods, other relevant entity-specific events, and events affecting CMP.

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

We had no impairment of goodwill in 2022 and 2021 as a result of our qualitative impairment testing. There were no events or circumstances subsequent to our annual impairment assessment for 2022 or 2021 that required us to update the assessment.

The carrying amount of goodwill was $324.9 million at both December 31, 2022 and 2021, with no accumulated impairment losses and no changes during 2022 and 2021.

Note 6. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,	2022	2021
(Thousands)		
Current		
Federal	$ 15,256	$ 10,095
State	4,813	(3,370)
Current taxes charged to expense	**20,069**	**6,725**
Deferred		
Federal	(7,797)	(284)
State	8,481	24,349
Deferred taxes charged to expense	**684**	**24,065**
Total Income Tax Expense	**$ 20,753**	**$ 30,790**

The differences between tax expense per the consolidated statements of income and tax expense at the 21% statutory federal tax rate for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,	2022	2021
(Thousands)		
Tax expense at federal statutory rate	$ 37,924	$ 44,872
Depreciation/amortization and other plant differences not normalized	(8,743)	(11,196)
State taxe expense, net of federal benefit	10,502	16,573
Excess ADIT giveback	(19,302)	(18,609)
Other, net	372	(850)
Total Income Tax Expense	**$ 20,753**	**$ 30,790**

Income tax expense for the year ended December 31, 2022 was $17.2 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to Excess ADIT amortization and Depreciation, amortization and other plant differences not normalized, partially offset by state taxes. This resulted in an effective tax rate of 11.5%. Income tax expense for the year ended December 31, 2021 was $14.1 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to Excess ADIT amortization and Depreciation, amortization and other plant differences not normalized, partially offset by state taxes. This resulted in an effective tax rate of 14.4%.

In 2021, CMP began refunding previously deferred Regional Transmission Excess ADITs and continued refunding previously deferred other Excess ADITs, established as a result of the 2017 Tax Act, pursuant to a regulatory order and as determined by the FERC, MPUC and IRS normalization rules.

Deferred tax assets and liabilities as of December 31, 2022 and 2021 consisted of:

December 31,		2022		2021
(Thousands)				
Non-current Deferred Income Tax Liabilities (Assets)				
Property related	$	701,941	$	668,742
Unfunded future income taxes		48,331		40,992
Pension and other postretirement benefits		13,149		8,540
Regulatory liability due to "Tax Cuts and Jobs Act"		(77,064)		(83,491)
Federal and state NOL's		(2,971)		(96)
Other		8,472		11,643
Total Non-current Deferred Income Tax Liabilities	**$**	**691,858**	**$**	**646,330**
Deferred tax assets	$	80,035	$	83,587
Deferred tax liabilities		771,893		729,917
Net Accumulated Deferred Income Tax Liabilities	**$**	**691,858**	**$**	**646,330**

CMP has gross Maine state net operating losses of $52.1 million for the year ended December 31, 2022. CMP had gross Maine state net operating losses of $15.5 million for the year ended December 31, 2021.

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. In 2022, we netted our liability for uncertain tax positions against all same jurisdiction deferred tax assets, net operating losses and tax credit carryforwards. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the consolidated statements of income.

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,		2022		2021
(Thousands)				
Beginning Balance	$	15,785	$	18,663
Reduction for tax positions related to prior years		(3,544)		(2,878)
Ending Balance	**$**	**12,241**	**$**	**15,785**

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, 2022 or 2021.

Note 7. Non-current Debt

Long-term debt as of December 31, 2022 and 2021 consisted of:

As of December 31,		2022		2021	
(Thousands, except interest rates)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
First mortgage bonds (a)	2025-2052	$ 1,150,000	1.87%-5.68%	$ 1,150,000	1.87%-5.68%
Senior unsecured notes	2025-2037	140,000	5.375%-6.40%	140,000	5.375%-6.40%
Unamortized debt issuance costs and discount		(4,731)		(4,403)	
Total Debt		**1,285,269**		**1,285,597**	
Less: debt due within one year, included in current liabilities		—		124,578	
Total Non-current Debt		**$ 1,285,269**		**$ 1,161,019**	

(a) The first mortgage bonds are secured by a first mortgage lien on substantially all of Net Utility Plant In Service.

On December 15, 2022, CMP issued $75 million aggregate principal amount of Green First Mortgage Bonds maturing in 2032 at an interest rate of 4.37% and $50 million aggregate principal amount of Green First Mortgage Bonds maturing in 2052 at an interest rate of 4.76%

On December 15, 2021, CMP issued $200 million aggregate principal amount of First Mortgage Bonds maturing in 2031 at an interest rate of 2.05%.

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

2023	2024	2025	2026	2027	Total
(Thousands)					
$ —	$ —	$ 80,000	$ 80,000	$ —	$ 160,000

We have no debt covenant requirements related to the maintenance of financial ratios in our long-term debt agreements at December 31, 2022 and 2021.

Note 8. Bank Loans and Other Borrowings

CMP had $46.0 million of notes payable at December 31, 2022 and $1.1 million at December 31, 2021. CMP funds short-term liquidity needs through an agreement among Avangrid’s regulated utility subsidiaries (the “Virtual Money Pool Agreement”), a bi-lateral intercompany credit agreement with Avangrid (the “Bi-Lateral Intercompany Facility”) and a bank provided credit facility to which CMP is a party (the “AGR Credit Facility”), each of which are described below.

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. CMP has a lending/borrowing limit of $100 million under this agreement. CMP had $7.0 million outstanding under this agreement at December 31, 2022 and no debt outstanding under this agreement at December 31, 2021.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $500 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. CMP had $39.0 million outstanding under this agreement at December 31, 2022 and $1.1 million outstanding at December 31, 2021.

On November 23, 2021, Avangrid and its investment-grade rated utility subsidiaries (New York State Electric & Gas Corporation ("NYSEG"), Rochester Gas and Electric Corporation ("RG&E"), CMP, The United Illuminating Company ("UI"), Connecticut Natural Gas Corporation ("CNG"), The Southern Connecticut Gas Company ("SCG") and The Berkshire Gas Company ("BGC")) executed a new credit facility with an aggregate limit of $3,575 million and a termination date of November 23, 2026. Under the terms of the AGR Credit Facility, each borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit contained in the agreement. NYSEG has a maximum sublimit of $700 million, RG&E has $300 million, CMP has $200 million, UI has $250 million, CNG and SCG have maximum sublimits of $150 million and BGC has a maximum sublimit of $50 million. Effective on November 23, 2021, the AGR Credit Facility was amended to increase Avangrid's maximum sublimit to $2,500 million and to establish minimum sublimits of $500 million for NYSEG, $200 million for RG&E, $100 million for CMP, $150 million for UI, $50 million for CNG and SCG and $25 million for BGC. Under the AGR Credit Facility, each of the borrowers are charged a facility fee that is dependent on their credit rating. The facility fees range from 10 to 22.5 basis points. CMP had not borrowed under this agreement as of both December 31, 2022 and 2021.

In the AGR Credit Facility we covenant not to permit, without the consent of the lender, our ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of indebtedness to total capitalization, the facility excludes from net worth the balance of accumulated other comprehensive loss as it appears on the balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness we may maintain. Continued un-remedied failure to comply with those covenants for five business days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity. Our ratio of indebtedness to total capitalization pursuant to the revolving credit facility was 0.38 to 1.00 at December 31, 2022. We are not in default as of December 31, 2022.

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, 2022 and 2021, our redeemable preferred stock was:

				Amount (Thousands)	
Series	**Par Value per Share**	**Redemption Price per Share**	**Shares Authorized and Outstanding(1)**	**2022**	**2021**
CMP, 6% Non-callable	$ 100	$ —	5,713	$ 571	$ 571
Total				**$ 571**	**$ 571**

(1) At December 31, 2022 CMP had $2,300,000 shares of $100 par value preferred stock authorized but unissued.

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

Note 10. Leases

We have operating leases for office buildings, facilities, vehicles and certain equipment. Our finance leases are primarily related to electric generation, distribution, transmission and other. Certain of our lease agreements include rental payments adjusted periodically for inflation or are based on other periodic input measures. Our leases do not contain any material residual value guarantees or material restrictive covenants. Our leases have remaining lease terms of 1 year to 61 years, some of which may include options to extend the leases for up to 10 years, and some of which may include options to terminate the leases within one year. We consider extension or termination options in the lease term if it is reasonably certain we will exercise the option.

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

For the Years Ended December 31,	2022	2021
(Thousands)		
Lease cost		
Finance lease cost		
Amortization of right-of-use assets	$ 285	$ 342
Interest on lease liabilities	(38)	6
Total finance lease cost	247	348
Operating lease cost	1,463	1,639
Short-term lease cost	50	33
Variable lease cost	37	56
Total lease cost	**$ 1,797**	**$ 2,076**

Balance sheet and other information for the years ended December 31, 2022 and 2021 was as follows:

As of December 31,	2022	2021
(Thousands, except lease term and discount rate)		
Operating Leases		
Operating lease right-of-use assets	$ 15,125	$ 14,774
Operating lease liabilities, current	1,071	1,161
Operating lease liabilities, long-term	15,359	14,791
Total operating lease liabilities	$ 16,430	$ 15,952
Finance Leases		
Other assets	$ 3,764	$ 4,058
Other current liabilities	13	—
Other non-current liabilities	17	—
Total finance lease liabilities	$ 30	$ —
Weighted-average Remaining Lease Term (years)		
Finance leases	2.33	—
Operating leases	16.26	18.71
Weighted-average Discount Rate		
Finance leases	3.47 %	—
Operating leases	3.89 %	3.84 %

For the years ended December 31, 2022 and 2021, supplemental cash flow information related to leases was as follows:

For the Years Ended December 31,	2022	2021
(Thousands)		
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 1,547	$ 1,804
Operating cash flows from finance leases	$ (38)	$ 6
Financing cash flows from finance leases	$ (39)	$ 254
Right-of-use assets obtained in exchange for lease obligations:		
Finance leases	$ (9)	$ —
Operating leases	$ 1,332	$ 455

As of December 31, 2022, maturities of lease liabilities were as follows:

	Finance Leases	Operating Leases
(Thousands)		
Year ending December 31,		
2023	$ 14	$ 1,566
2024	14	1,571
2025	3	1,520
2026	—	1,505
2027	—	1,034
Thereafter	—	16,166
Total lease payments	**31**	**23,362**
Less: imputed interest	(1)	(6,932)
Total	**$ 30**	**$ 16,430**

Most of our leases do not provide an implicit rate in the lease; thus we use our incremental borrowing rate based on the information available at the commencement date in determining the present value of lease payments.

Note 11. Commitments and Contingent Liabilities

Power purchase contracts including non-utility generator

We recognized expense of approximately $20.3 million for non-utility generator power in 2022 and $29.8 million in 2021 recorded in Electricity purchased in the consolidated statements of income.

Note 12. Environmental Liability

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

Waste sites

The Environmental Protection Agency (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 five waste sites. The five sites do not include sites where coal gas was manufactured in the past, which are discussed below. With respect to the five sites, four sites are included in Maine's Uncontrolled Sites Program (MUSP), one is subject to Maine's Waste Management Program and one is included on the Massachusetts Non-Priority Confirmed Disposal Site list. Two of the 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 $1.5 million related to the five sites at December 31, 2022.

We have recorded an estimated liability of $3.4 million at December 31, 2022, related to three additional sites where we believe it is probable that we will incur remediation costs and/or monitoring costs as a result of being 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 9 total sites ranges from $4.0 million to $10.3 million as of December 31, 2022. 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 and/or monitoring at our three sites where coal gas was manufactured in the past. The three sites are in Maine's Voluntary Response Action Program, Brownfield Cleanup Program or MUSP.

Our estimate for costs related to investigation, remediation and/or monitoring of the sites ranges from $0.1 million to $0.3 million at December 31, 2022. 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, changes due to property use and changes to current laws and regulations.

The liability to investigate and perform remediation, as necessary, at the known inactive coal gas manufacturing sites was $0.2 million and $0.6 million at December 31, 2022 and 2021, respectively. We recorded a corresponding regulatory asset because we expect to recover the net costs in rates.

Our environmental liabilities are recorded on an undiscounted basis.

Note 13. Accounting for Derivative Instruments and Hedging Activities

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

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

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

We did not have any derivatives designated as hedging instruments as of December 31, 2022. Our derivatives designated as hedging instruments, which are other commodity contracts (fleet fuel), had a fair value of $0.1 million as of December 31, 2021 and are included in current assets.

The effect of hedging instruments on OCI and income for the years ended December 31, 2022 and 2021, respectively, consisted of:

Years Ended December 31,	Gain Recognized in OCI on Derivatives	Location of Gain (Loss) Reclassified From Accumulated OCI into Income	(Loss) Gain Reclassified From Accumulated OCI into Income	Total Amount per Income Statement
(Thousands)				
2022				
Interest rate contracts	$ —	Interest expense	$ (181)	$ 47,760
Commodity contracts: Other	765	Other operating expenses	803	$ 562,255
Total	**$ 765**		**$ 622**	
2021				
Interest rate contracts	$ —	Interest expense	$ (181)	$ 46,347
Commodity contracts: Other	434	Other operating expenses	259	$ 486,685
Total	**$ 434**		**$ 78**	

The amount in AOCI related to previously settled interest rate hedging contracts at December 31 is a net loss of $2.1 million for 2022 and $2.3 million for 2021. For the year ended December 31, 2022, we recorded $0.2 million in net derivative losses related to discontinued cash flow hedges. We will amortize approximately $0.2 million of discontinued cash flow hedges in 2023.

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

	Electricity Contracts	Natural Gas Contracts	Other Fuel Contracts
Year to settle	**Mwhs**	**Dths**	**Gallons**
As of December 31, 2022 (a)			
2023	—	—	—
As of December 31, 2021			
2022	—	—	581,400

(a) As of December 31, 2022 the fleet fuel program was discontinued.

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

The estimated fair value of debt amounted to $1,182 million and $1,491 million as of December 31, 2022 and 2021, 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

There were no financial instruments as of December 31, 2022. The financial instruments measured at fair value as of December 31, 2021 consist of:

Description	Total	(Level 1)	(Level 2)	(Level 3)
(Thousands)				
2021				
Assets				
Derivatives	$ 38	$ —	$ —	$ 38
Total	**$ 38**	**$ —**	**$ —**	**$ 38**

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2022 and 2021. 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 enter into fuel derivative contracts to hedge our unleaded and diesel fuel requirements for our fleet vehicles. Exchange based forward market prices are used but because a basis adjustment is added to the forward prices, we include the fair value measurement for these contracts in Level 3.

The reconciliation of changes in the fair value of financial instruments based on Level 3 inputs for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,	2022	2021
(Thousands)		
Beginning balance	$ 38	$ (137)
Total (losses) gains (realized/unrealized)		
Included in earnings	(803)	(259)
Included in other comprehensive income	765	434
Ending balance	**$ —**	**$ 38**

The amounts of realized and unrealized gain and loss included in earnings for the period (above) are reported in Operations and maintenance of the consolidated statements of income.

Note 15. Accumulated Other Comprehensive Loss

Accumulated Other Comprehensive Loss for the years ended December 31, 2022 and 2021 consisted of:

(Thousands)	Balance December 31, 2020	2021 Change	Balance December 31, 2021	2022 Change	Balance December 31, 2022
Amortization of pension cost for nonqualified plans and current year actuarial gain, net of income tax expense of $33 for 2021 and $87 for 2022	$ (1,979)	$ 83	$ (1,896)	$ 224	$ (1,672)
Unrealized gain on derivatives qualified as hedges:					
Unrealized gain during period on derivatives qualified as hedges, net of income tax expense of $231 for 2021 and $214 for 2022		203		551	
Reclassification adjustment for gain included in net income, net of income tax benefit of ($138) for 2021 and ($225) for 2022		(121)		(578)	
Reclassification adjustment for loss on settled cash flow treasury hedges, net of income tax expense of $96 for 2021 and $51 for 2022		85		130	
Net unrealized gain on derivatives qualified as hedges	(1,814)	167	(1,647)	103	(1,544)
Accumulated Other Comprehensive Loss	**$ (3,793)**	**$ 250**	**$ (3,543)**	**$ 327**	**$ (3,216)**

No Accumulated Other Comprehensive Loss is attributable to the noncontrolling interest for the above periods.

Note 16. Post-Retirement and Similar Obligations

We have funded non-contributory defined benefit pension plans that cover all eligible employees. The plans provide defined benefits based on years of service and final average salary for employees hired before 2002. Most employees hired in 2002, or later based upon the plan, are covered under a cash balance plan or formula where their benefit accumulates based on a percentage of annual salary and credited interest. During 2013, we announced that we would discontinue, effective December 31, 2013, the cash balance accruals for all non-union employees covered under the cash balance plans or formula. At the same time, the plans were closed to newly-hired non-union employees. The plans had been closed to newly-hired union employees in prior years. CMP's unionized employees covered under the cash balance plans ceased to receive accruals as of December 31, 2014. Their earned balances will continue to accrue interest but will no longer be increased by a flat dollar amount or percentage of pay, as defined by the plan. Instead, they will receive a contribution to their account under their respective company’s defined contribution plan. During 2022, the Company decided to freeze pension benefit accruals and contribution credits for non-union employees and transition their retirement benefits to the 401(k) Plan. Employees not participating in a defined benefit plan are eligible to receive an enhanced or core 401(k) Company matching contribution, depending on whether they are union or non-union employees, respectively.

The company maintains a 401(k) Savings and Retirement Plan (the Plan) for all eligible employees as defined in the Plan agreement. Participants in the Plan may contribute a percentage of their compensation and the company may match a predetermined percentage of the participant contributions. Expenses under the Plan for the Company totaled approximately $7.9 million for 2022 and $5.3 million for 2021.

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

Non-Qualified Retirement Benefit Plans

We also sponsor various unfunded non-qualified pension plans for certain current employees, former employees and former directors. The total liability for these plans, which is included in Other non-current liabilities on our consolidated balance sheets, was $1.2 million and $1.6 million at December 31, 2022 and 2021, respectively.

Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2022 and 2021 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2022**	**2021**	**2022**	**2021**
(Thousands)				
Change in benefit obligation				
Benefit obligation as of January 1,	**$ 407,423**	**$ 462,706**	**$ 94,024**	**$ 108,172**
Service cost	4,673	6,101	537	626
Interest cost	12,447	11,603	2,491	2,402
Curtailments/Settlements	(50,326)	(21,790)	—	—
Actuarial gain	(83,071)	(34,213)	(28,899)	(11,097)
Benefits paid	(17,192)	(16,984)	(7,364)	(6,079)
Benefit obligation as of December 31,	**$ 273,954**	**$ 407,423**	**$ 60,789**	**$ 94,024**
Change in plan assets				
Fair value of plan assets at January 1,	**$ 368,366**	**$ 354,910**	**$ 22,161**	**$ 34,465**
Actual return on plan assets	(76,432)	32,230	(4,036)	3,509
Employer contributions	20,000	20,000	3,985	—
Settlements	(34,206)	(21,790)	—	—
Benefits paid	(17,192)	(16,984)	(7,364)	(15,813)
Fair value of plan assets at December 31,	**$ 260,536**	**$ 368,366**	**$ 14,746**	**$ 22,161**
Funded status at December 31,	**$ (13,418)**	**$ (39,057)**	**$ (46,043)**	**$ (71,863)**

During 2022, the pension and postretirement benefit obligations had actuarial gains of, respectively, $83.1 million and $28.9 million, primarily due to gains from discount rate increases of $81.7 million and $15.6 million, respectively. The pension benefit obligation had a reduction of $50.3 million from settlements ($34.2 million) and curtailments ($16.1 million). The settlements were lump-sum payments made within the pension plan guidelines at the discretion of the plan participants who opted to retire. The curtailments were driven by a Company decision to freeze pension benefit accruals and contribution credits for non-union employees and transition their retirement benefits to a 401(k) plan.

During 2021, the pension benefit obligation had an actuarial gain of $34.2 million, primarily due to a $24.1 million gain from increases in discount rates. There were no significant plan design changes in 2021. There were no significant gains and losses relating to the postretirement benefit obligations.

Amounts recognized in the consolidated balance sheets as of December 31, 2022 and 2021 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2022**	**2021**	**2022**	**2021**
(Thousands)				
Non-current liabilities	$ (13,418)	$ (39,057)	$ (46,043)	$ (71,863)

We have determined that we are allowed to defer as regulatory assets or regulatory liabilities items that would otherwise be recorded in accumulated other comprehensive income pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans.

Amounts recognized as regulatory assets or regulatory liabilities for the years ended December 31, 2022 and 2021 consisted of:

	Pension Benefits		Postretirement Benefits	
Years Ended December 31,	**2022**	**2021**	**2022**	**2021**
(Thousands)				
Net loss (gain)	$ 81,944	$ 101,256	$ (2,789)	$ 22,071
Prior service credit	$ —	$ —	$ —	$ (637)

Our accumulated benefit obligation (ABO) for all qualified defined benefit pension plans was $267.2 million and $377.5 million as of December 31, 2022 and 2021. Our postretirement benefits were partially funded at December 31, 2022 and 2021.

The projected benefit obligation (PBO) and ABO exceeded the fair value of pension plan assets for our qualified plans as of December 31, 2022 and 2021. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets for the relevant periods.

As of December 31,	**2022**	**2021**
(Thousands)		
Projected benefit obligation	$ 273,954	$ 407,423
Accumulated benefit obligation	$ 267,157	$ 377,500
Fair value of plan assets	$ 260,536	$ 368,366

As of December 31, 2022 and 2021, the accumulated postretirement benefits obligation for all the qualified plans exceeded the fair value of plan assets.

Components of net periodic benefit cost and other changes in plan assets and benefit obligations recognized in income and regulatory assets and liabilities for the years ended December 31, 2022 and 2021 consisted of:

For the years ended December 31,	Pension Benefits 2022	Pension Benefits 2021	Postretirement Benefits 2022	Postretirement Benefits 2021
(Thousands)				
Net Periodic Benefit Cost:				
Service cost	$ 4,673	$ 6,101	$ 537	$ 626
Interest cost	12,447	11,603	2,491	2,402
Expected return on plan assets	(19,483)	(23,532)	(1,323)	(1,768)
Amortization of prior service benefit	—	—	(637)	(2,013)
Settlement charge	10,096	5,421	—	—
Amortization of net loss	5,940	17,866	1,321	2,713
Net Periodic Benefit Cost	**$ 13,673**	**$ 17,459**	**$ 2,389**	**$ 1,960**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities:				
Net loss (gain)	$ 12,844	$ (42,911)	$ (23,539)	$ (12,837)
Amortization of net loss	(5,940)	(17,866)	(1,321)	(2,713)
Settlements	(10,096)	(5,421)	—	—
Curtailments	(16,120)	—	—	—
Amortization of prior service benefit	—	—	637	2,013
Total Other Changes	**(19,312)**	**(66,198)**	**(24,223)**	**(13,537)**
Total Recognized	**$ (5,639)**	**$ (48,739)**	**$ (21,834)**	**$ (11,577)**

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

The weighted-average assumptions used to determine benefit obligations as of December 31, 2022 and 2021 consisted of:

	Pension Benefits 2022	Pension Benefits 2021	Postretirement Benefits 2022	Postretirement Benefits 2021
Discount rate	5.21% / 5.25% union	2.96% / 3.05% union	5.13%	2.74 %
Rate of compensation increase	3.00%	Age-Related Rates / 3.50% union	3.00% for union	3.50 %
Interest crediting rate	4.48% non-union / 4.50% union	2.00% non-union / 4.50% union	N/A	N/A

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

The weighted-average assumptions used to determine net periodic benefit cost for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,	Pension Benefits 2022	2021	Postretirement Benefits 2022	2021
Discount rate	2.96% / 4.15% / 3.05%	2.56 %	2.74 %	2.29 %
Expected long-term return on plan assets	6.50% / 5.00% / 6.00%	7.00 %	5.97 %	5.13 %
Rate of compensation increase (Union/Non-Union)	Age-Related Rates / 3.50% union	Age-Related Rates / 3.50% union	3.50% for union	Age-Related Rates / 3.50% union

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations, and the effect of rebalancing of plan assets discussed below. Our analysis considered current capital market conditions and projected conditions. Our policy is to calculate the expected return on plan assets using the market related value of assets. We amortize unrecognized actuarial gains and losses using the standard amortization methodology under which amounts in excess of 10% of the greater of the projected benefit obligation or market related value are amortized over the plan participants' average remaining service to retirement.

Assumed health care cost trend rates used to determine benefit obligations as of December 31, 2022 and 2021 consisted of:

As of December 31,	2022	2021
Health care cost trend rate assumed for next year	6.00% / 6.50%	6.50% / 7.25%
Rate to which cost trend rate is assumed to decline (ultimate trend rate)	4.50 %	4.50 %
Year that the rate reaches the ultimate trend rate	2029/2027	2029/2027

Contributions

We make annual contributions in accordance with our funding policy of not less than the minimum amounts as required by applicable regulations. We do not expect to contribute to our pension or other postretirement plans during 2023.

Estimated future benefit payments

Expected benefit payments and Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) subsidy receipts reflecting expected future service as of December 31, 2022 consisted of:

(Thousands)	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
2023	$ 23,981	$ 5,482	$ 134
2024	$ 23,412	$ 5,354	$ 135
2025	$ 23,486	$ 5,193	$ 139
2026	$ 23,200	$ 5,078	$ 139
2027	$ 23,655	$ 4,975	$ 141
2028 - 2032	$ 108,324	$ 22,711	$ 701

Plan assets

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

The asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets within broad categories of asset classes made up of Return-Seeking and Liability-Hedging investments. We currently have target allocations ranging from 25%-60% for Return-Seeking assets and 40%-75% for Liability-Hedging assets. Return-Seeking assets include investments in domestic, international and emerging equity, real estate, global asset allocation strategies and hedge funds. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of pension benefits plan assets, by asset category, as of December 31, 2022, consisted of:

As of December 31, 2022		**Fair Value Measurements**		
(Thousands)	**Total**	**Level 1**	**Level 2**	**Level 3**
Asset Category				
Cash and cash equivalents	$ 7,298	$ 18	$ 7,280	$ —
U.S. government securities	22,837	22,837	—	—
Common stocks	7,819	7,819	—	—
Registered investment companies	12,796	12,796	—	—
Corporate bonds	79,902	—	79,902	—
Preferred stocks	92	92	—	—
Common collective trusts	67,859	—	67,859	—
Other, principally annuity, fixed income	473	—	473	—
	$ 199,076	**$ 43,562**	**$ 155,514**	**$ —**
Other investments measured at net asset value	61,460			
Total	**$ 260,536**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2021, consisted of:

As of December 31, 2021		Fair Value Measurements		
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 11,350	$ 1,663	$ 9,687	$ —
U.S. government securities	21,896	21,896	—	—
Common stocks	15,913	15,913	—	—
Registered investment companies	34,079	34,079	—	—
Corporate bonds	97,111	—	97,111	—
Preferred stocks	104	104	—	—
Common collective trusts	125,099	—	125,099	—
Other, principally annuity, fixed income	2,687	1	2,686	—
	$ 308,239	**$ 73,656**	**$ 234,583**	**$ —**
Other investments measured at net asset value	60,127			
Total	**$ 368,366**			

Valuation Techniques

We value our pension benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities - at the closing price reported in the active market in which the security is traded.
- Common stocks - at the closing price reported in the active market in which the individual investment is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks - at the closing price reported in the active market in which the individual investment is traded.
- Common collective trusts/Registered investment companies - Level 1: at the closing price reported in the active market in which the individual investment is traded. Level 2: the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Other investments measured at net asset value (NAV) - fund shares offered to a limited group of investors and alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

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. Substantially all 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 49%-69% for equity securities and 31%-51% for fixed income investments. Equity investments are diversified across U.S. and non-U.S. stocks, investment styles, and market capitalization ranges. Fixed income investments are primarily invested in U.S. bonds and may also include some non-U.S. bonds. We primarily minimize the risk of large losses through diversification but also through monitoring and managing other aspects of risk through quarterly investment portfolio reviews. Systematic rebalancing within target ranges increases the probability of increasing the projected expected return, while mitigating risk, should any asset categories drift outside their specified ranges.

The fair values of other postretirement benefits plan assets, by asset category, as of December 31, 2022, consisted of:

As of December 31, 2022		**Fair Value Measurements**		
(Thousands)	**Total**	**Level 1**	**Level 2**	**Level 3**
Asset Category				
Cash and cash equivalents	$ 602	$ 1	$ 601	$ —
U.S. government securities	259	259	—	—
Common stocks	277	277	—	—
Registered investment companies	9,656	9,656	—	—
Corporate bonds	1,188	—	1,188	—
Preferred stocks	1	1	—	—
Common collective trusts	1,938	—	1,938	—
Other, principally annuity, fixed income	18	—	18	—
	$ 13,939	**$ 10,194**	**$ 3,745**	**$ —**
Other investments measured at net asset value	807			
Total	**$ 14,746**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2021, consisted of:

As of December 31, 2021	Fair Value Measurements			
(Thousands)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 1,456	$ 32	$ 1,424	$ —
U.S. government securities	401	401	—	—
Common stocks	362	362	—	—
Registered investment companies	15,081	15,081	—	—
Corporate bonds	1,582	—	1,582	—
Preferred stocks	2	2	—	—
Common collective trusts	2,336	—	2,336	—
Other, principally annuity, fixed income	52	—	52	—
	$ 21,272	**$ 15,878**	**$ 5,394**	**$ —**
Other investments measured at net asset value	889			
Total	**$ 22,161**			

Valuation techniques

We value our postretirement benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities - at the closing price reported in the active market in which the security is traded.
- Common stocks and registered investment companies - at the closing price reported in the active market in which the individual investment is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Common collective trusts - the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Other investments measured at net asset value (NAV) - fund shares offered to a limited group of investors and alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

Pension and postretirement plan equity securities did not include any AGR and Iberdrola common stock as of both December 31, 2022 and 2021.

