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.

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.