UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2023

Or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ________ to ________

Commission File No. 001-37660

Avangrid
A member of the Iberdrola Group

Avangrid, Inc.

(Exact Name of Registrant as Specified in its Charter)

New York	**14-1798693**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
180 Marsh Hill Road	
Orange, Connecticut	**06477**
(Address of principal executive offices)	**(Zip Code)**

Registrant's telephone number, including area code: (207) 629-1190

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol	Name of exchange on which registered
Common Stock, par value $0.01 per share	AGR	New York Stock Exchange

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer	☒	Accelerated Filer	☐
Non-accelerated Filer	☐	Smaller Reporting Company	☐
Emerging Growth Company	☐		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).Yes ☐ No ☒

As of October 25, 2023, the registrant had 386,770,915 shares of common stock, par value $0.01, outstanding.

Avangrid, Inc.

REPORT ON FORM 10-Q
For the Quarter Ended September 30, 2023

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GLOSSARY OF TERMS AND ABBREVIATIONS

Unless the context indicates otherwise, the terms “we,” “our” and the “Company” are used to refer to Avangrid, Inc. and its subsidiaries.

2023 Joint Proposal	Joint proposal of NYSEG and RG&E and certain other signatory parties approved by the NYPSC on October 12, 2023, for a three-year rate plan for electric and gas service with effective date November 1, 2023.
Adjusted Daily Compounded SOFR	The rate per annum equal to (a) the Daily Compounded SOFR for such U.S. Government Securities Business Day and (b) the SOFR adjustment; provided that if Adjusted Daily Compounded SOFR as so determined shall ever be less than the Floor, then Adjusted Daily Compounded SOFR shall be deemed the Floor.
Adjusted Term SOFR	The rate per annum equal to (a) Term SOFR for such calculation plus (b) the SOFR adjustment; provided that if Adjusted Term SOFR as so determined shall ever be less than the Floor, then Adjusted Term SOFR shall be deemed to be the Floor.
AOCI	Accumulated other comprehensive income
ARHI	Avangrid Renewables Holdings, Inc.
ARP	Alternative Revenue Programs
ASC	Accounting Standards Codification
Avangrid	Avangrid, Inc.
BGC	The Berkshire Gas Company
PBR	Performance-Based Regulation
CfDs	Contracts for Differences
CBP	U.S. Customs and Border Protection
CFIUS	Committee on Foreign Investment in the United States
CL&P	The Connecticut Light and Power Company
CMP	Central Maine Power Company
CNG	Connecticut Natural Gas Corporation
DEEP	Connecticut Department of Energy and Environmental Protection
DIMP	Distribution Integrity Management Program
DOC	Department of Commerce
DPA	Deferred Payment Arrangements
DPU	Massachusetts Department of Public Utilities
EBITDA	Earnings before interest, taxes, depreciation and amortization
ESM	Earnings sharing mechanism
Evergreen Power	Evergreen Power, LLC
English Station	The former generation site on the Mill River in New Haven, Connecticut
Exchange Act	The Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FCC	Federal Communications Commission
FERC	Federal Energy Regulatory Commission
FirstEnergy	FirstEnergy Corp.
Form 10-K	Avangrid, Inc.’s Annual Report on Form 10-K for the year ended December 31, 2022, filed with the Securities and Exchange Commission on February 22, 2023.
HLBV	Hypothetical Liquidation at Book Value
HSR	Hart-Scott-Rodino Antitrust Improvements Act of 1976
IRA	Inflation Reduction Act
Iberdrola	Iberdrola, S.A.
Iberdrola Group	The group of companies controlled by Iberdrola, S.A.
Installed capacity	The production capacity of a power plant or wind farm based either on its rated (nameplate) capacity or actual capacity.
ISO	Independent system operator
Klamath Plant	Klamath gas-fired cogeneration facility located in the city of Klamath, Oregon.
KW	Kilowatts
Merger	The merger of PNMR with and into Merger Sub on the terms and subject to the conditions set forth in the Merger Agreement, with PNMR continuing as the surviving corporation and as a wholly-owned subsidiary of Avangrid.
Merger Agreement	Agreement and Plan of Merger, dated as of October 20, 2020 and as amended and modified as of June 19, 2023 among Avangrid, PNMR and Merger Sub.
Merger Sub	NM Green Holdings, Inc., a New Mexico corporation and wholly-owned subsidiary of Avangrid.
MNG	Maine Natural Gas Corporation
MPUC	Maine Public Utility Commission
MtM	Mark-to-market
MW	Megawatts

MWh	Megawatt-hours
Networks	Avangrid Networks, Inc.
NMPRC	New Mexico Public Regulation Commission
Non-GAAP	Financial measures that are not prepared in accordance with U.S. GAAP, including adjusted net income, adjusted earnings per share, adjusted EBITDA and adjusted EBITDA with tax credits.
NRC	Nuclear Regulatory Commission
NYPSC	New York State Public Service Commission
NYSE	New York Stock Exchange
NYSEG	New York State Electric & Gas Corporation
NYSERDA	New York State Energy Research and Development Authority
OCI	Other comprehensive income
PJM	PJM Interconnection, L.L.C.
PNMR	PNM Resources, Inc.
PUCT	Public Utility Commission of Texas
PURA	Connecticut Public Utilities Regulatory Authority
Renewables	Avangrid Renewables, LLC
RDM	Revenue Decoupling Mechanism
RG&E	Rochester Gas and Electric Corporation
ROE	Return on equity
SCG	The Southern Connecticut Gas Company
SEC	United States Securities and Exchange Commission
Side Letter	A side letter agreement dated as of April 15, 2021 and as amended and modified as of July 19, 2023 between Avangrid and Iberdrola concerning items
SOFR	Secured Overnight Financing Rate
Tax Act	Tax Cuts and Jobs Act of 2017 enacted by the U.S. federal government on December 22, 2017
TEF	Tax equity financing arrangements
UFLPA	Uyghur Forced Labor Prevention Act
UI	The United Illuminating Company
UIL	UIL Holdings Corporation
U.S. GAAP	Generally accepted accounting principles for financial reporting in the United States.
VIEs	Variable interest entities

PART I. FINANCIAL INFORMATION

Item 1. *Financial Statements*

Avangrid, Inc. and Subsidiaries
Condensed Consolidated Statements of Income
(unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
(Millions, except for number of shares and per share data)				
Operating Revenues	**$ 1,974**	**$ 1,838**	**$ 6,027**	**$ 5,765**
Operating Expenses				
Purchased power, natural gas and fuel used	482	535	1,844	1,716
Operations and maintenance	924	758	2,319	2,102
Depreciation and amortization	303	279	868	811
Taxes other than income taxes	176	154	516	501
Total Operating Expenses	**1,885**	**1,726**	**5,547**	**5,130**
Operating Income	**89**	**112**	**480**	**635**
Other Income and (Expense)				
Other income	42	18	96	38
(Losses) Earnings from equity method investments	(1)	2	5	261
Interest expense, net of capitalization	(107)	(76)	(301)	(226)
Income Before Income Tax	**23**	**56**	**280**	**708**
Income tax (benefit) expense	(8)	(50)	(17)	14
Net Income	**31**	**106**	**297**	**694**
Net loss (income) attributable to noncontrolling interests	28	(1)	92	40
Net Income Attributable to Avangrid, Inc.	**$ 59**	**$ 105**	**$ 389**	**$ 734**
Earnings Per Common Share, Basic	**$ 0.15**	**$ 0.27**	**$ 1.00**	**$ 1.90**
Earnings Per Common Share, Diluted	**$ 0.15**	**$ 0.27**	**$ 1.00**	**$ 1.90**
Weighted-average Number of Common Shares Outstanding:				
Basic	386,869,341	386,736,774	386,788,279	386,724,035
Diluted	387,322,281	387,280,621	387,122,498	387,200,882

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

Avangrid, Inc. and Subsidiaries
Condensed Consolidated Statements of Comprehensive Income
(unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
(Millions)				
Net Income	**$ 31**	**$ 106**	**$ 297**	**$ 694**
Other Comprehensive Income (Loss)				
Gain for defined benefit plans, net of income taxes of $ 0 for the three months ended, and $ 0 and $ 3 for the nine months ended, respectively	—	—	—	8
Amortization of pension cost, net of income tax of $ 0 and $ 0 for the three months, and $ 1 and $ 0 for the nine months ended, respectively	—	—	2	1
Unrealized (loss) gain from equity method investment, net of income taxes of $ 0 and $(5) for the three months ended, respectively, and $ 1 and $(1) for the nine months ended, respectively	(1)	(13)	4	(2)
Unrealized gain during the period on derivatives qualifying as cash flow hedges, net of income taxes of $ 11 and $ 1 for the three months ended, respectively, and $ 22 and $ 1 for the nine months ended, respectively	30	3	62	3
Reclassification to net income of losses on cash flow hedges, net of income taxes $ 15 and $ 7 for the three months ended, respectively, and $ 39 and $ 13 for the nine months ended, respectively	40	19	107	36
Other Comprehensive Income	**69**	**9**	**175**	**46**
Comprehensive Income	**100**	**115**	**472**	**740**
Net loss (income) attributable to noncontrolling interests	28	(1)	92	40
Comprehensive Income Attributable to Avangrid, Inc.	**$ 128**	**$ 114**	**$ 564**	**$ 780**

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

Avangrid, Inc. and Subsidiaries
Condensed Consolidated Balance Sheets
(unaudited)

As of	September 30, 2023		December 31, 2022	
(Millions)				
Assets				
Current Assets				
Cash and cash equivalents	$	75	$	69
Accounts receivable and unbilled revenues, net		1,417		1,737
Accounts receivable from affiliates		5		5
Notes receivable from affiliates		3		3
Derivative assets		48		60
Fuel and gas in storage		197		268
Materials and supplies		279		235
Prepayments and other current assets		464		386
Regulatory assets		570		447
Total Current Assets		**3,058**		**3,210**
Total Property, Plant and Equipment ($ 2,663 and $ 2,707 related to VIEs, respectively)		**32,068**		**30,994**
Operating lease right-of-use assets		196		159
Equity method investments		514		437
Other investments		43		49
Regulatory assets		2,487		2,321
Other Assets				
Goodwill		3,119		3,119
Intangible assets		290		281
Derivative assets		192		140
Other		419		413
Total Other Assets		**4,020**		**3,953**
Total Assets	**$**	**42,386**	**$**	**41,123**

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

Avangrid, Inc. and Subsidiaries
Condensed Consolidated Balance Sheets
(unaudited)

As of	September 30, 2023	December 31, 2022
(Millions, except share information)		
Liabilities		
Current Liabilities		
Current portion of debt	$ 55	$ 412
Notes payable	952	566
Notes payable to affiliates	6	2
Interest accrued	103	66
Accounts payable and accrued liabilities	1,517	2,007
Accounts payable to affiliates	47	39
Dividends payable	170	170
Taxes accrued	61	61
Operating lease liabilities	15	13
Derivative liabilities	73	133
Other current liabilities	693	593
Regulatory liabilities	235	354
Total Current Liabilities	**3,927**	**4,416**
Regulatory liabilities	2,838	2,915
Other Non-current Liabilities		
Deferred income taxes	2,406	2,234
Deferred income	1,013	1,062
Pension and other postretirement	450	491
Operating lease liabilities	197	161
Derivative liabilities	141	164
Asset retirement obligations	296	273
Environmental remediation costs	258	279
Other	566	563
Total Other Non-current Liabilities	**5,327**	**5,227**
Non-current debt	9,111	8,215
Non-current debt to affiliate	808	8
Total Non-current Liabilities	**18,084**	**16,365**
Total Liabilities	**22,011**	**20,781**
Commitments and Contingencies		
Equity		
Stockholders' Equity:		
Common stock, $ .01 par value, 500,000,000 shares authorized, 387,872,787 and 387,734,757 shares issued; 386,770,915 and 386,628,586 shares outstanding, respectively	3	3
Additional paid in capital	17,699	17,694
Treasury stock	(47)	(47)
Retained earnings	1,789	1,910
Accumulated other comprehensive loss	(5)	(180)
Total Stockholders' Equity	**19,439**	**19,380**
Non-controlling interests	936	962
Total Equity	**20,375**	**20,342**
Total Liabilities and Equity	**$ 42,386**	**$ 41,123**

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

Avangrid, Inc. and Subsidiaries
Condensed Consolidated Statements of Cash Flows
(unaudited)

(Millions)	Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022
Cash Flow from Operating Activities:		
Net income	**$ 297**	**$ 694**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	868	811
Regulatory assets/liabilities amortization and carrying cost	(48)	(37)
Pension cost	(11)	(6)
Earnings from equity method investments	(5)	(261)
Distributions of earnings received from equity method investments	21	19
Unrealized loss on marked-to-market derivative contracts	19	17
Deferred taxes	53	10
Other non-cash items	(49)	(28)
Changes in operating assets and liabilities:		
Current assets	170	(360)
Noncurrent assets	(107)	8
Current liabilities	(408)	95
Noncurrent liabilities	(43)	(68)
Net Cash Provided by Operating Activities	**757**	**894**
Cash Flow from Investing Activities:		
Capital expenditures	(2,078)	(1,940)
Contributions in aid of construction	101	90
Proceeds and refund from disposal of assets	48	16
Proceeds from notes receivable from affiliates	—	(1)
Distributions received from equity method investments	4	4
Other investments and equity method investments, net	(99)	(189)
Net Cash Used in Investing Activities	**(2,024)**	**(2,020)**
Cash Flow from Financing Activities:		
Non-current debt issuances	842	216
Non-current debt issuance with affiliate	800	—
Repayments of non-current debt	(303)	(332)
Receipts of other short-term debt, net	390	209
Repayments of financing leases	(3)	(8)
Issuance of common stock	(3)	(1)
Distributions to noncontrolling interests	(13)	(8)
Contributions from noncontrolling interests	79	146
Dividends paid	(510)	(510)
Net Cash Provided by (Used in) Financing Activities	**1,279**	**(288)**
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	**12**	**(1,414)**
Cash, Cash Equivalents and Restricted Cash, Beginning of Period	**72**	**1,477**
Cash, Cash Equivalents and Restricted Cash, End of Period	**$ 84**	**$ 63**
Supplemental Cash Flow Information		
Cash paid for interest, net of amounts capitalized	$ 217	$ 200
Cash (refund) paid for income taxes, net of transferred tax credits (Note 16)	$ (30)	$ 13

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

Avangrid, Inc. and Subsidiaries
Condensed Consolidated Statements of Changes in Equity
(unaudited)

(Millions, except for number of shares)	Number of shares (*)	Common Stock	Additional paid-in capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholders' Equity	Noncontrolling Interests	Total
As of June 30, 2022	**386,624,231**	**$ 3**	**$ 17,687**	**$ (47)**	**$ 2,003**	**$ (236)**	**$ 19,410**	**$ 976**	**$ 20,386**
Net income	—	—	—	—	105	—	105	1	106
Other comprehensive income, net of tax of $ 3	—	—	—	—	—	9	9	—	9
Comprehensive income									115
Dividends declared, $ 0.44 /share	—	—	—	—	(170)	—	(170)	—	(170)
Stock-based compensation	—	—	1	—	—	—	1	—	1
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(2)	(2)
Contributions from noncontrolling interests	—	—	—	—	(4)	—	(4)	8	4
As of September 30, 2022	**386,624,231**	**$ 3**	**$ 17,688**	**$ (47)**	**$ 1,934**	**$ (227)**	**$ 19,351**	**$ 983**	**$ 20,334**
As of June 30, 2023	**386,645,258**	**$ 3**	**$ 17,695**	**$ (47)**	**$ 1,900**	**$ (74)**	**$ 19,477**	**$ 966**	**$ 20,443**
Net income (loss)	—	—	—	—	59	—	59	(28)	31
Other comprehensive income, net of tax of $ 26	—	—	—	—	—	69	69	—	69
Comprehensive income									100
Dividends declared, $ 0.44 /share	—	—	—	—	(170)	—	(170)	—	(170)
Release of common stock held in trust	—	—	—	—	—	—	—	—	—
Issuance of common stock	125,657	—	—	—	—	—	—	—	—
Stock-based compensation	—	—	4	—	—	—	4	—	4
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(6)	(6)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	4	4
As of September 30, 2023	**386,770,915**	**$ 3**	**$ 17,699**	**$ (47)**	**$ 1,789**	**$ (5)**	**$ 19,439**	**$ 936**	**$ 20,375**

(Millions, except for number of shares)	Number of shares (*)	Common Stock	Additional paid-in capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholders' Equity	Noncontrolling Interests	Total
As of December 31, 2021	**386,568,104**	**$ 3**	**$ 17,679**	**$ (47)**	**$ 1,714**	**$ (273)**	**$ 19,076**	**$ 885**	**$ 19,961**
Net income (loss)	—	—	—	—	734	—	734	(40)	694
Other comprehensive loss, net of tax of $ 16	—	—	—	—	—	46	46	—	46
Comprehensive income									740
Dividends declared, $ 1.32 /share	—	—	—	—	(510)	—	(510)	—	(510)
Issuance of common stock	56,127	—	(1)	—	—	—	(1)	—	(1)
Stock-based compensation	—	—	10	—	—	—	10	—	10
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(8)	(8)
Contributions from noncontrolling interests	—	—	—	—	(4)	—	(4)	146	142
As of September 30, 2022	**386,624,231**	**$ 3**	**$ 17,688**	**$ (47)**	**$ 1,934**	**$ (227)**	**$ 19,351**	**$ 983**	**$ 20,334**
As of December 31, 2022	**386,628,586**	**$ 3**	**$ 17,694**	**$ (47)**	**$ 1,910**	**$ (180)**	**$ 19,380**	**$ 962**	**$ 20,342**
Net income (loss)	—	—	—	—	389	—	389	(92)	297
Other comprehensive loss, net of tax of $ 63	—	—	—	—	—	175	175	—	175
Comprehensive income									472
Dividends declared, $ 1.32 /share	—	—	—	—	(510)	—	(510)	—	(510)
Release of common stock held in trust	4,299	—	—	—	—	—	—	—	—
Issuance of common stock	138,030	—	(4)	—	—	—	(4)	—	(4)
Stock-based compensation	—	—	9	—	—	—	9	—	9
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(13)	(13)
Contributions from noncontrolling interests	—	—	—	—		—	—	79	79
As of September 30, 2023	**386,770,915**	**$ 3**	**$ 17,699**	**$ (47)**	**$ 1,789**	**$ (5)**	**$ 19,439**	**$ 936**	**$ 20,375**

(*) Par value of share amounts is $ 0.01

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

Note 1. Background and Nature of Operations

Avangrid, Inc. (Avangrid, we or the Company) is an energy services holding company engaged in the regulated energy transmission and distribution business through its principal subsidiary, Avangrid Networks, Inc. (Networks), and in the renewable energy generation business through its principal subsidiary, Avangrid Renewables Holding, Inc. (ARHI). ARHI in turn holds subsidiaries including Avangrid Renewables, LLC (Renewables). Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain, owns 81.6 % of the outstanding common stock of Avangrid. The remaining outstanding shares are owned by various shareholders, with approximately 14.7 % of Avangrid's outstanding shares publicly traded on the New York Stock Exchange (NYSE).

Proposed Merger with PNMR

On October 20, 2020, Avangrid, PNM Resources, Inc., a New Mexico corporation (PNMR), and NM Green Holdings, Inc., a New Mexico corporation and wholly-owned subsidiary of Avangrid (Merger Sub), entered into an Agreement and Plan of Merger (Merger Agreement), pursuant to which Merger Sub is expected to merge with and into PNMR, with PNMR surviving the Merger as a direct wholly-owned subsidiary of Avangrid (Merger). Pursuant to the Merger Agreement, each issued and outstanding share of the common stock of PNMR (PNMR common stock) (other than (i) the issued shares of PNMR common stock that are owned by Avangrid, Merger Sub, PNMR or any wholly-owned subsidiary of Avangrid or PNMR, which will be automatically cancelled at the time the Merger is consummated and (ii) shares of PNMR common stock held by a holder who has not voted in favor of, or consented in writing to, the Merger who is entitled to, and who has demanded, payment for fair value of such shares) will be converted, at the time the Merger is consummated, into the right to receive $ 50.30 in cash (Merger Consideration).

Consummation of the Merger (Closing) is subject to the satisfaction or waiver of certain customary closing conditions, including, without limitation, the approval of the Merger Agreement by the holders of at least a majority of the outstanding shares of PNMR common stock entitled to vote thereon, the absence of any material adverse effect on PNMR, the receipt of certain required regulatory approvals (including approvals from the Public Utility Commission of Texas (PUCT), the New Mexico Public Regulation Commission (NMPRC), the Federal Energy Regulatory Commission (FERC), the Federal Communications Commission (FCC), the Committee on Foreign Investment in the United States (CFIUS), the Nuclear Regulatory Commission (NRC) and approval under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR)), the Four Corners Divestiture Agreements (as defined below) being in full force and effect and all applicable regulatory filings associated therewith being made, as well as holders of no more than 15 % of the outstanding shares of PNMR common stock validly exercising their dissenters’ rights. On February 12, 2021, the shareholders of PNMR approved the proposed Merger. As of November 1, 2021, the Merger had obtained all regulatory approvals other than from the NMPRC. On November 1, 2021, after public hearing and briefing on the matter, the hearing examiner in the Merger proceeding at the NMPRC issued an unfavorable recommendation related to the amended stipulated agreement entered into by PNMR's subsidiary, Public Service Company of New Mexico (PNM), Avangrid and a number of interveners in the NMPRC proceeding with respect to consideration of the joint Merger application. On December 8, 2021, the NMPRC issued an order rejecting the amended stipulated agreement. On January 3, 2022, Avangrid and PNM filed a notice of appeal of the December 8, 2021 decision of the NMPRC with the New Mexico Supreme Court. The Statement of Issues was filed on February 2, 2022 and the Brief in Chief was filed on April 7, 2022. Oral arguments were held on September 15, 2023. We cannot predict the outcome of this proceeding.

On February 24, 2022, the FCC granted an extension to its approval to transfer operating licenses in connection with the Merger, which was further extended on August 9, 2022 and again on February 16, 2023. On May 20, 2022, the NRC issued an order extending the effectiveness of its approval until May 25, 2023, and again on March 14, 2023 until May 25, 2024. Furthermore, a new HSR filing was submitted and the waiting period expired on March 10, 2023, providing HSR clearance for another year.