Note 17. Other Income and Other Deductions

Other income and deductions for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,		2022		2021
(Thousands)				
Interest and dividends income	$	2,871	$	3,308
Allowance for funds used during construction		12,585		15,136
Carrying costs on regulatory assets		10		473
Equity earnings		58		55
Miscellaneous		353		225
Total other income	**$**	**15,877**	**$**	**19,197**
Pension non-service components	$	(10,899)	$	(12,152)
Miscellaneous		(3,558)		(5,203)
Total other deductions	**$**	**(14,457)**	**$**	**(17,355)**

Note 18. Related Party Transactions

Certain Networks subsidiaries, including CMP, borrow from AGR, the parent of Networks, through intercompany revolving credit agreements. For CMP, the intercompany revolving credit agreements provide access to supplemental liquidity. See Note 8 for further detail on the credit facility with AGR.

AGR, through its affiliates, provides administrative and management services to Networks operating utilities, including CMP, pursuant to service agreements. The cost of those services is allocated in accordance with methodologies set forth in the service agreements. The cost allocation methodologies vary depending on the type of service provided. Management believes such allocations are reasonable. The charge for operating and capital services provided to CMP by AGR and its affiliates was $44.9 million and $42.3 million for 2022 and 2021, respectively. Cost for services includes amounts capitalized in utility plant, which was approximately $9.5 million in 2022 and $8.4 million in 2021. The remainder was primarily recorded as operations and maintenance expense. The charges for services provided by CMP to AGR and its subsidiaries were approximately $9.4 million for 2022 and $5.1 million for 2021. 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 $40.9 million at December 31, 2022 and the balance of $38.3 million at December 31, 2021 is mostly payable to Avangrid Service Company. The balance in accounts receivable from affiliates of $6.9 million at December 31, 2022 and the balance of $63.9 million at December 31, 2021 is mostly receivable from New England Clean Energy Connect.

The $0.2 million of notes receivable from affiliates at December 31, 2022 is from Avangrid, Inc. There were no notes receivable from affiliates at December 31, 2021. Notes receivable from affiliates relate to the Virtual Money Pool Agreement as discussed in Note 8 of these financial statements.

In 2018, the New England Clean Energy Connect, or NECEC, transmission project, proposed in a joint bid by CMP and Hydro-Québec, was selected by the Massachusetts electric distribution utilities and the Massachusetts Department of Energy Resources in the Commonwealth of Massachusetts' 83D clean energy Request for Proposal. The NECEC transmission project includes a 145-mile transmission line linking the electrical grids in Québec, Canada and New England.

On January 4, 2021, in connection with certain stipulation agreements (Stipulations), CMP transferred the NECEC project to NECEC Transmission LLC pursuant to the terms of a transfer agreement dated November 3, 2020. At that time, NECEC Transmission LLC reimbursed to CMP approximately $101 million in construction and other costs CMP had incurred in connection with the NECEC through the date of transfer.

As consideration for the transfer of the NECEC project, NECEC Transmission LLC agreed to pay CMP the sum total of $60 million, payable in one hundred and sixty equal installments of $375,000 each, due the first business day of each January, April, July and October, to be included in CMP's NECEC Rate Relief Fund as established by the Stipulations. CMP received $1.5 million in such payments from NECEC Transmission LLC in 2021. Similarly and in connection with the Stipulations, CMP will receive $80 million, payable in one hundred and sixty equal installments of $500,000, due the first business day of each January, April, July and October, from funding provided by H.Q. Energy Services (U.S.) Inc., an unaffiliated entity, which will be included in CMP's NECEC Rate Relief Fund. Pursuant to the terms of the Stipulations, all these payments were suspended in December 2021 following the stoppage of construction of the NECEC project and remained suspended as of December 31, 2022. Payments will remain suspended until construction resumes. In addition, as of December 31, 2021, CMP accrued $61.4 million of contributions in aid of construction within Construction work in progress related to NECEC Transmission LLC paying for CMP-owned assets which CMP is improving related to the NECEC interconnection. The accrued amount was paid to CMP in January 2022.

Note 19. Subsequent Events

The company has performed a review of subsequent events through March 24, 2023, which is the date these consolidated financial statements were available to be issued.

The Berkshire Gas Company

Financial Statements

As of and for the Years Ended December 31, 2022 and 2021

The Berkshire Gas Company

Index

Financial Statements As of and for the Years Ended December 31, 2022 and 2021

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

Independent Auditors' Report

The Stockholder and Board of Directors
The Berkshire Gas Company:

Opinion

We have audited the financial statements of The Berkshire Gas Company (the Company), which comprise the balance sheets as of December 31, 2022 and 2021, 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.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

Basis for Opinion

We conducted our audits in accordance with auditing standards generally accepted in the United States of America (GAAS). Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with U.S. generally accepted accounting principles, and for 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.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for one year after the date that the financial statements are issued.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control related matters that we identified during the audit.

KPMG LLP

New York, New York
March 31, 2023

The Berkshire Gas Company
Statements of Income

Years Ended December 31,		2022		2021
(Thousands)				
Operating Revenues	$	**101,757**	$	**85,465**
Operating Expenses				
Natural gas purchased		42,103		28,901
Operations and maintenance		33,467		31,616
Depreciation and amortization		9,088		8,920
Taxes other than income taxes, net		7,581		6,317
Total Operating Expenses		**92,239**		**75,754**
Operating Income		**9,518**		**9,711**
Other income		859		539
Other deductions		(972)		(2,202)
Interest expense, net of capitalization		(2,742)		(2,806)
Income Before Tax		**6,663**		**5,242**
Income tax expense		562		879
Net Income	$	**6,101**	$	**4,363**

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

The Berkshire Gas Company
Statements of Comprehensive Income

Years Ended December 31,		2022		2021
(Thousands)				
Net Income	$	**6,101**	$	**4,363**
Other Comprehensive Income, Net of Tax				
Remeasurement of non-qualified plan, net of tax expense of $21		57		—
Other Comprehensive Income, Net of Tax		**57**		**—**
Comprehensive Income	$	**6,158**	$	**4,363**

The Berkshire Gas Company
Balance Sheets

As of December 31,		2022		2021
(Thousands)				
Assets				
Current Assets				
Cash and cash equivalents	$	668	$	4,537
Accounts receivable and unbilled revenues, net		19,705		15,724
Accounts receivable from affiliates		4		26
Fuel and gas in storage		4,436		2,636
Materials and supplies		2,249		1,799
Income tax receivable		2,478		—
Other current assets		366		146
Regulatory assets		14,653		15,916
Total Current Assets		**44,559**		**40,784**
Utility plant, at original cost		321,780		304,225
Less accumulated depreciation		(106,642)		(100,334)
Net Utility Plant in Service		**215,138**		**203,891**
Construction work in progress		7,242		4,619
Total Utility Plant		**222,380**		**208,510**
Operating lease right-of-use assets		105		141
Other property and investments		1,990		2,179
Regulatory and Other Assets				
Regulatory assets		20,115		22,857
Goodwill		51,932		51,932
Other		10		6
Total Regulatory and Other Assets		**72,057**		**74,795**
Total Assets	**$**	**341,091**	**$**	**326,409**

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

The Berkshire Gas Company
Balance Sheets

As of December 31,		2022		2021
(Thousands)				
Liabilities				
Current Liabilities				
Notes payable to affiliates	$	9,650	$	—
Accounts payable and accrued liabilities		24,237		16,279
Accounts payable to affiliates		1,048		754
Interest accrued		758		729
Taxes accrued		100		7,318
Operating lease liabilities		7		6
Regulatory liabilities		—		198
Other		3,307		4,159
Total Current Liabilities		**39,107**		**29,443**
Regulatory and Other Liabilities				
Regulatory liabilities		51,824		51,908
Other Non-current Liabilities				
Deferred income taxes		30,383		26,803
Pension and other postretirement		12,537		15,472
Operating lease liabilities		96		133
Environmental remediation costs		2,342		3,620
Other		1,220		1,717
Total Regulatory and Other Liabilities		**98,402**		**99,653**
Non-current debt		59,595		59,547
Total Liabilities		**197,104**		**188,643**
Commitments and Contingencies				
Common Stock Equity				
Additional paid-in capital		126,506		116,443
Retained earnings		17,424		21,323
Accumulated other comprehensive income		57		—
Total Common Stock Equity		**143,987**		**137,766**
Total Liabilities and Equity	**$**	**341,091**	**$**	**326,409**

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

The Berkshire Gas Company
Statements of Cash Flows

Years Ended December 31,	2022	2021
(Thousands)		
Cash Flow From Operating Activities:		
Net income	**$ 6,101**	**$ 4,363**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	9,088	8,920
Regulatory assets/liabilities amortization	(533)	(22)
Regulatory assets/liabilities carrying cost	(765)	(212)
Amortization of debt issuance costs	26	50
Deferred taxes	3,115	(2,099)
Pension cost	252	509
Stock-based compensation	90	71
Other non-cash items	244	(287)
Changes in operating assets and liabilities:		
Accounts receivable, from affiliates, and unbilled revenues	(3,959)	(265)
Inventories	(2,250)	(1,041)
Accounts payable, to affiliates, and accrued liabilities	3,572	5,176
Taxes accrued	(9,695)	9,022
Other assets/liabilities	(5,070)	1,936
Regulatory assets/liabilities	3,553	(3,137)
Net Cash Provided by Operating Activities	**3,769**	**22,984**
Cash Flow From Investing Activities:		
Capital expenditures	(17,629)	(18,448)
Contributions in aid of construction	303	214
Proceeds from sale of property, plant and equipment	38	231
Net Cash Used in Investing Activities	**(17,288)**	**(18,003)**
Cash Flow From Financing Activities:		
Repayments of non-current debt	—	(1,646)
Notes payable to affiliates	9,650	(9,010)
Capital contributions	10,000	10,000
Dividends paid	(10,000)	—
Net Cash Provided by (Used in) Financing Activities	**9,650**	**(656)**
Net (Decrease) Increase in Cash and Cash Equivalents	**(3,869)**	**4,325**
Cash and Cash Equivalents, Beginning of Period	**4,537**	**212**
Cash and Cash Equivalents, End of Period	**$ 668**	**$ 4,537**

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

The Berkshire Gas Company
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	Total Common Stock Equity
Balance, December 31, 2020	**100**	**$ —**	**$ 106,095**	**$ 16,960**	**$ —**	**$ 123,055**
Net income	—	—	—	4,363	—	4,363
Stock-based compensation	—	—	348	—	—	348
Capital contributions	—	—	10,000	—	—	10,000
Balance at December 31, 2021	**100**	**$ —**	**$ 116,443**	**$ 21,323**	**$ —**	**$ 137,766**
Net income	—	—	—	6,101		6,101
Other comprehensive income, net of tax	—	—	—	—	57	57
Comprehensive income						6,158
Stock-based compensation	—	—	63	—	—	63
Common stock dividends	—	—	—	(10,000)	—	(10,000)
Capital contributions	—	—	10,000	—	—	10,000
Balance at December 31, 2022	**100**	**$ —**	**$ 126,506**	**$ 17,424**	**$ 57**	**$ 143,987**

(*) Par value of share amounts is $2.50

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

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

***Background and nature of operations*:** The Berkshire Gas Company (Berkshire, the company, we, our, us), engages in natural gas transportation, distribution and sales operations in Massachusetts serving approximately 40,600 customers in its service area totaling 738 square miles as of December 31, 2022. Berkshire is regulated by the Massachusetts Department of Public Utilities (DPU) as it relates to utility service.

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

***Basis of presentation*:** The accompanying financial statements have been prepared in accordance with generally accepted accounting principles in the United States (U.S. GAAP) and are also maintained in accordance with the uniform system of accounts prescribed by the Federal Energy Regulatory Commission (FERC) and the DPU.

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

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

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

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

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

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

In assessing goodwill for impairment, we have the option to first perform a qualitative assessment to determine whether a quantitative assessment is necessary. If we determine, based on qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If we bypass the qualitative assessment, or perform the qualitative assessment but determine it is more likely than not that its fair value is less than its carrying amount, we perform a quantitative test to compare the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, we record an impairment loss as a reduction to goodwill and a charge to operating expenses, but the loss recognized would not exceed the total amount of goodwill allocated to the reporting unit.

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

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

We transfer assets from “Construction work in progress” to “Utility plant” when they are available for service.

We determine depreciation expense for utility plant in service using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Consistent with FERC accounting requirements, we charge the original cost of utility plant retired or otherwise disposed of to accumulated depreciation. Our composite rates for depreciation were 2.7% of average depreciable property for both 2022 and 2021. We amortize our capitalized software cost, using the straight-line method, based on useful lives of 3 to 10 years. Depreciation expense was $8.2 million in 2022 and $8.0 million in 2021. Amortization of capitalized software was $0.9 million in 2022 and in 2021.

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

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

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

Utility Plant	Estimated useful life range (years)		2022		2021
(thousands)					
Gas distribution plant	8-65	$	266,562	$	250,804
Software	3-10		12,704		11,590
Land			2,305		2,305
Buildings and improvements	50-55		32,228		31,465
Other plant	25-55		7,981		8,061
Utility plant at original cost			321,780		304,225
Less accumulated depreciation			(106,642)		(100,334)
Net Utility Plant in Service			**215,138**		**203,891**
Construction work in progress			7,242		4,619
Total Utility Plant		$	**222,380**	$	**208,510**

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

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

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

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

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

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

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

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

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

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

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

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

Concentration of risk: We maintain our cash and cash equivalents in accounts with major financial institutions in the form of demand deposits and money market accounts. Deposits in these financial institutions may exceed the amount of federal deposit insurance provided on such deposits.

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

		2022		2021
(Thousands)				
Cash paid during the years ended December 31:				
Interest, net of amounts capitalized	$	2,457	$	2,660
Income taxes paid (refunded), net	$	8,360	$	(5,343)

Of the income taxes paid (refunded), substantially all were paid (refunded) to AGR under the tax sharing agreement. Interest capitalized was $0.1 million in 2022 and 2021. Accrued liabilities for utility plant additions were $4.1 million at December 31, 2022 and $1.3 million at December 31, 2021.

***Trade receivables and unbilled revenue, net of allowance for credit losses*:** We record trade receivables at amounts billed to customers and we record unbilled revenues based on an estimate of energy delivered or services provided to customers. The estimates for unbilled revenues are determined based on various assumptions, including current month energy load requirements, billing rates by customer class and delivery loss factors. Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

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

Trade receivables at December 31 include unbilled revenues of $9.0 million for 2022 and $7.2 million for 2021, and are shown net of an allowance for credit losses at December 31 of $3.6 million for 2022 and $3.2 million for 2021. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $1.6 million in 2022 and $1.0 million in 2021.

We establish our allowance for credit losses, including for unbilled revenue (also referred to as contract assets), by using both historical average loss percentages to project future losses, and by establishing a specific allowance for known credit issues or for specific items not considered in the historical average calculation. We also consider whether we need to adjust historical loss rates to reflect the effects of current conditions and forecasted changes considering various economic indicators (e.g., Gross Domestic Product, Personal Income, Consumer Price Index, Unemployment Rate) over the contractual life of the trade receivables. We write off amounts when we have exhausted reasonable collection efforts.

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

Gas in storage: We own natural gas that is stored in third-party owned underground storage facilities, which we record as inventory. We price injections of inventory into storage at the market purchase cost at the time of injection, and price withdrawals of working gas from storage at the weighted-average cost in storage. We continuously monitor the weighted-average cost of gas value to ensure it remains at the lower of cost and net realizable value. We report inventories to support gas operations on our balance sheets within “Fuel and natural gas in storage.”

Materials and supplies: Materials and supplies inventories that are used for construction of new facilities and repairs of existing facilities. These inventories are carried and withdrawn at the lower of cost and net realizable value and reported on our balance sheets within “Materials and supplies.” We combine inventory items for the statement of cash flow presentation purposes.

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

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

There were no government grants recorded as of December 31, 2022 and 2021.

Deferred income: Apart from government grants, we occasionally receive revenues from transactions in advance of the resulting performance obligations arising from the transaction. It is our policy to defer such revenues on our balance sheets and amortize them to earnings when revenue recognition criteria are met.

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

Environmental remediation liability**:** In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. We record our environmental liabilities on an undiscounted basis. We expect to pay our environmental liability accruals through the year 2028.

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

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

We account for defined benefit pension or other postretirement plans, recognizing an asset or liability for the overfunded or underfunded plan status. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. We generally reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in OCI, as management believes it is probable that such items will be recoverable through the ratemaking process. Certain non-qualified plan expenses are not recoverable through the ratemaking process and we present the unrecognized prior service costs and credits and unrecognized actuarial gains and losses in accumulated other comprehensive loss. If a plan meets settlement or curtailment accounting criteria, we recognize a regulatory asset or liability if these costs are probable of recovery from ratepayers.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 employees active on the date of the amendment. Effective March 31, 2022, the amortization period for prior service cost changes for the Berkshire Non-Union Plan was updated from average remaining service to future expected lifetime as the plan was frozen, or predominantly frozen, to future accruals. We amortize unrecognized actuarial gains and losses in excess of 10% of the greater of PBO or market-related value of assets (MRVA) related to the pension and other postretirement benefits plans on straight line basis over future working lifetime. Effective March 31, 2022, the amortization period for the Berkshire Non-Union Plan was updated from future working lifetime to future expected lifetime as the plan was frozen, or predominantly frozen, to future accruals. Our policy is to calculate the expected return on plan assets using the market-related value of assets. We determine that value by recognizing the difference between actual returns and expected returns over a five-year period.

Income taxes**:** In August 2022, the Inflation Reduction Act of 2022 ("IRA") was signed into law in the United States. The IRA created a new corporate alternative minimum tax ("CAMT") of 15% on adjusted financial statement income and an excise tax of 1% on the value of certain stock repurchases. Based on initial guidance, Berkshire currently expects to be subject to the CAMT starting in 2023 but does not expect it to have a material impact on earnings, financial condition, or cash flow. Given the complexity and uncertainty around the applicability of the legislation to our specific facts and circumstances, the company continues to analyze the IRA provisions while waiting on pending Department of Treasury regulatory guidance.

AGR, the parent company of Networks, files a consolidated federal income tax return and various state income tax returns, some of which are unitary as required or permitted, including all of the activities of its subsidiaries. Each subsidiary company is treated as a member of the consolidated group and determines its current and deferred taxes based on the separate return with benefits for loss method. As a member, Berkshire 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 $2.5 million for 2022, and the aggregate amount of the related party income tax payable due to AGR is $7.3 million for 2021.

We use the asset and liability method of accounting for income taxes. Deferred tax assets and liabilities reflect the expected future tax consequences, based on enacted tax laws, of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts. In accordance with U.S. GAAP for regulated industries, we have established regulatory assets for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences. We defer the investment tax credits when earned and amortize them over the estimated lives of the related assets. We also recognize the income tax consequences of intra-entity transfers of assets other than inventory when the transfer occurs. We had no intra-entity transfers of assets other than inventory during the years ended December 31, 2022 and 2021.

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

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

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

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the statements of income.

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

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

Adoption of New Accounting Pronouncements

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

There have been no new accounting pronouncements adopted as of December 31, 2022.

Accounting Pronouncements Issued But Not Yet Adopted

There have been no new accounting pronouncements issued but not yet adopted that are expected to have a material effect on our 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 credit losses and unbilled revenues; (2) asset impairments; (3) investments in equity instruments; (4) depreciable lives of assets; (5) income tax valuation allowances; (6) uncertain tax positions; (7) reserves for professional, workers' compensation, and comprehensive general insurance liability risks; (8) contingency and litigation reserves; (9) earnings sharing mechanism (ESM); (10) environmental remediation liabilities; (11) pension and other postretirement employee benefits (OPEB); and (12) fair value measurements. 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 75% 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

Rates

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

Berkshire's rates are established by the DPU. On January 18, 2019, the DPU approved new distribution rates for Berkshire. The distribution rate increase was based on an ROE of 9.70% and 54.0% equity ratio. The new tariffs provided for the implementation of a revenue decoupling mechanism and pension expense tracker and also provide that Berkshire will not file to change base distribution rates to become effective before November 1, 2021. During the second quarter of 2022, Berkshire and the Mass AG reached an agreement with respect to Berkshire's proposed base distribution rate case. The Settlement Agreement was filed with the DPU on June 24, 2022, DPU-22-20. On January 4, 2023, Berkshire received approval from the DPU of new base rates to be effective January 1, 2023.

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.

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. Berkshire also owns or has rights to the propane stored in its on-system propane facilities, which are also directly connected to its distribution system.

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 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 $15.9 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.

Regulatory assets at December 31, 2022 and 2021 consisted of:

December 31,		**2022**		**2021**
(Thousands)				
Deferred purchased gas	$	9,038	$	9,486
Energy efficiency programs		518		1,820
Environmental remediation costs		4,748		5,104
Pension and other postretirement benefits		14,466		16,942
Recoverable bad debt		1,537		1,196
Revenue decoupling mechanism		1,731		2,385
Unfunded future income taxes		597		482
Other		2,133		1,358
Total regulatory assets		**34,768**		**38,773**
Less: current portion		14,653		15,916
Total non-current regulatory assets	**$**	**20,115**	**$**	**22,857**

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

Energy efficiency programs represent all expenditures for a twelve month period as contained in the Company's Energy Efficiency (EE) budgets as defined and approved by the Department, including, but not limited to, Energy Efficiency Program Costs, Reconciliation Adjustments, Energy Efficiency Lost Margins, Energy Efficiency Performance Incentives, Working Capital and Interest. At the end of each twelve-month period, the Company will include the Reconciliation Adjustment associated with over- or under-recoveries of allowable EE Expenditures billed over the prior twelve-month period. Pursuant to the Department's approved Energy Efficiency Guidelines, estimated lost margins and performance incentives approved in the Company's Plan may be collected during the term of the Plan and shall be reconciled at the end of the term in the Company's Term Report.

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.

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.

Recoverable bad debt represents the portion of uncollectible expense attributable to gas costs.

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

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

Other includes items such as rate case cost and system expansion.

Regulatory liabilities at December 31, 2022 and 2021 consisted of:

December 31,		2022		2021
(Thousands)				
Asset removal obligations	$	39,146	$	38,117
Pension and other postretirement benefits		1,330		1,082
Tax Act – remeasurement		11,242		12,709
Other		106		198
Total regulatory assets		**51,824**		**52,106**
Less: current portion		—		198
Total non-current regulatory assets	**$**	**51,824**	**$**	**51,908**

Asset 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.

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.

Other includes items such as accumulated deferred investment tax credits.

Note 4. Revenue

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

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

Berkshire derives revenue primarily from tariff-based sales of natural gas delivered to customers. For such revenues, Berkshire recognize 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.

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

Berkshire also has various other sources of revenue including billing, collection, other administrative charges, sundry billings, rent of utility property, and miscellaneous revenue. They classify 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 for the years ended December 31, 2022 and 2021 are as follows:

Years Ended December 31,		**2022**		**2021**
(Thousands)				
Regulated operations – natural gas	$	98,469	$	82,557
Other (a)		125		12
Revenue from contracts with customers		**98,594**		**82,569**
Leasing revenue		1,044		956
Alternative revenue programs		2,105		1,918
Other revenue		14		22
Total operating revenues	**$**	**101,757**	**$**	**85,465**

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

Note 5. Goodwill

We do not amortize goodwill, but perform our annual impairment assessment testing at least annually as described in Note 1, in the fourth quarter, as of October 1. Our qualitative assessment involves evaluating key events and circumstances that could affect the fair value of our company, as well as other factors. Events and circumstances evaluated include macroeconomic conditions, industry, regulatory and market considerations, cost factors and their effect on earnings and cash flows, overall financial performance as compared with projected results and actual results of relevant prior periods, other relevant entity-specific events, and events affecting Berkshire.

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

We had no impairment of goodwill in 2022 and 2021 as a result of our qualitative impairment testing. There were no events or circumstances subsequent to our annual impairment assessment for 2022 or 2021 that required us to update the assessment.

The carrying amount of goodwill, which resulted from the purchase of Berkshire by UIL Holdings in 2010, was $51.9 million at both December 31, 2022 and 2021, with no accumulated impairment losses and no changes during 2022 and 2021.

Note 6. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,		**2022**		**2021**
(Thousands)				
Current				
Federal	$	(2,200)	$	2,371
State		(353)		607
Current taxes charged to (benefit) expense		**(2,553)**		**2,978**
Deferred				
Federal		2,202		(1,841)
State		913		(258)
Deferred taxes charged to expense (benefit)		**3,115**		**(2,099)**
Total Income Tax Expense	**$**	**562**	**$**	**879**

The differences between tax expense per the statements of income and tax expense at the 21% statutory federal tax rate for the years ended December 31, 2022 and 2021, respectively, consisted of:

Years Ended December 31,		2022		2021
(Thousands)				
Tax expense at federal statutory rate	$	1,399	$	1,101
Excess ADIT amortization		(838)		(838)
State tax expense, net of federal benefit		442		275
Other, net		(442)		341
Total Income Tax Expense	**$**	**562**	**$**	**879**

Income tax expense for the year ended December 31, 2022 was $0.8 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to excess ADIT amortization, partially offset by state tax expense. This resulted in an effective tax rate of 8.4%. Income tax expense for the year ended December 31, 2021 was $0.22 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to state taxes. This resulted in an effective tax rate of 16.8%.

Deferred tax assets and liabilities as of December 31, 2022 and 2021 consisted of:

December 31,		2022		2021
(Thousands)				
Non-current Deferred Income Tax Liabilities (Assets)				
Property related	$	33,138	$	30,230
Deferred gas and other deferred charges		(1,748)		1,884
2017 Tax Act measurement		(3,071)		(3,701)
Federal and state net operating loss		(2,399)		(1,212)
Pension and other postretirement benefits		223		43
Gas supply charges		2,889		2,592
Other		1,351		(3,033)
Total Non-current Deferred Income Tax Liabilities	**$**	**30,383**	**$**	**26,803**
Deferred tax assets		7,218		7,946
Deferred tax liabilities		37,601		34,749
Net Accumulated Deferred Income Tax Liabilities	**$**	**30,383**	**$**	**26,803**

Berkshire has federal net operating losses of $1.8 million and $1.2 million for the years ended December 31, 2022 and 2021, respectively. Berkshire has net Massachusetts state net operating losses of $0.6 million for the year ended December 31, 2022. Berkshire had no state net operating losses for the year ended December 31, 2021.

There were no additional accruals for interest and penalties on tax reserves as of December 31, 2022 and December 31, 2021.

Note 7. Long-term Debt

Long-term debt as of December 31, 2022 and 2021 consisted of:

December 31,		2022		2021	
(Thousands, except interest rates)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
Senior unsecured notes	2029-2050	$ 60,000	3.68%-5.33%	$ 60,000	3.68%-5.33%
Unamortized debt issuance cost and discount		(405)		(453)	
Total Debt		**59,595**		**59,547**	
Less: debt due within one year, included in current liabilities		—		—	
Total Non-current Debt		**$ 59,595**		**$ 59,547**	

We have no long-term debt, including sinking fund obligations, due during the next five years.

We have no financial debt covenant requirements related to our long-term debt at December 31, 2022 and 2021.

Note 8. Bank Loans and Other Borrowings

Berkshire had $9.7 million notes payable as of December 31, 2022 and no notes payable outstanding as of December 31, 2021. 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 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. Berkshire has a lending/ borrowing limit of $15 million under this agreement. Berkshire had $9.7 million outstanding under this agreement as of December 31, 2022 and no debt outstanding as of December 31, 2021.

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. Berkshire had no debt outstanding under this agreement as of December 31, 2022 and 2021.

On November 23, 2021, AGR and its investment-grade rated utility subsidiaries (New York State Electric and Gas Corporation ("NYSEG"), Rochester Gas and Electric Corporation ("RG&E"), Central Maine Power Company ("CMP"), The United Illuminating Company ("UI"), Connecticut Natural Gas Corporation ("CNG"), The Southern Connecticut Gas Company ("SCG") and The Berkshire Gas Company ("BGC")) executed a new credit facility with an aggregate limit of $3,575 million and a termination date of November 23, 2026.

Under the terms of the Avangrid Credit Facility, each borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit contained in the agreement. NYSEG has a maximum sublimit of $700 million, RG&E has $300 million, CMP has $200 million and UI has a maximum sublimit of $250 million, CNG and SCG have maximum sublimits of $150 million, and BGC has a maximum sublimit of $50 million. Effective on November 23, 2021, the AGR Credit

Facility was amended to increase AGR's maximum sublimit to $2,500 million and to establish minimum sublimits of $500 million for NYSEG, $200 million for RG&E, $100 million for CMP, $150 million for UI, $50 million for CNG and SCG, and $25 million for BGC. Under the AGR Credit Facility, each of the borrowers are charged a facility fee that is dependent on their credit rating. The facility fees range from 10.0 to 22.5 basis points Berkshire had not borrowed under this agreement as of both December 31, 2022 and 2021.

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 0.33 to 1.00 at December 31, 2022. We are not in default as of December 31, 2022.