In addition, on January 3, 2022, Avangrid, PNMR and Merger Sub entered into an Amendment to the Merger Agreement (the First Amendment), pursuant to which Avangrid, PNMR and Merger Sub each agreed to extend the “End Date” for consummation of the Merger until April 20, 2023. The parties acknowledged in the First Amendment that the required regulatory approval from the NMPRC had not been obtained and that the parties reasonably determined that such outstanding approval would not be obtained by April 20, 2022. In light of this outstanding approval, the parties determined to approve the First Amendment. Subsequently, on April 12, 2023, Avangrid, PNMR and Merger Sub entered into a Second Amendment to the Merger Agreement (the Second Amendment), pursuant to which Avangrid, PNMR and Merger Sub each agreed to further extend the “End Date” for consummation of the Merger until July 20, 2023. The parties acknowledged in the Second

Amendment that the required regulatory approval from the NMPRC had not been obtained and that the parties reasonably determined that such outstanding approval would not be obtained by April 20, 2023. Subsequently, on June 19, 2023, Avangrid, PNMR and Merger Sub entered into a Third Amendment to the Merger Agreement (the Third Amendment), pursuant to which Avangrid, PNMR and Merger Sub each agreed to further extend the “End Date” for consummation of the Merger until December 31, 2023. The parties acknowledged in the Third Amendment that the required regulatory approval from the NMPRC has not been obtained and the parties reasonably determined that such outstanding approval would not be obtained by July 20, 2023. As amended by the Third Amendment, the Merger Agreement may be terminated by each of Avangrid and PNMR under certain circumstances, including if the Merger is not consummated by December 31, 2023. The Third Amendment also provides that the Merger Agreement can be further extended by 90 days upon mutual agreement by PNMR and Avangrid. During the pendency of the appeal described above, certain required regulatory approvals and consents may expire and Avangrid and PNMR will reapply and/or apply for extensions of such approvals, as the case may be. We cannot predict the outcome of any other re-applications or requests for extensions of such approvals that may be required.

The Merger Agreement contains representations, warranties and covenants of PNMR, Avangrid and Merger Sub, which are customary for transactions of this type. In addition, among other things, the Merger Agreement contains a covenant requiring PNMR to, prior to the closing, enter into agreements (Four Corners Divestiture Agreements) providing for, and to make filings required to, exit from all ownership interests in the Four Corners Power Plant, all with the objective of having the closing date for such exit be no later than December 31, 2024.

The Merger Agreement (as amended) provides for certain customary termination rights including the right of either party to terminate the Merger Agreement if the Merger is not completed on or before December 31, 2023. The Merger Agreement further provides that, upon termination of the Merger Agreement under certain specified circumstances (including if Avangrid terminates the Merger Agreement due to a change in recommendation of the board of directors of PNMR or if PNMR terminates the Merger Agreement to accept a superior proposal (as defined in the Merger Agreement)), PNMR will be required to pay Avangrid a termination fee of $ 130 million. In addition, the Merger Agreement provides that (i) if the Merger Agreement is terminated by either party due to a failure of a regulatory closing condition and such failure is the result of Avangrid’s breach of its regulatory covenants, or (ii) Avangrid fails to effect the Closing when all closing conditions have been satisfied and it is otherwise obligated to do so under the Merger Agreement, then, in either such case, upon termination of the Merger Agreement, Avangrid will be required to pay PNMR a termination fee of $ 184 million as the sole and exclusive remedy. Upon the termination of the Merger Agreement under certain specified circumstances involving a breach of the Merger Agreement, either PNMR or Avangrid will be required to reimburse the other party’s reasonable and documented out-of-pocket fees and expenses up to $ 10 million (which amount will be credited toward, and offset against, the payment of any applicable termination fee).

In connection with the Merger, Iberdrola has provided Avangrid a commitment letter (the Iberdrola Funding Commitment Letter), pursuant to which Iberdrola has unilaterally agreed to provide to Avangrid, or arrange the provision to Avangrid of, funds to the extent necessary for Avangrid to consummate the Merger, up to a maximum aggregate amount of approximately $ 4,300 million, including the payment of the aggregate Merger Consideration.

On April 15, 2021, Avangrid entered into a side letter agreement with Iberdrola, which sets forth certain terms and conditions relating to the Iberdrola Funding Commitment Letter (the Side Letter Agreement, which was amended on July 19, 2023 to replace the LIBOR-based rates with Secured Overnight Financing Rate (SOFR)-based rates). The Side Letter Agreement, as amended, provides that any drawing in the form of indebtedness made by the Corporation pursuant to the Funding Commitment Letter shall bear interest at an interest rate equal to Adjusted Term SOFR or Adjusted Daily Compounded SOFR, as defined in the Side Letter Agreement, plus 0.75 % per annum calculated on the basis of a 360-day year for the actual number of days elapsed and, commencing on the date of the Funding Commitment Letter, we shall pay Iberdrola a facility fee equal to 0.12 % per annum on the undrawn portion of the funding commitment set forth in the Funding Commitment Letter. On May 20, 2023, Iberdrola assigned the Side Letter Agreement and the Iberdrola Funding Commitment Letter to Iberdrola Financiación, S.A.U., a subsidiary of Iberdrola.

On May 18, 2021, we issued 77,821,012 shares of common stock in two private placements. Iberdrola purchased 63,424,125 shares and Hyde Member LLC, a Delaware limited liability company and a wholly owned subsidiary of Qatar Investment Authority, purchased 14,396,887 shares of our common stock, par value $ 0.01 per share, at the purchase price of $ 51.40 per share, which was the closing price of the shares of our common stock on the NYSE as of May 11, 2021. Proceeds of the private placements were $ 4,000 million. $ 3,000 million of the proceeds were used to repay the Iberdrola Loan. After the effect of the private placements, Iberdrola retained its 81.6 % ownership interest in Avangrid.

Note 2. Basis of Presentation

The accompanying condensed consolidated financial statements should be read in conjunction with the Form 10-K for the fiscal year ended December 31, 2022.

The accompanying unaudited financial statements are prepared on a consolidated basis and include the accounts of Avangrid and its consolidated subsidiaries, Networks and ARHI. All intercompany transactions and accounts have been eliminated in consolidation. The year-end balance sheet data was derived from audited financial statements. The unaudited condensed consolidated financial statements for the interim periods have been prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, the interim condensed consolidated financial statements do not include all the information and note disclosures required by U.S. GAAP for complete financial statements.

In the opinion of management, the accompanying condensed consolidated financial statements contain all adjustments necessary to present fairly our condensed consolidated financial statements for the interim periods described herein. All such adjustments are of a normal and recurring nature, except as otherwise disclosed. The results for the three and nine months ended September 30, 2023, are not necessarily indicative of the results for the entire fiscal year ending December 31, 2023.

Note 3. Significant Accounting Policies and New Accounting Pronouncements

The new accounting pronouncements we have adopted as of January 1, 2023, and reflected in our condensed consolidated financial statements are described below. There have been no other material changes to the significant accounting policies described in our Form 10-K for the fiscal year ended December 31, 2022, except for those described below resulting from the adoption of new authoritative accounting guidance issued by the Financial Accounting Standards Board (FASB).

Adoption of New Accounting Pronouncements

(a) Disclosure of Supplier Finance Program Obligations

In September 2022, the FASB issued new disclosure requirements for supplier finance programs. These requirements include key terms of the program, the amount of obligations that remain unpaid at the end of an accounting period, a description of where those obligations are presented in the balance sheet and a roll forward of those obligations during the annual period. We adopted the new disclosure requirements pursuant to this guidance on January 1, 2023.

Accounting Pronouncements Issued but Not Yet Adopted

There are no new accounting pronouncements not yet adopted, including those issued since December 31, 2022, that will materially affect our condensed consolidated financial statements.

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 significant payment terms that are material because we receive payment at or shortly after the point of sale.

The following describes the principal activities, by reportable segment, from which we generate revenue. For more detailed information about our reportable segments, refer to Note 13.

Networks Segment

Networks derives its revenue primarily from tariff-based sales of electricity and natural gas service to customers in New York, Connecticut, Maine and Massachusetts 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. The applicable tariffs are based on the cost of providing service. The utilities' approved base rates are designed to recover their allowable operating costs, including energy costs, finance costs, and the costs of equity, the last of which reflect our capital ratio and a reasonable return on equity. We traditionally invoice our customers by applying approved base rates to usage. Maine state law prohibits the utility from providing the electricity commodity to customers. In New York, Connecticut and Massachusetts, 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. Networks entities calculate revenue earned but not yet billed based on the number of days not billed in the month, the estimated amount of energy delivered during those days and the estimated average price per customer class for that month. Differences between actual and estimated unbilled revenue are immaterial.

Transmission revenue results from others' use of the utility's transmission system to transmit electricity and is subject to FERC regulation, which establishes the prices and other terms of service. Long-term wholesale sales of electricity are based on individual bilateral contracts. Short-term wholesale sales of electricity are generally on a daily basis based on market prices and are administered by the Independent System Operator-New England (ISO-NE) and the New York Independent System Operator (NYISO) or PJM Interconnection, L.L.C. (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 Networks delivers or sells the electricity or natural gas or provides the delivery or transmission service. We record revenue for all of such sales based upon the regulatory-approved tariff and the volume delivered or transmitted, which corresponds to the amount that we have a right to invoice. There are no material initial incremental costs of obtaining a contract in any of the arrangements. Networks does not adjust the promised consideration for the effects of a significant financing component if it expects, at contract inception, that the time between the delivery of promised goods or service and customer payment will be one year or less. For its New York and Connecticut utilities, Networks assesses its DPAs at each balance sheet date for the existence of significant financing components, but has had no material adjustments as a result.

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

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

Renewables Segment

Renewables derives its revenue primarily from the sale of energy, transmission, capacity and other related charges from its renewable wind, solar and thermal energy generating sources. For such revenues, we will recognize revenues in an amount derived from the commodities delivered and from services as they are made available. Renewables has bundled power purchase agreements consisting of electric energy, transmission, capacity and/or renewable energy credits (RECs). The related contracts are generally long-term with no stated contract amount, that is, the customer is entitled to all or a percentage of the unit's output. Renewables also has unbundled sales of electric energy and capacity, RECs and natural gas, which are generally for periods of less than a year. The performance obligations in substantially all of both bundled and unbundled arrangements for electricity and natural gas are satisfied over time, for which we record revenue based on the amount invoiced to the customer for the actual energy delivered. The performance obligation for stand-alone RECs is satisfied at a point in time, for which we record revenue when the performance obligation is satisfied upon delivery of the REC. There are no material initial incremental costs of obtaining a contract or significant financing elements in any of the arrangements.

Renewables classifies certain contracts for the sale of electricity as derivatives, in accordance with the applicable accounting standards. Renewables also has revenue from its energy trading operations, which it generally classifies as derivative revenue. However, trading contracts not classified as derivatives are within the scope of ASC 606, with the performance obligation of the delivery of energy (electricity, natural gas) and settlement of the contracts satisfied at a point in time at which time we recognize the revenue. Renewables also has other ASC 606 revenue, which we recognize based on the amount invoiced to the customer.

Certain customers may receive cash credits, which we account for as variable consideration. Renewables estimates those amounts based on the expected amount to be provided to customers and reduces revenues recognized. We believe that there will not be significant changes to our estimates of variable consideration.

Other

Other, which does not represent a segment, includes miscellaneous Corporate revenues and intersegment eliminations.

Contract Costs and Contract Liabilities

We recognize an asset for incremental costs of obtaining a contract with a customer when we expect the benefit of those costs to be longer than one year. We have contract assets for costs from development success fees, which we paid during the solar asset development period in 2018, and will amortize ratably into expense over the 15 -year life of the power purchase agreement (PPA), expected to commence in April 2024 upon commercial operation. Contract assets totaled $ 9 million at both September 30, 2023 and December 31, 2022, and are presented in "Other non-current assets" on our condensed consolidated balance sheets.

We have contract liabilities for revenue from transmission congestion contract (TCC) auctions, for which we receive payment at the beginning of an auction period, and amortize ratably each month into revenue over the applicable auction period. The auction periods range from six months to two years . TCC contract liabilities totaled $ 9 million and $ 33 million at September 30, 2023 and December 31, 2022, respectively, and are presented in "Other current liabilities" on our condensed consolidated balance sheets. We recognized $ 8 million and $ 36 million as revenue during the three and nine months ended September 30, 2023, respectively, and $ 6 million and $ 20 million for the three and nine months ended September 30, 2022, respectively.

Revenues disaggregated by major source for our reportable segments for the three and nine months ended September 30, 2023 and 2022 are as follows:

	Three Months Ended September 30, 2023				Nine Months Ended September 30, 2023			
	Networks	Renewables	Other (b)	Total	Networks	Renewables	Other (b)	Total
(Millions)								
Regulated operations – electricity	$ 1,341	$ —	$ —	$ 1,341	$ 3,602	$ —	$ —	$ 3,602
Regulated operations – natural gas	185	—	—	185	1,158	—	—	1,158
Nonregulated operations – wind	—	206	—	206	—	638	—	638
Nonregulated operations – solar	—	19	—	19	—	40	—	40
Nonregulated operations – thermal	—	69	—	69	—	125	—	125
Other(a)	27	(27)	—	—	46	(54)	—	(8)
Revenue from contracts with customers	**1,553**	**267**	**—**	**1,820**	**4,806**	**749**	**—**	**5,555**
Leasing revenue	4	—	—	4	10	—	—	10
Derivative revenue	—	121	—	121	—	335	—	335
Alternative revenue programs	20	—	—	20	90	—	—	90
Other revenue	10	(1)	—	9	30	8	(1)	37
Total operating revenues	**$ 1,587**	**$ 387**	**$ —**	**$ 1,974**	**$ 4,936**	**$ 1,092**	**$ (1)**	**$ 6,027**

	Three Months Ended September 30, 2022				Nine Months Ended September 30, 2022			
	Networks	Renewables	Other (b)	Total	Networks	Renewables	Other (b)	Total
(Millions)								
Regulated operations – electricity	$ 1,258	$ —	$ —	$ 1,258	$ 3,457	$ —	$ —	$ 3,457
Regulated operations – natural gas	248	—	—	248	1,319	—	—	1,319
Nonregulated operations – wind	—	223	—	223	—	720	—	720
Nonregulated operations – solar	—	13	—	13	—	29	—	29
Nonregulated operations – thermal	—	8	—	8	—	32	—	32
Other(a)	23	(11)	(1)	11	82	31	(1)	112
Revenue from contracts with customers	**1,529**	**233**	**(1)**	**1,761**	**4,858**	**812**	**(1)**	**5,669**
Leasing revenue	3	—	—	3	7	—	—	7
Derivative revenue	—	60	—	60	—	2	—	2
Alternative revenue programs	7	—	—	7	43	—	—	43
Other revenue	7	—	—	7	37	7	—	44
Total operating revenues	**$ 1,546**	**$ 293**	**$ (1)**	**$ 1,838**	**$ 4,945**	**$ 821**	**$ (1)**	**$ 5,765**

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

(b) Does not represent a segment. Includes Corporate and intersegment eliminations.

As of September 30, 2023 and December 31, 2022, accounts receivable balances related to contracts with customers were approximately $ 1,299 million and $ 1,622 million, respectively, including unbilled revenues of $ 322 million and $ 541 million, which are included in “Accounts receivable and unbilled revenues, net” on our condensed consolidated balance sheets.

As of September 30, 2023, the aggregate amount of the transaction price allocated to performance obligations that are unsatisfied (or partially unsatisfied) were as follows:

As of September 30, 2023	2024	2025	2026	2027	2028	Thereafter	Total
(Millions)							
Revenue expected to be recognized on multiyear retail energy sales contracts in place	$ 1	$ —	$ —	$ —	$ —	$ —	$ 1
Revenue expected to be recognized on multiyear capacity and carbon-free energy sale contracts	89	18	10	7	5	54	183
Revenue expected to be recognized on multiyear renewable energy credit sale contracts	71	64	21	13	2	2	173
Total operating revenues	**$ 161**	**$ 82**	**$ 31**	**$ 20**	**$ 7**	**$ 56**	**$ 357**

As of September 30, 2023, the aggregate amount of the transaction price allocated to performance obligations that are unsatisfied (or partially unsatisfied) for the remainder of 2023 was $ 38 million.

We do not disclose information about remaining performance obligations for contracts for which we recognize revenue in the amount to which we have the right to invoice (e.g., usage-based pricing terms).

Note 5. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations, our utilities 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 regulatory order, we use regulatory precedent to determine if recovery is probable. Our operating utilities also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs. The primary items that are not included in rate base or accruing carrying costs are regulatory assets for qualified pension and other postretirement benefits, which reflect unrecognized actuarial gains and losses; debt premium; environmental remediation costs, which are primarily the offset of accrued liabilities for future spending; unfunded future income taxes, which are the offset to the unfunded future deferred income tax liability recorded; asset retirement obligations; hedge losses; and contracts for differences. As of September 30, 2023, the total net amount of these items is approximately $ 972 million.

CMP Distribution Rate Case

On August 11, 2022, CMP filed a three-year rate plan, with adjustments to the distribution revenue requirement in each year. Following discovery and technical conferences and settlement negotiations, on May 31, 2023, CMP filed a Stipulation resolving all issues in the case providing for a 9.35 % ROE, 50 % equity ratio, and 50 % earnings sharing for annual earnings in excess of 100 basis points of CMP's allowed ROE. The Stipulation also provides for a two-year forward looking rate plan with increases to occur in four equal levelized amounts every six months beginning on July 1, 2023. The next three increases will occur on January 1, 2024, July 1, 2024, and January 1, 2025. The amount of each increase is $ 16.75 million. These revenue increases include amounts for operations and maintenance but are primarily driven by increases in capital investment forecast by CMP to occur during the period covered by the Stipulation. The Stipulation also imposes a service quality indicator incentive mechanism on CMP. The incentive is provided by a penalty mechanism that would impose a maximum of $ 8.8 million per year for a failure to meet specified service quality indicator targets.

No party opposed the Stipulation and it was approved in its entirety by the MPUC on June 6, 2023.

NYSEG and RG&E Rate Plans

On May 26, 2022, NYSEG and RG&E filed for a new rate plan with the NYPSC. The rate filings were based on test year 2021 financial results adjusted to the rate year May 1, 2023 – April 30, 2024. NYSEG and RG&E filed for a one-year rate plan but expressed interest in exploring a multi-year plan during the pendency of the case (as is the custom in New York). On August 12, 2022, NYSEG and RG&E filed an update to its rate plan filing called for in the litigation schedule.

On September 16, 2022, the NYPSC suspended new tariffs and rates through April 21, 2023, and NYSEG and RG&E voluntarily agreed to subsequent suspensions through October 18, 2023, subject to a make-whole provision.

Following discovery, settlement negotiations, and a hearing on the settlement, on June 14, 2023, NYSEG and RG&E filed a Joint Proposal (2023 JP) settlement for a three-year rate plan with the NYPSC. The 2023 JP proposes a three-year rate plan for electric and gas service at NYSEG and RG&E commencing May 1, 2023 and continuing through April 30, 2026. For purposes of the 2023 JP, the three rate years are defined as the 12 months ending April 30, 2024 (New York Rate Year 1); April 30, 2025 (New York Rate Year 2); and April 30, 2026 (New York Rate Year 3); respectively. On October 12, 2023, the NYPSC approved the JP 2023, commencing May 1, 2023 and continuing through April 30, 2026. The effective date of new tariffs is November 1, 2023 with a make-whole provision back to May 1, 2023.

The 2023 JP, as approved, changes in delivery rates for NYSEG's and RG&E's Electric and Gas businesses that were levelized. Actual bill impacts will vary by customer class based on the agreed-upon revenue allocation and rate design. The table below illustrates the Revenue Requirements and provides delivery and total bill percentages with rate levelization:

Delivery Rate Increase Summary With Rate Levelization

	Year 1			Year 2			Year 3		
	Rate Increase (Millions)	Delivery Rate % Increase	Total Rate % Increase	Rate Increase (millions)	Delivery Rate % Increase	Total Rate % Increase	Rate Increase (millions)	Delivery Rate % Increase	Total Rate % Increase
NYSEG Electric	$ 137	14.4 %	6.6 %	$ 161	14.7 %	7.3 %	$ 201	15.1 %	8.2 %
NYSEG Gas	$ 12	5.5 %	2.0 %	$ 12	5.5 %	2.0 %	$ 13	5.5 %	2.1 %
RG&E Electric	$ 51	10.0 %	5.0 %	$ 57	10.1 %	5.3 %	$ 65	10.2 %	5.7 %
RG&E Gas	$ 18	9.7 %	3.4 %	$ 20	9.8 %	3.6 %	$ 22	9.8 %	3.9 %

The allowed rate of return on common equity for NYSEG Electric, NYSEG Gas, RG&E Electric and RG&E Gas is 9.20 %. The common equity ratio for each business is 48.00 %.

The Earnings Sharing Mechanism (ESM) applicable to each business will be based on Rate Year ESM thresholds as set forth in the table below. 100 % of the customers' portion of earnings above the sharing threshold that would otherwise be deferred for the benefit of customers will be used to reduce NYSEG's and RG&E's respective outstanding regulatory asset deferral balances.

In addition, 50 % of NYSEG's and RG&E’s portion will be used to reduce their respective outstanding storm-related regulatory asset deferral balances to the extent such balances exist.

Customers / Shareholders	Earned ROE
No Sharing	ROE ≤ 9.70 %
50 % / 50 %	ROE > 9.70 % and ≤ 10.20 %
75 % / 25 %	ROE > 10.20 % and ≤ 10.70 %
90 % / 10 %	ROE > 10.70 %

The 2023 JP further enhances distribution vegetation management at NYSEG Electric. NYSEG Electric’s total distribution vegetation management spending will increase to approximately $ 66 million in Rate Year 1 through three programs. NYSEG Electric routine distribution vegetation management spending will be approximately $ 34 million in Rate Year 1. In addition, NYSEG Electric will continue its distribution vegetation management Reclamation Program with planned spending of approximately $ 21 million in Rate Year 1. NYSEG Electric will also continue its Danger Tree program to address danger trees outside of the distribution right-of-way at approximately $ 11 million in Rate Year 1. RG&E Electric’s total distribution vegetation management spending will be approximately $ 10.7 million in Rate Year 1 comprised of approximately $ 9 million for routine distribution vegetation management and $ 1.7 million for its Danger Tree program, which addresses danger trees outside of the distribution right-of-way.

NYSEG and RG&E will continue to be subject to three Electric Reliability Performance Measures: the SAIFI; the CAIDI; and the Distribution Line Inspection Program Metric for Level II Deficiencies. Beginning with calendar year 2023, if NYSEG is assessed a negative revenue adjustment (NRA) for failing to meet its annual SAIFI performance metric, NYSEG will use such NRA(s) for purposes of accelerating its vegetation management reclamation program.

The 2023 JP maintains NYSEG’s and RG&E’s current Gas Safety Performance Measures. NYSEG and RG&E will continue to work with New York State Department of Public Service Staff, local fire departments, and emergency management organizations to adopt the principles of the Pipeline Emergency Responders Initiative. NYSEG and RG&E will continue to conduct scenario and hands-on drill trainings for First Responders. In addition, NYSEG and RG&E will continue their Residential Methane Detection (RMD) Program that distributes RMDs to targeted customers and implement a Meter Relocation Pilot Program through which NYSEG and RG&E will move gas meters and service regulators from the inside of a customer’s premises to the outside of a customer’s premises.