Note 9. Leases

We have operating leases for land rights. As of December 31, 2022 and 2021, we had no finance leases. Certain of our lease agreements include rental payments adjusted periodically for inflation or are based on other periodic input measures. Our leases do not contain any material residual value guarantees or material restrictive covenants. Our leases have remaining lease terms of 1 year to 15 years, some of which may include options to terminate the leases within one year. We consider extension or termination options in the lease term if it is reasonably certain we will exercise the option.

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

For the Years Ended December 31,	**2022**	**2021**
(Thousands)		
Lease cost		
Operating lease cost	$ 9	$ 4
Short-term lease cost	38	64
Total lease cost	**$ 47**	**$ 68**

Balance sheet and other information for the years ended December 31, 2022 and 2021 was as follows:

As of December 31,		2022		2021
(Thousands, except lease term and discount rate)				
Operating Leases				
Operating lease right-of-use assets	$	105	$	141
Operating lease liabilities, current		7		6
Operating lease liabilities, long-term		96		133
Total operating lease liabilities	$	103	$	139
Weighted-average Remaining Lease Term (years):				
Operating leases		12.93		13.50
Weighted-average Discount Rate:				
Operating leases		2.46 %		2.50 %

Supplemental cash flows information related to leases was as follows:

For the Years Ended December 31,		2022		2021
(Thousands)				
Cash paid for amounts included in the measurement of lease liabilities:				
Operating cash flows from operating leases	$	8	$	6
Right-of-use assets obtained in exchange for lease obligations:				
Operating leases	$	(29)	$	—

As of December 31, 2022, maturities of lease liabilities were as follows:

		Operating Leases
(Thousands)		
Years ending December 31,		
2023	$	8
2024		8
2025		9
2026		9
2027		9
Thereafter		78
Total lease payments		**121**
Less: imputed interest		(18)
Total	**$**	**103**

Most of our leases do not provide an implicit rate in the lease; thus we use our incremental borrowing rate based on the information available at the commencement date in determining the present value of lease payments.

Note 10. 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 natural gas service.

Manufactured gas plants

We own or have 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. We have 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, 2022 and no amount of loss, if any, can be reasonably estimated at this time. In the past, we have 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.

We own 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, 2022. Historically, we have received approval from the DPU for recovery of environmental expenses in its customer rates.

We 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. We 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, we reached a settlement with GE which provides, among other things, a framework for us and GE to allocate various monitoring and remediation costs at the East Street Site. As of December 31, 2022, we have accrued approximately $2.2 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, we have received approval from the DPU for recovery of remediation expenses in its customer rates.

Our environmental liabilities are recorded on an undiscounted basis and are expected to be paid through the year 2028.

Note 11. Fair Value of Financial Instruments and Fair Value Measurements

The estimated fair value of debt amounted to $51 million as of December 31, 2022 and $70 million as of December 31, 2021. 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 financial instruments measured at fair value as of December 31, 2022 and 2021 consisted of:

Description	Level 1	Level 2	Level 3	Total
(Thousands)				
2022				
Assets				
Non-current investments	$ 1,990			$ 1,990
Total	**$ 1,990**	**$ —**	**$ —**	**$ 1,990**
2021				
Assets				
Non-current investments	$ 2,179	$ —	$ —	$ 2,179
Total	**$ 2,179**	**$ —**	**$ —**	**$ 2,179**

We had no transfers to or from Level 1 and 2 during the year ended December 31, 2022. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

Valuation techniques: We measure the fair value of our non-current investments available for sale using quoted market prices in active markets for identical assets and include the measurements in Level 1. The investments which are Rabbi Trusts for deferred compensation plans primarily consist of money market funds.

Note 12. Post-retirement and Similar Obligations

We have multiple qualified pension plans covering eligible union and management employees and retirees. The union plans are all closed to new hires, and the non-union plans were closed as of December 31, 2017. The qualified pension plans are traditional defined benefit plans or cash balance plans for those hired on or after specified dates.

Berkshire 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 totaled approximately $0.9 million in 2022 and $0.7 million in 2021.

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

Non-Qualified Retirement Benefit Plans

We also sponsor various unfunded pension plans for certain current employees, former employees and former directors. The total liability for these plans, which is included in other non-current liabilities on our balance sheets, was $1.1 million and $1.4 million at December 31, 2022 and 2021, respectively.

Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2022 and 2021 consisted of:

As of December 31,	Pension Benefits 2022	Pension Benefits 2021	Postretirement Benefits 2022	Postretirement Benefits 2021
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	$ 54,066	$ 59,395	$ 1,947	$ 2,361
Service cost	708	947	35	49
Interest cost	1,696	1,487	49	45
Curtailments	(1,730)	(1,306)	—	—
Settlements	(2,507)	—	—	—
Actuarial gain	(10,953)	(2,763)	(356)	(374)
Benefits paid	(3,594)	(3,694)	(3)	(134)
Benefit obligation at December 31	**$ 37,686**	**$ 54,066**	**$ 1,672**	**$ 1,947**
Change in plan assets				
Fair value of plan assets at January 1	40,541	41,902	—	—
Actual return on plan assets	(8,283)	3,399	—	—
Employer contributions	522	240	3	134
Settlements	(2,507)	(1,306)	—	—
Benefits paid	(3,594)	(3,694)	(3)	(134)
Fair value of plan assets at December 31	**$ 26,679**	**$ 40,541**	**$ —**	**$ —**
Funded status	**$ (11,007)**	**$ (13,525)**	**$ (1,672)**	**$ (1,947)**

During 2022, the pension benefit obligation had an actuarial gain of $11.0 million, primarily due to a $10.6 million gain from increases in discount rates. In 2022, the pension benefit obligation had a reduction of $2.5 million from settlements and $1.7 million from curtailments. The settlements were lump-sum payments made within the pension plan guidelines at the discretion of the plan participants who opted to retire. The curtailments were driven by a Company decision to freeze pension benefit accruals and contribution credits for non-union employees and transition their retirement benefits to a 401(k) plan. There were no significant gains or losses relating to the postretirement benefit obligations in 2022.

During 2021, the pension benefit obligation had an actuarial gain of $2.8 million, primarily due to a $2.8 million gain from increases in discount rates. There were no significant gains or losses relating to the postretirement benefit obligations.

Amounts recognized in the balance sheet as of December 31, 2022 and 2021 consisted of:

December 31,	Pension Benefits 2022	Pension Benefits 2021	Postretirement Benefits 2022	Postretirement Benefits 2021
(Thousands)				
Other current liabilities	$ —	$ —	$ (168)	$ (142)
Pension and other postretirement benefits	(11,007)	(13,525)	(1,504)	(1,805)
Total	**$ (11,007)**	**$ (13,525)**	**$ (1,672)**	**$ (1,947)**

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 2022	Pension Benefits 2021	Postretirement Benefits 2022	Postretirement Benefits 2021
(Thousands)				
Net loss (gain)	$ 4,950	$ 7,198	$ (1,330)	$ (1,082)
Prior service cost	—	1	—	—

Our accumulated benefit obligation for all qualified defined benefit pension plans was $37.2 million at December 31, 2022 and $50.7 million at December 31, 2021.

The projected benefit obligation and the accumulated benefit obligation exceeded the fair value of pension plan assets for all of our qualified plans as of both December 31, 2022 and 2021. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets of our plans as of December 31, 2022 and 2021.

December 31,	2022	2021
(Thousands)		
Projected benefit obligation	$ 37,686	$ 54,066
Accumulated benefit obligation	$ 37,182	$ 50,706
Fair value of plan assets	$ 26,679	$ 40,541

The postretirement benefits obligation for all qualified plans exceeded the fair value of plan assets as of December 31, 2022 and 2021.

Components of net periodic benefit cost and other changes in plan assets and benefit obligations recognized in income and regulatory assets and liabilities for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,	Pension Benefits 2022	Pension Benefits 2021	Postretirement Benefits 2022	Postretirement Benefits 2021
(Thousands)				
Net periodic benefit cost				
Service cost	$ 708	$ 947	$ 35	$ 49
Interest cost	1,696	1,487	49	45
Expected return on plan assets	(2,444)	(2,903)	—	—
Amortization of actuarial loss (gain)	132	880	(108)	(79)
Settlement charge	159	98	—	—
Net periodic benefit cost	**$ 251**	**$ 509**	**$ (24)**	**$ 15**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net gain	$ (225)	$ (3,260)	$ (356)	$ (373)
Amortization of actuarial (loss) gain	(132)	(880)	108	79
Curtailment charge	(1,731)	—	—	—
Settlement charge	(159)	(98)	—	—
Total recognized in regulatory assets and regulatory liabilities	**(2,247)**	**(4,238)**	**(248)**	**(294)**
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$ (1,996)**	**$ (3,729)**	**$ (272)**	**$ (279)**

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

The weighted-average assumptions used to determine benefit obligations as of December 31, 2022 and 2021 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2022**	**2021**	**2022**	**2021**
Discount rate	5.21%	2.96%	5.08%	2.61%
Rate of compensation increase	N/A / 2.50%	3.50% / 2.50%	N/A	N/A
Interest crediting rate	4.48% / N/A	2.00% / N/A	N/A	N/A

The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rate by developing a yield curve derived from a portfolio of high grade non-callable bonds with above median yields that closely matches the duration of the expected cash flows of our benefit obligations.

The weighted-average assumptions used to determine net periodic benefit cost for the years ended December 31, 2022 and 2021 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2022**	**2021**	**2022**	**2021**
Discount rate	2.96% / 4.15%	2.56%	2.61%	2.00%
Expected long-term return on plan assets	7.00%	7.00%	N/A	N/A
Rate of compensation increase	3.50% / N/A / 2.50%	3.50% / 2.50%	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 in excess of 10% of the greater of PBO or MRVA related to the pension and other postretirement benefits plans on straight line basis over future working lifetime. Effective March 31, 2022, the amortization period for the Berkshire Non-Union Plan was updated from future working lifetime to future expected lifetime as the plan was frozen, or predominantly frozen, to future accruals.

Assumed health care cost trend rates used to determine benefit obligations as of December 31, 2022 and 2021 consisted of:

As of December 31,	**2022**	**2021**
Health care cost trend rate (pre 65/post 65)	6.00% / 6.50%	6.25% / 7.00%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	4.50% / 4.50%	4.50% / 4.50%
Year that the rate reaches the ultimate trend rate	2029 / 2027	2029 / 2027

Contributions: In accordance with our funding policy, we make annual contributions of not less than the minimum required by applicable regulations. We expect to contribute $0.2 million to both our pension and other postretirement benefit plans during 2023.

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)			
2023	$ 3,826	$ 168	$ —
2024	$ 3,009	$ 179	$ —
2025	$ 3,152	$ 211	$ —
2026	$ 3,059	$ 198	$ —
2027	$ 2,881	$ 198	$ —
2028 - 2032	$ 13,894	$ 629	$ —

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

The asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets within broad categories of asset classes made up of Return-Seeking and Liability-Hedging investments. We have targets of 25%-60% for Return-Seeking assets and 40%-75% for Liability-Hedging assets. Return-Seeking investments generally consist of domestic, international, global, and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking assets also include investments in real estate, global asset allocation strategies and hedge funds. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS, and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of pension benefits plan assets, by asset category, as of December 31, 2022, consisted of:

Asset Category	Total	Fair Value Measurements at December 31, Using Level 1	Level 2	Level 3
(Thousands)				
2022				
Cash and cash equivalents	$ 1,240	$ 3	$ 1,237	$ —
U.S. government securities	1,395	1,395	—	—
Common stocks	1,156	1,156	—	—
Registered investment companies	1,290	1,290	—	—
Corporate bonds	7,026	—	7,026	—
Preferred stocks	7	7	—	—
Common collective trusts	9,528	—	9,528	—
Other investments, principally annuity and fixed income	92	—	92	—
	$ 21,734	**$ 3,851**	**$ 17,883**	**$ —**
Other investments measured at net asset value	4,945			
Total	**$ 26,679**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2021, consisted of:

Asset Category	Total	Fair Value Measurements at December 31, Using Level 1	Level 2	Level 3
(Thousands)				
2021				
Cash and cash equivalents	$ 944	$ 181	$ 763	$ —
U.S. government securities	2,224	2,224	—	—
Common stocks	1,845	1,845	—	—
Registered investment companies	3,828	3,828	—	—
Corporate bonds	10,665	—	10,665	—
Preferred stocks	12	12	—	—
Common collective trusts	13,641	—	13,641	—
Other investments, principally annuity and fixed income	262	—	262	—
	$ 33,421	**$ 8,090**	**$ 25,331**	**$ —**
Other investments measured at net asset value	7,120			
Total	**$ 40,541**			

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, 2022 and 2021.

Note 13. Other Income and Other Deductions

Other income and deductions for the years ended December 31, 2022 and 2021, consisted of:

Years Ended December 31,		**2022**		**2021**
(Thousands)				
Allowance for funds used during construction	$	5	$	79
Carrying costs on regulatory assets		774		369
Interest and dividend income		84		90
Miscellaneous		(4)		1
Total other income	**$**	**859**	**$**	**539**
Pension non-service components		(414)		(962)
Miscellaneous		(558)		(1,240)
Total other deductions	**$**	**(972)**	**$**	**(2,202)**

Note 14. Related Party Transactions

Certain Networks subsidiaries borrow from AGR, the parent of Networks, through intercompany revolving credit agreements, including Berkshire. For Berkshire the intercompany revolving credit agreements provide access to supplemental liquidity. See Note 8 for further detail on the credit facility with AGR.

Avangrid Service Company provides administrative and management services to Networks operating utilities, including Berkshire, 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 services provided to Berkshire by AGR and its affiliates was approximately $4.9 million in 2022 and $4.3 million in 2021. Cost for services was primarily recorded as operations and maintenance expense for both years. The charge for services provided by Berkshire to AGR and its subsidiaries was approximately $0.1 million in 2022. There were no charges for services provided by Berkshire to AGR in 2021. 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 balances in accounts payable to affiliates of $1.0 million at December 31, 2022 and $0.8 million at December 31, 2021 are mostly payable to UIL Holdings and Avangrid Service Company.

Note 15. Subsequent Events

The company has performed a review of subsequent events through March 31, 2023, which is the date these financial statements were available to be issued.

Rochester Gas and Electric Corporation

Financial Statements

As of and for the Years Ended December 31, 2022 and 2021

Rochester Gas and Electric Corporation

Index

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

Independent Auditors' Report

Stockholder and The Board of Directors
Rochester Gas and Electric Corporation:

Opinion

We have audited the financial statements of Rochester Gas and Electric Corporation (the Company), which comprise the balance sheets as of December 31, 2022 and 2021, 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.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

Basis for Opinion

We conducted our audits in accordance with auditing standards generally accepted in the United States of America (GAAS). Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with U.S. generally accepted accounting principles, and for 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.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for one year after the date that the financial statements are issued.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control related matters that we identified during the audit.

KPMG LLP

New York, New York
March 22, 2023

Rochester Gas and Electric Corporation
Statements of Income

Years Ended December 31,	2022	2021
(Thousands)		
Operating Revenues	$ 1,180,485	$ 957,789
Operating Expenses		
Electricity purchased	202,554	136,998
Natural gas purchased	173,509	103,875
Operations and maintenance	349,207	312,466
Depreciation and amortization	121,478	106,704
Taxes other than income taxes, net	149,796	144,145
Total Operating Expenses	996,544	804,188
Operating Income	183,941	153,601
Other income	18,388	18,521
Other deductions	(8,722)	(5,907)
Interest expense, net of capitalization	(42,641)	(43,898)
Income Before Tax	150,966	122,317
Income tax expense	28,395	19,433
Net Income	$ 122,571	$ 102,884

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

Rochester Gas and Electric Corporation
Statements of Comprehensive Income

Years Ended December 31,	2022	2021
(Thousands)		
Net Income	$ 122,571	$ 102,884
Other Comprehensive Income, Net of Tax		
Amortization of pension cost for non-qualified plans and current year actuarial gain, net of income tax	1,453	479
Unrealized gain during the period on derivatives qualifying as cash flow hedges, net of income tax	311	186
Reclassification to net income of gain on settled cash flow commodity hedges, net of income tax	(315)	(132)
Reclassification to net income of loss on settled cash flow treasury hedges, net of income tax	2,716	2,716
Other Comprehensive Income, Net of Tax	4,165	3,249
Comprehensive Income	$ 126,736	$ 106,133

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

Rochester Gas and Electric Corporation
Balance Sheets

As of December 31,	2022	2021
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$ 4	$ 3
Accounts receivable and unbilled revenues, net	231,159	171,416
Accounts receivable from affiliates	3,633	2,893
Fuel and natural gas in storage	35,302	13,903
Materials and supplies	19,668	16,871
Broker margin accounts	16,542	—
Income tax receivable	—	3,646
Prepaid property taxes	41,531	41,747
Regulatory assets	57,485	77,459
Other current assets	11,009	12,895
Total Current Assets	**416,333**	**340,833**
Utility plant, at original cost	5,099,925	4,762,539
Less accumulated depreciation	(1,296,550)	(1,202,628)
Net Utility Plant in Service	**3,803,375**	**3,559,911**
Construction work in progress	346,560	332,901
Total Utility Plant	**4,149,935**	**3,892,812**
Operating lease right of use assets	525	1,124
Regulatory and Other Assets		
Regulatory assets	402,941	377,240
Other	47,910	51,506
Total Regulatory and Other Assets	**450,851**	**428,746**
Total Assets	**$ 5,017,644**	**$ 4,663,515**

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

Rochester Gas and Electric Corporation
Balance Sheets

As of December 31,	2022	2021
(Thousands)		
Liabilities		
Current Liabilities		
Notes payable to affiliates	$ 76,300	$ 53,500
Accounts payable and accrued liabilities	258,994	238,380
Accounts payable to affiliates	54,091	48,383
Interest accrued	8,266	7,902
Taxes accrued	15,511	3,967
Operating lease liabilities	1,986	287
Environmental remediation costs	18,945	4,030
Regulatory liabilities	82,138	101,801
Other	65,804	52,376
Total Current Liabilities	**582,035**	**510,626**
Regulatory and Other Liabilities		
Regulatory liabilities	620,788	695,703
Other Non-current Liabilities		
Deferred income taxes	463,266	416,223
Nuclear plant obligations	131,336	129,414
Pension and other postretirement	91,103	109,979
Operating lease liabilities	100	2,253
Asset retirement obligations	2,312	2,430
Environmental remediation costs	83,043	95,604
Other	50,408	58,891
Total Regulatory and Other Liabilities	**1,442,356**	**1,510,497**
Non-current debt	1,489,902	1,366,168
Total Liabilities	**3,514,293**	**3,387,291**
Commitments and Contingencies		
Common Stock Equity		
Common stock ($5 par value, 50,000,000 shares authorized, 38,885,813 shares outstanding at December 31, 2022 and 2021)	194,429	194,429
Additional paid-in capital	1,080,703	855,312
Retained earnings	376,434	378,863
Accumulated other comprehensive loss	(30,977)	(35,142)
Treasury stock, at cost (4,379,300 shares at December 31, 2022 and 2021)	(117,238)	(117,238)
Total Common Stock Equity	**1,503,351**	**1,276,224**
Total Liabilities and Equity	**$ 5,017,644**	**$ 4,663,515**

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

Rochester Gas and Electric Corporation
Statements of Cash Flows

Years Ended December 31,	2022	2021
(Thousands)		
Cash Flow From Operating Activities:		
Net income	**$ 122,571**	**$ 102,884**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	121,478	106,704
Regulatory assets/liabilities amortization	21,643	(65,697)
Regulatory assets/liabilities carrying cost	1,213	2,833
Amortization of debt issuance costs	(1,812)	1,125
Deferred taxes	30,669	31,177
Pension cost	9,037	9,619
Stock-based compensation	420	231
Accretion expenses	128	135
Gain from disposal of property	(69)	(228)
Other non-cash items	(9,788)	(10,104)
Changes in operating assets and liabilities:		
Accounts receivable, from affiliates, and unbilled revenues	(60,483)	(23,227)
Inventories	(24,196)	(10,037)
Accounts payable, to affiliates, and accrued liabilities	(28,936)	86,702
Taxes accrued	15,190	25,540
Other assets/liabilities	26,282	18,558
Regulatory assets/liabilities	(149,919)	(3,060)
Net Cash Provided by Operating Activities	**73,428**	**273,155**
Cash Flow From Investing Activities:		
Capital expenditures	(352,922)	(435,551)
Contributions in aid of construction	35,809	20,243
Proceeds from sale of property, plant and equipment	1,073	1,215
Notes receivable from affiliates	—	19,200
Net Cash Used in Investing Activities	**(316,040)**	**(394,893)**
Cash Flow From Financing Activities:		
Non-current debt issuance	125,413	246,838
Repayments of non-current debt	—	(125,000)
Repayments of finance leases	(5,600)	(3,598)
Notes payable to affiliates	22,800	53,500
Capital contributions	225,000	200,000
Dividends paid	(125,000)	(250,000)
Net Cash Provided by Financing Activities	**242,613**	**121,740**
Net Increase in Cash and Cash Equivalents	**1**	**2**
Cash and Cash Equivalents, Beginning of Period	**3**	**1**
Cash and Cash Equivalents, End of Period	**$ 4**	**$ 3**

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 Loss		Treasury Stock		Total Common Stock Equity
Balance, December 31, 2020	**38,885,813**	**$**	**194,429**	**$**	**655,111**	**$**	**525,979**	**$**	**(38,391)**	**$**	**(117,238)**	**$**	**1,219,890**
Net income	—		—		—		102,884		—		—		102,884
Other comprehensive income, net of tax	—		—		—		—		3,249		—		3,249
Comprehensive income													106,133
Stock-based compensation	—		—		201		—		—		—		201
Common stock dividends	—		—		—		(250,000)		—		—		(250,000)
Capital contributions	—		—		200,000		—		—				200,000
Balance, December 31, 2021	**38,885,813**	**$**	**194,429**	**$**	**855,312**	**$**	**378,863**	**$**	**(35,142)**	**$**	**(117,238)**	**$**	**1,276,224**
Net income	—		—		—		122,571		—		—		122,571
Other comprehensive income, net of tax	—		—		—		—		4,165		—		4,165
Comprehensive income													126,736
Stock-based compensation	—		—		391		—		—		—		391
Common stock dividends	—		—		—		(125,000)		—		—		(125,000)
Capital contributions	—		—		225,000		—		—		—		225,000
Balance, December 31, 2022	**38,885,813**	**$**	**194,429**	**$**	**1,080,703**	**$**	**376,434**	**$**	**(30,977)**	**$**	**(117,238)**	**$**	**1,503,351**

(*) Par value of share amounts is $5

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

Notes to Financial Statements

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

***Background and nature of operations*:** Rochester Gas and Electric Corporation (RG&E, the company, we, our, us), conducts regulated electricity transmission, distribution, and generation operations and regulated natural gas transportation and distribution operations in western New York. RG&E generates electricity from hydroelectric stations. RG&E serves approximately 390,500 electricity and 322,900 natural gas customers as of December 31, 2022, in its service territory of approximately 2,700 square miles. The service territory contains a substantial suburban area and a large agricultural area in parts of nine counties including and surrounding the city of Rochester, New York with a population of approximately one million people. We operate under the authority of the New York State Public Service Commission (NYPSC) and are also subject to regulation by the Federal Energy Regulatory Commission (FERC).

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

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

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

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

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

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

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

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

We transfer assets from “Construction work in progress” to “Utility plant” when they are available for service.

We determine depreciation expense for utility plant in service using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Consistent with FERC accounting requirements, we charge the original cost of utility plant retired or otherwise disposed of to accumulated depreciation. Our composite rates for depreciation were 2.3% of average depreciable property for 2022 and 2.2% for 2021. We amortize our capitalized software cost, which is included in common plant, using the straight-line method, based on useful lives of 7 to 37 years. Capitalized software costs were approximately $167.0 million as of December 31, 2022 and $155.3 million as of December 31, 2021. Depreciation expense was $114.8 million in 2022 and $101.9 million in 2021. Amortization of capitalized software was $6.6 million in 2022 and $4.8 million in 2021.

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

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

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

Utility Plant	**Estimated useful life range (years)**		**2022**		**2021**
(thousands)					
Electric	2-90	$	3,382,030	$	3,161,156
Natural Gas	7-80		1,179,527		1,137,048
Common	3-60		538,368		464,335
Utility plant at original cost			**5,099,925**		**4,762,539**
Less accumulated depreciation			(1,296,550)		(1,202,628)
Net Utility Plant in Service			**3,803,375**		**3,559,911**
Construction work in progress			346,560		332,901
Total Utility Plant		**$**	**4,149,935**	**$**	**3,892,812**

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

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

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

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

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

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

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

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

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

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

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

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

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

Changes in conditions or the occurrence of unforeseen events could require discontinuance of the hedge accounting or could affect the timing of the reclassification of gains or losses on cash flow hedges from OCI into earnings. We record changes in the fair value of electric and natural gas hedge contracts to derivative assets or liabilities with an offset to regulatory assets or regulatory liabilities.

We offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement.

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

Concentration of risk: We maintain our cash and cash equivalents in accounts with major financial institutions in the form of demand deposits and money market accounts. Deposits in these financial institutions may exceed the amount of federal deposit insurance provided on such deposits.

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

		2022		2021
(Thousands)				
Cash paid during the years ended December 31:				
Interest, net of amounts capitalized	$	46,076	$	41,661
Income taxes refunded, net	$	(18,908)	$	(32,460)

Of the income taxes refunded, substantially all was refunded to AGR under the tax sharing agreement. Interest capitalized was $9.7 million in 2022 and $9.2 million in 2021. Accrued liabilities for utility plant additions were $41.0 million as of December 31, 2022 and $7.0 million as of December 31, 2021.

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

***Trade receivables and unbilled revenue, net of allowance for credit losses*:** We record trade receivables at amounts billed to customers and we record unbilled revenues based on an estimate of energy delivered or services provided to customers. The estimates for unbilled revenues are determined based on various assumptions, including current month energy load requirements, billing rates by customer class and delivery loss factors. Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

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

Trade receivables at December 31 include unbilled revenues of $69.8 million for 2022 and $60.6 million for 2021, and are shown net of an allowance for credit losses at December 31 of $37.2 million for 2022 and $46.7 million for 2021. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $34.9 million in 2022, including $31.2 million of arrears forgiveness balances that will be recovered through a tariff over the next 5 years. Credit loss expense was $17.0 million in 2021, with no arrears forgiveness balances.

Trade receivables include amounts due under deferred payment arrangements (DPAs). When a residential customer becomes delinquent in making payments, the NYPSC requires us to allow the customer to enter into a DPA to settle the account balance. A DPA allows the account balance to be paid in installments over an extended period without interest, which generally exceeds one year, by negotiating mutually acceptable payment terms. Generally, we must continue to serve a customer who cannot pay an account balance in full if the customer: (i) pays a reasonable portion of the balance; (ii) agrees to pay the balance in installments; and (iii) agrees to pay future bills within 30 days until the DPA is paid in full. Failure to make payments on a DPA results in the full amount of a receivable under a DPA being due. These accounts are part of the regular operating cycle and we classify them as short-term.

We establish our allowance for credit losses, including for unbilled revenue (also referred to as contract assets), by using both historical average loss percentages to project future losses, and by establishing a specific allowance for known credit issues or for specific items not considered in the historical average calculation. We also consider whether we need to adjust historical loss rates to reflect the effects of current conditions and forecasted changes considering various economic indicators (e.g., Gross Domestic Product, Personal Income, Consumer Price Index, Unemployment Rate) over the contractual life of the trade receivables. We write off amounts when we have exhausted reasonable collection efforts. The allowance for credit losses for DPAs at December 31 was $9.2 million in 2022 and $14.6 million in 2021. DPA receivable balances at December 31 were $19.1 million in 2022 and $22.0 million in 2021.

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

Inventory: Inventory comprises fuel and natural gas in storage and materials and supplies. We own natural gas that is stored in third-party owned underground storage facilities, which we record as inventory. We price injections of inventory into storage at the market purchase cost at the time of injection, and price withdrawals of working gas from storage at the weighted-average cost in storage. We continuously monitor the weighted-average cost of gas value to ensure it remains at the lower of cost and net realizable value. We report inventories to support gas operations on our balance sheets within “Fuel and natural gas in storage.”

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

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

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

In accounting for government grants related to operating and maintenance costs, we recognize amounts receivable as an offset to expenses in the statements of income in the period in which we incur the expenses.
The changes in government grants recorded as a reduction to the related utility plant as of December 31, 2022 and 2021 consisted of:

(Thousands)	Government grants	Total
As of December 31, 2020	**$ 18,252**	**$ 18,252**
Disposals	—	—
Recognized in income	(400)	(400)
As of December 31, 2021	**17,852**	**17,852**
Disposals	—	—
Recognized in income	(400)	(400)
As of December 31, 2022	**$ 17,452**	**$ 17,452**

We are required to comply with certain terms and conditions applicable to each grant and, if a disqualifying event should occur as specified in the grant's terms and conditions, we are required to repay the grant funds to the government. We believe we are in compliance with each grant's terms and conditions as of December 31, 2022 and 2021.

Deferred income: Apart from government grants, we occasionally receive revenues from transactions in advance of the resulting performance obligations arising from the transaction. It is our policy to defer such revenues on our balance sheets and amortize them to earnings when revenue recognition criteria are met.

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

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

The following table reconciles the beginning and ending aggregate carrying amount of the ARO, including our conditional ARO, for the years ended December 31, 2022 and 2021.

Years Ended December 31,	**2022**	**2021**
(Thousands)		
ARO, beginning of year	$ 2,430	$ 2,562
Liabilities settled during the year	(246)	(267)
Accretion expense	128	135
ARO, end of year	**$ 2,312**	**$ 2,430**

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

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

***Environmental remediation liability*:** In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. We record our environmental liabilities on an undiscounted basis. We expect to pay our environmental liability accruals through the year 2057.

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

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

We account for defined benefit pension or other postretirement plans, recognizing an asset or liability for the overfunded or underfunded plan status. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. We generally reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in OCI, as management believes it is probable that such items will be recoverable through the ratemaking process. Certain nonqualified plan expenses are not recoverable through the ratemaking process and we present the unrecognized prior service costs and credits and unrecognized actuarial gains and losses in accumulated other comprehensive loss. If a plan meets settlement or curtailment accounting criteria, we recognize a regulatory asset or liability if these costs are probable of recovery from ratepayers. 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 employees active on the date of the amendment. Prior service cost changes resulting from union bargaining agreements are amortized on a straight-line basis over the period from first recognition to the end of the bargaining agreement. We amortize unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans over 10 years from the time they are incurred as required by the NYPSC. Our policy is to calculate the expected return on plan assets using the market-related value of assets. We determine that value by recognizing the difference between actual returns and expected returns over a five-year period.

Income taxes**:** In August 2022, the Inflation Reduction Act of 2022 ("IRA") was signed into law in the United States. The IRA created a new corporate alternative minimum tax ("CAMT") of 15% on adjusted financial statement income and an excise tax of 1% on the value of certain stock repurchases. Based on initial guidance, RG&E currently expects to be subject to the CAMT starting in 2023 but does not expect it to have a material impact on earnings, financial condition, or cash flow. Given the complexity and uncertainty around the applicability of the legislation to our specific facts and circumstances, the company continues to analyze the IRA provisions while waiting on pending Department of Treasury regulatory guidance.

AGR, the parent company of Networks, files a consolidated federal income tax return and various state income tax returns, some of which are unitary as required or permitted, including all of the activities of its subsidiaries. Each subsidiary company is treated as a member of the consolidated group and determines its current and deferred taxes based on the separate return with benefits for loss method. As a member, 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 payable balance due to AGR at December 31, 2022 is $15.4 million. The aggregate amount of the related party income tax receivable balance due from AGR at December 31, 2021 is $3.6 million.

We use the asset and liability method of accounting for income taxes. Deferred tax assets and liabilities reflect the expected future tax consequences, based on enacted tax laws, of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts. In accordance with U.S. GAAP for regulated industries, we have established regulatory assets and liabilities for the net revenue requirements to be recovered from or refunded to customers for the related future tax expense or benefit associated with certain of these temporary differences. We defer the investment tax credits when earned and amortize them over the estimated lives of the related assets. We also recognize the income tax consequences of intra-entity transfers of assets other than inventory when the transfer occurs. We had no intra-entity transfers of assets other than inventory during the years ended December 31, 2022 and 2021.

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

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

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

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the statements of income.

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

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

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

Adoption of New Accounting Pronouncements

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

(a) Disclosures by business entities about government assistance

In November 2021, the FASB issued guidance that requires an entity to provide certain annual disclosures about government assistance received and accounted for by applying a grant or contribution accounting model by analogy. As the guidance is disclosure only, it did not have an impact to the consolidated financial results.

Accounting Pronouncements Issued But Not Yet Adopted

There have been no new accounting pronouncements issued but not yet adopted that are expected to have a material effect on our 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 credit losses and unbilled revenues; (2) asset impairments; (3) depreciable lives of assets; (4) income tax valuation allowances; (5) uncertain tax positions; (6) reserves for professional, workers' compensation, and comprehensive general insurance liability risks; (7) contingency and litigation reserves; (8) fair value measurements; (9) earnings sharing mechanisms; (10) environmental remediation liabilities; (11) AROs; and (12) pension and other postretirement employee benefits. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our financial statements will change as new events occur, as more experience is acquired, as additional information is obtained, and as our operating environment changes. We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside specialists to assist in our evaluations, as considered necessary. Actual results could differ from those estimates.

Union collective bargaining agreements: Approximately 46% 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 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, 2019, RG&E filed rate cases requesting increases in delivery revenues for both its electric and gas businesses. Other parties to the rate cases filed direct testimony on September 20, 2019, and RG&E filed rebuttal testimony on October 15, 2019. The Administrative Law Judges in the cases agreed to a series of extensions of the litigation schedule to allow the Company, the Department of Public Service Staff ("DPS Staff"), and other parties to enter into and conduct settlement discussions. A Joint Proposal for a three-year rate plan term was filed on June 22, 2020. A modified Joint Proposal was approved by the NYPSC on November 19, 2020, which included modifications to the electric business proposed rate increases to limit the projected total bill increases to 2% per year in consideration of the current COVID-driven economic climate. The effective date of new tariffs was December 1, 2020, with a make-whole provision back to April 17, 2020. The approved Joint Proposal includes several COVID-19 provisions, including the provision of up to $13.5 million in bill credits for the Company's most vulnerable residential and small business customers. The Joint Proposal bases delivery revenues on an 8.80% ROE and 48% equity ratio; however, for the proposed earnings sharing mechanism, the equity ratio is the lower of the actual equity ratio or 50%. The approved Joint Proposal was signed in whole or in part by more than 20 parties, and includes delivery rate increases (excluding the impact of moving energy efficiency costs from a surcharge to delivery rates) as summarized below:

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

The approved Joint Proposal also reflects increased distribution vegetation management, investments in aging infrastructure, the implementation of Advanced Metering Infrastructure (AMI), and increases in the Company's workforce, as well as continuation of many of the components of the last Joint Proposal described above. The rate plans continue the Rate adjustment mechanism (RAM) designed to return or collect certain defined reconciled revenues and costs, have new depreciation rates and continue RDMs for each business. The Proposal also continued reserve accounting for qualifying Major Storms ($3.4 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 approved Joint Proposal maintained 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 maintained 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 approved Joint Proposal established threshold performance levels for designated aspects of customer service quality and continues bill reduction and arrears forgiveness Low Income Programs. 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 approved Joint Proposal, RG&E continues the RAM, which is applicable to all customers, to return or collect RAM Eligible Deferrals and Costs, including: (1) property taxes; (2) Major Storm deferral balances; (3) gas leak prone pipe replacement; (4) REV costs and fees which are not covered by other recovery mechanisms; (5) COVID-19 bill credits; (6) certain Electric Vehicle program costs; and (7) Energy Efficiency and Heat Pump program costs in excess of what is included in delivery rates.

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

RG&E Rate Case Filing

On May 26, 2022, RG&E made an initial filing to the NYPSC requesting increases to the delivery rates for its electric business of 19.0% and for its gas business of 20.9%. This initial filing started a lengthy process guided by NYPSC regulations. The Department of Public Service Staff and other parties to the rate cases submitted testimony on September 26, 2022. On October 18, 2022, the Companies submitted rebuttal testimony responding to testimony of Department of Public Service Staff and other parties to the proceedings. On October 19, 2022, the Companies filed a notice of impending settlement negotiations. On November 2, 2022, the parties to the proceedings entered into confidential settlement discussions, which are expected to continue into the second quarter of 2023. The Company is seeking an order from the NYPSC related to the Company’s request in the second quarter of 2023.

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.

In 2015, the NYPSC issued an 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, as required and bi-annual updates of the DSIP on July 31, 2018 and June 30, 2020. The Joint Utilities requested an extension to December 30, 2022 for the next bi-annual update, which was granted by the Commission. An additional request for extension to June 30, 2023 was submitted by the Joint Utilities, which was subsequently granted by the Commission.

A Track 2 order was issued in May 2016 and included guidance related to the potential for Earnings Adjustment Mechanisms (EAMs), Platform Service Revenues, innovative rate designs, and data utilization and security EAMs were proposed in the companies' May 20, 2019 rate filing and approved by the Commission on November 19, 2020 in its Order approving the Companies' Rate Plan.

In March 2017, the NYPSC issued three separate REV-related orders. The three orders involve: 1) modifications to the electric utilities' proposed interconnection EAM framework; 2) further DSIP requirements, including the filing of an updated DSIP plan by mid-2018 and implementing two energy storage projects at RG&E by the end of 2018; and 3) Net Energy Metering Transition including implementation of Phase One of the VDER. RG&E 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 value-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 provided for a market transition consistent with the principles of gradualism and predictability and established a tranche system to manage impacts on non-participants.

The March 2017 Order also directed a Phase Two of the VDER proceeding. Phase Two would encompass improvements to the interim methodology established in Phase One, seek to expand Value Stack eligibility to technologies not included in Phase One, and review rate designs for mass market (i.e., residential and small non-residential) on-site DERs. Several orders were subsequently issued to further address VDER matters, which are summarized below.

- On April 18, 2019, the Commission issued an Order on Future Value Stack Compensation and Capacity Value Compensation. The Order established a new Community Credit in place of the Market Transition Credit for certain CDG projects in NYSEG's and RG&E's service territories and expanded eligibility for Phase One Net Metering for certain projects that have a rated capacity of 750 kW AC or lower. The changes became effective on June 1, 2019. On December 12, 2019, the NYPSC issued an Order Regarding Consolidated Billing For Community Distributed Generation. This Order led to CDG subscription charges being on the RG&E bill along with the CDG subscription credits, resulting in easier billing for customers and lower billing and service costs for CDG Hosts. Also on December 12, 2019, the NYPSC issued an Order on Value Stack Compensation for High-Capacity-Factor Resources, modifying the treatment of certain high-capacity-factor DER in the Value Stack compensation framework. The modification per the December 12, 2019 Order became effective February 1, 2020. On March 19, 2020, the Commission issued an additional Order regarding additional Value Stack Compensation. The new provisions per the March 19, 2020 Order became effective May 1, 2020. As eligible projects are interconnected, each project will receive MTC or Community Credit compensation for kWh produced, and the dollars provided to each project for this compensation will ultimately be collected from customers in a surcharge.

- On May 16, 2019, the Commission issued an Order on Standby and Buyback Service and Establishing Optional Demand Rates. The Order expands the availability of demand rates based on standby service rate design principles by requiring utilities to file tariffs to provide opt-in eligibility for all customers, including mass market (i.e., residential), to a demand-based rate option, irrespective of whether customers have on-site DERs. The availability of existing standby rates was expanded to all current demand-billed customers on an optional basis beginning July 1, 2019. A Commission Order was issued on March 16, 2022 adopting a new cost allocation methodology for standby and buyback service rates. Utilities were required to file draft tariff leaves by July 14, 2022, implementing the new methodology. Once approved, the rates will be required for customers with on-site generation, and available to all other customers on an optional basis, including residential customers. RG&E filed its draft tariffs on July 14, 2022. At this time, it is not known when the Commission will rule on the draft tariffs.

- On May 14, 2020, the Commission issued an Order extending and expanding distributed solar incentives. In addition to authorizing the extension of and additional funding for the NY-Sun program, the Commission modified certain program rules related to the NY-Sun program and the VDER policy. Tariffs implementing the above requirements became effective on September 1, 2021. The result of this Order reshaped an existing program and the impact to the Companies should be minimal.

- On July 16, 2020, the Commission issued an Order establishing a net metering successor tariff. The Order continues Phase One NEM for all eligible mass market and commercial projects under 750 kW interconnected after January 1, 2022 and implements a modest customer benefit contribution (CBC) for onsite DERs to address cost recovery of certain public benefit programs. Customers that install DERs interconnected after January 1, 2022 are charged a monthly per kW fee based on the nameplate rating of the DER. A final Commission Order was issued on August 13, 2021 implementing the CBC effective January 1, 2022 for new mass market net metering customers.

- On July 14, 2022 the Commission issued an Order approving remote crediting banking rules and addressing switching between CDG and remote crediting programs. The rules provide uniformity in the application of banking rules for the CDG, Net Crediting and Remote Crediting programs. The credits provided through these programs are recovered from other customers.

- On September 15, 2022 the Commission issued an Order to address ongoing issues associated with timeliness and accuracy of CDG billing by utilities. The Commission is focusing on developing CDG crediting and billing performance metrics and a negative revenue adjustment for failure to meet those metrics. At this time, the outcome of the proceeding is unknown.

Other REV-related orders pertaining to electric vehicles (EV), an Integrated Energy Data Resource (IEDR) platform and energy storage are summarized below.

- On April 24, 2018, the Commission instituted a proceeding to consider the role of utilities in providing infrastructure and rate design to encourage the adoption of EV and expansion of electric vehicle supply equipment. The Commission issued an Order on February 2, 2019 to establish a Direct Current Fast Charger incentive program, and subsequently clarified its Order on July 12, 2019 and March 3, 2020. A subsequent order in this proceeding was issued by the Commission on July 16, 2020, approving a $700 million statewide program (NYSEG and RG&E combined share is approximately $118 million) funded by customers to accelerate the deployment of electric vehicle charging stations in an effort to increase the number of electric vehicles. In addition, the July 16, 2020 Order directed the Utilities to submit filings to develop managed charging programs that would provide mass market customers with an alternative to the EV TOU rates already in place. RG&E complied by submitting its proposal on December 4, 2020 and subsequently filed suggestion revisions on June 4, 2021. On July 14, 2022 the Commission approved RG&E's program with modifications.

- On December 13, 2018, the Commission issued an Order for RG&E to file an implementation plan detailing a competitive procurement process and cost recovery for deploying 10 MW of qualified storage systems. RG&E filed its implementation plan and has issued requests for proposals to site storage systems within their service territory. On April 16, 2021, the Commission issued an Order to modify the term offered to developers for energy storage contracts and extended the in-service date for deployment of the 10 MW of energy storage. The Companies have tariffs in effect to collect costs for the procurement of qualified energy storage assets.

- On February 11, 2021, the Commission issued an Order to implement an Integrated Energy Data Resource platform, where NYSERDA was designated as the Program Sponsor of the platform. The Order established a combined cost cap of $12 Million for NYSEG and RG&E for Phase 1, to be deferred and recovered in the next rate case filing after Phase 1 is complete.

- On April 21, 2022, the Commission issued a Notice Soliciting Comments regarding the establishment of a commercial tariff to facilitate faster charging for eligible light duty, heavy duty and fleet electric vehicles. The notice is in response to enactment of Public Service Law 66-s which requires the Commission to establish a tariff utilizing alternative to traditional demand-based rate structures (i.e., solutions) to facilitate faster charging for eligible vehicles. The Commission issued an Order that adopted an immediate solution where a rebate will be provided to participants and a near-term solution where NYSEG and RG&E will submit and EV Phase-in Rate solution. NYSEG and RG&E will file an Implementation plan that includes a cost recovery mechanism.

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

On November 20, 2020, the NYPSC issued an Order Instituting Proceeding and to Show Cause (the "Show Cause Order") regarding alleged violations of the NYPSC's 2004 Order Adopting Policy Statement on Pole Attachments, dated August 6, 2004 (the "2004 Pole Order") by RG&E, Greenlight Networks, Inc. ("Greenlight"), and Frontier Communications ("Frontier"). The alleged violations detailed in the Show Cause Order arose from Greenlight's installation of more than 11,000 alleged unauthorized and substandard communications attachments throughout RG&E's and Frontier's service territories.

On August 12, 2021, the NYPSC approved a settlement between NYDPS and RG&E providing for, among other things, RG&E's payment of $2.5 million, which was deposited in a required escrow account in January 2022 and which will be used to support the State of New York's broadband initiative for underserved areas. This settlement amount could have increased to a maximum of $5 million had RG&E failed to resolve certain identified pole attachment violations caused by Greenlight's pole attachments on or before December 31, 2021. Pursuant to status reports filed with NYPSC in the fourth quarter of 2021 and January 2022, RG&E has met all compliance requirements of the settlement and successfully completed resolution of all specified violations caused by Greenlight's attachments.

Customer Arrearages Reduction Order

On June 16, 2022, the NYPSC issued an order (Phase 1) authorizing an arrears reduction program targeting low-income customers to provide COVID-19-related relief through a one-time bill credit to eliminate accrued arrears through May 1, 2022. A portion of the targeted arrearages will be funded via direct contributions from the State of New York, and the remainder to be received via a surcharge to all customers. The surcharge recovery is over five years for RG&E beginning on August 1, 2022.

On January 19, 2023, the NYPSC issued a subsequent order (Phase 2) providing bill relief for customers who did not receive a credit as part of the Phase 1 Program approved in 2022 (Low Income Program participants). Qualifying residential and small business customers are eligible to have any past-due balance from bills for service through May 1, 2022, reduced through a one time bill credit, up to a maximum credit below:

Residential	Total Forecast Residential Credits (Millions)	Small Business	Total Forecast Small Business Credits (Millions)
Up to $1,500	$15.2	Up to $1,500	$0.6

Community Leadership and Climate Protection Act Transmission

Pursuant to the Community Leadership and Climate Protection Act of 2019 (CLCPA) and Accelerated Renewable Energy Growth and Community Benefit Act of 2020, the Commission has issued orders addressing investment in transmission by RG&E to support the state achieving the CLCPA's goal of 70% renewable energy by 2030. On February 16, 2023, the Commission issued an Order approving the investment of approximately $157 Million by RG&E through 2030 in CLCPA "Phase 2" transmission projects. Phase 2 transmission projects are upgrades to the RG&E local transmission system that are being developed primarily to allow for the interconnection and delivery of renewable energy in the Southern Tier, an area that the Commission has designated as an "Area of Concern" for renewable energy development because there is substantial renewable energy development interest but inadequate transmission. Unlike other transmission owned by RG&E, the cost of CLCPA Phase 2 transmission will be recovered pursuant to a formula rate under the jurisdiction of the Federal Energy Regulatory Commission (FERC) so that costs can be allocated statewide. RG&E and other transmission-owning utilities in New York negotiated a Cost Sharing and Recovery Agreement (CSRA), which was approved by the Commission on May 12, 2022, and by FERC on August 22, 2022. Under the terms of the CSRA the cost of CLCPA Phase 2 transmission projects approved by the Commission will be recovered through the New York Independent System Operator tariff, with ROE and capital structure determined by the Commission, subject to an ROE ceiling set by FERC.

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 $98.0 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

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

On November 19, 2020, the NYPSC approved the proposal in connection with a three-year rate plan for electric and gas service at RG&E effective April 17, 2020. Following the approval of the proposal RG&E’s plant related tax items are amortized over the life of associated plant, and unfunded deferred taxes being amortized over a period of forty-six years. A majority of the other items related to RG&E will be amortized over a five-year period. In accordance with the Schedule of Regulatory Amortizations included in the approved Joint Proposal, net annual amortization revenue for RG&E is approximately $65.5 million for the year ended December 31, 2022.

Regulatory assets at December 31, 2022 and 2021 consisted of:

December 31,		2022		2021
(Thousands)				
Asset retirement obligation	$	3,199	$	3,206
COVID-19 uncollectible deferral		—		1,671
COVID-19 late payment surcharge		2,444		—
Decommissioning		784		1,504
Deferred meter replacement costs		9,186		6,014
Delivery rate shaping		—		23,853
Electric supply reconciliation		—		3,835
Environmental remediation costs		72,896		64,085
Federal tax depreciation normalization adjustment		43,566		44,991
Hedge losses		4,480		—
Low income program		15,960		12,404
Low income arrears forgiveness		16,926		—
Pension and other postretirement benefits		13,234		24,986
Pension and other postretirement benefits cost deferrals		13,050		23,058
Post term amortization		2,109		3,013
Rate adjustment mechanism		7,996		13,271
REV demand response		1,003		1,003
Revenue decoupling mechanism		4,358		14,165
Storm costs		65,240		47,454
Unamortized losses on reacquired debt		4,120		4,120
Unfunded future income taxes		150,465		143,424
Value of Distributed Energy Resources (VDER) Program		10,991		3,168
Other		18,419		15,474
Total regulatory assets		**460,426**		**454,699**
Less: current portion		57,485		77,459
Total non-current regulatory assets	**$**	**402,941**	**$**	**377,240**

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.

COVID-19 uncollectible deferral represents deferred COVID-19 related costs.

COVID-19 late payment surcharge represents deferred lost late payment revenue in the state of New York based on the order issued by PSC on June 17, 2022, approving deferral and surcharge/sur-credit mechanism to recover/return deferred balances starting July 1, 2022.

Decommissioning represents amounts to be collected in rates for the decommissioning of shut down plants.

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

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

Electric supply reconciliation represents over/under collection of costs related to electric supply in which RG&E supplies electricity as the default service option for customers.

Environmental remediation costs include spending that has occurred and is eligible for future recovery in customer rates. Environmental costs are currently recovered through a reserve mechanism whereby projected spending is included in rates with any variance recorded as a regulatory asset or a regulatory liability. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is seven years and began in 2020. It also includes the anticipated future rate recovery of costs that are recorded as environmental liabilities since these will be recovered when incurred. Because no funds have yet been expended for the regulatory asset related to future spending, it does not accrue carrying costs and is not included within rate base.

Federal tax depreciation normalization adjustment represents the deferral of the normalization of change impacts in book lives and the pass back of theoretical reserves associated with Powertax deferred income tax. It is being amortized over a thirty-five year period starting in 2020.

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

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

Low income arrears forgiveness represents deferred bill credits in the state of New York based on the order issued by PSC on June 16, 2022, approving deferral of bill credits for low income customers and recovery of regulatory asset from all customers over five years for RGE. Surcharge started on August 1, 2022.

Pension and other postretirement benefits represent the actuarial losses on the pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future pension expenses. Because no funds have yet been expended for this regulatory asset, it does not accrue carrying costs and is not included within the rate base.

Pension and other postretirement benefits cost deferrals include the difference between actual expense for pension and other postretirement benefits and the amount provided for in rates. The recovery of these amounts will be determined in future proceedings.

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

Rate adjustment mechanism (RAM) represents a mechanism each business implements to return or collect the net balance of RAM eligible deferrals and costs. The primary driver of RAM collections is storm costs but this also includes property taxes and REV costs and fees not covered in other recovery mechanisms.

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

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

Storm costs are allowed in rates based on an estimate of the routine costs of service restoration. RG&E is also allowed to defer unusually high levels of service restoration costs resulting from major storms when they meet certain criteria for severity and duration.

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

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

Value Distributed Energy Resource represents a mechanism to compensate energy created by distributed energy resources, like solar.

Other includes items such as bill credits, vegetation management, credit/debit card fees, earnings adjustment mechanism, and electric vehicle program.

Regulatory liabilities at December 31, 2022 and 2021 consisted of:

December 31,		2022		2021
(Thousands)				
Accrued removal obligations	$	190,158	$	197,909
Asset retirement obligation		4,851		4,751
Carrying costs on deferred income tax bonus depreciation		8,765		19,802
Debt rate reconciliations		5,451		17,168
Deferred property taxes		13,645		16,805
Deferred transmission congestion contracts		30,975		22,737
Delivery rate shaping		11,506		57,848
Earnings sharing		7,131		9,115
Economic development		13,625		18,769
Electric supply reconciliation		3,627		—
Energy efficiency programs		12,002		22,948
Environmental remediation costs		7,509		7,509
Gas supply charge		149		623
Hedge gains		—		9,936
Merger capital expense		2,778		3,969
Mixed use 263(a)		2,719		3,884
NEIL (Nuclear Electric Insurance Limited) credits		12,014		10,508
Net plant reconciliation		10,893		15,409
Pension and other postretirement benefits		20,058		6,636
Pension and other postretirement benefits cost deferrals		2,234		1,495
Positive benefit adjustment		15,231		21,759
Tax Act – remeasurement		259,878		271,059
Theoretical reserve flow through impact		2,930		4,186
Unfunded future income taxes		3,124		3,124
Other		61,673		49,555
Total regulatory liabilities		**702,926**		**797,504**
Less: current portion		82,138		101,801
Total non-current regulatory liabilities	**$**	**620,788**	**$**	**695,703**

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

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

Debt rate reconciliations represent the over/under collection of costs related to fixed and variable rate debt instruments identified in the rate case. Costs would include interest, commissions and fees versus amounts included in rates.

Deferred property taxes represent the customer portion of the difference between actual expense for property taxes and the amount provided for in rates. The amount is being amortized over a five-year period following the approval of the proposal by the NYPSC.

Deferred transmission congestion contracts represent the deferral of the right to collect day-ahead market congestions rents going forward in time.

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

Economic development represents the economic development program which enables RG&E to foster economic development through attraction, expansion, and retention of businesses within its service territory. If the level of actual expenditures for economic development allocated to RG&E varies in any rate year from the level provided for in rates, the difference is refunded to ratepayers. The amortization period is five years following the approval of the proposal by the NYPSC.

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

Gas supply charge reflects the actual cost of purchasing, transporting and storing natural gas for those customers who receive their natural gas supply from RG&E.

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

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

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

NEIL (Nuclear Electric Insurance Limited) credits represents the difference between insurance credit amounts reflected in rates and actual credits received.

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

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

Tax Act – remeasurement represents the impact from remeasurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates from 35% to 21% under the provisions of the Tax Act will result in amounts previously collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates. The amortization period in current rates is from one and half to ten years and began in 2020.

Theoretical reserve flow through impact represents the differences from the rate allowance for applicable federal and state flow through impacts related to the excess depreciation reserve amortization. It also represents the carrying cost on the differences. The amortization period is five years following the approval of the proposal by the NYPSC.

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

Other includes items such as asset retirement obligations, other taxes, and vegetation management, direct current fast charging, manhole maintenance, CEF, service quality metrics, and incremental maintenance.

Note 4. Revenue

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

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

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

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

Transmission revenue results from others' use of the utility's transmission system to transmit electricity and is subject to FERC regulation, which establishes the prices and other terms of service. Long-term wholesale sales of electricity are based on individual bilateral contracts. Short-term wholesale sales of electricity are generally on a daily basis based on market prices and are administered by the NYISO or PJM Interconnection, LLC (PJM), as applicable.

Wholesale sales of natural gas are generally short-term based on market prices through contracts with the specific customer.

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

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

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

We have contract liabilities for revenue from transmission congestion contract (TCC) auctions, for which we receive payment at the beginning of an auction period, and amortize ratably each month into revenue over the applicable auction period. The auction periods range from six months to two years. TCC contract liabilities totaled $0.6 million at December 31, 2022, and $0.5 million at December 31, 2021, and are presented in "Other current liabilities" on our balance sheets. We recognized $0.9 million as revenue in 2022 and $1.7 million in 2021.

We apply a practical expedient to expense as incurred costs to obtain a contract when the amortization period is one year or less. We record costs incurred to obtain a contract within operating expenses, including amortization of capitalized costs.

Revenues disaggregated by major source for the years ended December 31, 2022 and 2021 are as follows:

Years Ended December 31,	**2022**	**2021**
(Thousands)		
Regulated operations – electricity	$ 770,244	$ 643,228
Regulated operations – natural gas	373,666	288,759
Other (a)	24,386	9,024
Revenue from contracts with customers	**1,168,296**	**941,011**
Leasing revenue	69	61
Alternative revenue programs	8,556	13,958
Other revenue	3,564	2,759
Total operating revenues	**$ 1,180,485**	**$ 957,789**

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

Note 5. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,		2022		2021
(Thousands)				
Current				
Federal	$	(885)	$	(9,200)
State		(1,389)		(2,544)
Current taxes charged to benefit		**(2,274)**		**(11,744)**
Deferred				
Federal		20,310		21,238
State		10,359		9,939
Deferred taxes charged to expense		**30,669**		**31,177**
Total Income Tax Expense	**$**	**28,395**	**$**	**19,433**

The differences between tax expense per the statements of income and tax expense at the 21% statutory federal tax rate for the years ended December 31, 2022 and 2021, respectively, consisted of:

Years Ended December 31,		2022		2021
(Thousands)				
Tax expense at federal statutory rate	$	31,718	$	25,687
Equity AFUDC tax impacts not normalized		(2,305)		(2,303)
Excess ADIT amortization		(9,829)		(9,728)
Excess ADIT write-off		1,693		—
State tax expense, net of federal benefit		7,086		5,842
Other, net		32		(65)
Total Income Tax Expense	**$**	**28,395**	**$**	**19,433**

Income tax expense for the year ended December 31, 2022 was $3.3 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to Excess ADIT amortization and Equity AFUDC tax effects, partially offset by state tax expense and Excess ADIT write-off. This resulted in an effective tax rate of 18.8%. Income tax expense for the year ended December 31, 2021, was $6.3 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to Excess ADIT amortization and Equity AFUDC tax effects, partially offset by state tax expense. This resulted in an effective tax rate of 15.9%.

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

Deferred tax assets and liabilities as of December 31, 2022 and 2021 consisted of:

December 31,		2022		2021
(Thousands)				
Non-current Deferred Income Tax Liabilities (Assets)				
Property related	$	565,835	$	531,933
Unfunded future income taxes		37,493		35,653
Storms		18,775		15,776
Regulatory liability due to "Tax Cuts and Jobs Act"		(67,919)		(70,842)
Pension and other postretirement benefits		(25,634)		(21,817)
Derivative assets		(10,701)		(11,659)
Environmental		(9,566)		(11,253)
Federal and state net operating loss		(26,473)		(14,053)
Other		(18,544)		(37,515)
Total Non-current Deferred Income Tax Liabilities	**$**	**463,266**	**$**	**416,223**
Deferred tax assets	$	158,837	$	167,139
Deferred tax liabilities		622,103		583,362
Net Accumulated Deferred Income Tax Liabilities	**$**	**463,266**	**$**	**416,223**

RG&E has gross federal net operating losses of $71.7 million and gross New York state net operating losses of $222.3 million for the year ended December 31, 2022. RG&E has gross federal net operating losses of $27.7 million and gross New York state net operating losses of $157.9 million for the year ended December 31, 2021.