The 2023 JP establishes threshold performance levels for designated aspects of customer service quality (PSC Complaint Rate, Customer Satisfaction Survey; Calls Answered in 30 Seconds, and Percent of Estimated Bills) and subjects NYSEG and RG&E to potentially significant NRAs if they fail to meet the performance levels. The 2023 JP, among other things, also: 1) requires NYSEG and RG&E to provide a $ 35 bill credit if they miss a scheduled appointment with a residential customer; 2) provides that Community Distributed Generation (CDG) value stack customers who have not received a revised/corrected bill with the correct credit amount within 45 days of the bill issuance date, shall receive an additional bill credit of $ 10 per month for each month in excess of the initial 45-day period that the CDG/value stack bill credits are applied; 3) continues enhanced winter protections for residential customers during the cold weather period of November 1 through April 15; 4) enhances extreme heat protections by suspending residential terminations in a geographic operating region on days when temperatures are forecast at or above 85 degrees in that geographic operating region; and 5) commits NYSEG and RG&E to develop training materials, internal policy documents, and other relevant communications pertaining to situations in which a customer indicates that they have been victims of domestic violence.

NYSEG and RG&E will continue a RAM to return or collect the remaining Customer Bill Credits established in the 2020 Rate Plan, and the net balance of other 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) costs associated with the implementation of any NYPSC-ordered EV program which are not covered by any other cost recovery mechanisms; and (6) Covid-Related uncollectibles (Rate Year 1 and Rate Year 2 only). The annual RAM recovery/return has been increased from 2.00 % to 2.45 % of NYSEG’s and RG&E’s delivery revenues (by business) as follows: (1) $ 29.4 million for NYSEG Electric; (2) $ 5.8 million for NYSEG Gas; (3) $ 15.0 million for RG&E Electric; and (4) $ 5.4 million for RG&E Gas. Customer Bill Credits shall continue to be recovered from those service classes which were eligible to receive such credits.

The 2023 JP provides for partial or full reconciliation of certain expenses including, but not limited to pensions / OPEBs; property taxes; management, operations, and staffing audit expense; gas research and development; pipeline integrity costs; and Economic Development programs. The 2023 JP also includes a downward-only Net Plant reconciliation for certain specific projects as well as for the overall capital plan. In addition, the 2023 JP includes downward-only reconciliations for the costs of electric and gas distribution vegetation management; pipeline integrity; gas reconcilable programs; incremental maintenance and employee labor cost levels.

NYSEG and RG&E will continue an Electric Revenue Decoupling Mechanism on a total revenue per class basis.

The 2023 JP reflects the recovery of deferred NYSEG Electric and RG&E Electric Major Storm costs of approximately $ 371 million and $ 54.6 million, respectively. NYSEG's remaining super storm regulatory asset of $ 52.3 million and the non-super storm regulatory asset of $ 96.6 million from the 2020 Joint Proposal are being amortized over seven years . RG&E's remaining non-super storm regulatory asset of $ 19.6 million established prior to the 2020 Joint Proposal is being amortized over two years . All other deferred storm costs at both NYSEG and RG&E are being amortized over 10 years. The 2023 JP gradually increases NYSEG's and RG&E's Major Storm rate allowances over the term of the 2023 JP to better align NYSEG's and RG&E's actual Major Storm costs with such rate allowances and to support NYSEG's and RG&E's credit metrics. The Major Storm annual rate allowance for NYSEG Electric is approximately $ 31.5 million in New York Rate Year 1, $ 41.5 million in New York Rate Year 2, and $ 46.5 million in New York Rate Year 3. The Major Storm annual rate allowance for RG&E Electric is approximately $ 4.5 million in New York Rate Year 1, $ 6.0 million in New York Rate Year 2, and $ 7.6 million in New York Rate Year 3.

The 2023 JP contains provisions consistent with, supportive of, and in furtherance of the objectives of the Climate Leadership and Community Protection Act (CLCPA) including provisions that will, among other things, increase funding for energy efficiency programs, enhance the electric system in anticipation of increased electrification and increase funding for electric heat pump programs, provide funding for improved electric and gas reliability and resiliency, encourage non-pipe and non-wire alternatives, and replace leak prone pipe. The 2023 JP also includes support for $ 634 million of capital investment for CLCPA Phase 1 investments projected to be placed in-service beyond the three-year rate plan.

UI, CNG, SCG and BGC Rate Plans

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

UI has wholesale power supply agreements in place for its entire standard service load for the first and second half of 2023, 80 % of the first half of 2024, and 20 % for the second half of 2024. Supplier of last resort service is procured on a quarterly basis and UI has a wholesale power supply agreement in place for the second, third and fourth quarters of 2023.

In 2016, PURA approved new distribution rate schedules for UI for three years , which became effective January 1, 2017 and, among other things, provide for annual tariff increases and an ROE of 9.10 % based on a 50.00 % equity ratio, continued UI's existing ESM pursuant to which UI and its customers share on a 50 /50 basis all distribution earnings above the allowed ROE in a calendar year, continued the existing decoupling mechanism and approved the continuation of the requested storm reserve. Any dollars due to customers from the ESM continue to be first applied against any storm regulatory asset balance (if one exists at that time) or refunded to customers through a bill credit if such storm regulatory asset balance does not exist.

On September 9, 2022, UI filed a distribution revenue requirement case proposing a three-year rate plan commencing September 1, 2023 through August 31, 2026. The filing was based on a test year ending December 31, 2021, for the rate years beginning September 1, 2023 (UI Rate Year 1), September 1, 2024 (UI Rate Year 2), and September 1, 2025 (UI Rate Year 3). UI requested that PURA approve new distribution rates to recover an increase in revenue requirements of approximately $ 91 million in UI Rate Year 1, an incremental increase of approximately $ 20 million in UI Rate Year 2, and an incremental increase of approximately $ 19 million in UI Rate Year 3, compared to total revenues that would otherwise be recovered under UI's current rate schedules. UI's Rate Plan also included several measures to moderate the impact of the proposed rate update for all customers, including, without limitation a rate levelization proposal to spread the proposed total rate increase over the three rate years, which would result in a change in revenue in UI Rate Year 1 of approximately $ 54 million. On July 21, 2023, PURA issued a proposed Final Decision (draft decision), providng for an 8.8 % ROE, 50 % equity ratio, and for a one-year rate plan. UI filed exceptions to the draft decision on August 7, 2023. On August 25, 2023 PURA issued its Final Decision on UI's one-year rate plan commencing on September 1, 2023, providing for a rate increase of $ 23 million based on an allowed ROE of 9.1 % that was reduced to 8.63 % by certain adjustments. The Final Decision established a capital structure consisting of 50 % common equity and 50 % debt. The Final Decision results in an average increase in base distribution rates of about 6.6 % and an average increase in customer bills of about 2 % compared to current levels. On September 18, 2023, UI filed an appeal of the PURA's Final Decision in Connecticut Superior Court, because factual and legal errors related to the treatment of deferred assets, plant in service, and operating expenses. We cannot predict the outcome of this matter.

In 2017, PURA approved new tariffs for the SCG effective January 1, 2018 for a three-year rate plan with annual rate increases. The new tariffs also include an RDM and Distribution Integrity Management Program (DIMP) mechanism, ESM, the amortization of certain regulatory liabilities (most notably accumulated hardship deferral balances and certain accumulated deferred income taxes) and tariff increases based on an ROE of 9.25 % and approximately 52.00 % equity level. Any dollars due to customers from the ESM are be first applied against any environmental regulatory asset balance as defined in the settlement agreement (if one exists at that time) or refunded to customers through a bill credit if such environmental regulatory asset balance does not exist.

In 2018, PURA approved new tariffs for CNG effective January 1, 2019 for a three-year rate plan with annual rate increases. The new tariffs continued the RDM and DIMP mechanism. ESM and tariff increases are based on an ROE of 9.30 % and an equity ratio of 54.00 % in 2019, 54.50 % in 2020 and 55.00 % in 2021.

On April 24, 2023 the Connecticut Attorney General, Office of Consumer Counsel, Connecticut Public Utilities Regulatory Authority Office of Education, Outreach, and Enforcement and the Connecticut Industrial Energy Consumer filed a Petition requesting that PURA conduct a general rate hearing for CNG. On May 5, 2023, CNG and SCG responded indicating a willingness to file general rate cases for each company by November 1, 2023. PURA assented to the companies' proposal on May 21, 2023. On September 29, 2023, SCG and CNG filed a notice of intent to file general rate cases on or about November 3, 2023.

On June 24, 2022, BGC filed a Settlement Agreement with the Massachusetts Attorney General's Office (AGO) for DPU approval. The Settlement Agreement followed BGC's December 14, 2021 filing of a Notice of Intent to File Rate Schedules. Following that filing, BGC and the AGO negotiated the Settlement Agreement in lieu of a fully litigated rate case before the DPU. The Settlement Agreement allows for agreed-upon adjustments to BGC's revenue requirement as well as various step increases BGC shall be entitled to on January 1, 2023 and January 1, 2024. The Settlement Agreement provides that it shall be void unless approved in its entirety by the DPU by November 1, 2022. It provides for the opportunity to increase BGC's revenue requirement by as much as $ 5.6 million over current rates (reflective of a 9.70 % ROE and a 54.00 % equity ratio as well as other stepped adjustments) through January 1, 2024. The Settlement Agreement was approved in its entirety by the DPU on October 27, 2022, and new rates went into effect January 1, 2023.

Connecticut Energy Legislation

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

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

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

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

Pursuant to the legislation, PURA opened a docket to consider the implementation of the associated customer compensation and reimbursement provisions in emergency events where customers were without power for more than 96 consecutive hours. On June 30, 2021, PURA issued a final decision implementing the legislative mandate to create a program pursuant to which residential customers will receive $25 for each day without power after 96 hours and also receive reimbursement of $250 for spoiled food and medicine. The decision emphasizes that no costs incurred in connection with this program are recoverable from customers. On June 29, 2023 the Governor of Connecticut signed SB7 into law, which included language that Level 1 storm events were exempt from the waiver. We will continue to review the requirements of the program for the next legislative session.

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

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

On May 6, 2021, in connection with its findings in the Tropical Storm Isaias docket, PURA issued a Notice of Violation to UI for allegedly failing to comply with standards of acceptable performance in emergency preparation or restoration of service in an emergency and with orders of the Authority, and for violations of accident reporting requirements. PURA assessed a civil penalty in the total amount of approximately $ 2 million. PURA held a hearing on this matter and, in an order dated July 14, 2021, reduced the civil penalty to approximately $ 1 million. UI filed an appeal of PURA’s decision with the Connecticut Superior Court. This appeal and the appeal of PURA’s decision on the Tropical Storm Isaias docket have been consolidated. Oral arguments were held on October 11, 2022, and on October 17, 2022, the court denied UI’s appeal and affirmed PURA’s decisions in their entirety. UI filed a notice of appeal to Connecticut's Appellate court on November 7, 2022 and briefs in April and June 2023. We cannot predict the outcome of this proceeding.

Regulatory Assets and Liabilities

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

Regulatory assets as of September 30, 2023 and December 31, 2022, respectively, consisted of:

As of	September 30, 2023	December 31, 2022
(Millions)		
Pension and other post-retirement benefits	$ 362	$ 365
Pension and other post-retirement benefits cost deferrals	38	93
Storm costs	767	671
Rate adjustment mechanism	51	41
Revenue decoupling mechanism	59	52
Transmission revenue reconciliation mechanism	2	11
Contracts for differences	43	56
Hardship programs	33	33
Plant decommissioning	—	1
Deferred purchased gas	11	56
Environmental remediation costs	236	248
Debt premium	59	64
Unamortized losses on reacquired debt	19	19
Unfunded future income taxes	545	492
Federal tax depreciation normalization adjustment	132	137
Asset retirement obligation	20	20
Deferred meter replacement costs	59	55
COVID-19 cost recovery and late payment surcharge	12	17
Low income arrears forgiveness	61	31
Excess generation service charge	33	24
System Expansion	23	21
Non-bypassable charge	86	14
Hedges losses	14	13
Energy Efficiency Programs	22	13
Rate change levelization	18	—
Electric supply reconciliation	13	19
Value of distributed energy resources	48	36
Other	291	166
Total regulatory assets	**3,057**	**2,768**
Less: current portion	570	447
Total non-current regulatory assets	**$ 2,487**	**$ 2,321**

“Pension and other post-retirement benefits” represent the actuarial losses on the pension and other post-retirement plans that will be reflected in customer rates when they are amortized and recognized in future pension expenses.

“Pension and other post-retirement benefits cost deferrals” include the difference between actual expense for pension and other post-retirement benefits and the amount provided for in rates for certain of our regulated utilities. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases.

“Storm costs” for CMP, NYSEG, RG&E and UI are allowed in rates based on an estimate of the routine costs of service restoration. The companies are also allowed to defer unusually high levels of service restoration costs resulting from major storms when they meet certain criteria for severity and duration. A portion of this balance is amortized through current rates, and the remaining portion will be determined through future rate cases.

“Rate adjustment mechanism” represents an interim rate change to return or collect certain defined reconciled revenues and costs for NYSEG and RG&E following the approval of the Joint Proposal by the NYPSC. The RAM, when triggered, is implemented in rates on July 1 of each year for return or collection over a twelve-month period.

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

"Transmission revenue reconciliation mechanism" reflects differences in actual costs in the rate year from those used to set rates. This mechanism contains the Annual Transmission True up (ATU), which is recovered over the subsequent June to May period.

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

“Hardship Programs” represent hardship customer accounts deferred for future recovery to the extent they exceed the amount in rates.

“Plant decommissioning” represents decommissioning and demolition expenses related to closing fossil plant facilities - Beebe & Russell.

“Deferred Purchased Gas” represents the difference between actual gas costs and gas costs collected in rates.

“Environmental remediation costs” includes spending that has occurred and is eligible for future recovery in customer rates. Environmental costs are currently recovered through a reserve mechanism whereby projected spending is included in rates with any variance recorded as a regulatory asset or a regulatory liability. The amortization period will be established in future proceedings and will depend upon the timing of spending for the remediation costs. It also includes the anticipated future rate recovery of costs that are recorded as environmental liabilities since these will be recovered when incurred. Because no funds have yet been expended for the regulatory asset related to future spending, it does not accrue carrying costs and is not included within rate base.

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

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

“Unfunded future income taxes” represent unrecovered federal and state income taxes primarily resulting from regulatory flow through accounting treatment and are the offset to the unfunded future deferred income tax liability recorded. The income tax benefits or charges for certain plant related timing differences, such as removal costs, are immediately flowed through to, or collected from, customers. This amount is being amortized as the amounts related to temporary differences that give rise to the deferrals are recovered in rates. These amounts are being collected over a period of 46 years, and the NYPSC staff has initiated an audit, as required, of the unfunded future income taxes and other tax assets to verify the balances.

“Federal tax depreciation normalization adjustment” represents the revenue requirement impact of the difference in the deferred income tax expense required to be recorded under the IRS normalization rules and the amount of deferred income tax expense that was included in cost of service for rate years covering 2011 forward. The recovery period in New York is from 25 to 35 years and for CMP 32.5 years beginning in 2020.

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

“Deferred meter replacement costs” represent the deferral of the book value of retired meters which were replaced or are planned to be replaced by AMI meters. This amount is being amortized over the initial depreciation period of related retired meters.

"COVID-19 cost recovery and late payment surcharge" represents: a) deferred COVID-19-related costs in the state of Connecticut based on the order issued by PURA on April 29, 2020, requiring utilities to track COVID-19-related expenses and lost revenue and create a regulatory asset, and b) deferred lost late payment revenue in the state of New York based on the order issued by the NYPSC on June 17, 2022, approving deferral and surcharge/sur-credit mechanism to recover/return deferred balances starting July 1, 2022.

“Low-income arrears forgiveness” represents deferred bill credits in the state of New York based on the order issued by the NYPSC on June 16, 2022, approving deferral of bill credits for low-income customers and recovery of regulatory asset from all customers over five years for RG&E and three years for NYSEG. Surcharge will start August 1, 2022.

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

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

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

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

“Energy efficiency programs” represents the costs of energy efficiency programs deferred for future recovery to the extent they exceed the amount in rates. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases.

“Electric supply reconciliation” represents over/under-collection of costs related to electric supply in which NYSEG/RGE supply electricity as the default service option for customers.

“Rate change levelization" adjusts the New York delivery rate increases across the three-year plan to avoid unnecessary spikes and offsetting dips in customer rates. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is five years and began in 2020.

“Value of distributed energy resources” represents the mechanism to compensate for energy created by distributed energy resources, such as solar.

“Other” includes post-term amortization deferrals and various items subject to reconciliation including debt rate reconciliation and deferred property tax.

Regulatory liabilities as of September 30, 2023 and December 31, 2022, respectively, consisted of:

As of		September 30, 2023		December 31, 2022
(Millions)				
Energy efficiency portfolio standard	$	17	$	30
Gas supply charge and deferred natural gas cost		7		15
Pension and other post-retirement benefits cost deferrals		108		117
Carrying costs on deferred income tax bonus depreciation		2		9
Carrying costs on deferred income tax - Mixed Services 263(a)		1		3
2017 Tax Act		1,198		1,232
Rate Change Levelization		5		25
Revenue decoupling mechanism		11		13
Accrued removal obligations		1,150		1,178
Economic development		11		20
Positive benefit adjustment		10		16
Theoretical reserve flow thru impact		2		3
Deferred property tax		15		17
Net plant reconciliation		16		11
Debt rate reconciliation		22		32
Rate refund – FERC ROE proceeding		37		36
Transmission congestion contracts		31		31
Merger-related rate credits		8		10
Accumulated deferred investment tax credits		21		22
Asset retirement obligation		18		18
Earning sharing provisions		9		13
Middletown/Norwalk local transmission network service collections		16		17
Low income programs		14		18
Non-firm margin sharing credits		32		27
New York 2018 winter storm settlement		2		1
Non by-passable charges		8		76
Transmission revenue reconciliation mechanism		56		75
Other		246		204
Total regulatory liabilities		**3,073**		**3,269**
Less: current portion		235		354
Total non-current regulatory liabilities	**$**	**2,838**	**$**	**2,915**

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

“Gas supply charge and deferred natural gas cost" reflects the actual costs of purchasing, transporting and storing of natural gas. Gas supply reconciliation is determined by comparing actual gas supply expenses to the monthly gas cost recoveries in rates. Prior rate year balances are collected/returned to customers beginning the next calendar year.

“Pension and other postretirement benefits cost deferrals” include the difference between actual expense for pension and other post-retirement benefits and the amount provided for in rates for certain of our regulated utilities. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases.

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

"Carrying costs on deferred income tax - Mixed Services 263(a)" represent the carrying costs benefit of increased accumulated deferred income taxes created by Section 263 (a) IRC. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is three years and began in 2020.

“2017 Tax Act” represents the impact from remeasurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates from 35% to 21% under the provisions of the Tax Act will result in amounts previously and currently collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates. The NYPSC, MPUC, PURA, DPU and the FERC held separate proceedings in New York, Maine, Connecticut, Massachusetts and the FERC, respectively, and for the majority of our regulated utilities, authorized the amortization periods for the return of regulatory liabilities and the recovery regulatory assets, including the authorization of sur-credits to return the related benefits to rate payers in certain jurisdictions.

“Rate change levelization" adjusts the New York delivery rate increases across the three-year plan to avoid unnecessary spikes and offsetting dips in customer rates. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is five years and began in 2020.

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

“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.

“Economic development” represents the economic development program, which enables NYSEG and 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 NYSEG and RG&E varies in any rate year from the level provided for in rates, the difference is refunded to customers. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is three years and began in 2020.

“Positive benefit adjustment” resulted from Iberdrola’s 2008 acquisition of Avangrid (formerly Energy East Corporation). This is being used to moderate increases in rates. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is three years and began in 2020.

“Theoretical reserve flow thru 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. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is three to five years and began in 2020.

“Deferred property tax” represents the difference between actual expense for property taxes recoverable from customers and the amount provided for in rates . A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases. The amortization period in current rates is five years and began in 2020.

“Net plant reconciliation” represents the reconciliation of the actual electric and gas net plant and book depreciation to the targets set forth in the 2020 Joint Proposal. 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.

"Debt rate reconciliation" represents the over/under collection of costs related to debt instruments identified in the rate case. Costs would include interest, commissions and fees versus amounts included in rates.

"Rate refund - FERC ROE proceeding” represents the reserve associated with the FERC proceeding around the base return on equity (ROE) reflected in ISO New England, Inc.’s (ISO-NE) open access transmission tariff (OATT). See Note 8 for more details.

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

“Merger-related rate credits” resulted from the acquisition of UIL. This is being used to moderate increases in rates. During the three and nine months ended September 30, 2023, $ 1 million and $ 2 million, respectively, and $ 0 and $ 2 million, respectively, for the three and nine months ended September 30, 2022 of rate credits were applied against customer bills.

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

“Earning sharing provisions” represents the annual earnings over the earnings sharing threshold. A portion of this balance is amortized through current rates, the remaining portion will be refunded in future periods through future rate cases.

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

“Low income programs” represent various hardship and payment plan programs approved for recovery.

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

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

“Other” includes cost of removal being amortized through rates and various items subject to reconciliation.

Note 6. Fair Value of Financial Instruments and Fair Value Measurements

We determine the fair value of our derivative assets and liabilities and non-current equity investments associated with Networks’ activities utilizing market approach valuation techniques:

- Our equity and other investments consist of Rabbi Trusts. Our Rabbi Trusts, which cover certain deferred compensation plans and non-qualified pension plan obligations, consists of equity and other investments. The Rabbi Trusts primarily invest in equity securities, fixed income and money market funds. Certain Rabbi Trusts also invest in trust or company owned life insurance policies. We measure the fair value of our Rabbi Trust portfolio using observable, unadjusted quoted market prices in active markets for identical assets and include the measurements in Level 1. We measure the fair value of the supplemental retirement benefit life insurance trust based on quoted prices in the active markets for the various funds within which the assets are held and include the measurement in Level 2.
- NYSEG and RG&E enter into electric energy derivative contracts to hedge the forecasted purchases required to serve their electric load obligations. They hedge their electric load obligations using derivative contracts that are settled based upon Locational Based Marginal Pricing published by the NYISO. NYSEG and RG&E hedge approximately 70 % of their electric load obligations using contracts for a NYISO location where an active market exists. The forward market prices used to value the companies’ open electric energy derivative contracts are based on quoted prices in active markets for identical assets or liabilities with no adjustment required and therefore we include the fair value measurements in Level 1.
- NYSEG and RG&E enter into natural gas derivative contracts to hedge their forecasted purchases required to serve their natural gas load obligations. NYSEG and RG&E hedge up to approximately 55 % of its forecasted winter demand through the use of financial transactions and storage withdrawals. The forward market prices used to value open natural gas derivative contracts are exchange-based prices for the identical derivative contracts traded actively on the Intercontinental Exchange (ICE). We include the fair value measurements in Level 1 because we use prices quoted in an active market.

- UI enters into CfDs, which are marked-to-market based on a probability-based expected cash flow analysis that is discounted at risk-free interest rates and an adjustment for non-performance risk using credit default swap rates. We include the fair value measurement for these contracts in Level 3 (See Note 7 for further discussion of CfDs).

We determine the fair value of our derivative assets and liabilities associated with Renewables activities utilizing market approach valuation techniques. Exchange-traded transactions, such as New York Mercantile Exchange (NYMEX) futures contracts, that are based on quoted market prices in active markets for identical products with no adjustment are included in fair value Level 1. Contracts with delivery periods of two years or less which are traded in active markets and are valued with or derived from observable market data for identical or similar products such as over-the-counter NYMEX, foreign exchange swaps, and fixed price physical and basis and index trades are included in fair value Level 2. Contracts with delivery periods exceeding two years or that have unobservable inputs or inputs that cannot be corroborated with market data for identical or similar products are included in fair value Level 3. The unobservable inputs include modeled volumes on unit-contingent contracts, extrapolated power curves through May 2032 and scheduling assumptions on California power exports to cover Nevada physical power sales. The valuation for this category is based on our judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists.

We determine the fair value of our interest rate derivative instruments based on a model whose inputs are observable, such as SOFR, forward interest rate curves or other relevant benchmark. We include the fair value measurement for these contracts in Level 2 (See Note 7 for further discussion of interest rate contracts).

We determine the fair value of our foreign currency exchange derivative instruments based on current exchange rates compared to the rates at inception of the hedge. We include the fair value measurement for these contracts in Level 2.

The carrying amounts for cash and cash equivalents, restricted cash, accounts receivable, accounts payable, notes payable, lease obligations and interest accrued approximate fair value.

Restricted cash was $ 9 million and $ 3 million as of September 30, 2023 and December 31, 2022, respectively, and is included in "Other Assets" on our condensed consolidated balance sheets.

The financial instruments measured at fair value as of September 30, 2023 and December 31, 2022, respectively, consisted of:

As of September 30, 2023	Level 1	Level 2	Level 3	Netting	Total
(Millions)					
Equity investments with readily determinable fair values	**$ 27**	**$ 15**	**$ —**	**$ —**	**$ 42**
Derivative assets					
Derivative financial instruments - power	$ 29	$ 36	$ 84	$ (97)	$ 52
Derivative financial instruments - gas	—	14	—	(9)	5
Contracts for differences	—	—	1	—	1
Derivative financial instruments - Other	—	182	—	—	182
Total	**$ 29**	**$ 232**	**$ 85**	**$ (106)**	**$ 240**
Derivative liabilities					
Derivative financial instruments - power	$ (30)	$ (119)	$ (62)	$ 163	$ (48)
Derivative financial instruments - gas	(12)	(16)	(1)	29	—
Contracts for differences	—	—	(44)	—	(44)
Derivative financial instruments - Other	—	(122)	—	—	(122)
Total	**$ (42)**	**$ (257)**	**$ (107)**	**$ 192**	**$ (214)**

As of December 31, 2022	Level 1	Level 2	Level 3	Netting	Total
(Millions)					
Equity investments with readily determinable fair values	**$ 35**	**$ 13**	**$ —**	**$ —**	**$ 48**
Derivative assets					
Derivative financial instruments - power	$ 37	$ 55	$ 165	$ (177)	$ 80
Derivative financial instruments - gas	1	47	—	(45)	3
Contracts for differences	—	—	1	—	1
Derivative financial instruments - Other	—	116	—	—	116
Total	**$ 38**	**$ 218**	**$ 166**	**$ (222)**	**$ 200**
Derivative liabilities					
Derivative financial instruments - power	$ (46)	$ (350)	$ (93)	$ 364	$ (125)
Derivative financial instruments - gas	(4)	(26)	—	30	—
Contracts for differences	—	—	(57)	—	(57)
Derivative financial instruments - Other	—	(115)	—	—	(115)
Total	**$ (50)**	**$ (491)**	**$ (150)**	**$ 394**	**$ (297)**

The reconciliation of changes in the fair value of financial instruments based on Level 3 inputs for the three and nine months ended September 30, 2023 and 2022, respectively, is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Millions)	2023	2022	2023	2022
Fair Value Beginning of Period,	$ 23	$ (151)	$ 16	$ (69)
Gains recognized in operating revenues	—	17	8	69
(Losses) recognized in operating revenues	—	(17)	(12)	(79)
Total losses recognized in operating revenues	—	—	(4)	(10)
Gains recognized in OCI	—	(1)	8	2
(Losses) recognized in OCI	(9)	(13)	(10)	(105)
Total (losses) gains recognized in OCI	(9)	(14)	(2)	(103)
Net change recognized in regulatory assets and liabilities	5	5	13	14
Purchases	(2)	(4)	29	(5)
Settlements	(39)	(2)	(74)	7
Fair Value as of September 30,	$ (22)	$ (166)	$ (22)	$ (166)
Losses for the period included in operating revenues attributable to the change in unrealized gains relating to financial instruments still held at the reporting date	$ —	$ —	$ (4)	$ (10)

Level 3 Fair Value Measurement

The table below illustrates the significant sources of unobservable inputs used in the fair value measurement of our Level 3 derivatives and the variability in prices for those transactions classified as Level 3 derivatives.

As of September 30, 2023			
Index	Avg.	Max.	Min.
NYMEX ($/MMBtu)	$ 4.46	$ 9.86	$ 1.99
AECO ($/MMBtu)	$ 3.13	$ 10.80	$ 1.00
Ameren ($/MWh)	$ 53.89	$ 225.62	$ 20.92
COB ($/MWh)	$ 81.12	$ 400.10	$ 10.85
ComEd ($/MWh)	$ 49.05	$ 222.49	$ 16.77
ERCOT S hub ($/MWh)	$ 50.40	$ 320.63	$ 16.85
Mid C ($/MWh)	$ 78.25	$ 400.10	$ 7.85
AEP-DAYTON hub ($/MWh)	$ 54.66	$ 229.75	$ 22.50
PJM W hub ($/MWh)	$ 57.33	$ 227.60	$ 21.61

Our Level 3 valuations primarily consist of Hydro PPAs utilized for balancing services for the Northwest wind fleet, power swaps with delivery periods extending through May 2032 hedging Midwest and Texas wind farms and physical power sales agreements in Nevada.

We considered the measurement uncertainty regarding the Level 3 gas and power positions to changes in the valuation inputs. Given the nature of the transactions in Level 3, the primary input to the valuation is the market price of gas or power for transactions with delivery periods exceeding two years . The fixed price power swaps are economic hedges of future power generation, with decreases in power prices resulting in unrealized gains and increases in power prices resulting in unrealized losses. The hydro PPAs are long capacity/energy positions in the Northwest that provide balancing services with increases in power prices resulting in unrealized gains and decreases in power prices resulting in unrealized losses. The gas swaps are economic hedges of fuel purchases for a combined cycle gas plant, with increases in gas prices resulting in unrealized gains and decreases in gas prices resulting in unrealized losses. As all transactions are economic hedges of the underlying position, any changes in the fair value of these transactions will be offset by changes in the anticipated purchase/sales price of the underlying commodity.

Two elements of the analytical infrastructure employed in valuing transactions are the price curves used in the calculation of market value and the modeled volumes on unit-contingent agreements. We maintain and document authorized trading points and associated forward price curves, and we develop and document models used in valuation of the various products.

Transactions are valued in part on the basis of forward prices and estimated volumes. We maintain and document descriptions of these curves and their derivations. Forward price curves used in valuing the transactions are applied to the full duration of the transaction.

The determination of fair value of the CfDs (see Note 7 for further details on CfDs) was based on a probability-based expected cash flow analysis that was discounted at risk-free interest rates, as applicable, and an adjustment for non-performance risk using credit default swap rates. Certain management assumptions were required, including development of pricing that extends over the term of the contracts. We believe this methodology provides the most reasonable estimates of the amount of future discounted cash flows associated with the CfDs. Additionally, on a quarterly basis, we perform analytics to ensure that the fair value of the derivatives is consistent with changes, if any, in the various fair value model inputs. Significant isolated changes in the risk of non-performance, the discount rate or the contract term pricing would result in an inverse change in the fair value of the CfDs. Additional quantitative information about Level 3 fair value measurements of the CfDs is as follows:

Unobservable Input	Range at September 30, 2023
Risk of non-performance	0.72 % - 0.74 %
Discount rate	4.13 % - 4.80 %
Forward pricing ($ per KW-month)	$ 2.00 - $ 2.61

Fair Value of Debt

As of September 30, 2023 and December 31, 2022, debt consisted of first mortgage bonds, unsecured pollution control notes and other various non-current debt securities. The estimated fair value of debt was $ 9,091 million and $ 7,991 million as of September 30, 2023 and December 31, 2022, respectively. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rates used to make these calculations take into account the credit ratings of the borrowers in each case. All debt is considered Level 2 within the fair value hierarchy.

Note 7. Derivative Instruments and Hedging

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

(a) Networks activities

The tables below present Networks' derivative positions as of September 30, 2023 and December 31, 2022, respectively, including those subject to master netting agreements and the location of the net derivative positions on our condensed consolidated balance sheets:

As of September 30, 2023	Current Assets	Noncurrent Assets	Current Liabilities	Noncurrent Liabilities
(Millions)				
Not designated as hedging instruments				
Derivative assets	$ 26	$ 4	$ 25	$ 3
Derivative liabilities	(25)	(3)	(56)	(30)
	1	1	(31)	(27)
Designated as hedging instruments				
Derivative assets	—	—	—	—
Derivative liabilities	—	—	—	—
	—	—	—	—
Total derivatives before offset of cash collateral	1	1	(31)	(27)
Cash collateral receivable	—	—	15	—
Total derivatives as presented in the balance sheet	$ 1	$ 1	$ (16)	$ (27)

As of December 31, 2022	Current Assets	Noncurrent Assets	Current Liabilities	Noncurrent Liabilities
(Millions)				
Not designated as hedging instruments				
Derivative assets	$ 30	$ 8	$ 30	$ 7
Derivative liabilities	(30)	(7)	(58)	(50)
	—	1	(28)	(43)
Designated as hedging instruments				
Derivative assets	—	—	—	—
Derivative liabilities	—	—	—	—
	—	—	—	—
Total derivatives before offset of cash collateral	—	1	(28)	(43)
Cash collateral receivable	—	—	11	2
Total derivatives as presented in the balance sheet	$ —	$ 1	$ (17)	$ (41)

The net notional volumes of the outstanding derivative instruments associated with Networks' activities as of September 30, 2023 and December 31, 2022, respectively, consisted of:

As of	September 30, 2023	December 31, 2022
(Millions)		
Wholesale electricity purchase contracts (MWh)	5.2	5.7
Natural gas purchase contracts (Dth)	9.4	9.6

Derivatives not designated as hedging instruments

NYSEG and RG&E have an electric commodity charge that passes costs for the market price of electricity through rates. 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 accounting requirements concerning regulated operations.

NYSEG and RG&E have purchased gas adjustment clauses that allow us to recover through rates any changes in the market price of purchased natural gas, substantially eliminating our exposure to natural gas price risk. NYSEG and RG&E use natural gas futures and forwards to manage fluctuations in natural gas commodity prices 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 accounting requirements for regulated operations.

The amounts for electricity hedge contracts and natural gas hedge contracts recognized in regulatory liabilities and assets as of September 30, 2023 and December 31, 2022 and amounts reclassified from regulatory assets and liabilities into income for the three and nine months ended September 30, 2023 and 2022 are as follows:

(Millions)	Loss or Gain Recognized in Regulatory Assets/Liabilities		Location of Loss (Gain) Reclassified from Regulatory Assets/Liabilities into Income	Loss (Gain) Reclassified from Regulatory Assets/Liabilities into Income			
As of				Three Months Ended September 30,		Nine Months Ended September 30,	
September 30, 2023	Electricity	Natural Gas	2023	Electricity	Natural Gas	Electricity	Natural Gas
Regulatory assets	$ 2	$ 12	Purchased power, natural gas and fuel used	$ 14	$ —	$ 85	$ 6
December 31, 2022			2022				
Regulatory assets	$ 9	$ 4	Purchased power, natural gas and fuel used	$ (49)	$ —	$ (113)	$ (9)

Pursuant to a PURA order, UI and Connecticut's other electric utility, CL&P, each executed two long-term CfDs with certain incremental capacity resources, each of which specifies a capacity quantity and a monthly settlement that reflects the difference between a forward market price and the contract price. The costs or benefits of each contract will be paid by or allocated to customers and will be subject to a cost-sharing agreement between UI and CL&P pursuant to which approximately 20 % of the cost or benefit is borne by or allocated to UI customers and approximately 80 % is borne by or allocated to CL&P customers.

PURA has determined that costs associated with these CfDs will be fully recoverable by UI and CL&P through electric rates, and UI has deferred recognition of costs (a regulatory asset) or obligations (a regulatory liability), including carrying costs. For those CfDs signed by CL&P, UI records its approximate 20 % portion pursuant to the cost-sharing agreement noted above. As of September 30, 2023, UI has recorded a gross derivative asset of $ 1 million ($ 0 of which is related to UI's portion of the CfD signed by CL&P), a regulatory asset of $ 42 million, a gross derivative liability of $ 44 million ($ 42 million of which is related to UI's portion of the CfD signed by CL&P) and a regulatory liability of $ 0 . As of December 31, 2022, UI had recorded a gross derivative asset of $ 1 million ($ 0 of which is related to UI's portion of the CfD signed by CL&P), a regulatory asset of $ 56 million, a gross derivative liability of $ 57 million ($ 55 million of which is related to UI's portion of the CfD signed by CL&P) and a regulatory liability of $ 0 .

The unrealized gains and losses from fair value adjustments to these derivatives, which are recorded in regulatory assets, for the three and nine months ended September 30, 2023 and 2022, respectively, were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
(Millions)				
Derivative liabilities	$ 5	$ 5	$ 13	$ 14

Derivatives designated as hedging instruments

The effect of derivatives in cash flow hedging relationships on Other Comprehensive Income (OCI) and income for the three and nine months ended September 30, 2023 and 2022, respectively, consisted of:

Three Months Ended September 30,	Gain Recognized in OCI on Derivatives (a)	Location of Loss Reclassified from Accumulated OCI into Income	Loss Reclassified from Accumulated OCI into Income	Total amount per Income Statement
(Millions)				
2023				
Interest rate contracts	$ —	Interest expense	$ 1	$ 107
Commodity contracts	—	Purchased power, natural gas and fuel used	—	482
Total	**$ —**		**$ 1**	
2022				
Interest rate contracts	$ —	Interest expense	$ 1	$ 76
Commodity contracts	—	Purchased power, natural gas and fuel used	(1)	535
Total	**$ —**		**$ —**	

Nine Months Ended September 30,	Gain (Loss) Recognized in OCI on Derivatives (a)	Location of Loss Reclassified from Accumulated OCI into Income	Loss Reclassified from Accumulated OCI into Income	Total amount per Income Statement
(Millions)				
2023				
Interest rate contracts	$ —	Interest expense	$ 3	$ 301
Commodity contracts	—	Purchased power, natural gas and fuel used	—	1,844
Total	**$ —**		**$ 3**	
2022				
Interest rate contracts	$ —	Interest expense	$ 3	$ 226
Commodity contracts	2	Purchased power, natural gas and fuel used	(3)	1,716
Total	**$ 2**		**$ —**	

(a) Changes in accumulated OCI are reported on a pre-tax basis.

As of September 30, 2023 and December 31, 2022, the net loss in accumulated OCI related to previously settled forward starting swaps and accumulated amortization was $ 40 million and $ 43 million, respectively. Networks recorded net derivative losses related to discontinued cash flow hedges of $ 1 million and $ 3 million, for the three and nine months ended September 30, 2023 and 2022, respectively. Networks will amortize approximately $ 4 million of net derivative losses related to discontinued cash flow hedges within the next twelve months.

(b) Renewables activities

Renewables sells fixed-price gas and power forwards to hedge our merchant wind assets from declining commodity prices for our Renewables business. Renewables also purchases fixed-price gas and basis swaps and sells fixed-price power in the forward market to hedge the spark spread or heat rate of our merchant thermal assets and enters into tolling arrangements to sell the output of its thermal generation facilities.

Renewables has proprietary trading operations that enter into fixed-price power and gas forwards in addition to basis swaps. The intent is to speculate on fixed-price commodity and basis volatility in the U.S. commodity markets.

Renewables will periodically designate derivative contracts as cash flow hedges for both its thermal and wind portfolios. The fair value changes are recorded in OCI. For thermal operations, Renewables will periodically designate both fixed-price NYMEX gas contracts and natural gas basis swaps that hedge the fuel requirements of its Klamath Plant in Klamath, Oregon. Renewables will also designate fixed-price power swaps at various locations in the U.S. market to hedge future power sales from its Klamath facility and various wind farms.

The net notional volumes of outstanding derivative instruments associated with Renewables' activities as of September 30, 2023 and December 31, 2022, respectively, consisted of:

As of	September 30, 2023	December 31, 2022
(MWh/Dth in millions)		
Wholesale electricity purchase contracts	1	2
Wholesale electricity sales contracts	6	7
Natural gas and other fuel purchase contracts	17	15
Financial power contracts	4	6
Basis swaps – purchases	23	22
Basis swaps – sales	1	—

The fair values of derivative contracts associated with Renewables' activities as of September 30, 2023 and December 31, 2022, respectively, consisted of:

As of		September 30, 2023		December 31, 2022
(Millions)				
Wholesale electricity purchase contracts	$	57	$	149
Wholesale electricity sales contracts		(70)		(200)
Natural gas and other fuel purchase contracts		4		2
Financial power contracts		16		8
Total	**$**	**7**	**$**	**(41)**

On May 27, 2021, Renewables entered into a forward interest rate swap, with a total notional amount of $ 935 million, to hedge the issuance of forecasted variable rate debt. The forward interest rate swap is designated and qualifies as a cash flow hedge. As part of the financial close of Vineyard Wind 1 described in Note 19, this hedge was novated to the lending institutions and the notional value changed to $ 956 million. As of September 30, 2023 and December 31, 2022, the fair value of the interest rate swap was $ 182 million and $ 116 million, respectively, as a current and non-current asset. The gain or loss on the interest rate swap is reported as a component of accumulated OCI and will be reclassified into earnings in the period or periods during which the related interest expense on the debt is incurred.

The tables below present Renewables' derivative positions as of September 30, 2023 and December 31, 2022, respectively, including those subject to master netting agreements and the location of the net derivative position on our condensed consolidated balance sheets:

As of September 30, 2023		Current Assets		Noncurrent Assets		Current Liabilities		Noncurrent Liabilities
(Millions)								
Not designated as hedging instruments								
Derivative assets	$	67	$	29	$	22	$	4
Derivative liabilities		(32)		(12)		(33)		(7)
		35		17		(11)		(3)
Designated as hedging instruments								
Derivative assets		14		175		4		3
Derivative liabilities		(1)		(1)		(69)		(45)
		13		174		(65)		(42)
Total derivatives before offset of cash collateral		48		191		(76)		(45)
Cash collateral (payable) receivable		(1)		—		52		20
Total derivatives as presented in the balance sheet	$	47	$	191	$	(24)	$	(25)

As of December 31, 2022		Current Assets		Noncurrent Assets		Current Liabilities		Noncurrent Liabilities
(Millions)								
Not designated as hedging instruments								
Derivative assets	$	121	$	63	$	79	$	4
Derivative liabilities		(61)		(40)		(103)		(7)
		60		23		(24)		(3)
Designated as hedging instruments								
Derivative assets		—		116		—		1
Derivative liabilities		—		—		(168)		(89)
		—		116		(168)		(88)
Total derivatives before offset of cash collateral		60		139		(192)		(91)
Cash collateral receivable		—		—		105		54
Total derivatives as presented in the balance sheet	$	60	$	139	$	(87)	$	(37)

Derivatives not designated as hedging instruments

The effects of trading and non-trading derivatives associated with Renewables' activities for the three and nine months ended September 30, 2023, consisted of:

	Three Months Ended September 30, 2023			Nine Months Ended September 30, 2023		
	Trading	Non-trading	Total amount per income statement	Trading	Non-trading	Total amount per income statement
(Millions)						
Operating Revenues						
Wholesale electricity purchase contracts	$ (1)	$ (4)		$ (9)	$ (5)	
Wholesale electricity sales contracts	(19)	14		9	57	
Financial power contracts	(5)	14		(6)	39	
Financial and natural gas contracts	—	(1)		—	5	
Total (loss) gain included in operating revenues	$ (25)	$ 23	$ 1,974	$ (6)	$ 96	$ 6,027
Purchased power, natural gas and fuel used						
Wholesale electricity purchase contracts	$ —	$ (23)		$ —	$ (79)	
Financial and natural gas contracts	—	2		—	(30)	
Total loss included in purchased power, natural gas and fuel used	$ —	$ (21)	$ 482	$ —	$ (109)	$ 1,844
Total (loss) gain	$ (25)	$ 2		$ (6)	$ (13)	

The effects of trading and non-trading derivatives associated with Renewables' activities for the three and nine months ended September 30, 2022, consisted of:

	Three Months Ended September 30, 2022			Nine Months Ended September 30, 2022		
	Trading	Non-trading	Total amount per income statement	Trading	Non-trading	Total amount per income statement
(Millions)						
Operating Revenues						
Wholesale electricity purchase contracts	$ 1	$ 3		$ 2	$ 3	
Wholesale electricity sales contracts	(4)	(21)		2	(31)	
Financial power contracts	(3)	1		(5)	(40)	
Financial and natural gas contracts	(1)	(4)		(1)	(25)	
Total loss included in operating revenues	$ (7)	$ (21)	$ 1,838	$ (2)	$ (93)	$ 5,765
Purchased power, natural gas and fuel used						
Wholesale electricity purchase contracts	$ —	$ 12		$ —	$ 65	
Financial power contracts	—	1		—	—	
Financial and natural gas contracts	—	(8)		—	13	
Total gain included in purchased power, natural gas and fuel used	$ —	$ 5	$ 535	$ —	$ 78	$ 1,716
Total loss	$ (7)	$ (16)		$ (2)	$ (15)	

Derivatives designated as hedging instruments

The effect of derivatives in cash flow hedging relationships on accumulated OCI and income for the three and nine months ended September 30, 2023 and 2022, respectively, consisted of:

Three Months Ended September 30,	(Loss) Gain Recognized in OCI on Derivatives (a)	Location of (Gain) Reclassified from Accumulated OCI into Income	Loss Reclassified from Accumulated OCI into Income	Total amount per Income Statement
(Millions)				
2023				
Interest rate contracts	58	Interest Expense	—	$ 107
Commodity contracts	(17)	Operating revenues	52	$ 1,974
Total	$ 41		$ 52	
2022				
Interest rate contracts	40	Interest Expense	—	$ 76
Commodity contracts	(33)	Operating revenues	22	$ 1,838
Total	$ 7		$ 22	

Nine Months Ended September 30,	(Loss) Gain Recognized in OCI on Derivatives (a)	Location of (Gain) Reclassified from Accumulated OCI into Income	Loss Reclassified from Accumulated OCI into Income	Total amount per Income Statement
(Millions)				
2023				
Interest rate contracts	182	Interest Expense	—	$ 301
Commodity contracts	18	Operating revenues	136	$ 6,027
Total	$ 200		$ 136	
2022				
Interest rate contracts	167	Interest Expense	—	$ 226
Commodity contracts	(163)	Operating revenues	41	$ 5,765
Total	$ 4		$ 41	

(a) Changes in OCI are reported on a pre-tax basis.