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.

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,		2022		2021
(Thousands)				
Beginning Balance	$	49,100	$	49,387
Reduction for tax positions related to prior years		(287)		(287)
Ending Balance	**$**	**48,813**	**$**	**49,100**

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, 2022 and December 31, 2021.

Note 6. Long-term Debt

Long-term debt as of December 31, 2022 and 2021 consisted of:

As of December 31,		2022		2021	
(Thousands, except interest rates)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
First mortgage bonds (a)	2025-2052	$ 1,410,500	1.85%-8.00%	$ 1,285,500	1.85%-8.00%
Unsecured pollution control notes - fixed	2025	91,900	3.00%	91,900	3.00%
Unamortized debt issuance cost and discount		(12,498)		(11,232)	
Total Debt		**1,489,902**		**1,366,168**	
Less: debt due within one year, included in current liabilities		—		—	
Total Non-current Debt		**$ 1,489,902**		**$ 1,366,168**	

(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 December 15, 2021, RG&E issued $125 million aggregate principal amount of first mortgage bonds maturing in 2031 at an interest rate of 2.10%, as well as $125 million aggregate principal amount of first mortgage bonds maturing in 2051 at an interest rate of 2.91%.

On December 15, 2022, RG&E issued $125 million aggregate principal amount of first mortgage bonds maturing in 2052 at an interest rate of 4.86%.

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

2023	2024	2025	2026	2027	Total
(Thousands)					
$ —	$ —	$ 152,400	$ —	$ 450,000	$ 602,400

We have no financial debt covenant requirements related to our long-term debt at December 31, 2022 and 2021.

Note 7. Bank Loans and Other Borrowings

RG&E had $76.3 million of notes payable outstanding as of December 31, 2022 and $53.5 million of notes payable outstanding as of December 31, 2021. RG&E funds short-term liquidity needs through an agreement among Avangrid's regulated utility subsidiaries (the Virtual Money Pool Agreement), a bi-lateral intercompany credit agreement with Avangrid (the Bi-Lateral Intercompany Facility), and a bank provided credit facility to which RG&E is a party (the AGR Credit Facility), each of which are described below.

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. RG&E has a lending/borrowing limit of $100 million under this agreement. RG&E had no debt outstanding under this agreement as of December 31, 2022 and $21.5 million outstanding as of December 31, 2021.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $500 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. RG&E had $76.3 million outstanding under this agreement as of December 31, 2022 and $32.0 million as of December 31, 2021.

On November 23, 2021, AGR and its investment-grade rated utility subsidiaries (New York State Electric and Gas Corporation ("NYSEG"), Rochester Gas and Electric Corporation ("RG&E"), Central Maine Power Company ("CMP"), The United Illuminating Company ("UI"), Connecticut Natural Gas Corporation ("CNG"), The Southern Connecticut Gas Company ("SCG") and The Berkshire Gas Company ("BGC")) executed a new credit facility with an aggregate limit of $3,575 million and a termination date of November 23, 2026.

Under the terms of the Avangrid Credit Facility, each borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit contained in the agreement. NYSEG has a maximum sublimit of $700 million, RG&E has $300 million, CMP has $200 million and UI has a maximum sublimit of $250 million, CNG and SCG have maximum sublimits of $150 million, and BGC has a maximum sublimit of $50 million. Effective on November 23 2021, the AGR Credit Facility was amended to increase AGR's maximum sublimit to $2,500 million and to establish minimum sublimits of $500 million for NYSEG, $200 million for RG&E, $100 million for CMP, $150 million for UI, $50 million for CNG and SCG, and $25 million for BGC. Under the AGR Credit Facility, each of the borrowers are charged a facility fee that is dependent on their credit rating. The facility fees range from 10.0 to 22.5 basis points. RG&E had not borrowed under this agreement as of both December 31, 2022 and December 31, 2021.

In the AGR Credit Facility we covenant not to permit, without the consent of the lender, our ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of indebtedness to total capitalization, the facility excludes from net worth the balance of accumulated other comprehensive loss as it appears on the balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness we may maintain. Continued un-remedied failure to comply with those covenants for five business days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity. Our ratio of indebtedness to total capitalization pursuant to the revolving credit facility was 0.52 to 1.00 at December 31, 2022. We are not in default as of December 31, 2022.

Note 8. Leases

We have operating leases for office buildings, facilities, vehicles and certain equipment. Our finance leases are primarily related to electric generation, distribution, transmission and other. Certain of our lease agreements include rental payments adjusted periodically for inflation or are based on other periodic input measures. Our leases do not contain any material residual value guarantees or material restrictive covenants. Our leases have remaining lease terms of 1 year to 14 years, some of which may include options to extend the leases for up to 30 years, and some of which may include options to terminate the leases within one year. We consider extension or termination options in the lease term if it is reasonably certain we will exercise the option.

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

For the Years Ended December 31,		2022		2021
(Thousands)				
Lease cost				
Finance lease cost				
Amortization of right-of-use assets	$	4,679	$	1,003
Interest on lease liabilities		1,101		1,320
Total finance lease cost		5,780		2,323
Operating lease cost		510		530
Short-term lease cost		588		87
Variable lease cost		532		377
Intercompany		71		61
Total lease cost	**$**	**7,481**	**$**	**3,378**

Balance sheet and other information for the years ended December 31, 2022 and 2021 was as follows:

As of December 31,		2022		2021
(Thousands, except lease term and discount rate)				
Operating Leases				
Operating lease right-of-use assets	$	525	$	1,124
Operating lease liabilities, current		1,986		287
Operating lease liabilities, long-term		100		2,253
Total operating lease liabilities	$	2,086	$	2,540
Finance Leases				
Other assets	$	45,076	$	48,036
Other current liabilities		3,969		3,930
Other non-current liabilities		39,851		43,772
Total finance lease liabilities	$	43,820	$	47,702
Weighted-average Remaining Lease Term (years):				
Finance leases		7.33		8.13
Operating leases		1.31		2.25
Weighted-average Discount Rate:				
Finance leases		2.42 %		2.57 %
Operating leases		3.15 %		2.92 %

Supplemental cash flows information related to leases was as follows:

For the Years Ended December 31,		2022		2021
(Thousands)				
Cash paid for amounts included in the measurement of lease liabilities:				
Operating cash flows from operating leases	$	295	$	226
Operating cash flows from finance leases	$	1,136	$	1,320
Financing cash flows from finance leases	$	5,600	$	3,598
Right-of-use assets obtained in exchange for lease obligations:				
Finance leases	$	1,718	$	1,230
Operating leases	$	8	$	(52)

As of December 31, 2022, maturities of lease liabilities were as follows:

		Finance Leases		Operating Leases
(Thousands)				
Years ending December 31,				
2024	$	4,847	$	2,016
2025		22,352		18
2026		1,719		18
2027		1,744		18
2028		1,773		17
Thereafter		16,084		75
Total lease payments		**48,519**		**2,162**
Less: imputed interest		(4,699)		(76)
Total	**$**	**43,820**	**$**	**2,086**

Most of our leases do not provide an implicit rate in the lease; thus we use our incremental borrowing rate based on the information available at the commencement date in determining the present value of lease payments.

Note 9. Commitments and Contingencies

Purchase power and natural gas contracts, including non-utility generators

RG&E is the provider of last resort for customers. As a result, the company buys physical energy and capacity from the NYISO. In accordance with the NYPSC's February 26, 2008 Order, RG&E is required to hedge on behalf of non-demand billed customers. The physical electric capacity purchases we make from parties other than the NYISO are to comply with the hedge requirement for electric capacity. The company enters into financial swaps to comply with the hedge requirement for physical electric energy purchases. RG&E also makes purchases from other independent power producers and New York Power Authority (NYPA) under existing contracts or long-term supply agreements in order to comply with the company’s Public Utility Regulatory Policies Act (PURPA) purchase obligation.

RG&E satisfies its natural gas supply requirements through purchases from various producers and suppliers, withdrawals from natural gas storage, capacity contracts and winter peaking supplies and resources. The company operates diverse portfolios of gas supply, firm transportation capacity, gas storage and peaking resources. Actual gas costs incurred by each of the companies are passed through to customers through state regulated purchased gas adjustment mechanisms, subject to regulatory review.

The company purchases the majority of its natural gas supply at market prices under seasonal, monthly or mid-term supply contracts and the remainder is acquired on the spot market. The company acquires firm transportation capacity on interstate pipelines under long-term contracts and utilizes that capacity to transport both natural gas supply purchased and natural gas withdrawn from storage to the local distribution system. The company acquires firm underground natural gas storage capacity using long-term contracts and fills the storage facilities with gas in the summer months for subsequent withdrawal in the winter months.

We recognized expenses of approximately $53.5 million for Normal Purchase Normal Sale (NPNS) purchase power and natural gas contracts including non-utility generators in 2022 and $48.5 million in 2021.

Note 10. Environmental Liability

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

Waste sites

The Environmental Protection Agency (EPA) and the New York State Department of Environmental Conservation (NYSDEC), as appropriate, have notified us that we are among the potentially responsible parties that may be liable for costs incurred to remediate certain hazardous substances at nine waste sites. The nine sites do not include sites where coal gas was manufactured in the past, which are discussed below. With respect to the nine sites, eight sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites and two sites are also included on the National Priorities list.

Any liability may be joint and several for certain of those sites. We have recorded an estimated liability of $0.2 million at December 31, 2022, related to eight sites. We have recorded an estimated liability of $5.3 million related to another six sites where we believe it is probable that we will incur remediation costs and/or monitoring costs. It is possible the ultimate cost to remediate the sites may be significantly more than the accrued amount. Our estimate for costs to remediate these sites ranges from $5.1 million to $6.0 million as of December 31, 2022. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to us. It is anticipated that costs would be recovered in rates, typical of historical Site Investigation and Remediation rate recovery.

Manufactured gas plants

We have a program to investigate and perform necessary remediation and/or monitoring at our eleven sites where coal gas was manufactured in the past. The Company has advanced work under an existing order on consent with the NYSDEC at three of the sites, with a fourth site anticipated to be added to the order in 2023. The order requires us to investigate and, where necessary, remediate and/or monitor our eleven sites. Seven sites were advanced under NYS's former Voluntary Cleanup Program (VCP) that was discontinued in 2018. Work at those sites continues, as applicable in accordance with Site Management Plans (SMPs) and institutional controls.

Our estimate for costs related to investigation and remediation and/or monitoring of the eleven sites ranges from $94.1 million to $117.4 million at December 31, 2022. 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, changes due to property use and changes to current laws and regulations.

The liability to investigate and perform remediation, as necessary, at the known inactive coal gas manufacturing sites was $96.4 million at December 31, 2022, and $93.9 million at December 31, 2021. We recorded a corresponding regulatory asset, net of insurance recoveries, because we expect to recover the net costs in rates.

Our environmental liabilities are recorded on an undiscounted basis and are expected to be paid through the year 2057.

First Energy

RG&E sued FirstEnergy under the Comprehensive Environmental Response, Compensation, and Liability Act to recover environmental cleanup costs at two former manufactured coal gas sites, which are included in the discussion above. In 2008, the District Court issued a decision and order in RG&E's favor requiring FirstEnergy to pay RG&E for past and future clean-up costs at the two manufactured gas plant (MGP) sites. As such, FirstEnergy is liable for a share of clean up expenses at the two sites. Based on current projections, FirstEnergy’s share is estimated at approximately $7 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 RG&E ratepayers.

Note 11. Accounting for Derivative Instruments and Hedging Activities

We are exposed to certain risks relating to our ongoing business operations. The primary risk we manage by using derivative instruments is commodity price risk. In accordance with the accounting requirements concerning derivative instruments and hedging activities, we recognize all derivative instruments as either assets or liabilities at fair value on our balance sheet.

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

Commodity price risk*:* Commodity price risk, due to volatility experienced in the wholesale energy markets, is a significant issue for the electric and natural gas utility industries. We manage this risk through a combination of regulatory mechanisms, such as the pass-through of the market price of electricity and natural gas to customers, and through comprehensive risk management processes. Those measures mitigate our commodity price exposure, but do not completely eliminate it. Owned electric generation and long-term supply contracts reduce our exposure to market fluctuations.

We have electricity commodity purchases and sales contracts for both capacity and energy (physical contracts) that have been designated and qualify for the normal purchases and normal sales exception in accordance with the accounting requirements concerning derivative instruments and hedging activities.

We currently have a non by-passable wires charge adjustment that allows us to pass through rates any changes in the market price of electricity. We use electricity contracts, both physical and financial, to manage fluctuations in electricity commodity prices in order to provide price stability to customers. We include the cost or benefit of those contracts in the amount expensed for electricity purchased when the related electricity is sold. We record changes in the fair value of electric hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations.

We have a purchased gas adjustment clause that allows us to recover through rates any changes in the market price of purchased natural gas, substantially eliminating our exposure to natural gas price risk. We use natural gas futures and forwards to manage fluctuations in natural gas commodity prices in order to provide price stability to customers. We include the cost or benefit of natural gas futures and forwards in the commodity cost that is passed on to customers when the related sales commitments are fulfilled. We record changes in the fair value of natural gas hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations.

The amounts for electricity hedge contracts and natural gas hedge contracts recognized in regulatory liabilities and assets as of December 31, 2022 and 2021 and amounts reclassified from regulatory assets and liabilities into income for the years ended December 31, 2022 and 2021 are as follows:

(Thousands)	Loss (Gain) Recognized in Regulatory Assets/ Liabilities		Location of Loss (Gain) Reclassified from Regulatory Assets/ Liabilities into Income	Loss (Gain) Reclassified from Regulatory Assets/ Liabilities into Income	
As of			**Years Ended December 31,**		
December 31, 2022	**Electricity**	**Natural Gas**	**2022**	**Electricity**	**Natural Gas**
Regulatory assets	$ 2,231	$ 2,249	Electricity and natural gas purchased	$ (43,812)	$ (11,653)
Regulatory liabilities	$ —	$ —			
December 31, 2021			**2021**		
Regulatory assets	$ —	$ 154	Electricity and natural gas purchased	$ (8,300)	$ (6,327)
Regulatory liabilities	$ (7,304)	$ (2,632)			

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

	Electricity Contracts	Natural Gas Contracts	Other Fuel Contracts
Years to settle	**Mwhs**	**Dths**	**Gallons**
As of December 31, 2022 (a)			
2023	1,473,575	5,540,000	—
2024	449,000	840,000	—
As of December 31, 2021			
2022	1,429,550	5,820,000	334,700
2023	438,000	890,000	—

(a) As of December 31, 2022, the fleet fuel program was discontinued.

The offsetting of derivatives, location in the balance sheet and amounts of derivatives as of December 31, 2022 and 2021, respectively, consisted of:

December 31, 2022	Derivative Assets Current	Derivative Assets Non-current	Derivative Liabilities Current	Derivative Liabilities Non-current
(Thousands)				
Not designated as hedging instruments				
Derivative assets	$ 9,245	$ 2,488	$ 9,245	$ 2,488
Derivative liabilities	(9,245)	(2,488)	(12,593)	(3,620)
	—	—	(3,348)	(1,132)
Designated as hedging instruments				
Derivative assets	—	—	—	—
Derivative liabilities	—	—	(21)	—
	—	—	(21)	—
Total derivatives before offset of cash collateral	—	—	(3,369)	(1,132)
Cash collateral receivable	—	—	3,348	1,132
Total derivatives as presented in the balance sheet	**$ —**	**$ —**	**$ (21)**	**$ —**

December 31, 2021	Derivative Assets Current	Derivative Assets Non-current	Derivative Liabilities Current	Derivative Liabilities Non-current
(Thousands)				
Not designated as hedging instruments				
Derivative assets	$ 11,567	$ 2,031	$ 2,305	$ 1,357
Derivative liabilities	(2,305)	(1,357)	(2,305)	(1,511)
	9,262	674	—	(154)
Designated as hedging instruments				
Derivative assets	40	—	12	—
Derivative liabilities	(12)	—	(34)	—
	28	—	(22)	—
Total derivatives before offset of cash collateral	9,290	674	(22)	(154)
Cash collateral receivable	—	—	—	154
Total derivatives as presented in the balance sheet	**$ 9,290**	**$ 674**	**$ (22)**	**$ —**

As of both December 31, 2022 and 2021, the derivative assets and derivative liabilities are presented within other current and non-current assets and liabilities of the balance sheet, respectively.

Derivatives designated as hedging instruments

The effect of derivatives in cash flow hedging instruments on OCI and income for the years ended December 31, 2022 and 2021, respectively, consisted of:

Years Ended December 31,	(Loss) Gain Recognized in OCI on Derivatives	Location of Loss Reclassified From Accumulated OCI into Income	Loss Reclassified From Accumulated OCI into Income	Total Amount per Income Statement
(Thousands)				
2022				
Interest rate contracts	$ —	Interest expense	$ (3,678)	$ 42,641
Commodity contracts: Other	420	Other operating expenses	448	349,207
Foreign exchange contracts	—	Other operating expenses	(22)	349,207
Total	**$ 420**		**$ (3,252)**	
2021				
Interest rate contracts	$ —	Interest expense	$ (3,678)	$ 43,898
Commodity contracts: Other	273	Other operating expenses	178	312,466
Foreign exchange contracts	(22)	Other operating expenses	—	312,466
Total	**$ 251**		**$ (3,500)**	

The amount in AOCI related to previously settled forward starting interest rate swaps and accumulated amortization at December 31, 2022 is a net loss of $40.9 million as compared to $44.6 million at December 31, 2021. For the year ended December 31, 2022, we recorded $3.7 million in net derivative losses related to discontinued cash flow hedges. We will amortize approximately $3.7 million of discontinued cash flow hedges in 2023.

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, 2022 is $4.5 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 $1,401 million as of December 31, 2022 and $1,565 million as of December 31, 2021. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the electricity industry and the credit ratings of the borrowers in each case. The fair value of these unsecured pollution control notes-variable are determined using unobservable interest rates as the market for these notes is inactive. The fair value hierarchy for the fair value of debt is considered as Level 2.

The financial instruments measured at fair value as of December 31, 2022 and 2021 consisted of:

Description	Level 1	Level 2	Level 3	Netting	Total
(Thousands)					
As of December 31, 2022					
Assets					
Derivatives					
Commodity contracts:					
Electricity	$ 11,249	$ —	$ —	$ (11,249)	$ —
Natural Gas	484	—	—	(484)	—
Total	**$ 11,733**	**$ —**	**$ —**	**$ (11,733)**	**$ —**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	$ (13,480)	$ —	$ —	$ 13,480	$ —
Natural gas	(2,733)	—	—	2,733	—
Foreign exchange contracts	—	(21)	—	—	(21)
Total	**$ (16,213)**	**$ (21)**	**$ —**	**$ 16,213**	**$ (21)**

Description	Level 1	Level 2	Level 3	Netting	Total
(Thousands)					
As of December 31, 2021					
Assets					
Derivatives					
Commodity contracts:					
Electricity	$ 10,691	$ —	$ —	$ (3,387)	$ 7,304
Natural Gas	2,907	—	—	(275)	2,632
Other	—	—	40	(12)	28
Total	**$ 13,598**	**$ —**	**$ 40**	**$ (3,674)**	**$ 9,964**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	$ (3,387)	$ —	$ —	$ 3,387	$ —
Natural gas	(429)	—	—	429	—
Other	—	—	(12)	12	—
Foreign exchange contracts	—	(22)	—	—	(22)
Total	**$ (3,816)**	**$ (22)**	**$ (12)**	**$ 3,828**	**$ (22)**

We had no transfers to or from Level 1 and 2 during the year ended December 31, 2022. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

Valuation techniques: We measure the fair value of our non-current investments available for sale using quoted market prices in active markets for identical assets and include the measurements in Level 1.

We determine the fair value of our various derivative assets and liabilities utilizing market approach valuation techniques:

- We enter into electric energy derivative contracts to hedge the forecasted purchases required to serve our electric load obligations. We hedge our electric load obligations using derivative contracts that are settled based upon Locational Based Marginal Pricing published by the NYISO. We hedge approximately 70% of their electric load obligations using contracts for a NYISO location where an active market exists. The forward market prices used to value the companies' open electric energy derivative contracts are based on quotes prices in active markets for identical assets or liabilities with no adjustment required and therefore we include the fair value in Level 1.
- We enter into natural gas derivative contracts to hedge the forecasted purchases required to serve our natural gas load obligations. The forward market prices used to value our open natural gas derivative contracts are exchange-based prices for the identical derivative contracts traded actively on the New York Mercantile Exchange. Because we use prices quoted in an active market, we include those fair value measurements in Level 1.
- We enter into fuel derivative contracts to hedge our unleaded and diesel fuel requirements for our fleet vehicles. Exchange based forward market prices are used but because a basis adjustment is added to the forward prices, we include the fair value measurement for these contracts in Level 3.

The reconciliation of changes in the fair value of financial instruments based on Level 3 inputs for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,	2022	2021
(Thousands)		
Beginning balance	$ 28	$ (67)
Realized gains included in earnings	(448)	(178)
Unrealized gains included in other comprehensive income	420	273
Ending balance	**$ —**	**$ 28**

The gains and losses included in earnings for the periods above are reported in Operations and maintenance of the statements of income.

Note 13. Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss for the years ended December 31, 2022 and 2021, consisted of:

	Balance December 31, 2020	2021 Change	Balance December 31, 2021	2022 Change	Balance December 31, 2022
(thousands)					
Amortization of pension cost for non-qualified plans and current year actuarial gain, net of tax expense of $169 for 2021 and $514 for 2022	$ (2,670)	$ 479	$ (2,191)	$ 1,453	$ (738)
Unrealized gain (loss) on derivatives qualified as hedges:					
Unrealized gain during period on derivatives qualified as hedges, net of income tax expense of $65 for 2021 and $109 for 2022		186		311	
Reclassification adjustment for gain included in net income, net of income tax benefit of $46 for 2021 and $111 for 2022		(132)		(315)	
Reclassification adjustment for loss on settled cash flow treasury hedges included in net income, net of income tax expense of $962 for 2021 and $962 for 2022		2,716		2,716	
Net unrealized (loss) gain on derivatives qualified as hedges	(35,721)	2,770	(32,951)	2,712	(30,239)
Accumulated Other Comprehensive Loss	**$ (38,391)**	**$ 3,249**	**$ (35,142)**	**$ 4,165**	**$ (30,977)**

Note 14. Postretirement and Similar Obligations

We have funded non-contributory defined benefit pension plans that cover the eligible employees. For most employees, generally those hired before 2002, the plans provide defined benefits based on years of service and final average salary. Employees hired in 2002 or later are covered under a cash balance plan or formula where their benefit accumulates based on a percentage of annual salary and credited interest. During 2013 the company announced that we would freeze the benefits for all non-union employees covered under the cash balance plans effective December 31, 2013. Their earned balances would continue to accrue interest, but would no longer be increased by a percentage of earnings. In place of the pension benefit for these employees, they will receive a minimum contribution to their account under their respective company's defined contribution plan. During 2022, the Company decided to freeze pension benefit accruals and contribution credits for non-union employees and transition their retirement benefits to the 401(k) Plan.

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 $7.2 million in 2022 and $5.1 million in 2021.

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

Non-Qualified Retirement Benefit Plans

We also sponsor various unfunded pension plans for certain current employees, former employees and former directors. The total liability for these plans, which is included in Other non-current liabilities on our balance sheets, was $8.7 million and $11.0 million at December 31, 2022 and 2021, respectively.

Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2022 and 2021 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2022**	**2021**	**2022**	**2021**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	$ 345,135	$ 392,826	$ 61,025	$ 67,468
Service cost	3,389	5,333	126	158
Interest cost	10,580	6,379	1,444	1,298
Curtailments	(19,736)	—	—	—
Settlements	(13,295)	(12,322)	—	—
Actuarial gain	(51,275)	(24,132)	(14,191)	(4,584)
Benefits paid	(21,919)	(22,949)	(3,743)	(3,315)
Benefit obligation at December 31	**$ 252,879**	**$ 345,135**	**$ 44,661**	**$ 61,025**
Change in plan assets				
Fair value of plan assets at January 1	$ 291,097	$ 300,919	$ —	$ —
Actual return on plan assets	(54,327)	22,565	—	—
Employer and plan participants' contributions	—	2,884	3,743	3,315
Settlements	(13,295)	—	—	—
Benefits paid	(21,919)	(22,949)	(3,743)	(3,315)
Fair value of plan assets at December 31	**$ 201,556**	**$ 291,097**	**$ —**	**$ —**
Funded status	**$ (51,323)**	**$ (54,038)**	**$ (44,661)**	**$ (61,025)**

During 2022, the pension benefit obligation had an actuarial gain of $51.3 million, primarily due to a $50.8 million gain from increases in discount rates. In 2022, the pension benefit obligation had a reduction of $13.3 million from settlements and $19.7 million from curtailments. The settlements were lump-sum payments made within the pension plan guidelines at the discretion of the plan participants who opted to retire. The curtailments were driven by a Company decision to freeze pension benefit accruals and contribution credits for non-union employees and transition their retirement benefits to a 401(k) plan. During 2022, the postretirement benefit obligation had an actuarial gain of $14.2 million, primarily due to a $9.9 million gain from increases in discount rates.

During 2021, the pension benefit obligation had an actuarial gain of $24.1 million, primarily due to a $16.5 million gain from decreases in discount rates. There were no significant gains or losses relating to the postretirement benefit obligations.

Amounts recognized in the balance sheet as of December 31, 2022 and 2021 consisted of:

Amounts recognized in the balance sheet	**Pension Benefits**		**Postretirement Benefits**	
December 31,	**2022**	**2021**	**2022**	**2021**
(Thousands)				
Other current liabilities	$ —	$ —	$ (4,881)	$ (5,084)
Pension and other postretirement benefits	(51,323)	(54,038)	(39,780)	(55,941)
Total	**$ (51,323)**	**$ (54,038)**	**$ (44,661)**	**$ (61,025)**

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,	**2022**	**2021**	**2022**	**2021**
(Thousands)				
Net loss (gain)	$ 13,234	$ 24,986	$ (18,597)	$ (4,819)
Prior service credit	—	—	(1,461)	(1,817)

Our accumulated benefit obligation for all qualified defined benefit pension plans was $252.9 million at December 31, 2022 and $320.8 million at December 31, 2021.

The projected benefit obligation and the accumulated benefit obligation exceeded the fair value of pension plan assets for all of our qualified plans as of both December 31, 2022 and 2021. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets of our plans as of December 31, 2022 and 2021.

December 31,	**2022**	**2021**
(Thousands)		
Projected benefit obligation	$ 252,879	$ 345,135
Accumulated benefit obligation	$ 252,879	$ 320,803
Fair value of plan assets	$ 201,556	$ 291,097

The postretirement benefits obligation for all qualified plans exceeded the fair value of plan assets as of December 31, 2022 and 2021.

Components of net periodic benefit cost and other changes in plan assets and benefit obligations recognized in income and regulatory assets and liabilities for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,	Pension Benefits 2022	Pension Benefits 2021	Postretirement Benefits 2022	Postretirement Benefits 2021
(Thousands)				
Net periodic benefit cost				
Service cost	$ 3,389	$ 5,333	$ 126	$ 158
Interest cost	10,580	6,379	1,444	1,298
Expected return on plan assets	(13,886)	(19,260)	—	—
Amortization of prior service credit	—	—	(356)	(550)
Amortization of net loss	8,257	16,275	(413)	522
Settlement charge	696	892	—	—
Net periodic benefit cost	**$ 9,036**	**$ 9,619**	**$ 801**	**$ 1,428**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net (gain) loss	$ 16,938	$ (27,437)	$ (14,191)	$ (4,584)
Amortization of net loss (gain)	(8,257)	(16,275)	413	(522)
Settlement charge	(696)	(892)	—	—
Effect of curtailments on gain	(19,737)	—	—	—
Amortization of prior service credit	—	—	356	550
Total recognized in regulatory assets and regulatory liabilities	**$ (11,752)**	**$ (44,604)**	**$ (13,422)**	**$ (4,556)**
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$ (2,716)**	**$ (34,985)**	**$ (12,621)**	**$ (3,128)**

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

The weighted-average assumptions used to determine benefit obligations as of December 31, 2022 and 2021 consisted of:

	Pension Benefits 2022	Pension Benefits 2021	Postretirement Benefits 2022	Postretirement Benefits 2021
Discount rate	5.08%	2.31%	5.08%	2.47%
Rate of compensation increase	N/A	Age-Related / 3.00%	N/A	3.00% union
Interest crediting rate	4.48%	2.00%	N/A	N/A

The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rate by developing a yield curve derived from a portfolio of high grade non-callable bonds with above median yields that closely matches the duration of the expected cash flows of our benefit obligations.

The weighted-average assumptions used to determine net periodic benefit cost for the years ended December 31, 2022 and 2021 consisted of:

	Pension Benefits		Postretirement Benefits	
	2022	2021	2022	2021
Discount rate	2.31% / 3.55% / 4.94%	1.70%	2.47%	2.00%
Expected long-term return on plan assets	6.00% / 5.50%	7.00%	N/A	N/A
Rate of compensation increase	Age-Related / 3.00% Union	Age-Related Rates / 3.00% union	N/A	3.00% union

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations and the effect of rebalancing of plan assets discussed below. That analysis considered current capital market conditions and projected conditions. Our policy is to calculate the expected return on plan assets using the market related value of assets. We amortize unrecognized actuarial gains and losses over 10 years from the time they are incurred.