Amounts are reclassified from accumulated OCI into income in the period during which the transaction being hedged affects earnings or when it becomes probable that a forecasted transaction being hedged would not occur. Notwithstanding future changes in prices, approximately $ 65 million of losses included in accumulated OCI at September 30, 2023, are expected to be reclassified into earnings within the next twelve months. For all of the three and nine months ended September 30, 2023 and 2022, we did not record any net derivative losses related to discontinued cash flow hedges.

(c) Interest rate contracts

Avangrid uses financial derivative instruments from time to time to alter its fixed and floating rate debt balances or to hedge fixed rates in anticipation of future fixed rate issuances.

As of September 30, 2023 and December 31, 2022, the net loss in accumulated OCI related to previously settled interest rate contracts was $ 31 million and $ 38 million, respectively. We amortized into income $ 2 million and $ 7 million, for the three and nine months ended September 30, 2023 and 2022, respectively, of the loss related to settled interest rate contracts. We will amortize approximately $ 9 million of the net loss on the interest rate contracts within the next twelve months.

The effect of derivatives in cash flow hedging relationships on accumulated OCI for the three and nine months ended September 30, 2023 and 2022, respectively, consisted of:

Three Months Ended September 30,	(Loss) Recognized in OCI on Derivatives (a)		Location of Loss Reclassified from Accumulated OCI into Income	Loss Reclassified from Accumulated OCI into Income		Total amount per Income Statement	
(Millions)							
2023							
Interest rate contracts	$	—	Interest expense	$	2	$	107
2022							
Interest rate contracts	$	—	Interest expense	$	2	$	76

Nine Months Ended September 30,	(Loss) Recognized in OCI on Derivatives (a)		Location of Loss Reclassified from Accumulated OCI into Income	Loss Reclassified from Accumulated OCI into Income		Total amount per Income Statement	
(Millions)							
2023							
Interest rate contracts	$	—	Interest expense	$	7	$	301
2022							
Interest rate contracts	$	—	Interest expense	$	7	$	226

(a) Changes in OCI are reported on a pre-tax basis. The amounts in accumulated OCI are being reclassified into earnings over the underlying debt maturity periods which end in 2025 and 2029.

On July 15, 2021, Corporate entered into an interest rate swap to hedge the fair value of $ 750 million of existing debt included in "Non-current debt" on our consolidated balance sheets. The interest rate swap is designated and qualifies as a fair value hedge. The change in the fair value of the interest rate swap and the offsetting change in the fair value of the underlying debt are reported as components of "Interest expense."

The effects on our consolidated financial statements as of and for the three and nine months ended September 30, 2023 and 2022, respectively, are as follows:

	Fair value of hedge		Location of (Gain) Recognized in Income Statement	Loss Recognized in Income Statement				Total per Income Statement			
(Millions)	As of September 30, 2023			Three Months Ended September 30, 2023		Nine Months Ended September 30, 2023		Three Months Ended September 30, 2023		Nine Months Ended September 30, 2023	
Current Liabilities	$	(32)	Interest Expense	$	9	$	23	$	107	$	301
Non-current liabilities	$	(88)									
	Cumulative effect on hedged debt										
Current debt	$	32									
Non-current debt	$	88									

(Millions)	Fair value of hedge As of December 31, 2022	Location of Loss Recognized in Income Statement	Loss Recognized in Income Statement Three Months Ended September 30, 2022	 Nine Months Ended September 30, 2022	Total per Income Statement Three Months Ended September 30, 2022	 Nine Months Ended September 30, 2022
Current Liabilities	$ (29)	Interest Expense	$ 3	$ 1	$ 76	$ 226
Non-current liabilities	$ (86)					
	Cumulative effect on hedged debt					
Current debt	$ 29					
Non-current debt	$ 86					

(d) Counterparty credit risk management

NYSEG and RG&E 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 applicable based on the respective counterparty's or the counterparty guarantor's credit rating, as provided by Moody's or Standard & Poor's. When our exposure to risk for a 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.

The wholesale power supply agreements of UI contain default provisions that include required performance assurance, including certain collateral obligations, in the event that UI's credit ratings on senior debt were to fall below investment grade. If such an event had occurred as of September 30, 2023, UI would have had to post an aggregate of approximately $ 21 million in collateral.

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 a default on or termination of any single contract. For financial statement presentation purposes, 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. As of September 30, 2023 and December 31, 2022, the amount of cash collateral under master netting arrangements that have not been offset against net derivative positions was $ 60 million and $ 97 million, respectively. Derivative instruments settlements and collateral payments are included throughout the "Changes in operating assets and liabilities" section of operating activities in our condensed consolidated statements of cash flows.

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, we 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 as of September 30, 2023 was $ 14 million, for which we have posted collateral.

Note 8. Contingencies and Commitments

We are party to various legal disputes arising as part of our normal business activities. We assess our exposure to these matters and record estimated loss contingencies when a loss is probable and can be reasonably estimated. We do not provide for accrual of legal costs expected to be incurred in connection with a loss contingency.

Transmission - ROE Complaint – CMP and UI

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

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

CMP and UI reserved for refunds for Complaints I, II and III consistent with the FERC's March 3, 2015 decision in Complaint I. Refunds were provided to customers for Complaint I. The CMP and UI total reserve associated with Complaints II and III is $ 29 million and $ 8 million, respectively, as of September 30, 2023, which has not changed since December 31, 2022, except for the accrual of carrying costs. If adopted as final by the FERC, the impact of the initial decision by the FERC administrative law judge would be an additional aggregate reserve for Complaints II and III of $ 17 million, which is based upon currently available information for these proceedings.

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

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

On April 15, 2021, the FERC issued a supplemental Notice of Proposed Rulemaking (Supplemental NOPR) that proposes to eliminate the 50 basis-point ROE incentive for utilities who join Regional Transmission Organizations after three years of membership. The NETOs submitted initial comments in opposition to the Supplemental NOPR on June 25, 2021 and reply comments on July 26, 2021. If the elimination of the 50 basis-point ROE incentive adder becomes final, we estimate we would have an approximately $ 3 million reduction in earnings per year. We cannot predict the outcome of this proceeding.

California Energy Crisis Litigation

Two California agencies brought a complaint in 2001 against a long-term power purchase agreement entered into by Renewables, as seller, to the California Department of Water Resources, as purchaser, alleging that the terms and conditions of the power purchase agreement were unjust and unreasonable. The FERC dismissed Renewables from the proceedings; however, the Ninth Circuit Court of Appeals reversed the FERC's dismissal of Renewables from the proceeding.

Joining with two other parties, Renewables filed a petition for certiorari in the United States Supreme Court on May 3, 2007. In an order entered on June 27, 2008, the Supreme Court granted Renewables' petition for certiorari, vacated the appellate court's judgment, and remanded the case to the appellate court for further consideration in light of the Supreme Court's decision in a similar case. In light of the Supreme Court's order, on December 4, 2008, the Ninth Circuit Court of Appeals vacated its prior opinion and remanded the complaint proceedings to the FERC for further proceedings consistent with the Supreme Court's rulings. In 2014, the FERC assigned an administrative law judge to conduct evidentiary hearings. Following discovery, the FERC trial staff recommended that the complaint against Renewables be dismissed.

A hearing was held before a FERC administrative law judge in November and early December 2015. A preliminary proposed ruling by the administrative law judge was issued on April 12, 2016. The proposed ruling found no evidence that Renewables had engaged in any unlawful market conduct that would justify finding the Renewables power purchase agreements unjust and unreasonable. However, the proposed ruling did conclude that the price of the power purchase agreements imposed an excessive burden on customers in the amount of $ 259 million. Renewables position, as presented at hearings and agreed by the FERC trial staff, is that Renewables entered into bilateral power purchase contracts appropriately and complied with all applicable legal standards and requirements. The parties have submitted briefs on exceptions to the administrative law judge’s proposed ruling to the FERC. In April 2018, Renewables requested, based on the nearly two years of delay from the preliminary proposed ruling and the Supreme Court precedent, that the FERC issue a final decision expeditiously. On June 17, 2021, the FERC issued an Order Establishing Limited Remand remanding the case to the administrative law judge for additional detailed findings and legal analysis with respect to the impact of the conduct of one of the parties other than Renewables on their long-term contracts. The order did not address any of the other findings, including all of the findings with respect to Renewables, which remain pending. On July 9, 2021, Renewables filed a motion requesting that the FERC expeditiously issue a final decision with respect to the Renewables long-term contract rather than waiting for the administrative law judge’s ruling. On June 23, 2022, the administrative law judge issued additional findings and analysis to FERC with respect to the other party in the matter. These did not address any of the Renewables’ claims. The entire case has now been fully remanded to FERC. We cannot predict the outcome of this proceeding.

Customer Service Invoice Dispute

On May 4, 2021, Nike USA, Inc. (Nike), the buyer under a virtual PPA with a subsidiary of Renewables, provided notice that it disagrees with the settlement amounts included in certain invoices. The PPA provides for a monthly settlement between the parties based on the metered output of the project based on a stated hub price. The disagreement relates as to the appropriate hub price to use for settlement calculations, most notably during Winter Storm Uri in February of 2021. Nike has requested an adjustment to the invoices that would increase the amount payable by approximately $ 31 million. Renewables has responded that the invoices have been properly calculated in accordance with the provisions of the PPA. The parties participated in a mediation in March 2023, which was unsuccessful. On June 16, 2023, Nike filed suit against the Company and certain subsidiaries of Renewables alleging breach of contract. The parties have filed motions for summary judgement and oral arguments were held on October 23, 2023. The Company filed to dismiss the complaint, and following oral arguments, on October 25, 2023, the court denied the Company’s motion to dismiss, and the case will proceed. We cannot predict the outcome of this matter.

Commonwealth Wind and Park City PPAs

In October 2022, Commonwealth Wind and Park City Wind announced that they would seek to re-negotiate the price of the certain Power Purchase Agreements, or PPAs, to help mitigate the impacts of inflation, increased interest rates and supply chain disruptions on the projects.

On October 21, 2022, Commonwealth Wind filed a motion with the DPU seeking a one-month suspension in the DPU’s proceeding to review the power purchase agreements between Commonwealth Wind and the Massachusetts electric distribution companies, or EDCs, in order to provide an opportunity for Commonwealth Wind, the EDCs, state and regulatory officials, and other stakeholders to evaluate the current economic challenges facing Commonwealth Wind and assess measures that would return the project to economic viability including, but not limited to, certain amendments to the Power Purchase Agreements, or PPAs. In December 2022, Commonwealth Wind filed a motion opposing approval of the PPAs by the DPU and requesting that the proceeding be dismissed. On December 30, 2022, the DPU entered an order denying Commonwealth Wind’s motion and approving the PPAs. On January 30, 2023, Commonwealth Wind appealed the DPU’s December 30th order to the Supreme Judicial Court of Massachusetts. On July 13, 2023, each of the EDCs filed with the DPU a first amendment, termination agreement and release agreed with Commonwealth Wind, providing for an orderly termination of the PPAs, withdrawal of Commonwealth Wind’s appeal, and payment by Commonwealth Wind of a $ 48 million termination payment to the EDCs, an amount equal to the development period security provided for in the PPAs in connection with the regulatory approval that is under appeal. The DPU approved the termination agreements on August 2, 2023 and Commonwealth Wind dismissed its appeal of the DPU’s December 30th order.

On October 2, 2023, Park City Wind entered into a first amendment, termination agreement and release with each of the Connecticut EDCs, providing for an orderly termination of the Park City Wind PPAs and payment by Park City Wind of an approximately $ 16 million termination payment to the EDCs, an amount equal to the development period security provided for in the PPAs. On October 13, 2023, PURA approved the termination agreements.

Guarantee Commitments to Third Parties

As of September 30, 2023, we had approximately $ 801 million of standby letters of credit, surety bonds, guarantees and indemnifications outstanding. We also provided a guaranty related to Renewables' commitment to contribute equity to Vineyard

Wind as described in Note 19, which is in addition to the amounts above. These instruments provide financial assurance to the business and trading partners of Avangrid, its subsidiaries and equity method investees in their normal course of business. The instruments only represent liabilities if Avangrid or its subsidiaries fail to deliver on contractual obligations. We therefore believe it is unlikely that any material liabilities associated with these instruments will be incurred and, accordingly, as of September 30, 2023, neither we nor our subsidiaries have any liabilities recorded for these instruments.

NECEC Commitments

On January 4, 2021, CMP transferred the New England Clean Energy Connect, or NECEC, project to NECEC Transmission LLC, a wholly-owned subsidiary of Networks. Among other things, NECEC Transmission LLC and/or CMP committed to approximately $ 90 million of future payments to support various programs in the state of Maine, of which approximately $ 9 million was paid through the end of 2021. In December 2021 the remaining future payments were suspended following the halt in construction of the NECEC project. NECEC restarted the payments on July 3, 2023.

Note 9. Environmental Liabilities

Environmental laws, regulations and compliance programs may occasionally require changes in our operations and facilities and may increase the cost of electric and natural gas service. We do not provide for accruals of legal costs expected to be incurred in connection with loss contingencies.

Waste sites

The Environmental Protection Agency and various state environmental agencies, as appropriate, have notified us that we are among the potentially responsible parties that may be liable for costs incurred to remediate certain hazardous substances at twenty-four waste sites, which do not include sites where gas was manufactured in the past. Sixteen of the twenty-four sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites; two sites are included in Maine's Uncontrolled Sites Program; zero site is included in the Brownfield Cleanup Program and one site is included on the Massachusetts Non-Priority Confirmed Disposal Site list. The remaining sites are not included in any registry list. Finally, five of the twenty-four sites are also included on the National Priorities list. Any liability may be joint and several for certain sites.

We have recorded an estimated liability of $ 6 million related to six of the twenty-four sites. We have paid remediation costs related to the remaining eighteen sites and do not expect to incur additional liabilities. Additionally, we have recorded an estimated liability of $ 10 million related to another ten sites where we believe it is probable that we will incur remediation and/or monitoring costs, although we have not been notified that we are among the potentially responsible parties or that we are regulated under State Resource Conservation and Recovery Act programs. It is possible the ultimate cost to remediate these sites may be significantly more than the accrued amount. As of September 30, 2023, our estimate for costs to remediate these sites ranges from $ 15 million to $ 23 million. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination, and the allocation of the clean-up costs.

Manufactured Gas Plants

We have a program to investigate and perform necessary remediation at our fifty-three sites where gas was manufactured in the past (Manufactured Gas Plants, or MGPs). Six sites are included in the New York State Registry; thirty-nine sites are included in the New York State Department of Environmental Conservation (NYSDEC) Multi-Site Order of Consent; two sites with individual NYSDEC Orders of Consent; two site under a Brownfield Cleanup Program and two sites are included in Maine Department of Environmental Protection programs (none in the Voluntary Response Action Program, Brownfield Cleanup Program and Uncontrolled Sites Program). The remaining sites are not included in a formal program. We have entered into consent orders with various environmental agencies to investigate and, where necessary, remediate forty-one of the fifty-three sites.

As of September 30, 2023, our estimate for all costs related to investigation and remediation of the fifty-three sites ranges from $ 129 million to $ 225 million. Our estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial actions, changes in technology relating to remedial alternatives and changes to current laws and regulations.

Certain of our Connecticut and Massachusetts regulated gas companies own or have previously owned properties where MGPs had historically operated. MGP operations have led to contamination of soil and groundwater with petroleum hydrocarbons, benzene and metals, among other things, at these properties, the regulation and cleanup of which is regulated by the federal Resource Conservation and Recovery Act as well as other federal and state statutes and regulations. Each of the companies has or had an ownership interest in one or more such properties contaminated as a result of MGP-related activities. Under the existing regulations, the cleanup of such sites requires state and at times, federal, regulators' involvement and approval before cleanup can commence. In certain cases, such contamination has been evaluated, characterized and remediated. In other cases, the sites have been evaluated and characterized, but not yet remediated. Finally, at some of these sites, the scope of the contamination has not yet been fully characterized; as of September 30, 2023, no liability was recorded related to these sites and no amount of loss, if any, can be reasonably estimated at this time. In the past, the companies have received approval for the recovery of MGP-related remediation expenses from customers through rates and will seek recovery in rates for ongoing MGP-related remediation expenses for all of their MGP sites.

As of both September 30, 2023 and December 31, 2022, the liability associated with our MGP sites in Connecticut was $ 112 million, the remediation costs of which could be significant and will be subject to a review by PURA as to whether these costs are recoverable in rates.

As of September 30, 2023 and December 31, 2022, our total recorded liability to investigate and perform remediation at all known inactive MGP sites discussed above and other sites was $ 257 million and $ 289 million, respectively. We recorded a corresponding regulatory asset, net of insurance recoveries and the amount collected from FirstEnergy, as described below, because we expect to recover the net costs in rates. Our environmental liability accruals are recorded on an undiscounted basis and are expected to be paid through the year 2053.

FirstEnergy

NYSEG and RG&E each sued FirstEnergy under the Comprehensive Environmental Response, Compensation, and Liability Act to recover environmental cleanup costs at certain former MGP sites, which are included in the discussion above. In 2011, the District Court issued a decision and order in NYSEG’s favor, which was upheld on appeal, requiring FirstEnergy to pay NYSEG for past and future clean-up costs at the sixteen sites in dispute. 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 MGP sites in dispute. FirstEnergy remains liable for a substantial share of clean up expenses at the MGP sites. Based on projections as of September 30, 2023, FirstEnergy’s share of clean-up costs owed to NYSEG & RG&E is estimated at approximately $ 8 million and $ 6 million, respectively. These amounts are being treated as contingent assets and have not been recorded as either a receivable or a decrease to the environmental provision. Any recovery will be flowed through to NYSEG and RG&E customers, as applicable.

English Station

On April 8, 2013, DEEP issued an administrative order addressed to UI, Evergreen Power, LLC (Evergreen Power) and Asnat Realty LLC (Asnat), then owners of a former generation site on the Mill River in New Haven (English Station) that UI sold to Quinnipiac Energy in 2000, and others, ordering the parties to take certain actions related to investigating and remediating the English Station site. This proceeding was stayed while DEEP and UI continue to work through the remediation process pursuant to the consent order described below. Status reports are periodically filed with DEEP.

On August 4, 2016, DEEP issued a partial consent order (the consent order), that, subject to its terms and conditions, requires UI to investigate and remediate certain environmental conditions within the perimeter of the English Station site. Under the consent order, to the extent that the cost of this investigation and remediation is less than $ 30 million, UI will remit to the State of Connecticut the difference between such cost and $ 30 million to be used for a public purpose as determined in the discretion of the Governor of the State of Connecticut, the Attorney General of the State of Connecticut and the Commissioner of DEEP. UI is obligated to comply with the terms of the consent order even if the cost of such compliance exceeds $ 30 million. Under the terms of the consent order, the state will discuss options with UI on recovering or funding any cost above $ 30 million such as through public funding or recovery from third parties; however, it is not bound to agree to or support any means of recovery or funding. UI has continued its process to investigate and remediate the environmental conditions within the perimeter of the English Station site pursuant to the consent order. On April 18, 2023, DEEP issued a letter to UI requiring a response within 30 days that provides alternative remediation proposals to remediate certain environmental conditions and provides an accounting of costs incurred in connection compliance with the Consent Order. UI responded to the letter on May 18, 2023. UI received a second letter on June 1, 2023 requiring a response in 30 days to provide a schedule to complete investigation of the site and to complete the investigations by September 15, 2023. UI responded on July 3, 2023.

As of September 30, 2023 and December 31, 2022, the amount reserved related to English Station was $ 20 million and $ 19 million, respectively. Since inception, we have recorded $ 35 million to the reserve which has been offset with cash payments over time. We cannot predict the outcome of this matter.

Eagle Takings Inquiry

In April 2023, Avangrid Renewables received a letter from the U.S. Fish and Wildlife Service regarding certain bald and gold eagle fatalities that allegedly occurred at certain Avangrid Renewables facilities that are not covered by an eagle take permit. Avangrid Renewables has responded to the U.S. Fish and Wildlife Service providing information about the relevant eagle taking permit applications and relevant mitigation activity at each facility. We cannot predict the outcome of this preliminary inquiry.

Note 10. Post-retirement and Similar Obligations

During the three and nine months ended September 30, 2023, we made $ 15 million of pension contributions. We do not expect to make any additional contributions in 2023.

The components of net periodic benefit cost for pension benefits for the three and nine months ended September 30, 2023 and 2022, respectively, consisted of:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
(Millions)				
Service cost	$ 1	$ 6	$ 4	$ 21
Interest cost	30	10	91	27
Expected return on plan assets	(36)	(20)	(109)	(71)
Amortization of:				
Prior service costs	—	—	1	1
Actuarial loss	1	11	2	40
Curtailment Charge	—	(1)		(24)
Net Periodic Benefit Cost	**$ (4)**	**$ 6**	**$ (11)**	**$ (6)**

The components of net periodic benefit cost for postretirement benefits for the three and nine months ended September 30, 2023 and 2022, respectively, consisted of:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
(Millions)				
Service cost	$ —	$ 1	$ 1	$ 2
Interest cost	3	3	10	8
Expected return on plan assets	(1)	(1)	(4)	(4)
Amortization of:				
Prior service costs	—	(1)	—	(1)
Actuarial loss	(3)	(1)	(9)	(3)
Net Periodic Benefit Cost	**$ (1)**	**$ 1**	**$ (2)**	**$ 2**

Note 11. Equity

As of September 30, 2023 and December 31, 2022, we had, respectively, 103,889 and 108,188 shares of common stock held in trust and no convertible preferred shares outstanding. During the three and nine months ended September 30, 2023, we released 0 and 4,299 shares of common stock held in trust, respectively. During both the three and nine months ended September 30, 2022, we released 0 shares of common stock held in trust.

We maintain a repurchase agreement with J.P. Morgan Securities, LLC. (JPM), pursuant to which JPM will, from time to time, acquire, on behalf of Avangrid, shares of common stock of Avangrid. The purpose of the stock repurchase program is to allow Avangrid to maintain Iberdrola's relative ownership percentage of approximately 81.5 %. The stock repurchase program may be suspended or discontinued at any time upon notice. As of September 30, 2023, a total of 997,983 shares have been repurchased in the open market, all of which are included as Avangrid treasury shares. The total cost of all repurchases, including commissions, was $ 47 million as of September 30, 2023.

Accumulated Other Comprehensive Loss

Accumulated Other Comprehensive Loss for the three and nine months ended September 30, 2023 and 2022, respectively, consisted of:

	As of June 30, 2023	Three Months Ended September 30, 2023	As of September 30, 2023	As of June 30, 2022	Three Months Ended September 30, 2022	As of September 30, 2022
(Millions)						
Gain on defined benefit plans, net of income tax expense of $ 0 and $ 0 for 2023 and 2022		$ —			$ —	
Amortization of pension cost, net of income tax expense of $ 0 and $ 0 for 2023 and 2022		—			—	
Net gain (loss) on pension plans	(18)	—	(18)	(29)	—	(29)
Unrealized (loss) gain from equity method investment, net of income tax expense (benefit) of $ 0 for 2023 and $(5) for 2022 (a)	18	(1)	17	2	(13)	(11)
Unrealized (loss) gain during period on derivatives qualifying as cash flow hedges, net of income tax expense of $ 11 for 2023 and $ 1 for 2022	(163)	30	(133)	(194)	3	(191)
Reclassification to net income of losses on cash flow hedges, net of income tax expense of $ 15 for 2023 and $ 7 for 2022 (b)	89	40	129	(15)	19	4
(Loss) Gain on derivatives qualifying as cash flow hedges	(74)	70	(4)	(209)	22	(187)
Accumulated Other Comprehensive Loss	**$ (74)**	**$ 69**	**$ (5)**	**$ (236)**	**$ 9**	**$ (227)**

	As of December 31, 2022	Nine Months Ended September 30, 2023	As of September 30, 2023	As of December 31, 2021	Nine Months Ended September 30, 2022	As of September 30, 2022
(Millions)						
Gain on defined benefit plans, net of income tax expense of $ 0 and $ 3 for 2023 and 2022		$ —			$ 8	
Amortization of pension cost, net of income tax expense of $ 1 and $ 0 for 2023 and 2022		$ 2			$ 1	
Net gain (loss) on pension plans	$ (20)	$ 2	$ (18)	$ (38)	$ 9	$ (29)
Unrealized (loss) gain from equity method investment, net of income tax expense of $ 1 for 2023 and $(1) for 2022 (a)	$ 13	$ 4	$ 17	$ (9)	$ (2)	$ (11)
Unrealized loss during period on derivatives qualifying as cash flow hedges, net of income tax expense of $ 22 for 2023 and $ 1 for 2022	(195)	62	(133)	(194)	3	(191)
Reclassification to net income of losses on cash flow hedges, net of income tax expense of $ 39 for 2023 and $ 13 for 2022 (b)	22	107	129	(32)	36	4
(Loss) Gain on derivatives qualifying as cash flow hedges	(173)	169	(4)	(226)	39	(187)
Accumulated Other Comprehensive Loss	**$ (180)**	**$ 175**	**$ (5)**	**$ (273)**	**$ 46**	**$ (227)**

(a) Foreign currency and interest rate contracts.

(b) Reclassification is reflected in the operating expenses and interest expense, net of capitalization and line items in our condensed consolidated statements of income.

Note 12. Earnings Per Share

Basic earnings per share is computed by dividing net income attributable to Avangrid by the weighted-average number of shares of our common stock outstanding. During the three and nine months ended September 30, 2023 and 2022, while we did have securities that were dilutive, these securities did not result in a change in our earnings per share calculations for the both three and nine months ended September 30, 2023 and 2022.

The calculations of basic and diluted earnings per share attributable to Avangrid, for the three and nine months ended September 30, 2023 and 2022, respectively, consisted of:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	**2022**	**2023**	**2022**
(Millions, except for number of shares and per share data)				
Numerator:				
Net income attributable to Avangrid	$ 59	$ 105	$ 389	$ 734
Denominator:				
Weighted average number of shares outstanding - basic	386,869,341	386,736,774	386,788,279	386,724,035
Weighted average number of shares outstanding - diluted	387,322,281	387,280,621	387,122,498	387,200,882
Earnings per share attributable to Avangrid				
Earnings Per Common Share, Basic	$ 0.15	$ 0.27	$ 1.00	$ 1.90
Earnings Per Common Share, Diluted	$ 0.15	$ 0.27	$ 1.00	$ 1.90

Note 13. Segment Information

Our segment reporting structure uses our management reporting structure as its foundation to reflect how Avangrid manages the business internally and is organized by type of business. We report our financial performance based on the following two reportable segments:

- Networks: includes all of the energy transmission and distribution activities, any other regulated activity originating in New York and Maine and regulated electric distribution, electric transmission and gas distribution activities originating in Connecticut and Massachusetts. The Networks reportable segment includes nine rate regulated operating segments. These operating segments generally offer the same services distributed in similar fashions, have the same types of customers, have similar long-term economic characteristics and are subject to similar regulatory requirements, allowing these operations to be aggregated into one reportable segment.
- Renewables: activities relating to renewable energy, mainly wind energy generation and trading related with such activities.

The chief operating decision maker evaluates segment performance based on segment adjusted net income defined as net income adjusted to exclude mark-to-market earnings from changes in the fair value of derivative instruments, offshore contract provision, costs incurred in connection with the COVID-19 pandemic and costs incurred related to the PNMR Merger.

Products and services are sold between reportable segments and affiliate companies at cost. Segment income, expense and assets presented in the accompanying tables include all intercompany transactions that are eliminated in our condensed consolidated financial statements. Refer to Note 4 - Revenue for more detailed information on revenue by segment.

Segment information as of and for the three and nine months ended September 30, 2023, consisted of:

Three Months Ended September 30, 2023	Networks	Renewables	Other (a)	Avangrid Consolidated
(Millions)				
Revenue - external	$ 1,587	$ 387	$ —	$ 1,974
Revenue - intersegment	—	—	—	—
Depreciation and amortization	175	123	5	303
Operating income (loss)	134	(45)	—	89
Earnings (losses) from equity method investments	3	(4)	—	(1)
Interest expense, net of capitalization	76	6	25	107
Income tax expense (benefit)	12	(27)	7	(8)
Adjusted net income (loss)	92	55	(42)	105

Nine Months Ended September 30, 2023	Networks	Renewables	Other (a)	Avangrid Consolidated
(Millions)				
Revenue - external	$ 4,935	$ 1,092	$ —	$ 6,027
Revenue - intersegment	1	—	(1)	—
Depreciation and amortization	524	338	6	868
Operating income (loss)	531	(46)	(5)	480
Earnings (losses) from equity method investments	11	(6)	—	5
Interest expense, net of capitalization	215	16	70	301
Income tax expense (benefit)	70	(87)	—	(17)
Adjusted net income (loss)	364	170	(100)	434
Capital expenditures	1,551	505	22	2,078
As of September 30, 2023				
Property, plant and equipment	21,017	11,039	12	32,068
Equity method investments	187	327	—	514
Total assets	$ 29,161	$ 13,926	$ (701)	$ 42,386

(a) Includes Corporate and intersegment eliminations.

Segment information for the three and nine months ended September 30, 2022 and as of December 31, 2022, consisted of:

Three Months Ended September 30, 2022	Networks	Renewables	Other (a)	Avangrid Consolidated
(Millions)				
Revenue - external	$ 1,546	$ 293	$ (1)	$ 1,838
Revenue - intersegment	—	—	—	—
Depreciation and amortization	166	113	—	279
Operating income (loss)	141	(27)	(2)	112
Earnings (losses) from equity method investments	3	(1)	—	2
Interest expense, net of capitalization	60	2	14	76
Income tax expense (benefit)	13	(56)	(7)	(50)
Adjusted net income (loss)	89	45	(13)	122

Nine Months Ended September 30, 2022	Networks	Renewables	Other (a)	Avangrid Consolidated
(Millions)				
Revenue - external	$ 4,944	$ 821	$ —	$ 5,765
Revenue - intersegment	1	—	(1)	—
Depreciation and amortization	491	319	1	811
Operating income (loss)	660	(17)	(8)	635
Earnings from equity method investments	8	253	—	261
Interest expense, net of capitalization	171	8	47	226
Income tax expense (benefit)	65	(35)	(16)	14
Adjusted net income (loss)	471	322	(44)	749
Capital expenditures	1,315	617	8	1,940
As of December 31, 2022				
Property, plant and equipment	20,027	10,950	17	30,994
Equity method investments	171	266	—	437
Total assets	$ 28,069	$ 13,553	$ (499)	$ 41,123

(a) Includes Corporate and intersegment eliminations.

Reconciliation of Adjusted Net Income to Net Income attributable to Avangrid for the three and nine months ended September 30, 2023 and 2022, respectively, is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
(Millions)				
Adjusted Net Income Attributable to Avangrid, Inc.	**$ 105**	**$ 122**	**$ 434**	**$ 749**
Adjustments:				
Mark-to-market earnings - Renewables (1)	(23)	(22)	(19)	(17)
Impact of COVID-19 (2)	—	—	—	(2)
Merger costs (3)	(1)	(1)	(2)	(3)
Offshore contract provision (4)	(40)	—	(40)	—
Income tax impact of adjustments	17	6	16	6
Net Income Attributable to Avangrid, Inc.	**$ 59**	**$ 105**	**$ 389**	**$ 734**

(1) Mark-to-market earnings relates to earnings impacts from changes in the fair value of Renewables' derivative instruments associated with electricity and natural gas.
(2) Represents costs incurred in connection with the COVID-19 pandemic, mainly related to bad debt provisions.
(3) Pre-merger costs incurred.
(4) Costs incurred in connection with offshore contract provision.

Note 14. Related Party Transactions

We engage in related party transactions that are generally billed at cost and in accordance with applicable state and federal commission regulations.

Related party transactions for the three and nine months ended September 30, 2023 and 2022, respectively, consisted of:

Three Months Ended September 30,	2023		2022	
(Millions)	Sales To	Purchases From	Sales To	Purchases From
Iberdrola, S.A.	$ —	$ (8)	$ —	$ (12)
Iberdrola Renovables Energía, S.L.	$ —	$ (2)	$ —	$ (2)
Iberdrola Financiación, S.A.U.	$ —	$ (12)	$ —	$ (3)
Vineyard Wind	$ 2	$ —	$ 2	$ —
Other	$ —	$ (1)	$ —	$ (1)

Nine Months Ended September 30,	2023		2022	
(Millions)	Sales To	Purchases From	Sales To	Purchases From
Iberdrola, S.A.	$ —	$ (34)	$ —	$ (34)
Iberdrola Renovables Energía, S.L.	$ —	$ (5)	$ —	$ (7)
Iberdrola Financiación, S.A.U.	$ —	$ (20)	$ —	$ (8)
Vineyard Wind	$ 6	$ —	$ 5	$ —
Other	$ —	$ (1)	$ —	$ (2)

Related party balances as of September 30, 2023 and December 31, 2022, respectively, consisted of:

As of	September 30, 2023		December 31, 2022	
(Millions)	Owed By	Owed To	Owed By	Owed To
Iberdrola	$ —	$ (34)	$ 1	$ (29)
Iberdrola Financiación, S.A.U.	$ —	$ (807)	$ —	$ (9)
Vineyard Wind	$ 4	$ (8)	$ 3	$ (8)
Iberdrola Solutions	$ —	$ (6)	$ —	$ (2)
Other	$ 4	$ (6)	$ 4	$ (1)

Transactions with Iberdrola relate predominantly to the provision and allocation of corporate services and management fees, and certain financing arrangements described below. All costs that can be specifically allocated, to the extent possible, are charged directly to the company receiving such services. In situations when Iberdrola corporate services are provided to two or more companies of Avangrid, any costs remaining after direct charges are allocated using agreed upon cost allocation methods designed to allocate such costs. We believe that the allocation method used is reasonable.

We have a bi-lateral demand note agreement with Iberdrola Solutions, LLC, which had notes payable balance of $ 6 million and $ 2 million, respectively, as of September 30, 2023 and December 31, 2022.

There have been no guarantees provided or received for any related party receivables or payables. These balances are unsecured and are typically settled in cash. Interest is not charged on regular business transactions but is charged on outstanding loan balances. There have been no impairments or provisions made against any affiliated balances.

Avangrid optimizes its liquidity position as part of the Iberdrola Group and is a party to a liquidity agreement with a financial institution, along with certain members of the Iberdrola Group. Cash surpluses remaining after meeting the liquidity requirements of Avangrid and its subsidiaries may be deposited at the financial institution. Deposits, or credit balances, serve as collateral against the debit balances of other parties to the liquidity agreement. The balance at both September 30, 2023 and December 31, 2022, was $ 0 .

On June 18, 2023, Avangrid's credit facility with Iberdrola Financiación, S.A.U., a subsidiary of Iberdrola, matured. The facility had a limit of $ 500 million. On July 19, 2023, we replaced this credit facility with an increased limit of $ 750 million and maturity date of June 18, 2028. Avangrid pays a quarterly facility fee of 22.5 basis points (rate per annum) on the facility based on Avangrid’s current Moody’s and S&P ratings for senior unsecured long-term debt. As of September 30, 2023 and December 31, 2022, there was no outstanding amount under this credit facility.

On July 19, 2023, we entered into a green term loan agreement with Iberdrola Financiación, S.A.U., with an aggregate principal amount of $ 800 million maturing on July 13, 2033 at an interest rate of 5.45 % (the Intragroup Green Loan).

On July 3, 2023, we entered into a deposit agreement with Iberdrola Financiación, S.A.U., pursuant to which a deposit of $ 250 million was made on July 3, 2023, which matured on July 24, 2023 at an interest rate of 5.50 %. The deposit was paid out on July 24, 2023 with the proceeds of the Intragroup Green Loan.

See Note 19 - Equity Method Investments for more information on Vineyard Wind, LLC (Vineyard Wind).

Note 15. Other Financial Statement Items

Accounts receivable and unbilled revenue, net

Accounts receivable and unbilled revenues, net as of September 30, 2023 and December 31, 2022 consisted of:

As of	September 30, 2023	December 31, 2022
(Millions)		
Trade receivables and unbilled revenues	$ 1,580	$ 1,892
Allowance for credit losses	(163)	(155)
Accounts receivable and unbilled revenues, net	**$ 1,417**	**$ 1,737**

The change in the allowance for credit losses for the three and nine months ended September 30, 2023 and 2022 consisted of:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Millions)	2023	2022	2023	2022
As of Beginning of Period,	**$ 155**	**$ 142**	**$ 155**	**$ 151**
Current period provision	45	45	95	68
Write-off as uncollectible	(37)	(44)	(87)	(76)
As of September 30,	**$ 163**	**$ 143**	**$ 163**	**$ 143**

The Deferred Payment Arrangements (DPA) receivable balance was $ 124 million and $ 102 million at September 30, 2023 and December 31, 2022, respectively. The allowance for credit losses for DPAs at September 30, 2023 and December 31, 2022 was $ 48 million and $ 42 million, respectively. Furthermore, the change in the allowance for credit losses associated with the DPAs for the three and nine months ended September 30, 2023 was $ 1 million and $ 6 million, respectively, and for the three and nine months ended September 30, 2022 was $(11) million and $(5) million, respectively.

Prepayments and other current assets

Included in prepayments and other current assets are $ 190 million and $ 136 million of prepaid other taxes as of September 30, 2023 and December 31, 2022, respectively.

Property, plant and equipment and intangible assets

The accumulated depreciation and amortization as of September 30, 2023 and December 31, 2022, respectively, were as follows:

As of	September 30, 2023	December 31, 2022
(Millions)		
Property, plant and equipment		
Accumulated depreciation	$ 12,278	$ 11,542
Intangible assets		
Accumulated amortization	$ 347	$ 331

As of September 30, 2023 and 2022, accrued liabilities for property, plant and equipment additions were $ 469 million and $ 200 million, respectively.

Debt

On July 3, 2023, NYSEG remarketed $ 100 million aggregate principal amount of unsecured notes maturing in 2034 at a fixed interest rate of 4.00 %.

On August 3, 2023, NYSEG issued $ 350 million aggregate principal amount of unsecured notes maturing in 2028 at a fixed interest rate of 5.65 %.

On August 3, 2023, NYSEG issued $ 400 million aggregate principal amount of unsecured notes maturing in 2033 at a fixed interest rate of 5.85 %.

On October 2, 2023, UI remarketed $ 65 million aggregate principal amount of unsecured notes maturing in 2033 at a fixed interest rate of 4.50 %.

Commercial Paper

As of September 30, 2023 and December 31, 2022, there was $ 954 million and $ 397 million of commercial paper outstanding, respectively. As of September 30, 2023 and December 31, 2022, the weighted-average interest rate on commercial paper was 5.52 % and 4.66 %, respectively.

Supplier Financing Arrangements

We operate a supplier financing arrangement. We arranged for the extension of payment terms with some suppliers, which could elect to be paid by a financial institution earlier than maturity under supplier financing arrangements. Due to the interest cost associated with these arrangements, the balances are classified as "Notes payable" on our consolidated balance sheets. The balance relates to capital expenditures and, therefore, is treated as non-cash activity, and is reported under financing activity of the consolidated statement of cash flows when the balance is paid. As of September 30, 2023 and December 31, 2022, the amount of notes payable under supplier financing arrangements was $ 0 and $ 171 million, respectively. As of December 31, 2022, the weighted average interest rate on the balance was 5.48 %.

Other current liabilities

Included in other current liabilities are $ 325 million and $ 271 million of advances received as of September 30, 2023 and December 31, 2022, respectively.

Note 16. Income Tax Expense

The effective tax rates, inclusive of federal and state income tax, for the three and nine months ended September 30, 2023, were (34.8)% and (6.1)%, respectively. The effective tax rates for the three and nine months ended September 30, 2023, are below the federal statutory tax rate of 21%, primarily due to the recognition of production tax credits associated with wind production, the effect of the excess deferred tax amortization resulting from the Tax Act, the equity component of allowance for funds used during construction and other property related flow through items.

The effective tax rates, inclusive of federal and state income tax, for the three and nine months ended September 30, 2022, were (89.3)% and 2.0 %, respectively. The effective tax rates for the three and nine months ended September 30, 2022 are below the federal statutory tax rate of 21%, primarily due to the recognition of production tax credits associated with wind production, the effect of the excess deferred tax amortization resulting from the Tax Act, the equity component of allowance for funds used during construction, and the release of our federal valuation allowance in the third quarter of 2022 as a result of the Inflation Reduction Act enacted in August 2022 permitting us to utilize tax attributes that were previously expected to expire, partially offset by the tax on gain from the offshore joint venture restructuring transaction (see Note 19 for further details on the transaction).

In the third quarter of 2023, Avangrid executed an agreement to transfer the production tax credits generated in 2023 pursuant to the transferability provisions of the Inflation Reduction Act of 2022. Avangrid received cash of $ 62 million for the transfer of tax credits in the nine months ended September 30, 2023.

Note 17. Stock-Based Compensation Expense

The Avangrid, Inc. Amended and Restated Omnibus Incentive Plan (the Plan) provides for, among other things, the issuance of performance stock units (PSUs), restricted stock units (RSUs) and phantom share units (Phantom Shares).

Performance Stock Units

In March 2023, a total number of 677,752 PSUs, before applicable taxes, were approved to be earned by participants based on achievement of certain performance and market-based metrics for the 2021 to 2022 performance period and are payable in three equal installments, net of applicable taxes, in 2023, 2024 and 2025. The first installment was paid in June 2023, and 125,657 shares of common stock were issued in July 2023 to settle this installment payment.

On April 12, 2023 and July 20, 2023, 487,000 PSUs were granted to certain executives of Avangrid with achievement measured based on certain performance and market-based metrics for the 2023 to 2025 performance period. The PSUs will be payable in three equal installments, net of applicable taxes, in 2026, 2027 and 2028.

Restricted Stock Units

In March 2021, 5,000 RSUs were granted to an officer of Avangrid. The RSUs vest in full in one installment in March 2023, provided that the grantee remains continuously employed with Avangrid through the applicable vesting date. The fair value on the grant date was determined based on a price of $ 48.83 per share. The RSU grant was settled in March 2023, net of applicable taxes, by issuing 3,642 shares of common stock.

In June 2022, 25,000 RSUs were granted to an officer of Avangrid. The RSUs vest in two equal installments in 2023 and 2024, provided that the grantee remains continuously employed with Avangrid through the applicable vesting dates. The fair value on the grant date was determined based on a price of $ 47.64 per share. The first installment of this RSU grant was settled in January 2023, net of applicable taxes, by issuing 8,690 shares of common stock.

Phantom Share Units

In February 2022, 9,000 Phantom Shares were granted to certain Avangrid executives and employees. These awards vest in three equal installments in 2022, 2023 and 2024 and will be settled in a cash amount equal to the number of Phantom Shares multiplied by the closing share price of Avangrid’s common stock on the respective vesting dates, subject to continued employment. The liability of these awards is measured based on the closing share price of Avangrid’s common stock at each reporting date until the date of settlement. In February and August 2023, $ 0.2 million was paid to settle the second and third installments under this plan.

In February 2023, 81,000 Phantom Shares were granted to certain Avangrid executives and employees. These awards vest in three equal installments in 2024, 2025 and 2026 and will be settled in a cash amount equal to the number of Phantom Shares multiplied by the closing share price of Avangrid’s common stock on the respective vesting dates, subject to continued employment. The liability of these awards is measured based on the closing share price of Avangrid’s common stock at each reporting date until the date of settlement.

As of September 30, 2023 and December 31, 2022, the total liability was $ 2 million and $ 0 , respectively, which is included in other current and non-current liabilities.

The total stock-based compensation expense, which is included in "Operations and maintenance" in our condensed consolidated statements of income, for the three and nine months ended September 30, 2023 was $ 4 million and $ 11 million, respectively, and for the three and nine months ended September 30, 2022 was $ 2 million and $ 10 million, respectively.

Note 18. Variable Interest Entities

We participate in certain partnership arrangements that qualify as variable interest entities (VIEs). Consolidated VIE's consist of tax equity financing arrangements (TEFs) and partnerships in which an investor holds a noncontrolling interest and does not have substantive kick-out or participating rights.

The sale of a membership interest in the TEFs represents the sale of an equity interest in a structure that is considered a sale of non-financial assets. Under the sale of non-financial assets, the membership interests in the TEFs we sell to third-party investors are reflected as noncontrolling interest on our condensed consolidated balance sheets valued based on an HLBV model. Earnings from the TEFs are recognized in net income attributable to noncontrolling interests in our condensed consolidated statements of income. We consolidate the entities that have TEFs based on being the primary beneficiary for these VIEs.