Assumed health care cost trend rates used to determine benefit obligations as of December 31, 2022 and 2021 consisted of:

	2022	2021
Health care cost trend rate (pre 65/post 65)	6.25% / 7.00%	6.50%/7.25%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	4.50%	4.50%
Year that the rate reaches the ultimate trend rate	2029 / 2027	2029/2027

Contributions: In accordance with our funding policy, we make annual contributions of not less than the minimum required by applicable regulations. We do not expect to contribute to our pension benefit plan in 2022. We expect to contribute $4.9 million to our postretirement benefit plans during 2023.

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)			
2023	$ 36,873	$ 4,881	$ —
2024	$ 31,790	$ 4,715	$ —
2025	$ 28,842	$ 4,541	$ —
2026	$ 26,469	$ 4,382	$ —
2027	$ 24,273	$ 4,186	$ —
2028-2032	$ 91,709	$ 17,786	$ —

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

The asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets within broad categories of asset classes made up of Return-Seeking and Liability-Hedging investments. We have targets of 25%-60% for Return-Seeking assets and 40%-75% for Liability-Hedging assets. Return-Seeking investments generally consist of domestic, international, global, and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking assets also include investments in real estate, global asset allocation strategies and hedge funds. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS, and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of pension benefits plan assets, by asset category, as of December 31, 2022, consisted of:

		Fair Value Measurements at December 31, Using		
Asset Category	**Total**	**Level 1**	**Level 2**	**Level 3**
(Thousands)				
2022				
Cash and cash equivalents	$ 6,233	$ 5	$ 6,228	$ —
U.S. government securities	29,378	29,378	—	—
Common stocks	3,015	3,015	—	—
Registered investment companies	9,286	9,286	—	—
Corporate bonds	73,711	—	73,711	—
Preferred stocks	91	91	—	—
Common collective trusts	29,799	—	29,799	—
Other investments, principally annuity and fixed income	2,539	—	2,539	—
	$ 154,052	**$ 41,775**	**$ 112,277**	**$ —**
Other investments measured at net asset value	47,504			
Total	**$ 201,556**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2021, consisted of:

Asset Category	Total	Fair Value Measurements at December 31, Using Level 1	Level 2	Level 3
(Thousands)				
2021				
Cash and cash equivalents	$ 7,236	$ 2,247	$ 4,989	$ —
U.S. government securities	15,992	15,992	—	—
Common stocks	13,350	13,350	—	—
Registered investment companies	26,536	26,536	—	—
Corporate bonds	72,492	—	72,492	—
Preferred stocks	78	78	—	—
Common collective trusts	106,497	—	106,497	—
Other investments, principally annuity and fixed income	6,918	1	6,917	—
	$ 249,099	**$ 58,204**	**$ 190,895**	**$ —**
Other investments measured at net asset value	41,998			
Total	**$ 291,097**			

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, 2022 and 2021.

Note 15. Other Income and Other Deductions

Other income and deductions for the years ended December 31, 2022 and 2021, consisted of:

Years Ended December 31,		2022		2021
(Thousands)				
Interest and dividend income	$	2,574	$	209
Allowance for funds used during construction		12,945		12,669
Carrying costs on regulatory assets		2,673		5,593
Miscellaneous		196		50
Total other income	**$**	**18,388**	**$**	**18,521**
Pension non-service components	$	(6,781)	$	(5,553)
Miscellaneous		(1,941)		(354)
Total other deductions	**$**	**(8,722)**	**$**	**(5,907)**

Note 16. Related Party Transactions

Certain Networks subsidiaries borrow from AGR, the parent of Networks, through intercompany revolving credit agreements, including RG&E. For RG&E the intercompany revolving credit agreements provide access to supplemental liquidity. See Note 7 for further detail on the credit facility with AGR.

Avangrid Service Company provides some administrative and management services to Networks operating utilities, including RG&E, pursuant to service agreements. The cost of those services is allocated in accordance with methodologies set forth in the service agreements. The cost allocation methodologies vary depending on the type of service provided. Management believes such allocations are reasonable. The cost for services provided to RG&E by AGR and its affiliates was approximately $75.1 million in 2022 and $64.0 million in 2021. Cost for services includes amounts capitalized in utility plant, which was approximately $13.6 million in 2022 and $8.7 million in 2021. The remainder was primarily recorded as operations and maintenance expense. The charge for services provided by RG&E to AGR and its subsidiaries was approximately $25.3 million in 2022 and $18.9 million in 2021. 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 $54.1 million at December 31, 2022 and $48.4 million at December 31, 2021 is mostly payable to Avangrid Service Company. The balance in accounts receivable from affiliates of $3.6 million at December 31, 2022 and $2.9 million at December 31, 2021 is from various companies.

There were no notes receivable from affiliates at December 31, 2022 and December 31, 2021. 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 Ginna Nuclear Power Plant, LLC.

Note 17. Subsequent Events

The company has performed a review of subsequent events through March 22, 2023, which is the date these financial statements were available to be issued.

New York State Electric & Gas Corporation
Financial Statements
As of and for the Years Ended December 31, 2022 and 2021

New York State Electric & Gas Corporation

Index

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

Independent Auditors' Report

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

Opinion

We have audited the financial statements of New York State Electric & Gas Corporation (the Company), which comprise the balance sheets as of December 31, 2022 and 2021, 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.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

Basis for Opinion

We conducted our audits in accordance with auditing standards generally accepted in the United States of America (GAAS). Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with U.S. generally accepted accounting principles, and for 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.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for one year after the date that the financial statements are issued.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control related matters that we identified during the audit.

KPMG LLP

New York, New York
March 22, 2023

New York State Electric & Gas Corporation
Statements of Income

Years Ended December 31,	2022	2021
(Thousands)		
Operating Revenues	$ 2,220,777	$ 1,804,453
Operating Expenses		
Electricity purchased	675,965	396,439
Natural gas purchased	183,584	114,942
Operations and maintenance	793,570	756,212
Depreciation and amortization	190,719	172,600
Taxes other than income taxes, net	169,289	164,777
Total Operating Expenses	**2,013,127**	**1,604,970**
Operating Income	**207,650**	**199,483**
Other income	38,842	34,035
Other deductions	(11,951)	(15,703)
Interest expense, net of capitalization	(61,634)	(54,373)
Income Before Income Tax	**172,907**	**163,442**
Income tax expense	15,879	9,305
Net Income	**$ 157,028**	**$ 154,137**

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,	2022	2021
(Thousands)		
Net Income	**$ 157,028**	**$ 154,137**
Other Comprehensive Income (Loss), Net of Tax		
Amortization of pension cost for non-qualified plans and current year actuarial gain, net of income tax	286	108
Unrealized gain during the year on derivatives qualifying as cash flow hedges, net of income tax	1,002	486
Reclassification to net income of gain on settled cash flow commodity hedges, net of income tax	(1,026)	(304)
Reclassification to net income of loss on settled cash flow treasury hedges, net of income tax	87	63
Total Other Comprehensive Income, Net of Tax	**349**	**353**
Comprehensive Income	**$ 157,377**	**$ 154,490**

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

New York State Electric & Gas Corporation
Balance Sheets

As of December 31,	2022	2021
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$ 1	$ 1
Accounts receivable and unbilled revenues, net	430,952	301,099
Accounts receivable from affiliates	3,726	2,415
Fuel and natural gas in storage	55,701	22,100
Materials and supplies	32,870	25,031
Broker margin accounts	32,425	12,043
Derivative assets	—	7,977
Prepaid property taxes	38,020	38,090
Other current assets	11,136	3,318
Regulatory assets	141,420	112,422
Total Current Assets	**746,251**	**524,496**
Utility plant, at original cost	7,967,438	7,383,849
Less accumulated depreciation	(2,410,717)	(2,339,717)
Net Utility Plant in Service	**5,556,721**	**5,044,132**
Construction work in progress	674,505	597,562
Total Utility Plant	**6,231,226**	**5,641,694**
Operating lease right-of-use assets	9,022	8,345
Other property and investments	8,262	10,561
Regulatory and Other Assets		
Regulatory assets	830,199	742,160
Other	43,739	42,947
Total Regulatory and Other Assets	**873,938**	**785,107**
Total Assets	**$ 7,868,699**	**$ 6,970,203**

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

New York State Electric & Gas Corporation
Balance Sheets

As of December 31,	2022	2021
(Thousands, except share information)		
Liabilities		
Current Liabilities		
Current portion of long-term debt	$ 298,492	$ 73,083
Notes payable to affiliates	89,800	79,800
Accounts payable and accrued liabilities	615,117	445,640
Accounts payable to affiliates	113,221	100,067
Interest accrued	13,345	13,171
Taxes accrued	2,380	39,508
Operating lease liabilities	1,293	915
Derivative liabilities	21	27
Environmental remediation costs	14,254	27,657
Customer deposits	13,300	19,810
Regulatory liabilities	67,048	106,440
Other	162,432	100,883
Total Current Liabilities	**1,390,703**	**1,007,001**
Regulatory and Other Liabilities		
Regulatory liabilities	1,040,544	1,074,886
Other Non-current Liabilities		
Deferred income taxes	770,556	664,095
Pension and other postretirement	87,538	143,562
Operating lease liabilities	8,573	8,294
Asset retirement obligation	11,349	11,583
Environmental remediation costs	62,828	64,832
Other	26,180	27,577
Total Regulatory and Other Liabilities	**2,007,568**	**1,994,829**
Non-current debt	2,041,562	1,997,311
Total Liabilities	**5,439,833**	**4,999,141**
Commitments and Contingencies		
Common Stock Equity		
Common stock ($6.66 2/3 par value, 90,000,000 shares authorized and 64,508,477 shares outstanding at December 31, 2022 and 2021)	430,057	430,057
Additional paid-in capital	1,529,469	1,054,042
Retained earnings	470,160	488,132
Accumulated other comprehensive loss	(820)	(1,169)
Total Common Stock Equity	**2,428,866**	**1,971,062**
Total Liabilities and Equity	**$ 7,868,699**	**$ 6,970,203**

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,	2022	2021
(Thousands)		
Cash Flow from Operating Activities:		
Net income	**$ 157,028**	**$ 154,137**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	190,719	172,600
Regulatory assets/liabilities amortization	(98,703)	(11,984)
Regulatory assets/liabilities carrying cost	(6,333)	(568)
Amortization of debt issuance costs	2,036	808
Deferred taxes	64,665	20,345
Pension cost	24,685	33,795
Stock-based compensation	520	451
Accretion expenses	608	648
Gain from disposal of property	(3,200)	(675)
Other non-cash items	(71,636)	(54,374)
Changes in assets and liabilities		
Accounts receivable, from affiliates, and unbilled revenues	(131,164)	(43,962)
Inventories	(41,440)	(15,719)
Accounts payable, to affiliates, and accrued liabilities	90,290	148,389
Taxes accrued	(37,130)	33,223
Other assets/liabilities	107,958	73,311
Regulatory assets/liabilities	(190,907)	(110,284)
Net Cash Provided by Operating Activities	**57,996**	**400,141**
Cash Flow from Investing Activities:		
Capital expenditures	(685,078)	(799,032)
Contributions in aid of construction	45,420	48,072
Proceeds from sale of property, plant and equipment	7,224	2,178
Notes receivable from affiliates	—	7,150
Net Cash Used in Investing Activities	**(632,434)**	**(741,632)**
Cash Flow from Financing Activities:		
Non-current debt issuance	342,623	346,807
Repayments of non-current debt	(75,000)	—
Payments of finance leases	(3,185)	(381)
Notes payable to affiliates	10,000	79,800
Capital contribution	475,000	185,000
Dividends paid	(175,000)	(270,000)
Net Cash Provided by Financing Activities	**574,438**	**341,226**
Net Decrease in Cash and Cash Equivalents	**—**	**(265)**
Cash and Cash Equivalents, Beginning of Year	**1**	**266**
Cash and Cash Equivalents, End of Year	**$ 1**	**$ 1**

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

New York State Electric & Gas Corporation
Statements of Changes in Common Stock Equity

(Thousands, except per share amounts)	Number of Shares (*)	Common Stock	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stock Equity
Balance, December 31, 2020	**64,508,477**	**$ 430,057**	**$ 868,686**	**$ 603,995**	**$ (1,522)**	**$ 1,901,216**
Net income	—	—	—	154,137	—	154,137
Other comprehensive loss, net of tax	—	—	—	—	353	353
Comprehensive income						154,490
Stock-based compensation	—	—	356	—	—	356
Common stock dividends	—	—	—	(270,000)	—	(270,000)
Capital contribution	—	—	185,000	—	—	185,000
Balance, December 31, 2021	**64,508,477**	**430,057**	**1,054,042**	**488,132**	**(1,169)**	**1,971,062**
Net income	—	—	—	157,028	—	157,028
Other comprehensive income, net of tax	—	—	—	—	349	349
Comprehensive income						157,377
Stock-based compensation	—	—	427	—	—	427
Common stock dividends	—	—	—	(175,000)	—	(175,000)
Capital contribution	—	—	475,000	—	—	475,000
Balance, December 31, 2022	**64,508,477**	**$ 430,057**	**$ 1,529,469**	**$ 470,160**	**$ (820)**	**$ 2,428,866**

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

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

Notes to Financial Statements

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

Background and nature of operations: New York State Electric & Gas Corporation (NYSEG, the company, we, our, us) conducts regulated electricity transmission and distribution operations and regulated natural gas transportation, storage and distribution operations in upstate New York. It also generates electricity, primarily from its several hydroelectric stations. NYSEG serves approximately 917,000 electricity and 272,000 natural gas customers as of December 31, 2022, in its service territory of approximately 20,000 square miles, which is located in the central, eastern and western parts of the state of New York and has a population of approximately 2.5 million. The larger cities in which NYSEG serves electricity and natural gas customers are Binghamton, Elmira, Auburn, Geneva, Ithaca and Lockport. We operate under the authority of the New York State Public Service Commission (NYPSC) and are also subject to regulation by the Federal Energy Regulatory Commission (FERC).

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

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

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

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

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

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

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

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

We transfer assets from “Construction work in progress” to “Utility plant” when they are available for service.

We determine depreciation expense for utility plant in service using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Consistent with FERC accounting requirements, we charge the original cost of utility plant retired or otherwise disposed of to accumulated depreciation. Our composite rate for depreciation was 2.3% of average depreciable property for both 2022 and 2021. We amortize our capitalized software cost which is included in common plant, using the straight line method, based on useful lives of 7 to 27 years. Capitalized software costs were approximately $275.6 million as of December 31, 2022 and $254.9 million as of December 31, 2021. Depreciation expense was $176.2 million in 2022 and $161.4 million in 2021. Amortization of capitalized software was $14.5 million in 2022 and $11.2 million in 2021.

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

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

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

Utility Plant	**Estimated useful life range (years)**	**2022**	**2021**
(Thousands)			
Electric	2-80	$ 5,646,997	$ 5,252,740
Natural Gas	2-75	1,309,408	1,260,361
Common	7-70	1,011,033	870,748
Total Utility Plant in Service		**7,967,438**	**7,383,849**
Total accumulated depreciation		(2,410,717)	(2,339,717)
Total Net Utility Plant in Service		**5,556,721**	**5,044,132**
Construction work in progress		674,505	597,562
Total Utility Plant		**$ 6,231,226**	**$ 5,641,694**

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

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

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

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

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

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

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

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

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

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

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

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

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

Changes in conditions or the occurrence of unforeseen events could require discontinuance of the hedge accounting or could affect the timing of the reclassification of gains or losses on cash flow hedges from OCI into earnings. We record changes in the fair value of electric and natural gas hedge contracts to derivative assets or liabilities with an offset to regulatory assets or regulatory liabilities.

We offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement.

Notes to Financial Statements

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

Concentration of risk: We maintain our cash and cash equivalents in accounts with major financial institutions in the form of demand deposits and money market accounts. Deposits in these financial institutions may exceed the amount of federal deposit insurance provided on such deposits.

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

(Thousands)		2022		2021
Cash paid during the years ended December 31:				
Interest, net of amounts capitalized	$	55,562	$	47,314
Income taxes refunded, net	$	(12,859)	$	(36,996)

Of the income taxes refunded, substantially all was refunded to AGR under the tax sharing agreement. Interest capitalized was $10.8 million in 2022 and in $8.8 million in 2021. Accrued liabilities for utility plant additions were $98.3 million and $6.6 million as of December 31, 2022 and 2021, respectively.

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

***Trade receivables and unbilled revenues, net of allowance for credit losses*:** We record trade receivables at amounts billed to customers and we record unbilled revenues based on an estimate of energy delivered or services provided to customers. The estimates for unbilled revenues are determined based on various assumptions, including current month energy load requirements, billing rates by customer class and delivery loss factors. Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

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

Trade receivables at December 31 include unbilled revenues of $119.7 million for 2022 and $101 million for 2021, and are shown net of an allowance for credit losses at December 31 of $52.6 million for 2022 and $49.3 million for 2021. Trade receivables do not bear interest, although late fees may be assessed. Credit loss expense was $47.7 million in 2022, including $24.5 million of arrears forgiveness balances that will be recovered through a tariff over the next 3 years. Credit loss expense was $20.7 million in 2021, with no arrears forgiveness balances.

Trade receivables include amounts due under deferred payment arrangements (DPAs). When a residential customer becomes delinquent in making payments, the NYPSC requires us to allow the customer to enter into a DPA to settle the account balance. A DPA allows the account balance to be paid in installments without interest over an extended period of time, which generally exceeds one year, by negotiating mutually acceptable payment terms. Generally, we must continue to serve a customer who cannot pay an account balance in full if the customer: (i) pays a reasonable portion of the balance; (ii) agrees to pay the balance in installments; and (iii) agrees to pay future bills within 30 days until the DPA is paid in full. Failure to make payments on a DPA results in the full amount of a receivable under a DPA being due. These accounts are part of the regular operating cycle and we classify them as short term.

We establish our allowance for credit losses, including for unbilled revenue (also referred to as contract assets), by using both historical average loss percentages to project future losses, and by establishing a specific allowance for known credit issues or for specific items not considered in the historical average calculation. We consider whether we need to adjust historical loss rates to reflect the effects of current conditions and forecasted changes considering various economic indicators (e.g., Gross Domestic Product, Personal Income, Consumer Price Index, Unemployment Rate) over the contractual life of the trade receivables. We write off amounts when we have exhausted reasonable collection efforts. The allowance for credit losses for DPAs at December 31 was $13.6 million for 2022 and $14.6 million for 2021. DPA receivable balances at December 31 were $28.2 million for 2022 and $23.4 million for 2021.

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

***Inventory**:* Inventory comprises fuel and natural gas in storage and materials and supplies. We own natural gas that is stored in third-party owned underground storage facilities, which we record as inventory. We price injections of inventory into storage at the market purchase cost at the time of injection, and price withdrawals of working gas from storage at the weighted-average cost in storage. We continuously monitor the weighted-average cost of gas value to ensure it remains at the lower of cost and net realizable value. We report inventories to support gas operations on our balance sheets within “Fuel and natural gas in storage.”

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

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

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

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

The changes in government grants recorded as a reduction to the related utility plant as of December 31, 2022 and 2021 consisted of:

(Thousands)	Government grants	Total
As of December 31, 2020	**$ 11,365**	**$ 11,365**
Disposals	—	—
Recognized in income	(291)	(291)
As of December 31, 2021	**$ 11,074**	**$ 11,074**
Disposals	—	—
Recognized in income	(291)	(291)
As of December 31, 2022	**$ 10,783**	**$ 10,783**

We are required to comply with certain terms and conditions applicable to each grant and, if a disqualifying event should occur as specified in the grant's terms and conditions, we are required to repay the grant funds to the government. We believe we are in compliance with each grant's terms and conditions as of December 31, 2022 and 2021.

Deferred income: Apart from government grants, we occasionally receive revenues from transactions in advance of the resulting performance obligations arising from the transaction. It is our policy to defer such revenues on our balance sheets and amortize them into earnings when revenue recognition criteria are met.

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

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

The following table reconciles the beginning and ending aggregate carrying amount of the ARO for the years ended December 31, 2022 and 2021.

Notes to Financial Statements

Years ended December 31,		2022		2021
(Thousands)				
ARO, beginning of year	$	11,583	$	12,284
Liabilities settled during the year		(842)		(1,349)
Accretion expense		608		648
ARO, end of year	**$**	**11,349**	**$**	**11,583**

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

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

Environmental remediation liability: In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. We record our environmental liabilities on an undiscounted basis. We expect to pay our environmental liability accruals through the year 2048.

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

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

We account for defined benefit pension or other postretirement plans, recognizing an asset or liability for the overfunded or underfunded plan status. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. We generally reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in OCI, as management believes it is probable that such items will be recoverable through the ratemaking process. Certain nonqualified plan expenses are not recoverable through the ratemaking process and we present the unrecognized prior service costs and credits and unrecognized actuarial gains and losses in accumulated other comprehensive loss. If a plan meets settlement or curtailment accounting criteria, we recognize a regulatory asset or liability if these costs are probable of recovery from ratepayers. 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 by assigning an equal amount to each future period of service of each employee active on the date of the amendment who is expected to receive benefits under the plan. Prior service cost changes resulting from union bargaining agreements are amortized on a straight-line basis over the period from first recognition to the end of the bargaining agreement. We amortize unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans over 10 years from the time they are incurred as required by the NYPSC. Our policy is to calculate the expected return on plan assets using the market-related value of assets. We determine that value by recognizing the difference between actual returns and expected returns over a five-year period.

***Income taxes*:** In August 2022, the Inflation Reduction Act of 2022 ("IRA") was signed into law in the United States. The IRA created a new corporate alternative minimum tax (“CAMT”) of 15% on adjusted financial statement income and an excise tax of 1% on the value of certain stock repurchases. Based on initial guidance, NYSEG currently expects to be subject to the CAMT starting in 2023 but does not expect it to have a material impact on earnings, financial condition, or cash flow. Given the complexity and uncertainty around the applicability of the legislation to our specific facts and circumstances, the company continues to analyze the IRA provisions while waiting on pending Department of Treasury regulatory guidance.

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

The aggregate amount of the related party income tax payable to AGR is $0.1 million and $31.9 million at December 31, 2022 and 2021, respectively.

We use the asset and liability method of accounting for income taxes. Deferred tax assets and liabilities reflect the expected future tax consequences, based on enacted tax laws, of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts. In accordance with U.S. GAAP for regulated industries, we have established regulatory assets and liabilities for the net revenue requirements to be recovered from or refunded to customers for the related future tax expense or benefit associated with certain of these temporary differences. We defer investment tax credits when earned and amortize them over the estimated lives of the related assets. We also recognize the income tax consequences of intra-entity transfers of assets other than inventory when the transfer occurs. We had no intra-entity transfers of assets other than inventory during the years ended December 31, 2022 and 2021.

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

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

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

Uncertain tax positions have been classified as non-current unless expected to be paid within one year. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the statements of income.

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

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

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

Adoption of New Accounting Pronouncements

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

(a) Disclosures by business entities about government assistance

In November 2021, the FASB issued guidance that requires an entity to provide certain annual disclosures about government assistance received and accounted for by applying a grant or contribution accounting model by analogy. As the guidance is disclosure only, it did not have an impact to the financial results.

Accounting Pronouncements Issued But Not Yet Adopted

There have been no accounting pronouncements issued but not yet adopted that are expected to have a material impact on NYSEG’s 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 credit losses and unbilled revenues; (2) asset impairments; (3) depreciable lives of assets; (4) income tax valuation allowances; (5) uncertain tax positions; (6) reserves for professional, workers’ compensation, and comprehensive general insurance liability risks; (7) contingency and litigation reserves; (8) earnings sharing mechanism (ESM); (9) environmental remediation liabilities; (10) pension and other postretirement employee benefits (OPEB); (11) fair value measurements and (12) AROs. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our financial statements will change as new events occur, as more experience is acquired, as additional information is obtained, and as our operating environment changes. We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside specialists to assist in our evaluations, as considered necessary. Actual results could differ from those estimates.

Union collective bargaining agreements: Approximately 74% of our employees are covered by a collective bargaining agreement. We have no agreements that will expire within the coming year.

Note 2. Industry Regulation

Electricity and Natural Gas Distribution

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

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

NYSEG Rate Plan

On May 20, 2019, NYSEG filed rate cases requesting increases in delivery revenues for both its electric and gas businesses. Other parties to the rate cases filed direct testimony on September 20, 2019, and NYSEG filed rebuttal testimony on October 15, 2019. The Administrative Law Judges in the cases agreed to a series of extensions of the litigation schedule to allow the Company, the Department of Public Service Staff (DPS Staff), and other parties to enter into and conduct settlement discussions. A Joint Proposal for a three year rate plan term was filed on June 22, 2020. A modified Joint Proposal was approved by the NYPSC on November 19, 2020, which included modifications to the electric business proposed rate increases to limit the projected total bill increases to 2% per year in consideration of the current COVID-driven economic climate. The effective date of new tariffs was December 1, 2020 with a make-whole provision back to April 17, 2020. The approved Joint Proposal includes several COVID-19 provisions, including the provision of up to $16.5 million in bill credits for the Company's most vulnerable residential and small business customers. The Joint Proposal bases delivery revenues on an 8.80% ROE and 48% equity ratio; however, for the proposed earnings sharing mechanism, the equity ratio is the lower of the actual equity ratio or 50%. The approved Joint Proposal was signed in whole or in part by more than 20 parties, and includes delivery rate increases (excluding the impact of moving energy efficiency costs from a surcharge to delivery rates) as summarized below:

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

The approved Joint Proposal also reflects increased distribution vegetation management, investments in aging infrastructure, the implementation of Advanced Metering Infrastructure (AMI), and increases in the Company's workforce. The approved Joint Proposal reflects the recovery of deferred NYSEG Electric storm costs of approximately $227 million, of which $194 million will be amortized over ten years and the remaining $33 million will be amortized over five years. The approved Joint Proposal also continued reserve accounting for qualifying Major Storms ($25.6 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 approved Joint Proposal maintained 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 maintained 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 approved Joint Proposal established threshold performance levels for designated aspects of customer service quality and continues bill reduction and arrears forgiveness Low Income Programs. REV-related incremental costs and fees will be included in the revenue adjustment mechanism (RAM) to the extent cost recovery is not provided for elsewhere. Under the approved Joint Proposal, NYSEG continues the RAM, which is applicable to all customers, to return or collect RAM Eligible Deferrals and Costs, including: (1) property taxes; (2) Major Storm deferral balances; (3) gas leak prone pipe replacement; (4) REV costs and fees which are not covered by other recovery mechanisms; (5) COVID-19 bill credits; (6) certain Electric Vehicle program costs; and (7) Energy Efficiency and Heat Pump program costs in excess of what is included in delivery rates.

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

NYSEG Rate Case Filing

On May 26, 2022, NYSEG made an initial filing to the NYPSC requesting increases to the delivery rates for its electric business of 31.2% and for its gas business of 20.7%. This initial filing started a lengthy process guided by NYPSC regulations. The Department of Public Service Staff and other parties to the rate cases submitted testimony on September 26, 2022. On October 18, 2022, the Companies submitted rebuttal testimony responding to the testimony of Department of Public Service Staff and other parties to the proceedings. On October 19, 2022, the Companies filed a notice of impending settlement negotiations. On November 2, 2022, the parties to the proceedings entered into confidential settlement discussions, which are expected to continue into the second quarter of 2023. The Company is seeking an order from the NYPSC related to the Company's request in the second quarter of 2023.

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.

In 2015, the NYPSC issued an 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, as required, and bi-annual updates on July 31, 2018 and June 30, 2020. The Joint Utilities requested an extension to December 30, 2022 for the next bi-annual update, which was granted by the Commission. An additional request for extension to June 30, 2023 was submitted by the Joint Utilities, which was subsequently granted by the Commission.

A Track 2 order was issued in May 2016, and included guidance related to the potential for Earnings Adjustment Mechanisms (EAMs), Platform Service Revenues, innovative rate designs, and data utilization and security. EAMs proposed in the companies' May 20, 2019 rate filing and approved by the Commission on November 19, 2020 in its Order approving the Companies' Rate Plan.

In March, 2017, the NYPSC issued three separate REV-related orders. The three orders involve: 1) modifications to the electric utilities' proposed interconnection EAM framework; 2) further DSIP requirements, including the filing of an updated DSIP plan by mid-2018 and implementing two energy storage projects at NYSEG by the end of 2018; and 3) Net Energy Metering Transition including implementation of Phase One of VDER. NYSEG 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 provided for a market transition consistent with the principles of gradualism and predictability and established a tranche system to manage impacts on non-participants.

The March 2017 Order also directed a Phase Two of the VDER proceeding. Phase Two would encompass improvements to the interim methodology established in Phase One, seek to expand

Value Stack eligibility to technologies not included in Phase One, and review rate designs for mass market (i.e., residential and small non-residential) on-site DERs. Several orders were subsequently issued to further address VDER matters, which are summarized below.