On April 29, 2022, we closed on a TEF agreement, receiving $ 14 million from a tax equity investor related to the Lund Hill solar farm that reached partial mechanical completion on the same date. In March 2023 we received additional investment from our investor in the amount of $ 61 million. Lund Hill is owned by Solis Solar Power I, LLC (Solis I).

The assets and liabilities of the VIEs totaled approximately $ 2,768 million and $ 179 million, respectively, at September 30, 2023. As of December 31, 2022, the assets and liabilities of VIEs totaled approximately $ 2,853 million and $ 424 million, respectively. At September 30, 2023 and December 31, 2022, the assets and liabilities of the VIEs consisted primarily of property, plant and equipment.

Wind power generation is subject to certain favorable tax treatments in the U.S. In order to monetize the tax benefits, we have entered into these structured institutional partnership investment transactions related to certain wind farms. Under these structures, we contribute certain wind assets, relating both to existing wind farms and wind farms that are being placed into operation at the time of the relevant transaction, and other parties invest in the share equity of the limited liability holding company. As consideration for their investment, the third parties make either an upfront cash payment or a combination of upfront cash and payments over time. We retain a class of membership interest and day-to-day operational and management control, subject to investor approval of certain major decisions. The third-party investors do not receive a lien on any assets and have no recourse against us for their upfront cash payments.

The partnerships generally involve disproportionate allocations of profit or loss, cash distributions and tax benefits resulting from the wind farm energy generation between the investor and sponsor until the investor recovers its investment and achieves a cumulative annual after-tax return. Once this target return is met, the relative sharing of profit or loss, cash distributions and taxable income or loss between the Company and the third-party investor flips, with the sponsor generally receiving higher percentages thereafter. We also have a call option to acquire the third-party investors' membership interest within a defined time period after this target return is met.

At September 30, 2023, El Cabo Wind, LLC (El Cabo), Patriot Wind Farm LLC (Patriot), Aeolus Wind Power VII, LLC (Aeolus VII), Aeolus VIII, and Solis I are our consolidated VIEs.

Our El Cabo, Patriot, Aeolus VII, Aeolus VIII, and Solis I interests are not subject to any rights of investors that may restrict our ability to access or use the assets or to settle any existing liabilities associated with the interests.

See Note 19 - Equity Method Investments for information on our VIE we do not consolidate.

Note 19. Equity Method Investments

Renewables holds a 50 % indirect ownership interest in Vineyard Wind 1, LLC (Vineyard Wind 1), a joint venture with Copenhagen Infrastructure Partners (CIP). Prior to a restructuring transaction that took place on January 10, 2022 (Restructuring Transaction), Renewables held a 50 % ownership interest in Vineyard Wind, LLC (Vineyard Wind) which held rights to two easements from the U.S. Bureau of Ocean Energy Management (BOEM) for the development of offshore wind generation, Lease Area 501 which contained 166,886 acres and Lease Area 522 which contained 132,370 acres, both located southeast of Martha's Vineyard. Lease Area 501 was subsequently subdivided in 2021, creating Lease Area 534. On September 15, 2021, Vineyard Wind closed on construction financing for the Vineyard Wind 1 project. Among other items, the Vineyard Wind 1 project was transferred into a separate joint venture, Vineyard Wind 1. Following the Restructuring Transaction, Vineyard Wind 1 remained a 50 -50 joint venture and kept the rights to develop Lease Area 501, and Vineyard Wind was effectively dissolved where Renewables received rights to the Lease Area 534 and CIP received rights to Lease Area 522 as liquidating distributions. In contemplation of the liquidating distributions, Renewables also made an incremental payment of approximately $ 168 million to CIP. Consequently in 2022, Renewables recognized a pretax gain of $ 246 million and an after tax gain of $ 181 million, driven by the increase in the market value of its acquired interest in the leases and related development activities over its carrying value. The gain is classified in Earnings from equity method investments in the condensed consolidated statement of income for the three months ended March 31, 2022.

Concurrently with the closing on the construction financing for the Vineyard Wind 1 project, Renewables entered into a credit agreement with certain banks to provide future term loans and letters of credit up to a maximum of approximately $ 1.2 billion to finance a portion of its share of the cost of Vineyard Wind 1 at the maturity of the Vineyard Wind 1 project construction loan. Any term loans mature by October 15, 2031, subject to certain extension provisions. Renewables also entered into an Equity Contribution Agreement in which Renewables agreed to, among other things, make certain equity contributions to fund certain costs of developing and constructing the Vineyard Wind 1 project in accordance with the credit agreement. In addition, we issued a guaranty up to $ 827 million for Renewables' equity contributions under the Equity Contribution Agreement. As part of the Vineyard Wind 1 financial close, $ 152 million of Renewables prior contributions for the Vineyard Wind 1 project were returned in 2021.

Vineyard Wind 1 is considered a VIE because it cannot finance its activities without additional support from its owners or third parties. Renewables is not the primary beneficiary of the entity since it does not have a controlling financial interest, and therefore we do not consolidate this entity. During the third quarter of 2023 Renewables made a capital contribution of $ 78 million to Vineyard Wind 1. As of September 30, 2023 and December 31, 2022, the carrying amount of Renewables' investments in Vineyard Wind 1, LLC and Vineyard Wind 1 Pledgor LLC was $ 87 million and $ 9 million, respectively.

On October 24, 2023, Vineyard Wind 1 closed on a TEF agreement, pursuant to which Vineyard Wind 1 is expected to receive approximately $ 1.2 billion from tax equity investors in installments based on the number of turbines reaching or about to reach mechanical completion each month until the entire project reaches commercial operation date.

Note 20. Subsequent Event

On October 18, 2023, the board of directors of Avangrid declared a quarterly dividend of $ 0.44 per share on its common stock. This dividend is payable on January 2, 2024 to shareholders of record at the close of business on December 1, 2023.

Item 2. *Management’s Discussion and Analysis of Financial Condition and Results of Operations*

You should read the following discussion of our financial condition and results of operations in conjunction with the condensed consolidated financial statements and the notes thereto included elsewhere in this Quarterly Report on Form 10-Q and with our audited consolidated financial statements as of December 31, 2022 and 2021, and for the three years ended December 31, 2022, included in our Annual Report on Form 10-K for the year ended December 31, 2022, filed with the Securities and Exchange Commission, or the SEC, on February 22, 2023, which we refer to as our “Form 10-K.” In addition to historical condensed consolidated financial information, the following discussion contains forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those discussed in the forward-looking statements. The foregoing and other factors are discussed and should be reviewed in our Form 10-K and other subsequent filings with the SEC.

Overview

Avangrid aspires to be the leading sustainable energy company in the United States. Our purpose is to work every day to deliver a more accessible clean energy model that promotes healthier, more sustainable communities. A commitment to sustainability is firmly entrenched in the values and principles that guide Avangrid, with environmental, social, governance and financial sustainability key priorities driving our business strategy.

Avangrid has approximately $42 billion in assets and operations in 24 states concentrated in our two primary lines of business - Avangrid Networks and Avangrid Renewables. Avangrid Networks owns eight electric and natural gas utilities, serving approximately 3.3 million customers in New York and New England. Avangrid Renewables owns and operates 9.2 gigawatts of electricity capacity, primarily through wind and solar power, with a presence in 22 states across the United States. Avangrid supports the achievement of the Sustainable Development Goals approved by the member states of the United Nations, was named among the World’s Most Ethical companies in 2023 for the fifth consecutive year by the Ethisphere Institute and recognized by Just Capital as one of the 2023 Just 100, an annual ranking of the most just U.S. public companies for the third time. Avangrid employs approximately 7,600 people. Iberdrola S.A., or Iberdrola, a corporation *(sociedad anónima)* organized under the laws of the Kingdom of Spain, a worldwide leader in the energy industry, directly owns 81.6% of the outstanding shares of Avangrid common stock. The remaining outstanding shares are owned by various shareholders with approximately 14.7% of Avangrid's outstanding shares publicly-traded on the New York Stock Exchange (NYSE). Avangrid's primary businesses are described below.

Our direct, wholly-owned subsidiaries include Avangrid Networks, Inc., or Networks, and Avangrid Renewables Holdings, Inc., or ARHI. ARHI in turn holds subsidiaries including Avangrid Renewables, LLC, or Renewables. Networks owns and operates our regulated utility businesses through its subsidiaries, including electric transmission and distribution and natural gas distribution, transportation and sales. Renewables operates a portfolio of renewable energy generation facilities primarily using onshore wind power and also solar, biomass and thermal power.

Through Networks, we own electric distribution, transmission and generation companies and natural gas distribution, transportation and sales companies in New York, Maine, Connecticut and Massachusetts, delivering electricity to approximately 2.3 million electric utility customers and delivering natural gas to approximately 1.0 million natural gas utility customers as of September 30, 2023.

Networks, a Maine corporation, holds regulated utility businesses, including electric transmission and distribution and natural gas distribution, transportation and sales. Networks serves as a super-regional energy services and delivery company through the eight regulated utilities it owns directly:

- New York State Electric & Gas Corporation, or NYSEG, which serves electric and natural gas customers across more than 40% of the upstate New York geographic area;
- Rochester Gas and Electric Corporation, or RG&E, which serves electric and natural gas customers within a nine-county region in western New York, centered around Rochester;
- The United Illuminating Company, or UI, which serves electric customers in southwestern Connecticut;
- Central Maine Power Company, or CMP, which serves electric customers in central and southern Maine;
- The Southern Connecticut Gas Company, or SCG, which serves natural gas customers in Connecticut;
- Connecticut Natural Gas Corporation, or CNG, which serves natural gas customers in Connecticut;
- The Berkshire Gas Company, or BGC, which serves natural gas customers in western Massachusetts; and
- Maine Natural Gas Corporation, or MNG, which serves natural gas customers in several communities in central and southern Maine.

Renewables has a combined wind, solar and thermal installed capacity of 9,243 megawatts, or MW, as of September 30, 2023, including Renewables' share of joint projects, of which 8,061 MW was installed wind capacity. Renewables targets to contract or hedge above 80% of its capacity under long-term PPAs and hedges to limit market volatility. As of September 30, 2023, approximately 75% of the capacity was contracted with PPAs for an average period of approximately 10 years and an additional 11% of production was hedged. Avangrid is one of the three largest wind operators in the United States based on installed capacity as of September 30, 2023, and strives to lead the transformation of the U.S. energy industry to a sustainable, competitive, clean energy future. Renewables installed capacity includes 67 wind farms and six solar facilities in 21 states across the United States.

Texas Weather Event

During February 2021, Texas and the surrounding region experienced unprecedented extreme cold weather, resulting in outages impacting millions in the state. Renewables safely operated our Texas wind generation facilities during this event meeting all of our delivery obligations in Texas and producing excess energy that was sold based on the rules established at the time by the Energy Reliability Council of Texas, or ERCOT. If the received payments are adjusted by ERCOT, it could adversely affect our results of operations.

In connection with the Texas Weather Event, a number of plaintiffs have filed multiple cases against generators and natural gas suppliers, including certain Renewables entities in Texas, alleging liability for injuries and damages arising from the event under a variety of legal theories. The plaintiffs have amended many of their petitions within the multidistrict litigation, and more than 100 of the cases now name Renewables entities among the defendants. Four of the consolidated cases have been designated as "bellwether" cases and are proceeding to resolve certain common issues of fact and law. In May 2022, the Renewables entities were part of a broader motion to dismiss by all generators in the bellwether cases in which they were named. These motions were argued on October 11, 2022. On January 27, 2023 the Court issued orders granting in part and denying in part the generators' motion to dismiss. The Court's order dismissed plaintiffs' tortious interference and conspiracy claims, but allowed all other claims to proceed. The generators subsequently filed mandamus petitions with the Texas Courts of Appeal, seeking review of the lower court's decision on the motions. We cannot predict the outcome of these matters.

Proposed Merger with PNMR

On October 20, 2020, Avangrid, PNM Resources, Inc., a New Mexico corporation, or PNMR, and NM Green Holdings, Inc., a New Mexico corporation and wholly-owned subsidiary of Avangrid, or Merger Sub, entered into an Agreement and Plan of Merger, or Merger Agreement, pursuant to which Merger Sub is expected to merge with and into PNMR, with PNMR surviving the Merger as a direct wholly-owned subsidiary of Avangrid, or the Merger. PNMR is a publicly-owned holding company with two regulated utilities providing electricity and electric services in New Mexico and Texas. PNMR's electric utilities are the Public Service Company of New Mexico and the Texas-New Mexico Power Company. Following consummation of the Merger, Avangrid will expand its geographic and regulatory diversity with ten regulated electric and gas companies in six states to help expand our growing leadership position in transforming the U.S. energy industry.

Pursuant to the Merger Agreement, each issued and outstanding share of the common stock of PNMR (other than (i) the issued shares of PNMR common stock that are owned by Avangrid, Merger Sub, PNMR or any wholly-owned subsidiary of Avangrid or PNMR, which will be automatically cancelled at the time the Merger is consummated and (ii) shares of PNMR common stock held by a holder who has not voted in favor of, or consented in writing to, the Merger who is entitled to, and who has demanded, payment for fair value of such shares) will be converted, at the time the Merger is consummated, into the right to receive $50.30 in cash, or Merger Consideration, or approximately $4.3 billion in aggregate consideration. In connection with the Merger, Iberdrola has provided the Iberdrola Funding Commitment Letter, pursuant to which Iberdrola has unilaterally agreed to provide to Avangrid, or arrange the provision to Avangrid of, funds to the extent necessary for Avangrid to consummate the Merger, including the payment of the aggregate Merger Consideration.

On April 15, 2021, Avangrid entered into a side letter agreement with Iberdrola, which sets forth certain terms and conditions relating to the Iberdrola Funding Commitment Letter (the Side Letter Agreement). The Side Letter Agreement provides that any drawing in the form of indebtedness made by the Corporation pursuant to the Funding Commitment Letter shall bear interest at an interest rate equal to Adjusted Term SOFR or Adjusted Daily Compounded SOFR plus 0.75% per annum calculated on the basis of a 360-day year for the actual number of days elapsed and, commencing on the date of the Funding Commitment Letter, we shall pay Iberdrola a facility fee equal to 0.12% per annum on the undrawn portion of the funding commitment set forth in the Funding Commitment Letter.

On February 12, 2021, the shareholders of PNMR approved the proposed Merger. As of November 1, the Merger had obtained all regulatory approvals other than from the New Mexico Public Regulation Commission, or NMPRC. On November 1, 2021, after public hearing and briefing on the matter, the hearing examiner in the Merger proceeding at the NMPRC issued an unfavorable recommendation related to the amended stipulated agreement entered into by PNMR, Avangrid and several interveners in the NMPRC proceeding with respect to consideration of the joint Merger application in June 2021. On December 8, 2021, the NMPRC issued an order rejecting the amended stipulated agreement. On January 3, 2022, Avangrid and PNMR filed a notice of appeal of the December 8, 2021 decision of the NMPRC with the New Mexico Supreme Court. The Statement of Issues was filed on February 2, 2022 and the Brief in Chief was filed on April 7, 2022. Oral arguments were held on September 15, 2023. We cannot predict the outcome of this proceeding.

On February 24, 2022, the FCC granted an extension to its approval to transfer operating licenses in connection with the Merger, which was further extended on August 9, 2022 and again on February 16, 2023. On May 20, 2022, the NRC issued an order extending the effectiveness of its approval until May 25, 2023, and again on March 14, 2023 until May 25, 2024. Furthermore, a new HSR filing was submitted and the waiting period expired on March 10, 2023, providing HSR clearance for another year.

In addition, on January 3, 2022, Avangrid, PNMR and Merger Sub entered into an Amendment to the Merger Agreement (the First Amendment), pursuant to which Avangrid, PNMR and Merger Sub each agreed to extend the “End Date” for consummation of the Merger until April 20, 2023. The parties acknowledged in the First Amendment that the required regulatory approval from the NMPRC had not been obtained and that the parties reasonably determined that such outstanding approval would not be obtained by April 20, 2022. In light of this outstanding approval, the parties determined to approve the First Amendment. Subsequently, on April 12, 2023, Avangrid, PNMR and Merger Sub entered into a Second Amendment to the Merger Agreement (the Second Amendment), pursuant to which Avangrid, PNMR and Merger Sub each agreed to further extend the “End Date” for consummation of the Merger until July 20, 2023. The parties acknowledged in the Second Amendment that the required regulatory approval from the NMPRC had not been obtained and that the parties reasonably determined that such outstanding approval would not be obtained by April 20, 2023. Subsequently, on June 19, 2023, Avangrid, PNMR and Merger Sub entered into a Third Amendment to the Merger Agreement (the Third Amendment), pursuant to which Avangrid, PNMR and Merger Sub each agreed to further extend the “End Date” for consummation of the Merger until December 31, 2023. The parties acknowledged in the Third Amendment that the required regulatory approval from the NMPRC has not been obtained and the parties reasonably determined that such outstanding approval would not be obtained by July 20, 2023. As amended by the Third Amendment, the Merger Agreement may be terminated by each of Avangrid and PNMR under certain circumstances, including if the Merger is not consummated by December 31, 2023. The Third Amendment also provides that the Merger Agreement can be further extended by 90 days upon mutual agreement by PNMR and Avangrid. During the pendency of the appeal described above, certain required regulatory approvals and consents may expire and Avangrid and PNMR will reapply and/or apply for extensions of such approvals, as the case may be. We cannot predict the outcome of any other re-applications or requests for extensions of such approvals that may be required.

The Merger Agreement contains representations, warranties and covenants of PNMR, Avangrid and Merger Sub, which are customary for transactions of this type. In addition, among other things, the Merger Agreement contains a covenant requiring PNMR to, prior to the closing, enter into agreements (Four Corners Divestiture Agreements) providing for, and to make filings required to, exit from all ownership interests in the Four Corners Power Plant, all with the objective of having the closing date for such exit be no later than December 31, 2024.

The Merger Agreement (as amended) provides for certain customary termination rights including the right of either party to terminate the Merger Agreement if the Merger is not completed on or before December 31, 2023. The Merger Agreement further provides that, upon termination of the Merger Agreement under certain specified circumstances (including if Avangrid terminates the Merger Agreement due to a change in recommendation of the board of directors of PNMR or if PNMR terminates the Merger Agreement to accept a superior proposal (as defined in the Merger Agreement)), PNMR will be required to pay Avangrid a termination fee of $130 million. In addition, the Merger Agreement provides that (i) if the Merger Agreement is terminated by either party due to a failure of a regulatory closing condition and such failure is the result of Avangrid’s breach of its regulatory covenants, or (ii) Avangrid fails to effect the Closing when all closing conditions have been satisfied and it is otherwise obligated to do so under the Merger Agreement, then, in either such case, upon termination of the Merger Agreement, Avangrid will be required to pay PNMR a termination fee of $184 million as the sole and exclusive remedy. Upon the termination of the Merger Agreement under certain specified circumstances involving a breach of the Merger Agreement, either PNMR or Avangrid will be required to reimburse the other party’s reasonable and documented out-of-pocket fees and expenses up to $10 million (which amount will be credited toward, and offset against, the payment of any applicable termination fee).

In connection with the Merger, Iberdrola has provided Avangrid a commitment letter (the Iberdrola Funding Commitment Letter), pursuant to which Iberdrola has unilaterally agreed to provide to Avangrid, or arrange the provision to Avangrid of, funds to the extent necessary for Avangrid to consummate the Merger, up to a maximum aggregate amount of approximately $4,300 million, including the payment of the aggregate Merger Consideration.

Business Environment

The impact of extraordinary external events such as global pandemics and geopolitical instability continue to cause global economic and supply chain disruption and volatility in financial markets and the United States economy. We continue to experience changes in inflation levels resulting from various supply chain disruptions, increased business and labor costs, increased financing costs from changes in the Federal Reserve's monetary policy and other disruptions caused by global economic conditions. We continue to monitor the further developments, which may include further sanctions imposed by the United States, Canada, and the European Union on Russia, supply chain instability, and potential retaliatory action by the Russian government and/or other countries. We are taking steps intended to mitigate the potential risks from continued conflict, including without limitation, communication with suppliers to ensure that the supply chains are free from sanctioned materials and efforts to diversify sourcing and capacity planning to help avoid supply chain disruptions. To date, there has been no material impact on our operations or financial performance as a result of ongoing extraordinary events including, without limitation, the conflicts in Eastern Europe and the Middle East; however, we cannot predict the extent of these effects, given the evolving nature of the geopolitical situation, on our business, results of operations or financial condition.

We are monitoring the Department of Commerce's, or DOC, anti-circumvention petition alleging that solar panels and cells shipped from Vietnam, Thailand, Malaysia and Cambodia have circumvented tariffs imposed on Chinese solar panels and cells. The petition calls for anti-dumping and countervailing duties to be applied to solar panels. In June 2022, President Biden's Administration announced a 24-month tariff exemption on any potential tariff resulting from the anti-circumvention investigation. On August 18, 2023, DOC issued final rulings, concluding some manufacturers operating in the named countries circumvented the AD/CVD duties on a country-wide basis. Renewables is taking steps intended to mitigate potential risks to their solar project development portfolio. To date, there has been no material impact on Renewables' operations or financial performance as a result of this investigation. Despite the 24-month tariff exemption, there is uncertainty around related long-term effects to the solar panel supply chain and we currently cannot predict if there will be materially adverse impacts to our business, results of operations or financial condition.

In April 2023, the House Transportation and Infrastructure Committee included maritime crewing provisions within the Coast Guard Authorization bill which passed the committee. The bill was not included in the House National Defense Authorization Act - there is no clear path for passage at this point. If enacted, the Coast Guard authorization may only allow foreign vessels to operate on the Outer Continental Shelf if they have a U.S. crew or the crew of the nation of which the vessel is from. If passed, the legislation could affect expected timelines and returns on approved projects. To date, there has been no material impact on Renewables' operations or financial performance as a result of these bills; however, given the uncertainty of resolution of the final legislation and the related effects to our offshore projects, we currently cannot predict if there will be materially adverse impacts to our business, results of operations or financial condition.

There are a limited number of turbine suppliers in the market. Renewables’ largest turbine suppliers, Siemens-Gamesa and GE Wind, were engaged in an intellectual property dispute with respect to certain offshore wind turbines including the wind turbines to be used in the Vineyard Wind 1 project. In July 2022, the federal district court granted Siemens-Gamesa’s request for a permanent injunction barring GE Wind from importing and selling the infringing wind turbines, which carved out the wind turbines for the Vineyard Wind 1 project from such injunction. On April 1, 2023, Siemens-Gamesa and GE Wind announced a global settlement resolving the dispute. Following the settlement, the judge in the patent case vacated the permanent injunction by an order dated April 3, 2023. While there was no material impact on Renewables' operations or turbine procurement arising out this dispute, we continue to monitor developments with the limited number of turbine suppliers that may have an impact on Renewables' operations or turbine procurement.