- On April 18, 2019, the Commission issued an Order on Future Value Stack Compensation and Capacity Value Compensation. The Order established a new Community Credit in place of the Market Transition Credit for certain CDG projects in NYSEG's and RG&E's service territories and expanded eligibility for Phase One Net Metering for certain projects that have a rated capacity of 750 kW AC or lower. The changes became effective on June 1, 2019. On December 12, 2019, the NYPSC issued an Order Regarding Consolidated Billing For Community Distributed Generation. This Order led to CDG subscription charges being on the NYSEG bill along with the CDG subscription credits, resulting in easier billing for customers and lower billing and service costs for CDG Hosts. Also on December 12, 2019, the NYPSC issued an Order on Value Stack Compensation for High-Capacity-Factor Resources, modifying the treatment of certain high-capacity-factor DER in the Value Stack compensation framework. The modification per the December 12, 2019 Order became effective February 1, 2020. On March 19, 2020, the Commission issued an additional Order regarding additional Value Stack Compensation. The new provisions per the March 19, 2020 Order became effective May 1, 2020. As eligible projects are interconnected, each project will receive MTC or Community Credit compensation for kWh produced, and the dollars provided to each project for this compensation will ultimately be collected from customers in a surcharge.

- On May 16, 2019, the Commission issued an Order on Standby and Buyback Service and Establishing Optional Demand Rates. The Order expands the availability of demand rates based on standby service rate design principles by requiring utilities to file tariffs to provide opt-in eligibility for all customers, including mass market (i.e., residential), to a demand-based rate option, irrespective of whether customers have on-site DERs. The availability of existing standby rates was expanded to all current demand-billed customers on an optional basis beginning July 1, 2019. A Commission Order was issued on March 16, 2022 adopting a new cost allocation methodology for standby and buyback service rates. Utilities were required to file draft tariff leaves by July 14, 2022, implementing the new methodology. Once approved, the rates will be required for customers with on-site generation, and available to all other customers on an optional basis, including residential customers. NYSEG filed its draft tariffs on July 14, 2022. At this time, it is not known when the Commission will rule on the draft tariffs.

- On May 14, 2020, the Commission issued an Order extending and expanding distributed solar incentives. In addition to authorizing the extension of and additional funding for the NY-Sun program, the Commission modified certain program rules related to the NY-Sun program and the VDER policy. Tariffs implementing the above requirements became effective on September 1, 2021. The result of this Order reshaped an existing program and the impact to the Companies should be minimal.

- On July 16, 2020, the Commission issued an Order establishing a net metering successor tariff. The Order continues Phase One NEM for all eligible mass market and commercial projects under 750 kW interconnected after January 1, 2022 and implements a modest customer benefit contribution (CBC) for onsite DERs to address cost recovery of certain public benefit programs. Customers that install DERs interconnected after January 1, 2022 are charged a monthly per kW fee based on the nameplate rating of the DER. A final

Commission Order was issued on August 13, 2021 implementing the CBC effective January 1, 2022 for new mass market net metering customers.

- On July 14, 2022 the Commission issued an Order approving remote crediting banking rules and addressing switching between CDG and remote crediting programs. The rules provide uniformity in the application of banking rules for the CDG, Net Crediting and Remote Crediting programs. The credits provided through these programs are recovered from other customers.

- On September 15, 2022 the Commission issued an Order to address ongoing issues associated with timeliness and accuracy of CDG billing by utilities. The Commission is focusing on developing CDG crediting and billing performance metrics and a negative revenue adjustment for failure to meet those metrics. At this time, the outcome of the proceeding is unknown.

Other REV-related orders pertaining to electric vehicles (EV), an Integrated Energy Data Resource (IEDR) platform and energy storage are summarized below.

- On April 24, 2018, the Commission instituted a proceeding to consider the role of utilities in providing infrastructure and rate design to encourage the adoption of electric vehicles (EV) and expansion of electric vehicle supply equipment. The Commission issued an Order on February 2, 2019 to establish a Direct Current Fast Charger incentive program, and subsequently clarified its Order on July 12, 2019 and March 3, 2020. A subsequent order in this proceeding was issued on July 16, 2020 approving a $700 million statewide program (NYSEG and RG&E combined share is approximately $118 million) funded by customers to accelerate the deployment of electric vehicle charging stations in an effort to increase the number of electric vehicles. In addition, the July 16, 2020 Order directed the Utilities to submit filings to develop managed charging programs that would provide mass market customers with an alternative to the EV TOU rates already in place. NYSEG complied by submitting its proposal on December 4, 2020 and subsequently filed suggestion revisions on June 4, 2021. On July 14, 2022 the Commission approved NYSEG's program with modifications.

- On December 13, 2018, the Commission issued an Order for NYSEG to file an implementation plan detailing a competitive procurement process and cost recovery for deploying 10 MW of qualified storage systems. NYSEG filed its implementation plan and has issued requests for proposals to site storage systems within their service territory. On April 16, 2021, the Commission issued an Order to modify the term offered to developers for energy storage contracts and extended the in-service date for deployment of the 10 MW of energy storage. The Companies have tariffs in effect to collect costs for the procurement of qualified energy storage assets.

- On February 11, 2021, the Commission issued an Order to implement an Integrated Energy Data Resource platform, where NYSERDA was designated as the Program Sponsor of the platform. The Order established a combined cost cap of $12 Million for NYSEG and RG&E for Phase 1, to be deferred and recovered in the next rate case filing after Phase 1 is complete.

- On April 21, 2022, the Commission issued a Notice Soliciting Comments regarding the establishment of a commercial tariff to facilitate faster charging for eligible light duty, heavy duty and fleet electric vehicles. The notice is in response to enactment of Public Service Law 66-s which requires the Commission to establish a tariff utilizing alternative to traditional demand-based rate structures (i.e., solutions) to facilitate faster charging for eligible vehicles. The Commission issued an Order that adopted an immediate solution where a rebate will be provided to participants and a near-term solution where NYSEG will submit an EV Phase-in Rate solution. NYSEG will file an Implementation plan that includes a cost recovery mechanism.

Customer Arrearages Reduction Order

On June 16, 2022, the NYPSC issued an order (Phase 1) authorizing an arrears reduction program targeting low-income customers to provide COVID-19-related relief through a one-time bill credit to eliminate accrued arrears through May 1, 2022. A portion of the targeted arrearages will be funded via direct contributions from the State of New York, and the remainder to be received via a surcharge to all customers. The surcharge recovery is over three years for NYSEG beginning on August 1, 2022.

On January 19, 2023, the NYPSC issued a subsequent order (Phase 2) providing bill relief for customers who did not receive a credit as part of the Phase 1 Program approved in 2022 (Low Income Program participants). Qualifying residential and small business customers are eligible to have any past-due balance from bills for service through May 1, 2022, reduced through a one time bill credit, up to a maximum credit below:

Residential	Total Forecast Residential Credits (Millions)	Small Business	Total Forecast Small Business Credits (Millions)
Up to $,1000	$16.9	Up to $1,250	$1.4

Community Leadership and Climate Protection Act Transmission

Pursuant to the Community Leadership and Climate Protection Act of 2019 (CLCPA) and Accelerated Renewable Energy Growth and Community Benefit Act of 2020, the Commission has issued orders addressing investment in transmission by NYSEG to support the state achieving the CLCPA's goal of 70% renewable energy by 2030. First, on December 15, 2022, the Commission issued an Order authorizing NYSEG to continue the development of CLCPA "Phase 1" transmission projects with an estimated investment of approximately $1.27 billion through 2030. CLCPA Phase 1 transmission projects are upgrades to the NYSEG local transmission system that are being developed to satisfy reliability needs, but that also create headroom on the transmission system for the interconnection and delivery of new generation sources. The December 15, 2022 Order allows NYSEG to continue development of the projects while the rate case is pending, with any final project approvals to be addressed in the rate case.

Second, on February 16, 2023, the Commission issued an Order approving the investment of approximately $2.05 billion by NYSEG through 2030 in CLCPA "Phase 2" transmission projects. Phase 2 transmission projects are upgrades to the NYSEG local transmission system that are being developed primarily to allow for the interconnection and delivery of renewable energy in the Southern Tier, an area that the Commission has designated as an "Area of Concern" for renewable energy development because there is substantial renewable energy development interest but inadequate transmission. Unlike other transmission owned by NYSEG, the cost of

CLCPA Phase 2 transmission will be recovered pursuant to a formula rate under the jurisdiction of the Federal Energy Regulatory Commission (FERC) so that costs can be allocated statewide. NYSEG and other transmission-owning utilities in New York negotiated a Cost Sharing and Recovery Agreement (CSRA), which was approved by the Commission on May 12, 2022, and by FERC on August 22, 2022. Under the terms of the CSRA the cost of CLCPA Phase 2 transmission projects approved by the Commission will be recovered through the New York Independent System Operator tariff, with ROE and capital structure determined by the Commission, subject to an ROE ceiling set by FERC.

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 $97.3 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

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

On November 19, 2020, the NYPSC approved the Proposal in connection with a three-year rate plan for electric and gas service at NYSEG effective April 17, 2020. Following the approval of the proposal most of these items related to NYSEG are amortized over a three- or five-year period, except the portion of storm costs to be recovered over ten years, plant related tax items which are amortized over the life of associated plant, and unfunded deferred taxes which are amortized over forty six years. In accordance with the Schedule of Regulatory Amortizations included in the approved Joint Proposal, annual net amortization revenue for NYSEG is approximately $88.7 million for the year ended December 31, 2022.

Regulatory assets at December 31, 2022 and 2021 consisted of:

December 31,	2022	2021
(Thousands)		
Asset retirement obligation	$ 11,550	$ 11,757
COVID-19 deferral	—	6,014
COVID-19 late payment surcharge	2,669	—
Electric supply reconciliation	18,927	8,213
Environmental remediation costs	50,332	68,251
Federal tax depreciation normalization adjustment	79,411	83,212
Low income programs	14,252	8,871
Low income arrears forgiveness	14,332	—
Pension and other post-retirement benefits	62,615	114,164
Pension and other post-retirement benefits cost deferrals	40,783	60,016
Rate adjustment mechanism	33,158	54,077
Rate change levelization	—	11,354
Revenue decoupling mechanism	4,479	2,661
Sales and use tax audit deferral	17,911	11,016
Storm costs	456,467	298,986
Unamortized loss on re-acquired debt	11,411	13,129
Unfunded future income taxes	8,972	—
Value distributed energy resource	24,810	11,849
Vegetation management	61,611	51,447
Other	57,929	39,565
Total regulatory assets	**971,619**	**854,582**
Less: current portion	141,420	112,422
Total non-current regulatory assets	**$ 830,199**	**$ 742,160**

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.

COVID-19 cost deferral represents deferred COVID-19 related uncollectible costs net of amounts in rates.

COVID-19 late payment surcharge represents deferred lost late payment revenue in the state of New York based on the order issued by PSC on June 17, 2022, approving deferral and surcharge/sur-credit mechanism to recover/return deferred balances starting July 1, 2022.

Electric supply reconciliation represents over/under collection of costs related to electric supply in which NYSEG supplies electricity as the default service option for customers.

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.

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

Low income arrears forgiveness represents deferred bill credits in the state of New York based on the order issued by the NYPSC on June 16, 2022, approving deferral of bill credits for low-income customers and recovery of regulatory asset from all customers over three years. Surcharge is effective August 1, 2022.

Pension and other postretirement benefits represent the actuarial losses on the pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future pension expenses. Because no funds have yet been expended for this regulatory asset, it does not accrue carrying costs and is not included within the rate base.

Pension and other postretirement benefits cost deferrals include the difference between actual expense for pension and other postretirement benefits and the amount provided for in rates. A portion of this balance is amortized through current rates over a five-year amortization period which began in 2020. The remaining balance will be refunded in future periods through future rate cases.

Rate adjustment Mechanism (RAM) represents a mechanism each business implements to return or collect the net balance of RAM eligible deferrals and costs. The primary driver of RAM collections is storm costs but it also includes property taxes, REV costs and fees not covered in other recovery mechanisms, energy efficiency program costs, and COVID customer bill credits.

Rate change levelization represents NY delivery rate levelization to smooth the rate increase across the three-year plan to avoid unnecessary spikes and offsetting dips in customer rates.

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

Sales and use tax audit deferral represents sales and use tax refund allocated to operating expenses.

Storm costs for NYSEG are allowed in rates based on an estimate of the routine costs of service restoration. NYSEG is also allowed to defer unusually high levels of service restoration costs resulting from major storms when they meet certain criteria for severity and duration. Since the approval of the 2010 rate plan in New York (see Note 2), we have experienced unusually high levels of restoration costs resulting from various storms including Hurricane Sandy, Hurricane Irene and tropical storm Lee. NYSEG’s total storm balance was $456.5 million at December 31, 2022 and $299.0 million at December 31, 2021. Pursuant to the most recent Joint Proposal approved by the Commission, which began May 1, 2020, NYSEG will recover $33.0 million of the balance over five years and $119.2 million of the balance over ten years for non-super-storms, and $74.8 million of the balance over ten years for the super-storm balance.

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

Value distributed energy resource represents a mechanism to compensate energy created by distributed energy resources like solar.

Vegetation management represents a program to address danger trees outside of the distribution right-of-way, including but not limited to, ash trees.

Other includes items such as COVID customer bill credits not in RAM and Reforming the Energy Vision (REV).

Regulatory liabilities at December 31, 2022 and 2021 consisted of:

December 31,	**2022**	**2021**
(Thousands)		
Accrued removal obligation	$ 472,647	$ 496,392
Accumulated deferred investment tax credits	11,197	11,841
Carrying costs on deferred income tax depreciation	—	3,271
Carrying costs on mixed use 263(a)	390	3,082
Debt rate reconciliation	26,611	32,073
Economic development	6,546	7,576
Energy efficiency programs	8,833	22,128
Gas supply charge and deferred natural gas cost	14,514	5,003
Hedge gains	—	9,031
Merchant function charge	188	1,406
New York 2018 winter storm settlement	2,881	5,782
Non by-passable charges	5,482	5,695
Pension and other postretirement benefits	48,159	19,125
Pension and other postretirement benefits cost deferral	13,261	17,901
Positive benefit adjustment	323	1,048
Property tax	4,161	5,578
Rate change levelization	13,329	40,857
Service quality performance mechanism	30,788	20,263
Tax Act remeasurement	378,015	410,772
Theoretical reserve flow through impact	—	2,306
Unfunded future income taxes	1,398	1,478
Other	68,869	58,718
Total regulatory liabilities	**1,107,592**	**1,181,326**
Less: current portion	67,048	106,440
Total non-current regulatory liabilities	**$ 1,040,544**	**$ 1,074,886**

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

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

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

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

Debt rate reconciliation represents the over/under collection of costs related to fixed and variable rate debt instruments identified in the rate case. Costs include interest, commissions and fees versus amounts included in rates.

Economic development represents the economic development program which enables NYSEG to foster economic development through attraction, expansion, and retention of businesses within its service territory. If the level of actual expenditures for economic development allocated to NYSEG varies in any rate year from the level provided for in rates, the difference is refunded to ratepayers. The amortization period is five years following the approval of the proposal by the NYPSC.

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

Gas supply costs represent the actual costs of purchasing, transporting and storing natural gas for those customers who receive their natural gas supply from NYSEG.

Hedge gains regulatory liability represents the deferred fair value gains on electric and gas hedge contracts.

Merchant function charge represents the administrative costs of obtaining natural gas supply. Customers with supplier other than NYSEG are not charged for this service.

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

Non by-passable charges represent the non by-passable charge paid by all customers. An asset or liability is recognized resulting from differences between actual revenues and the underlying cost being recovered. This liability will be refunded to customers within the next year.

Pension and other postretirement benefits represent the actuarial gains on pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future expenses. Because no funds have yet been received for this, a regulatory liability is not reflected within rate base. They also represent the difference between actual expense for pension and other postretirement benefits and the amount provided for in rates. A portion of this balance is amortized through current rates; the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is five years and began in 2020.

Positive benefit adjustment resulted from Iberdrola's 2008 acquisition of Energy East. This is being used to moderate increases in rates. The amortization period is three years following the approval of the proposal by the NYPSC and included in the Ginna RSSA settlement.

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. The amortization period in current rates is five years and began in 2020.

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

Tax Act - remeasurement represents the impact from remeasurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates from 35% to 21% under the provisions of the Tax Act will result in amounts previously collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates. The amortization period in current rates is from one and half to ten years and began in 2020.

Theoretical reserve flow through impact represents the differences from the rate allowance for applicable federal and state flow through impacts related to the excess depreciation reserve amortization. It also represents the carrying cost on the differences. The amortization period is five years following the approval of the proposal by the NYPSC.

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

Other includes various items subject to reconciliation including low income, earnings sharing provision and asset retirement obligations.

Note 4. Revenue

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

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

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

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

Transmission revenue results from others' use of the utility's transmission system to transmit electricity and is subject to FERC regulation, which establishes the prices and other terms of service. Long-term wholesale sales of electricity are based on individual bilateral contracts. Short-term wholesale sales of electricity are generally on a daily basis based on market prices and are administered by the New York Independent System Operator (NYISO) or PJM Interconnection, LLC (PJM), as applicable. Wholesale sales of natural gas are generally short-term based on market prices through contracts with the specific customer.

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

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

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

We have contract liabilities for revenue from transmission congestion contract (TCC) auctions, for which we receive payment at the beginning of an auction period, and amortize ratably each month into revenue over the applicable auction period. The auction periods range from six months to two years. TCC contract liabilities totaled $31.9 million at December 31, 2022 and $15.4 million at December 31, 2021, and are presented in "Other current liabilities" on our balance sheets. We recognized $32.4 million and $20.6 million as revenue during the years ended December 31, 2022 and 2021, respectively.

Notes to Financial Statements

We apply a practical expedient to expense as incurred costs to obtain a contract when the amortization period is one year or less. We record costs incurred to obtain a contract within operating expenses, including amortization of capitalized costs.

Revenues disaggregated by major source for the years ended December 31, 2022 and 2021 are as follows:

Years Ended December 31,	2022	2021
(Thousands)		
Regulated operations – electricity	$ 1,740,129	$ 1,428,894
Regulated operations – natural gas	410,137	322,073
Other(a)	38,727	25,861
Revenue from contracts with customers	**2,188,993**	**1,776,828**
Leasing revenue	1,152	1,166
Alternative revenue programs	17,346	15,489
Other revenue	13,286	10,970
Total operating revenues	**$ 2,220,777**	**$ 1,804,453**

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

Note 5. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,	2022	2021
(Thousands)		
Current		
Federal	$ (41,402)	$ (61)
State	(7,384)	(10,979)
Current taxes charged to benefit	**(48,786)**	**(11,040)**
Deferred		
Federal	46,233	(2,344)
State	18,942	23,327
Deferred taxes charged to expense	**65,175**	**20,983**
Investment tax credit adjustments	(510)	(638)
Total Income Tax Expense	**$ 15,879**	**$ 9,305**

The differences between tax expense per the statements of income and tax expense at the 21% statutory federal tax rate for the years ended December 31, 2022 and 2021, respectively, consisted of:

Notes to Financial Statements

Years Ended December 31,	2022	2021
(Thousands)		
Tax expense at statutory rate	$ 36,310	$ 34,323
Equity AFUDC tax effects	(4,507)	(4,764)
Excess ADIT giveback	(24,682)	(29,444)
Investment tax credit amortization	(510)	(638)
State tax expense, net of federal benefit	9,131	9,755
Other, net	137	73
Total Income Tax Expense	**$ 15,879**	**$ 9,305**

Income tax expense for the year ended December 31, 2022 was $20.4 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to excess ADIT amortization and AFUDC Equity tax effects, partially offset by state taxes. This resulted in an effective tax rate of 9.2%. Income tax expense for the year ended December 31, 2021 was $25.0 million lower than it would have been at the statutory federal income tax rate of 21% due predominately to excess ADIT amortization and AFUDC Equity tax effects, partially offset by state taxes. This resulted in an effective tax rate of 5.7%.

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

Deferred tax assets and liabilities as of December 31, 2022 and 2021 consisted of:

December 31,	2022	2021
(Thousands)		
Non-current Deferred Income Tax Liabilities (Assets)		
Property related	$ 862,600	$ 753,028
Storm costs	123,956	88,688
Pension and other post-retirement benefits	(9,709)	809
Power tax deferred income tax	20,833	21,823
Regulatory liability due to "Tax Cuts and Jobs Act"	(99,171)	(107,727)
Environmental	(20,222)	(24,256)
Federal and state NOL’s	(120,618)	(61,242)
Other	12,887	(7,028)
Total Non-current Deferred Income Tax Liabilities	**$ 770,556**	**$ 664,095**
Deferred tax assets	$ 249,720	$ 200,253
Deferred tax liabilities	1,020,276	864,348
Net Accumulated Deferred Income Tax Liabilities	**$ 770,556**	**$ 664,095**

NYSEG has gross federal net operating losses of $410.8 million and gross NY state net operating losses of $658.2 million for the year ended December 31, 2022. NYSEG had gross federal net operating losses of $209.1 million and gross NY state net operating losses of $331.5 million for the year ended December 31, 2021.

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.

Notes to Financial Statements

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,		2022		2021
(Thousands)				
Balance as of January 1	$	45,051	$	45,124
Reduction for tax positions related to prior years		(73)		(73)
Balance as of December 31	**$**	**44,978**	**$**	**45,051**

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, 2022 and 2021.

Note 6. Long-term Debt

Long-term debt as of December 31, 2022 and 2021 consisted of:

As of December 31,		2022		2021	
(Thousands, except interest rates)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
Senior unsecured debt	2023-2052	$ 1,900,000	1.95% - 5.75%	$ 1,700,000	1.95% - 5.75%
Unsecured pollution control notes – fixed	2023-2029	453,210	1.40% - 4.00%	386,000	1.40% - 3.50%
Unamortized debt issuance costs and discount		(13,156)		(15,606)	
Total Debt		**$2,340,054**		**$2,070,394**	
Less: debt due within one year, included in current liabilities		298,492		73,083	
Total Non-current Debt		**$ 2,041,562**		**$ 1,997,311**	

On September 24, 2021, NYSEG issued $350 million aggregate principal amount of unsecured notes maturing in 2031 at an interest of 2.15%.

On April 6, 2022, NYSEG issued $67 million aggregate principal amount of unsecured, tax-exempt pollution control notes maturing in 2028 at an interest of 4.00%.

On December 15, 2022, NYSEG issued $150 million aggregate principal amount of unsecured notes maturing in 2032 at an interest of 4.62%.

On December 15, 2022, NYSEG issued $125 million aggregate principal amount of unsecured notes maturing in 2052 at an interest of 4.96%.

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

2023	2024	2025	2026	2027	Total
(Thousands)					
$298,492	$12,000	$—	$565,000	$34,000	$909,492

Note 7. Bank Loans and Other Borrowings

NYSEG had $89.8 million notes payable at December 31, 2022 and $79.8 million notes payable at December 31, 2021, 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 $16.1 million outstanding under this agreement at December 31, 2022 and $64.6 million outstanding under this agreement at December 31, 2021, respectively.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $500 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. NYSEG had $73.7 million outstanding under this agreement at December 31, 2022 and $15.2 million outstanding under this agreement at December 31, 2021, respectively.

On November 23, 2021, AGR and its investment-grade rated utility subsidiaries (NYSEG, Rochester Gas and Electric Corporation ("RG&E"), Central Maine Power Company ("CMP"), The United Illuminating Company ("UI"), Connecticut Natural Gas Corporation ("CNG"), The Southern Connecticut Gas Company ("SCG") and The Berkshire Gas Company ("BGC")) executed a new credit facility with an aggregate limit of $3,575 million and a termination date of November 23, 2026. Under the terms of the Avangrid Credit Facility, each borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit contained in the agreement. NYSEG has a maximum sublimit of $700 million, RG&E has $300 million, CMP has $200 million and UI has a maximum sublimit of $250 million, CNG and SCG have maximum sublimits of $150 million, and BGC has a maximum sublimit of $50 million. Effective on November 23 2021, the AGR Credit Facility was amended to increase AGR's maximum sublimit to $2,500 million and to establish minimum sublimits of $500 million for NYSEG, $200 million for RG&E, $100 million for CMP, $150 million for UI, $50 million for CNG and SCG, and $25 million for BGC. Under the AGR Credit Facility, each of the borrowers are charged a facility fee that is dependent on their credit rating. The facility fees range from 10.0 to 22.5 basis points. NYSEG had no outstanding balance as of December 31, 2022 and December 31, 2021.

In the AGR Credit Facility we covenant not to permit, without the consent of the lenders, our ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of indebtedness to total capitalization, the facility excludes from net worth the balance of accumulated other comprehensive loss as it appears on the balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness we may maintain. Continued un-remedied failure to comply with those covenants beyond any applicable cure period, constitutes an event of default, and events of default could result in termination or reduction of lenders' commitments or acceleration of amounts owed under the facility. Our ratio of indebtedness to total capitalization pursuant to the revolving credit facility was 0.50 to 1.00 at December 31, 2022. We are not in default as of December 31, 2022.

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

At December 31, 2022 and 2021, NYSEG had 2,455,000 shares of $100 par value preferred stock, 10,800,000 shares of $25 par value preferred stock and 1,000,000 shares of $100 par value preference stock authorized but unissued.

Note 9. Leases

We have operating leases for office buildings, facilities, vehicles and certain equipment. Our finance leases are primarily related to electric generation, distribution, transmission and other. Certain of our lease agreements include rental payments adjusted periodically for inflation or are based on other periodic input measures. Our leases do not contain any material residual value guarantees or material restrictive covenants. Our leases have remaining lease terms of 1 to 49 years, some of which may include options to extend the leases for up to 20 years, and some of which may include options to terminate the leases within one year. We consider extension or termination options in the lease term if it is reasonably certain we will exercise the option.

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

Years Ended December 31,	**2022**	**2021**
(Thousands)		
Lease cost		
Finance lease cost		
Amortization of right-of-use assets	$ 3,216	$ 2,923
Interest on lease liabilities	133	143
Total finance lease cost	3,349	3,066
Operating lease cost	1,567	1,384
Short-term lease cost	1,430	756
Variable lease cost	24	295
Intercompany	(71)	(61)
Total lease cost	**$ 6,299**	**$ 5,440**

Balance sheet and other information for the years ended December 31, 2022 and 2021 was as follows:

Notes to Financial Statements

As of December 31,		2022		2021
(Thousands, except lease term and discount rate)				
Operating Leases				
Operating lease right of use assets	$	9,022	$	8,345
Operating lease liabilities, current		1,293		915
Operating lease liabilities, long-term		8,573		8,294
Total operating lease liabilities	$	9,866	$	9,209
Finance Leases				
Other assets	$	31,738	$	32,056
Other current liabilities		230		200
Other non-current liabilities		1,691		2,008
Total finance lease liabilities	$	1,921	$	2,208
Weighted-average Remaining Lease Term (years):				
Finance leases		8.11		9.16
Operating leases		9.51		9.85
Weighted-average Discount Rate:				
Finance leases		5.70 %		5.72 %
Operating leases		3.26 %		3.33 %

Supplemental cash flows information related to leases was as follows:

Years Ended December 31,		2022		2021
(Thousands)				
Cash paid for amounts included in the measurement of lease liabilities:				
Operating cash flows from operating leases	$	1,280	$	1,184
Operating cash flows from finance leases	$	133	$	143
Financing cash flows from finance leases	$	3,185	$	381
Right-of-use assets obtained in exchange for lease obligations:				
Finance leases	$	(13)	$	15
Operating leases	$	4,650	$	542

Maturities of lease liabilities were as follows:

(Thousands)	Finance	Operating
Years Ended December 31,		
2023	$ 333	$ 1,502
2024	333	1,219
2025	324	1,342
2026	401	1,108
2027	401	848
Thereafter	685	5,760
Total lease payments	**2,477**	**11,779**
Less: imputed interest	(556)	(1,913)
Total	**$ 1,921**	**$ 9,866**

Most of our leases do not provide an implicit rate in the lease, thus we use our incremental borrowing rate based on the information available at the commencement date in determining the present value of lease payments.

Note 10. Commitments and Contingencies

Purchase power and natural gas contracts, including nonutility generators

NYSEG is the provider of last resort for customers. As a result, the company buys physical energy and capacity from the NYISO. In accordance with the NYPSC's February 26, 2008 Order, NYSEG is required to hedge on behalf of non-demand billed customers. The physical electric capacity purchases we make from parties other than the NYISO are to comply with the hedge requirement for electric capacity. The company enters into financial swaps to comply with the hedge requirement for physical electric energy purchases. NYSEG also makes purchases from other independent power producers and New York Power Authority (NYPA) under existing contracts or long-term supply agreements in order to comply with the company’s Public Utility Regulatory Policies Act (PURPA) purchase obligation.

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

The company purchases the majority of its natural gas supply at market prices under seasonal, monthly or mid-term supply contracts and the remainder is acquired on the spot market. The company acquires firm transportation capacity on interstate pipelines under long-term contracts and utilizes that capacity to transport both natural gas supply purchased and natural gas withdrawn from storage to the local distribution system. The company acquires firm underground natural gas storage capacity using long-term contracts and fills the storage facilities with gas in the summer months for subsequent withdrawal in the winter months.

We recognized expenses of approximately $90.9 million for Normal Purchase Normal Sale (NPNS) purchase power and natural gas contracts including non-utility generators in 2022 and $81.1 million in 2021.

Note 11. Environmental Liability

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

Waste sites

The Environmental Protection Agency (EPA) and the New York State Department of Environmental Conservation (NYSDEC), as appropriate, have notified us that we are among the potentially responsible parties that may be liable for costs incurred to remediate certain hazardous substances at twelve waste sites. The twelve sites do not include sites where coal gas was manufactured in the past, which are discussed below. With respect to the twelve sites, ten sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites and two 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 $5.0 million as of December 31, 2022, related to the twelve sites. We have paid remediation costs related to the twelve sites. We have recorded an estimated liability of $0.5 million related to other two sites where we believe it is probable that we will incur remediation costs and/or monitoring costs, although we have not been notified that we are among the potentially responsible parties. It is possible that the ultimate cost to remediate the sites may be significantly more than the accrued amount. Our estimate for costs to remediate these sites ranges from $5.5 million to $6.1 million as of December 31, 2022. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to us. It is anticipated that costs would be recovered in rates typical of historical Site Investigation and Remediation (SIR) rate recovery.

Manufactured gas plants

We have a program to investigate and perform necessary remediation and/or monitoring at our 39 sites where coal gas was manufactured in the past. The Company has entered into orders on consent with the NYSDEC for 37 sites and into a Brownfield Cleanup Program for 1 site. Those orders require us to investigate and, where necessary, remediate 38 of our 39 sites, with the 39th site the responsibility of another potentially responsible party (PRP). Six sites are included in the New York State Registry.

Our estimate for costs related to investigation, remediation and/or monitoring of the 38 sites ranges from $66.0 million to $142.6 million at December 31, 2022. 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, changes due to property use and changes to current laws and regulations.

The liability to investigate and perform remediation and/or monitoring, as necessary, at the known inactive coal gas manufacturing sites was $71.6 million at December 31, 2022 and $87.0 million at December 31, 2021. 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 2048.

FirstEnergy

NYSEG sued FirstEnergy under the Comprehensive Environmental Response, Compensation, and Liability Act to recover environmental cleanup costs at sixteen former manufactured coal 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 share of clean up expenses at nine manufactured gas plant (MGP) sites. Based on current projections, FirstEnergy's share is estimated at approximately $9.5 million. This amount is being treated as a contingent asset and has not been recorded as either a receivable or a decrease to the environmental provision. Any recovery will be flowed through to NYSEG ratepayers.

Note 12. Accounting for Derivative Instruments and Hedging Activities

We are exposed to certain risks relating to our ongoing business operations. The primary risk we manage by using derivative instruments is commodity price risk. In accordance with the accounting requirements concerning derivative instruments and hedging activities, we recognize all derivative instruments as either assets or liabilities at fair value on our balance sheet.

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

Commodity price risk: Commodity price risk, due to volatility experienced in the wholesale energy markets, is a significant issue for the electric and natural gas utility industries. We manage this risk through a combination of regulatory mechanisms, such as the pass-through of the market price of electricity and natural gas to customers, and through comprehensive risk management processes. Those measures mitigate our commodity price exposure, but do not completely eliminate it. Owned electric generation and long-term supply contracts reduce our exposure to market fluctuations.

We have electricity commodity purchases and sales contracts for both capacity and energy (physical contracts) that have been designated and qualify for the normal purchases and normal sales exception in accordance with the accounting requirements concerning derivative instruments and hedging activities.

We currently have a non by-passable wires charge adjustment that allows us to pass through rates any changes in the market price of electricity. We use electricity contracts, both physical and financial, to manage fluctuations in electricity commodity prices in order to provide price stability to customers. We include the cost or benefit of those contracts in the amount expensed for electricity purchased when the related electricity is sold. We record changes in the fair value of electric hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations.

We have a purchased gas adjustment clause that allows us to recover through rates any changes in the market price of purchased natural gas, substantially eliminating our exposure to natural gas price risk. We use natural gas futures and forwards to manage fluctuations in natural gas commodity prices in order to provide price stability to customers. We include the cost or benefit of natural gas futures and forwards in the commodity cost that is passed on to customers when the related sales commitments are fulfilled. We record changes in the fair value of natural gas hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations.

The amounts for electricity hedge contracts and natural gas hedge contracts recognized in regulatory liabilities and assets as of December 31, 2022 and 2021, respectively, and amounts reclassified from regulatory assets and liabilities into income for the years ended December 31, 2022 and 2021, respectively, are as follows:

	Loss or (Gain) Recognized in Regulatory Assets/ Liabilities		Location of Loss (Gain) Reclassified from Regulatory Assets/ Liabilities into Income		Loss (Gain) Reclassified From Regulatory Assets/ Liabilities Into Income	
(Thousands)						
As of			Years Ended December 31,			
December 31, 2022	Electricity	Natural Gas		2022	Electricity	Natural Gas
Regulatory assets	$ 6,893	$ 1,531	Electricity and natural gas purchased		$ (82,937)	$ (4,644)
Regulatory liabilities	$ —	$ —				
December 31, 2021				2021		
Regulatory assets	$ —	$ 48	Electricity and natural gas purchased		$ (14,291)	$ (4,625)
Regulatory liabilities	$ (8,347)	$ (684)				

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

	Electricity Contracts	Natural Gas Contracts	Other Fuel Contracts
Year to settle	Mwhs	Dths	Gallons
As of December 31, 2022			
2023	2,940,250	2,920,000	—
2024	877,800	330,000	—
As of December 31, 2021			
2022	2,838,275	2,410,000	1,120,300
2023	998,625	250,000	—

The offsetting of derivatives, location in the balance sheet and amounts of derivatives as of December 31, 2022 and 2021, respectively, consisted of:

Notes to Financial Statements

December 31, 2022	Derivative Assets-current	Derivative Assets-Non-current	Derivative Liabilities-current	Derivative Liabilities-Non-current
(Thousands)				
Not designated as hedging instruments				
Derivative assets	$ 20,979	$ 4,611	$ 20,978	$ 4,611
Derivative liabilities	(20,979)	(4,611)	(28,251)	(5,762)
	—	—	(7,273)	(1,151)
Designated as hedging instruments				
Derivative assets	—	—	—	—
Derivative liabilities	—	—	(21)	—
	—	—	(21)	—
Total derivatives before offset of cash collateral	—	—	(7,294)	(1,151)
Cash collateral receivable	—	—	7,273	1,151
Total derivatives as presented in the balance sheet	**$ —**	**$ —**	**$ (21)**	**$ —**

December 31, 2021	Derivative Assets-current	Derivative Assets-Non-current	Derivative Liabilities-current	Derivative Liabilities-Non-current
(Thousands)				
Not designated as hedging instruments				
Derivative assets	$ 17,432	$ 4,245	$ 9,511	$ 3,136
Derivative liabilities	(9,511)	(3,135)	(9,511)	(3,184)
	7,921	1,110	—	(48)
Designated as hedging instruments				
Derivative assets	111	—	55	—
Derivative liabilities	(55)	—	(82)	—
	56	—	(27)	—
Total derivatives before offset of cash collateral	7,977	1,110	(27)	(48)
Cash collateral receivable	—	—	—	48
Total derivatives as presented in the balance sheet	**$ 7,977**	**$ 1,110**	**$ (27)**	**$ —**

As of December 31, 2022 and 2021, the derivative assets – non-current are presented within other non-current assets of the balance sheet. The derivative liabilities – non-current are presented within other non-current liabilities of the balance sheet.

Derivatives designated as hedging instruments

The effect of derivatives in cash flow hedging instruments on OCI and income for the years ended December 31, 2022 and 2021, respectively, consisted of:

Years Ended December 31,	(Loss) Gain Recognized in OCI on Derivatives	Location of (Loss) Gain Reclassified From Accumulated OCI into Income	(Loss) Gain Reclassified From Accumulated OCI into Income	Total Amount per Income Statement
(Thousands)				
2022				
Interest rate contracts	$ —	Interest expense	$ (105)	$ 61,634
Commodity contracts: Other	1,207	Operations and maintenance	1,263	793,570
Foreign exchange contracts	—	Operations and maintenance	(27)	793,570
Total	**$ 1,207**		**$ 1,131**	
2021				
Interest rate contracts	$ —	Interest expense	$ (105)	$ 54,373
Commodity contracts: Other	827	Operations and maintenance	501	756,212
Foreign exchange contracts	(27)	Operations and maintenance	—	756,212
Total	**$ 800**		**$ 396**	

The amounts in AOCI related to previously settled forward starting swaps and accumulated amortization as of December 31, 2022 is a net loss of $0.1 million as compared to a net loss of $0.1 million for 2021. For the year ended December 31, 2022, we recorded $0.1 million in net derivative losses related to discontinued cash flow hedges. We will amortize approximately $0.1 million of discontinued cash flow hedges in 2023.

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, 2022 is $8.4 million for which we have posted collateral.

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

The estimated fair value of debt amounted to $2,056 million and $2,159 million as of December 31, 2022 and 2021, 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, 2022 and 2021 consisted of:

Notes to Financial Statements

Description	(Level 1)	(Level 2)	(Level 3)	Netting	Total
(Thousands)					
As of December 31, 2022					
Assets					
Non-current investments available for sale, primarily money market funds	$ 8,262	$ —	$ —	$ —	$ 8,262
Derivatives					
Commodity contracts:					
Electricity	25,476	—	—	(25,476)	—
Natural gas	114	—	—	(114)	—
Total	**$ 33,852**	**$ —**	**$ —**	**$ (25,590)**	**$ 8,262**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	$ (32,369)	$ —	$ —	$ 32,369	$ —
Natural gas	(1,644)	—	—	1,644	—
Foreign exchange contracts	—	(21)	—	—	(21)
Total	**$ (34,013)**	**$ (21)**	**$ —**	**$ 34,013**	**$ (21)**
As of December 31, 2021					
Assets					
Non-current investments available for sale, primarily money market funds	$ 10,561	$ —	$ —	$ —	$ 10,561
Derivatives					
Commodity contracts:					
Electricity	20,798	—	—	(12,451)	8,347
Natural gas	879	—	—	(195)	684
Other	—	—	111	(55)	56
Total	**$ 32,238**	**$ —**	**$ 111**	**$ (12,701)**	**$ 19,648**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	$ (12,451)	$ —	$ —	$ 12,451	$ —
Natural gas	(244)	—	—	244	—
Other	—	—	(55)	55	—
Foreign exchange contracts	—	(27)	—	—	(27)
Total	**$ (12,695)**	**$ (27)**	**$ (55)**	**$ 12,750**	**$ (27)**

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2022 and 2021. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

Valuation techniques: We measure the fair value of our non-current investments available for sale using quoted market prices in active markets for identical assets and include the measurements in Level 1. The investments which are Rabbi Trusts for deferred compensation plans primarily consist of money market funds.

We determine the fair value of our derivative assets and liabilities utilizing market approach valuation techniques:

- We enter into electric energy derivative contracts to hedge the forecasted purchases required to serve their electric load obligations. We hedge our electric load obligations using derivative contracts that are settled based upon Locational Based Marginal Pricing published by the NYISO. We hedge approximately 70% of their electric load obligations using contracts for a NYISO location where an active market exists. The forward market prices used to value the companies' open electric energy derivative contracts are based on quoted prices in active markets for identical assets or liabilities with no adjustment required and therefore we include the fair value in Level 1.
- We enter into natural gas derivative contracts to hedge the forecasted purchases required to serve our natural gas load obligations. The forward market prices used to value our open natural gas derivative contracts are exchange-based prices for the identical derivative contracts traded actively on the New York Mercantile Exchange. Because we use prices quoted in an active market, we include those fair value measurements in Level 1.
- We enter into fuel derivative contracts to hedge our unleaded and diesel fuel requirements for our fleet vehicles. Exchange based forward market prices are used but because a basis adjustment is added to the forward prices, we include the fair value measurement for these contracts in Level 3.

The reconciliation of changes in the fair value of financial instruments based on Level 3 inputs for the years ended December 31, 2022 and 2021 consisted of:

	(Level 3) Derivatives, Net	
Years Ended December 31,	**2022**	**2021**
(Thousands)		
Beginning balance	$ 56	$ (270)
Realized gains included in earnings	(1,263)	(501)
Unrealized gains included in other comprehensive income	1,207	827
Ending balance	**$ —**	**$ 56**

The gains and losses included in earnings for the periods above are reported in Operations and maintenance of the statements of income.

Note 14. Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss for the years ended December 31, 2022 and 2021, consisted of:

(Thousands)	Balance, December 31, 2020	Change 2021	Balance, December 31, 2021	Change 2022	Balance, December 31, 2022
Amortization of pension cost for non-qualified plans and current year actuarial gain, net of income tax expense of $38 for 2021 and $102 for 2022	$ (997)	$ 108	$ (889)	$ 286	$ (603)
Unrealized gain (loss) on derivatives qualified as hedges:					
Unrealized gain during period on derivatives qualified as hedges, net of income tax expense of $314 for 2021 and $205 for 2022		486		1,002	
Reclassification adjustment for gain included in net income, net of income tax benefit of ($197) for 2021 and ($210) for 2022		(304)		(1,026)	
Reclassification adjustment for loss on settled cash flow treasury hedges, net of income tax expense of $42 for 2021 and $18 for 2022		63		87	
Net unrealized gain (loss) on derivatives qualified as hedges	(525)	245	(280)	63	(217)
Accumulated Other Comprehensive Loss	**$ (1,522)**	**$ 353**	**$ (1,169)**	**$ 349**	**$ (820)**

Note 15. Post-retirement and Similar Obligations

We have funded non-contributory defined benefit pension plans that cover all eligible employees. For employees hired before 2002, the plans provide defined benefits based on years of service and final average salary. Employees hired in 2002 or later are covered under a cash balance plan or formula where their benefit accumulates based on a percentage of annual salary and credited interest. During 2013, we announced that we would stop the cash balance accruals for all non-union employees covered under the cash balance plans effective December 31, 2013. NYSEG's unionized employees covered under the cash balance plans ceased to receive accruals as of December 31, 2015. Their earned balances would continue to accrue interest, but would no longer be increased by a percentage of earnings. In place of the pension benefit for those employees, they will receive a minimum contribution to their account under their respective company's defined contribution plan. During 2022, the Company decided to freeze pension benefit accruals and contribution credits for non-union employees and transition their retirement benefits to the 401(k) Plan.

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 $16.7 million for 2022 and $11.3 million for 2021.

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

Non-Qualified Retirement Benefit Plans

We also sponsor various unfunded non-qualified pension plans for certain current employees, former employees and former directors. The total liability for these plans, which is included in Other non-current liabilities on our balance sheets, was $2.7 million and $3.3 million at December 31, 2022 and 2021, respectively.

Qualified Retirement Benefit Plans

Obligations and funded status as of December 31, 2022 and 2021 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2022**	**2021**	**2022**	**2021**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	$ 1,592,830	$ 1,730,911	$ 143,135	$ 161,600
Service cost	10,986	16,270	795	1,047
Interest cost	51,367	38,597	3,598	3,354
Actuarial gain	(342,467)	(77,307)	(41,098)	(9,829)
Curtailments	(20,456)	—	—	—
Settlements	(67,875)	—	—	—
Benefits paid	(88,264)	(115,641)	(10,670)	(13,037)
Benefit obligation at December 31	**$ 1,136,121**	**$ 1,592,830**	**$ 95,760**	**$ 143,135**
Change in plan assets				
Fair value of plan assets at January 1	$ 1,543,061	$ 1,550,984	$ 49,342	$ 80,309
Actual return on plan assets	(271,916)	107,718	(10,010)	4,989
Employer & plan participants’ contributions	—	—	675	—
Settlements	(67,875)	—	—	—
Benefits paid	(88,264)	(115,641)	(10,670)	(35,956)
Fair value of plan assets at December 31	**$ 1,115,006**	**$ 1,543,061**	**$ 29,337**	**$ 49,342**
Funded status	**$ (21,115)**	**$ (49,769)**	**$ (66,423)**	**$ (93,793)**

During 2022, the pension benefit obligation had an actuarial gain of $342.5 million. This gain was primarily driven by $293.9 million gain from increase in discount rates. In 2022, the pension benefit obligation had a reduction of $67.9 million from settlements and $20.5 million from curtailments. The settlements were lump-sum payments made within the pension plan guidelines at the discretion of the plan participants who opted to retire. The curtailments were driven by a Company decision to freeze pension benefit accruals and contribution credits for non-union employees and transition their retirement benefits to a 401(k) plan. During 2022, the postretirement benefit obligation had an actuarial gain of $41.1 million. This gain was primarily driven by $22.9 million gain from increase in discount rates.

During 2021, the pension benefit obligation had an actuarial gain of $77.3 million. This gain was primarily driven by $103.3 million gain from increase in discount rates. There were no significant plan design changes in 2021. There were no significant gains and losses relating to the postretirement benefit obligations.

Amounts recognized in the balance sheet as of December 31, 2022 and 2021 consisted of:

		Pension Benefits		Postretirement Benefits	
As of December 31,		**2022**	**2021**	**2022**	**2021**
(Thousands)					
Noncurrent liabilities	$	(21,115) $	(49,769) $	(66,423) $	(93,793)

We have determined that we are allowed to defer as regulatory assets or regulatory liabilities items that would otherwise be recorded in accumulated other comprehensive income pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans.

Amounts recognized as regulatory assets or regulatory liabilities consist of:

		Pension Benefits		Postretirement Benefits	
As of December 31,		**2022**	**2021**	**2022**	**2021**
(Thousands)					
Net loss (gain)	$	60,826 $	112,045 $	(46,370) $	(19,125)
Prior service cost	$	— $	2,119 $	— $	—

Our accumulated benefit obligation for all qualified defined benefit pension plans was $1,119 million and $1,535 million as of December 31, 2022 and 2021. NYSEG's postretirement benefits were partially funded as of December 31, 2022 and 2021.

The projected benefit obligation exceeded the fair value of pension plan assets for our qualified plans as of both December 31, 2022 and 2021. The accumulated benefit obligation exceeded the fair value of pension plan assets as of December 31, 2022. The accumulated benefit obligation did not exceed the fair value of pension plan assets as of December 31, 2021. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets as of December 31, 2022 and 2021.

As of December 31,		**2022**		**2021**
(Thousands)				
Projected benefit obligation	$	1,136,121	$	1,592,830
Accumulated benefit obligation	$	1,119,298	$	1,535,479
Fair value of plan assets	$	1,115,006	$	1,543,061

The postretirement benefits obligation for all the qualified plans exceeded the fair value of plan assets as of December 31, 2022 and 2021.

Components of net periodic benefit cost and other amounts recognized in regulatory assets and regulatory liabilities for the years ended December 31, 2022 and 2021 consisted of:

Years Ended December 31,	Pension Benefits 2022	Pension Benefits 2021	Postretirement Benefits 2022	Postretirement Benefits 2021
(Thousands)				
Net periodic benefit cost				
Service cost	$ 10,986	$ 16,270	$ 795	$ 1,047
Interest cost	51,367	38,597	3,598	3,354
Expected return on plan assets	(78,148)	(97,894)	(1,584)	(2,409)
Amortization of prior service cost (credit)	124	662	—	(2,678)
Amortization of net loss	34,727	76,161	(2,260)	779
Curtailment charge	1,995	—	—	—
Settlement charge	3,634	—	—	—
Net periodic benefit cost	**$ 24,685**	**$ 33,796**	**$ 549**	**$ 93**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net (gain) loss	$ 7,598	$ (87,131)	$ (29,505)	$ (12,409)
Amortization of net loss	(34,727)	(76,161)	2,260	(779)
Amortization of prior service (cost) credit	(124)	(662)	—	2,678
Effect of curtailments on prior service credit	(1,995)	—	—	—
Effect of curtailments on gain	(20,456)	—	—	—
Settlements	(3,634)	—	—	—
Total recognized in regulatory assets and regulatory liabilities	**$ (53,338)**	**$ (163,954)**	**$ (27,245)**	**$ (10,510)**
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$ (28,653)**	**$ (130,158)**	**$ (26,696)**	**$ (10,417)**

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

The weighted-average assumptions used to determine benefit obligations as of December 31, 2022 and 2021 consisted of:

As of December 31,	Pension Benefits 2022	Pension Benefits 2021	Postretirement Benefits 2022	Postretirement Benefits 2021
Discount rate	5.17 %	2.85 %	5.10 %	2.61 %
Rate of compensation increase	3.00% Union	Age-Related Rates / 3.00% Union	N/A	3.00% Union
Interest crediting rate	3.56 %	3.00 %	N/A	N/A

The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rate developing a yield curve derived from a portfolio of high grade non-callable bonds with yields that closely matches the duration of the expected cash flows of our benefit obligations.

The weighted-average assumptions used to determine net periodic benefit cost for the years ended December 31, 2022 and 2021 consisted of:

Notes to Financial Statements

Years Ended December 31,	Pension Benefits 2022	Pension Benefits 2021	Postretirement Benefits 2022	Postretirement Benefits 2021
Discount rate	2.85% / 4.08%	2.29%	2.61 %	2.15 %
Expected long-term return on plan assets	6.00% / 5.50%	7.00%	3.21 %	3.00 %
Rate of compensation increase	Age-Related Rates / 3.00% Union	Age-Related Rates / 3.00% Union	N/A	3.00% Union

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations and the effect of rebalancing of plan assets discussed below. That analysis considered current capital market conditions and projected conditions. Our policy is to calculate the expected return on plan assets using the market related value of assets. We amortize unrecognized actuarial gains and losses over 10 years from the time they are incurred.

Assumed health care cost trend rates to determine benefit obligations as of December 31, 2022 and 2021 consisted of:

As of December 31,	2022	2021
Health care cost trend rate (pre 65/post 65)	6.00% / 6.50%	6.50% / 7.25%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	4.50%	4.50%
Year that the rate reaches the ultimate trend rate	2029 / 2027	2029 / 2027

Contributions: In accordance with our funding policy, we make annual contributions of not less than the minimum required by applicable regulations. We do not expect to contribute to our pension and postretirement benefit plans in 2023.

Estimated future benefit payments: Our expected benefit payments and expected Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) subsidy receipts, which reflect expected future service, as appropriate, are:

(Thousands)	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
2023	$ 99,074	$ 9,992	$ —
2024	$ 96,831	$ 9,635	$ —
2025	$ 96,114	$ 9,287	$ —
2026	$ 95,434	$ 8,927	$ —
2027	$ 93,764	$ 8,530	$ —
2028-2031	$ 434,747	$ 36,404	$ —

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

The asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets within broad categories of asset classes made up of Return-Seeking and Liability-Hedging investments. We have targets of 25%-60% for Return-Seeking assets and 40%-75% for Liability-Hedging assets. Return-Seeking investments generally consist of domestic, international, global, and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking assets also include investments in real estate, global asset allocation strategies and hedge funds. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS, and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of pension benefits plan assets as of December 31, 2022, by asset category, consisted of:

		Fair Value Measurements		
Asset Category	**Total**	**(Level 1)**	**(Level 2)**	**(Level 3)**
(Thousands)				
As of December 31, 2022				
Cash and cash equivalents	$ 17,898	$ 33	$ 17,865	$ —
U.S. government securities	169,505	169,505	—	—
Common stocks	20,492	20,492	—	—
Registered investment companies	53,212	53,212	—	—
Corporate bonds	403,442	—	403,442	—
Preferred stocks	498	498	—	—
Common collective trusts	161,134	—	161,134	—
Other, principally annuity, fixed income	29,335	—	29,335	—
	$ 855,516	**$ 243,740**	**$ 611,776**	**$ —**
Other investments measured at net asset value	259,490			
Total	**$ 1,115,006**			

The fair values of pension benefits plan assets as of December 31, 2021, by asset category, consisted of:

Asset Category	Total	Fair Value Measurements (Level 1)	(Level 2)	(Level 3)
(Thousands)				
As of December 31, 2021				
Cash and cash equivalents	$ 33,572	$ 12,405	$ 21,167	$ —
U.S. government securities	209,504	209,504	—	—
Common stocks	69,435	69,435	—	—
Registered investment companies	132,377	132,377	—	—
Corporate bonds	435,532	—	435,532	—
Preferred stocks	533	533	—	—
Common collective trusts	314,001	—	314,001	—
Other, principally annuity, fixed income	35,481	4	35,477	—
	$ 1,230,435	**$ 424,258**	**$ 806,177**	**$ —**
Other investments measured at net asset value	312,626			
Total	**$ 1,543,061**			

Valuation Techniques

We value our pension benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities - at the closing price reported in the active market in which the security is traded.
- Common stock - at the closing price reported in the active market in which the individual investment is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks - at the closing price reported in the active market in which the individual investment is traded.
- Registered investment companies - at the closing price reported in the active market in which the individual investment is traded.
- Common collective trusts - the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Other investments measured at net asset value (NAV) - fund shares offered to a limited group of investors and alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

Our postretirement benefits plan assets are held with trustees in multiple voluntary employees' beneficiary association (VEBA) and 401(h) arrangements and are invested among and within various asset classes to achieve sufficient diversification in accordance with our risk tolerance. This is achieved for our postretirement benefits plan assets through the utilization of multiple institutional mutual and money market funds, providing exposure to different segments of the fixed income, equity and short-term cash markets. NYSEG's postretirement benefits plan assets are invested in a VEBA arrangement that is subject to income taxes.

We have established a target asset allocation policy within allowable ranges for postretirement benefits plan assets of 49% - 69% for equity securities and 31%- 51% for fixed income investments. Equity investments are diversified across U.S. and non-U.S. stocks, investment styles, and market capitalization ranges. Fixed income investments are primarily invested in U.S. bonds and may also include some non-U.S. bonds. We primarily minimize the risk of large losses through diversification but also through monitoring and managing other aspects of risk through quarterly investment portfolio reviews. Systematic rebalancing within target ranges increases the probability that the annualized return on investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair value of other postretirement benefits plan assets, by asset category, as of December 31, 2022 consisted of:

		Fair Value Measurements		
Asset Category	**Total**	**(Level 1)**	**(Level 2)**	**(Level 3)**
(Thousands)				
As of December 31, 2022				
Cash and cash equivalents	$ 689	$ —	$ 689	$ —
Registered investment companies	28,648	28,648	—	—
Total	**$ 29,337**	**$ 28,648**	**$ 689**	**$ —**

The fair value of other postretirement benefits plan assets, by asset category, as of December 31, 2021 consisted of:

		Fair Value Measurements		
Asset Category	**Total**	**(Level 1)**	**(Level 2)**	**(Level 3)**
(Thousands)				
As of December 31, 2021				
Cash and cash equivalents	$ 2,097	$ —	$ 2,097	$ —
Registered investment companies	47,245	47,245	—	—
Total	**$ 49,342**	**$ 47,245**	**$ 2,097**	**$ —**

Valuation Techniques

We value our postretirement benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- Registered investment companies - at the closing price reported in the active market in which the individual investment is traded.

Pension and postretirement benefit plan equity securities did not include any AGR and Iberdrola common stock as of both December 31, 2022 and 2021.

Note 16. Other Income and Other Deductions

Other income and deductions for the years ended December 31, 2022 and 2021, consisted of:

Years Ended December 31,	2022	2021
(Thousands)		
Interest and dividend income	$ 9,238	$ 266
Carrying costs on regulatory assets	5,630	9,449
Allowance for funds used during construction	23,591	24,249
Miscellaneous	383	71
Total other income	**$ 38,842**	**$ 34,035**
Pension non-service components	$ (12,012)	$ (14,268)
Miscellaneous	61	(1,435)
Total other deductions	**$ (11,951)**	**$ (15,703)**

Note 17. Related Party Transactions

Certain Networks subsidiaries, including NYSEG, borrow from AGR, the parent of Networks, through intercompany revolving credit agreements. For NYSEG, the intercompany revolving credit agreements provide access to supplemental liquidity. See Note 7 for further detail on the credit facility with AGR.

Avangrid Service Company provides administrative and management services to Networks operating utilities, including NYSEG, pursuant to service agreements. The cost of those services is allocated in accordance with methodologies set forth in the service agreements. The cost allocation methodologies vary depending on the type of service provided. Management believes such allocations are reasonable. The charge for operating and capital services provided to NYSEG by AGR and its affiliates was approximately $130.8 million for 2022 and $114.6 million for 2021. Cost for services includes amounts capitalized in utility plant, which was approximately $19.6 million in 2022 and $17.1 million in 2021. The remainder was primarily recorded as operations and maintenance expense. The charges for services provided by NYSEG to AGR and its subsidiaries were approximately $20.4 million for 2022 and $16.8 million for 2021. 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 $113.2 million at December 31, 2022 and $100.1 million at December 31, 2021 is mostly payable to Avangrid Service Company. The balance in accounts receivable from affiliates of $3.7 million at December 31, 2022 and $2.4 million at December 31, 2021 is from various companies. There were no notes receivable from affiliates at December 31, 2022 and 2021. Notes receivable from affiliates relate to the Virtual Money Pool Agreement as discussed in Note 7 of these financial statements.

Networks holds an approximate 20% ownership interest in the regulated New York TransCo. Through New York TransCo, Networks has formed a partnership with Central Hudson Gas and Electric Corporation, Consolidated Edison, Inc., National Grid, plc and Orange and Rockland Utilities, Inc. to develop a portfolio of interconnected transmission lines and substations to fulfill the objectives of the New York energy highway initiative, which is a proposal to install up to 3,200 MW of new electric generation and transmission capacity in order to deliver more power generated from upstate New York power plants to downstate New York. In 2016 NYSEG received approximately $67 million from New York TransCo in the form of $43 million for assets constructed and transferred to the New York TransCo, $22 million in contributions in aid of construction and approximately $2 million in advanced lease payments for a 99 year lease of land and attachment rights. We had no outstanding receivable as of December 31, 2022 and $0.6 million outstanding receivable balance from New York TransCo as of December 31, 2021.

Note 18. Subsequent Events

The company has performed a review of subsequent events through March 22, 2023, which is the date these financial statements were available to be issued.