In April 2023, Avangrid Renewables received a letter from the U.S. Fish and Wildlife Service regarding certain bald and gold eagle fatalities that allegedly occurred at certain Avangrid Renewables facilities that are not covered by an eagle take permit. Avangrid Renewables has responded to the U.S. Fish and Wildlife Service providing information about the relevant eagle taking permit applications and relevant mitigation activity at each facility. We cannot predict the outcome of this preliminary inquiry.

On June 30, 2023 Avangrid received an exclusion notice from the U.S. Customs and Border Protection, or CBP, in the Port of Fresno, California, denying entry to approximately 220 MWs of solar modules for use in the company’s Bakeoven and Daybreak solar projects. The notice states that the modules were rejected due to insufficient documentation demonstrating the merchandise was not produced in whole or in part in the Xinjiang Uyghur Autonomous Region or by an entity on the Uyghur Forced Labor Prevention Act, or UFLPA, Entity List within 30 days from which the cargo was detained. In September 2023 Avangrid entered into a bill of sale and assumption and assignment agreement with Iberdrola Renovables Energia SAU, or IRE, a subsidiary of Iberdrola, and the solar panel supplier to assign all of its rights, title and interest in the 220 MWs of solar modules to IRE. Pursuant to such agreement, Avangrid will receive reimbursement of the amounts previously paid to the solar supplier for such modules, when the title to such modules are transferred to IRE upon delivery to IRE's delivery location.

For more information, see the risk factor under the heading “Catastrophic or geopolitical events may disrupt operations and negatively impact the financial condition of the business, cash flows, and the trading value of its securities.” in Item 1A. Risk Factors in our Form 10-K for the year ended December 31, 2022.

Summary of Results of Operations

Our operating revenues increased by $136 million from $1,838 million for the three months ended September 30, 2022 to $1,974 million for the three months ended September 30, 2023.

Networks business revenues increased mainly due to rate increases in New York effective December 1, 2020 and favorable changes in regulatory deferrals in the current period. Renewables revenues increased mainly due to higher wind and solar generation output and favorable thermal and power trading due to higher average prices in the period primarily driven by weather.

Net income attributable to Avangrid decreased by $46 million from $105 million for the three months ended September 30, 2022 to $59 million for the three months ended September 30, 2023, primarily due to offshore contract provision in Renewables, higher interest expenses and unfavorable taxes from applying the annual consolidated estimated tax rate in the current period in Other.

Adjusted net income (a non-GAAP financial measure) decreased by $16 million from $122 million for the three months ended September 30, 2022 to $105 million for the three months ended September 30, 2023. The decrease is primarily due to a $29 million decrease in Corporate mainly driven by higher interest expenses and unfavorable taxes from applying the annual consolidated estimated tax rate, offset by a $10 million increase in Renewables driven primarily by higher wind and solar generation output and favorable thermal and power trading due to higher average prices in the period primarily driven by weather and $3 million increase in Networks driven primarily by rate increases in New York effective December 1, 2020 in the period.

For additional information and reconciliation of the non-GAAP adjusted net income to net income attributable to Avangrid, see “— *Non-GAAP Financial Measures*”.

See “—*Results of Operations*” for further analysis of our operating results for the quarter.

Legislative and Regulatory Update

We are subject to complex and stringent energy, environmental and other laws and regulations at the federal, state and local levels as well as rules within the independent system operator, or ISO, markets in which we participate. Federal and state legislative and regulatory actions continue to change how our business is regulated. We actively participate in the regulatory process at the federal, regional, state and ISO levels. Significant updates are discussed below. For a further discussion of the environmental and other governmental regulations that affect us, see our Form 10-K for the year ended December 31, 2022.

New England Clean Energy Connect

In 2018, the New England Clean Energy Connect, or NECEC, transmission project, proposed in a joint bid by CMP and Hydro-Québec, was selected by the Massachusetts electric distribution utilities (EDCs) and the DOER in the Commonwealth of Massachusetts’s 83D clean energy Request for Proposal. The NECEC transmission project includes a 145-mile transmission line linking the electrical grids in Québec, Canada and New England. The project, which has an estimated cost of approximately $1.5 billion in total, would add 1,200 MW of transmission capacity to supply Maine and the rest of New England with power from reliable hydroelectric generation.

On June 13, 2018, CMP entered into transmission service agreements, or TSAs, with the Massachusetts EDCs, and H.Q. Energy Services (U.S.) Inc., or HQUS, an affiliate of Hydro-Québec, which govern the terms of service and revenue recovery for the NECEC transmission project. Simultaneous with the execution of the TSAs with CMP, the EDCs executed certain PPAs with HQUS for sales of electricity and environmental attributes to the EDCs. On October 19, 2018, FERC issued an order accepting the TSAs for filing as CMP rate schedules effective as of October 20, 2018. On June 25, 2019, the Massachusetts DPU issued an Order approving the NECEC project long term PPAs and the cost recovery by the EDCs of the TSA charges. This Order was subsequently appealed by NextEra Energy Resources. On September 3, 2020, the Massachusetts Supreme Judicial Court denied NextEra Energy Resources’ appeal of the DPU Order.

The NECEC project requires a Certificate of Public Convenience and Necessity, or CPCN, from the MPUC. On May 3, 2019, the MPUC issued an Order granting the CPCN for the NECEC project. This Order was subsequently appealed by NextEra Energy Resources. On March 17, 2020, the Maine Law Court denied NextEra Energy Resources’ appeal of the CPCN.

On January 4, 2021, CMP transferred the NECEC project to NECEC Transmission LLC, a wholly-owned subsidiary of Networks, pursuant to the terms of a transfer agreement dated November 3, 2020.

The NECEC project requires certain permits, including environmental, from multiple state and federal agencies and a presidential permit from the U.S. Department of Energy, or DOE, authorizing the construction, operation, maintenance and connection of facilities for the transmission of electric energy at the international border between the United States and Canada. On January 8, 2020, the Maine Land Use Planning Commission, or LUPC, granted the LUPC Certification for the NECEC. The Maine Department of Environmental Protection, or MDEP, granted Site Location of Development Act, Natural Resources Protection Act, and Water Quality Certification permits for the NECEC by an Order dated May 11, 2020. The MDEP Order was appealed by certain intervenors. Through an Order dated July 21, 2022, the Maine Board of Environmental Protection, or MBEP, denied the appeals of the MDEP Order, as well as the appeal of MDEP's December 4, 2020 Order approving the partial transfer of the permits for the project to NECEC Transmission LLC. In August 2022, the intervenors that had appealed the MDEP Order appealed the MBEP Order. Certain of those intervenors dismissed their challenge in June 2023, though one group has continued to maintain their challenge. That appeal is pending before the Maine Superior Court. In addition, certain intervenors appealed MDEP's May 7, 2021 Order approving certain minor revisions. On February 16, 2023 the MBEP denied the appeal and affirmed the referred MDEP Order. In March 2023, the intervenors appealed the MBEP order to the Maine Superior Court, though subsequently dismissed that challenge in June 2023.

On November 6, 2020, the project received the required approvals from the U.S. Army Corps of Engineers, or Army Corps, pursuant to Section 10 of the Rivers and Harbor Act of 1899 and Section 404 of the Clean Water Act. A complaint for declaratory and injunctive relief asking the court to, among other things, vacate or remand the Section 404 Clean Water Act permit for the NECEC project filed by three environmental groups is currently pending before the District Court in Maine.

ISO-NE issued the final System Impact Study (SIS) for NECEC on May 13, 2020, determining the upgrades required to permit the interconnection of NECEC to the ISO-NE system. On July 9, 2020, the project received the formal I.3.9 approval associated with this interconnection request. CMP, NECEC Transmission LLC and ISO-NE executed an interconnection agreement. With respect to the upgrade required at the Seabrook Nuclear Generation Station, or Seabrook Station, on February 1, 2023, FERC issued an order granting in part Avangrid and NECEC Transmission LLC's complaint against NextEra Energy Resources, LLC and NextEra Energy Seabrook, LLC, or Seabrook, denying in part Avangrid and NECEC Transmission LLC's complaint, and dismissing Seabrook's petition for declaratory order. Among other things, FERC directs Seabrook to replace the breaker at Seabrook Station pursuant to its obligations under Seabrook Station's large generator interconnection agreement and good utility practice. Furthermore, FERC has determined that Seabrook should not recover opportunity or legal costs in connection with the breaker replacement. In the event that there are additional disputes between the parties in connection with the agreement for implementation of the breaker replacement, FERC notes that the parties may file an unexecuted agreement. NextEra sought reconsideration of FERC's decision, which was denied in April 2023 and by further FERC order in June 2023. NextEra has appealed that decision to the U.S. Court of Appeals for the D.C. Circuit, where it remains pending.

On January 14, 2021, the DOE issued a Presidential Permit granting permission to NECEC Transmission LLC to construct, operate, maintain and connect electric transmission facilities at the international border of the United States and Canada. On March 26, 2021, the plaintiffs challenging the Army Corps permit filed a motion for leave before the District Court in Maine to supplement their complaint to add claims against DOE in connection with the Presidential Permit. On April 20, 2021, the District Court granted the plaintiffs motion to amend the complaint. On April 22, 2021, the plaintiffs filed their amended complaint asking the Court, among other things, to vacate, set aside, remand or stay the Presidential Permit. This challenge to the Presidential Permit is currently pending before the District Court in Maine. We cannot predict the outcome of this proceeding.

On November 2, 2021, Maine voters approved, by virtue of a referendum, L.D. 1295 (I.B. 1) (130th Legis. 2021), "An Act To Require Legislative Approval of Certain Transmission Lines, Require Legislative Approval of Certain Transmission Lines and Facilities and Other Projects on Public Reserved Lands and Prohibit the Construction of Certain Transmission Lines in the Upper Kennebec Region" (the "Initiative"), which per its terms would retroactively apply to the NECEC project. In particular, the Initiative (i) requires, retroactive to 2020, legislative approval for the construction of any high-impact transmission line in Maine, with approval by a 2/3 vote of all members elected to each House of the Maine Legislature required for such lines crossing or utilizing public lands; (ii) prohibits, retroactive to 2020, construction of a high-impact electric transmission line in the Upper Kennebec Region, and (iii) requires, retroactive to 2014, the vote of 2/3 of all members elected to each House of the Maine Legislature for a lease by the Bureau of Parks and Lands ("BPL") of public reserved lands for transmission lines and similar linear projects.

On November 3, 2021, Networks and NECEC Transmission LLC filed a lawsuit challenging the constitutionality of the Initiative and requesting injunctive relief preventing retroactive enforcement of the Initiative to the NECEC transmission project. Networks and NECEC Transmission LLC also requested a preliminary injunction preventing such retroactive enforcement during the pendency of the lawsuit, which was ultimately denied. The Initiative took effect on December 19, 2021.

On December 22, 2021, Networks and NECEC Transmission LLC moved that the Business & Consumer Court report its decision to the Maine Law Court for an interlocutory appeal under the applicable rule of appellate procedure. The Business & Consumer Court granted this motion, thereby sending its decision to the Law Court for review. On August 30, 2022, the Law Court ruled that certain Initiative provisions would infringe on NECEC's constitutionally protected vested rights if NECEC Transmission LLC can demonstrate that it engaged in substantial construction of the NECEC project in good-faith reliance of the authority under the CPCN granted by the MPUC before Maine voters approved the Initiative. The Maine Law Court remanded the matter to the Business & Consumer Court for a trial to determine that question. The trial began on April 10, 2023 and concluded on April 20, 2023, when the jury reached a unanimous decision finding that NECEC had constructed substantial construction in good faith. The Court subsequently entered an Order that NECEC had obtained vested rights to continue work on the project, and that retroactively applying the Initiative to the NECEC project would violate the Maine Constitution. No party appealed that decision.

On November 23, 2021, the MDEP issued an Order finding that the Initiative constituted a changed circumstance justifying the suspension of the MDEP permits for the NECEC project. In its order, the MDEP ruled that, so long as such MDEP permits are suspended, all construction must stop, subject to the performance and completion of certain activities required by the Order. The MDEP lifted the Order in May 2023.

On August 3, 2023, NECEC resumed limited construction and is continuing to evaluate the construction schedule for the NECEC project, related commercial operation date, and total project cost, including potential impacts from increased construction costs, disputes with third party vendors regarding contracts and certain change orders, and a decrease in expected returns. As of September 30, 2023, we have capitalized approximately $692 million for the NECEC project.

In connection with the lease granted by BPL over a small area of Maine public lands to house a 0.9-mile section of the NECEC, on November 29, 2022, the Law Court vacated the trial court's prior decision to reverse BPL's decision to grant the lease. The Law Court confirmed that BPL acted within its constitutional and statutory authority when granting the lease. Furthermore, the Law Court held that the section of the Initiative that requires the vote of 2/3 of all members elected to each House of the Maine Legislature for a lease by BPL of public reserved lands for transmission lines and similar linear projects, as retroactively applied to the lease for the NECEC, violates the Contracts Clauses of the U.S. and Maine Constitutions and, accordingly, that the lease was not voided by the Initiative.

At the municipal level, the project has obtained multiple municipal approvals and will pursue any remaining municipal approvals in accordance with the project schedule.

Maine Government-Run Power Referendum

On September 18, 2020, a request was submitted to the Maine Secretary of State to initiate the process of placing a government-run power referendum on the ballot. The proponents did not submit signatures in January 2022, the deadline to place the referendum on the November 2022 ballot, but made statements that they intended to continue to collect sufficient signatures to present the referendum in a future general election. On October 31, 2022, proponents of government-run power submitted signatures for a Citizen's Initiative to the Maine Secretary of State. The Secretary of State certified that the proponents submitted more than the required signatures to place the referendum on the ballot in November 2023. Subsequently, the Secretary of State released final ballot language for the November 2023 election. In addition, proponents of the "No Blank Checks" Citizen's Initiative submitted signatures to the Maine Secretary of State. This referendum would require citizens to approve the debt issued by the State of Maine greater than $1 billion, including debt necessary for a government-controlled entity to seize the assets of an investor-owned utility. A Petition for Review of Final Agency action was filed in Maine Superior Court challenging the Secretary's signature determination relative to the "No Blank Checks" Citizen's Initiative and the Maine Superior Court upheld the Secretary's determination. We cannot predict the outcome of the Citizen's Initiative.

Power Tax Audits

Previously, CMP, NYSEG and RG&E implemented Power Tax software to track and measure their respective deferred tax amounts. In connection with this change, we identified historical updates needed with deferred taxes recognized by CMP, NYSEG and RG&E and increased our deferred tax liabilities, with a corresponding increase to regulatory assets, to reflect the updated amounts calculated by the Power Tax software. Since 2015, the NYPSC and MPUC accepted certain adjustments to deferred taxes and associated regulatory assets for this item in recent distribution rate cases, resulting in regulatory asset balances of approximately $132 million and $137 million, respectively, for this item at September 30, 2023 and December 31, 2022.

CMP began recovering its regulatory asset in 2020. In 2017, the NYPSC commenced an audit of the power tax regulatory assets. On January 11, 2018, the NYPSC issued an order opening an operations audit of NYSEG and RG&E and certain other New York utilities regarding tax accounting. In September 2023, NYSEG and RG&E received the NYPSC final audit report and in October 2023 we responded with comments and a request for certain clarifications. The report includes recommendations that are primarily intended to enhance existing practices. We expect the NYPSC to issue a final report order in November 2023. Upon order issuance, NYSEG and RG&E will have thirty days to submit a recommendation implementation plan. We cannot predict the final outcome of this audit.

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

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

On May 6, 2021, in connection with its findings in the Tropical Storm Isaias docket, PURA issued a Notice of Violation to UI for allegedly failing to comply with standards of acceptable performance in emergency preparation or restoration of service in an emergency and with orders of the Authority, and for violations of accident reporting requirements. PURA assessed a civil penalty in the total amount of approximately $2 million. PURA held a hearing on this matter and, in an order dated July 14, 2021, reduced the civil penalty to approximately $1 million. UI filed an appeal of PURA’s decision with the Connecticut Superior Court. This appeal and the appeal of PURA’s decision on the Tropical Storm Isaias docket have been consolidated. Oral arguments were held on October 11, 2022, and on October 17, 2022, the court denied UI’s appeal and affirmed PURA’s decisions in their entirety. UI filed a notice of appeal to Connecticut's Appellate court on November 7, 2022 and briefs in April and June 2023. We cannot predict the outcome of this proceeding.

Connecticut Energy Legislation

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

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

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

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

Pursuant to the legislation, PURA opened a docket to consider the implementation of the associated customer compensation and reimbursement provisions in emergency events where customers were without power for more than 96 consecutive hours. On June 30, 2021, PURA issued a final decision implementing the legislative mandate to create a program pursuant to which residential customers will receive $25 for each day without power after 96 hours and also receive reimbursement of $250 for spoiled food and medicine. The decision emphasizes that no costs incurred in connection with this program are recoverable from customers. On June 29, 2023 the Governor of Connecticut signed SB7 into law, which included language that Level 1 storm events were exempt from the waiver. We will continue to review the requirements of the program for the next legislative session.

Proposed Connecticut Performance-Based Regulation

On March 17, 2023, PURA issued a draft decision proposing a regulatory framework for Performance-Based Regulation, or PBR, for electric distribution companies. The Draft Decision establishes the regulatory goals, foundational considerations, and priority outcomes to guide PBR development among other things. The intent of the PBR framework is to drive improvement in utility performance to better serve the public interest. Additional areas of focus include establishing an equitable modern grid framework, and providing a toolkit for regulatory reform. We cannot predict the outcome of this proposed regulation.

Proposed New York Legislation in Response to the Tropical Storm Isaias

Proposed legislation has been introduced that would amend the public service law to, among other things, increase potential penalties and give greater discretion to the NYPSC to assess penalties for violations of the Public Service Law, Regulations, or Orders of the NYPSC. We cannot predict the outcome of this proposed legislation.

New York Climate Leadership and Community Protection Act

In June 2019, the New York State legislature passed a new law titled the Climate Leadership and Community Protection Act, or CLCPA, which could have significant impacts on the operations of electric and gas utilities in New York. A Climate Action Council has been formed consistent with the CLCPA, and that council will be providing guidance to New York State in reaching aggressive renewable and emission reduction goals delineated in the CLCPA. On December 30, 2021, the Climate Action Council issued a Draft Scoping Plan, which includes numerous draft recommendations designed to ensure a fair transition to achieving New York's greenhouse gas emission reduction goals and renewable energy goals. The Draft Scoping Plan is subject to a 120-day public comment period, and the Climate Action Council published the final Scoping Plan on December 16, 2022, which was approved by the Climate Action Council on December 19, 2022.

On February 16, 2023, the NYPSC issued an order to authorize transmission upgrades solely to support new renewable generation sources (Phase 2) pursuant to the implementation of the Accelerated Renewable Growth and Community Benefit Act. The order approves an estimated $4.4 billion in transmission upgrades proposed by upstate utilities to help integrate 3,500 MW of clean energy capacity into the grid, of which NYSEG and RG&E are approved for estimated upgrade costs of $2.25 billion, including participation with other upstate utilities on certain projects.

The Joint Proposal (2023 JP) filed by NYSEG and RG&E for a three-year rate plan and approved by the NYPSC on October 12, 2023, contains provisions consistent with, supportive of, and in furtherance of the objectives of the CLCPA including provisions that will, among other things, increase funding for energy efficiency programs, enhance the electric system in anticipation of increased electrification and increase funding for electric heat pump programs, provide funding for improved electric and gas reliability and resiliency, encourage non-pipe and non-wire alternatives, and replace leak prone pipe.

Customer Arrearages Reduction Order

On June 16, 2022, the NYPSC issued an order 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 and three years for NYSEG beginning on August 1, 2022.

On January 19, 2023, the NYPSC issued a subsequent order 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:

Company	Residential	Total Forecast Residential Credits (Millions)	Small Business	Total Forecast Small Business Credits (Millions)
NYSEG	Up to $1,000	$ 16.9	Up to $1,250	$ 1.4
RG&E	Up to $1,500	$ 15.2	Up to $1,500	$ 0.6

Inflation Reduction Act

In August 2022, the Inflation Reduction Act of 2022, or IRA, was signed into law in the United States. The IRA created a new corporate alternative minimum tax, or CAMT, of 15% on adjusted financial statement income and an excise tax of 1% on the value of certain stock repurchases. The IRA also contains a number of additional provisions related to tax incentives for investments in renewable energy production, carbon capture, and other climate actions. The CAMT and other various applicable provisions of the IRA are effective for the Company for periods beginning after December 31, 2022. The impact of CAMT will depend on our facts in each year and anticipated guidance from the U.S. Department of Treasury. We currently expect to incur CAMT in 2023, however it is not expected to have a material impact on our earnings, financial condition, or cash flow as the Company can utilize tax attributes to reduce the overall cash tax impact.

Partnership with Navajo Tribal Utility Authority

In March 2023, Renewables and Navajo Tribal Utility Authority Generation, Inc., or NTUAG, a wholly-owned subsidiary of Navajo Tribal Utility Authority, or NTUA, signed a Memorandum of Understanding, or MoU, to jointly explore opportunities for developing up to 1 GW of renewable energy generation, including solar, wind, hydrogen and back-up battery storage, on the reservation of Navajo Nation located in portions of states of New Mexico, Utah and Arizona. Once built, that would constitute enough generation to supply clean energy to hundreds of thousands of homes and businesses, both on the reservation, and in regional markets through export to surrounding states. All projects built through the partnership would be joint ventures, with NTUA maintaining at least 51% majority ownership to retain tribal sovereignty and control.

Commonwealth Wind and Park City PPAs

In October 2022 Commonwealth Wind and Park City Wind announced that they would seek to re-negotiate the price of the certain Power Purchase Agreements, or PPAs, to help mitigate the impacts of inflation, increased interest rates and supply chain disruptions on the projects. On October 21, 2022, Commonwealth Wind filed a motion with the DPU seeking a one-month suspension in the DPU's proceeding to review the power purchase agreements between Commonwealth Wind and the Massachusetts electric distribution companies, or EDCs, in order to provide an opportunity for Commonwealth Wind, the EDCs, state and regulatory officials, and other stakeholders to evaluate the current economic challenges facing Commonwealth Wind and assess measures that would return the project to economic viability including, but not limited to, certain amendments to the Power Purchase Agreements, or PPAs. In December 2022, Commonwealth Wind filed a motion opposing approval of the PPAs by the DPU and requesting that the proceeding be dismissed. On December 30, 2022, the DPU entered an order denying Commonwealth Wind's motion and approving the PPAs. On January 30, 2023, Commonwealth Wind appealed the DPU's December 30th order to the Supreme Judicial Court of Massachusetts. On July 13, 2023, each of the EDCs filed with the DPU a first amendment, termination agreement and release agreed with Commonwealth Wind, providing for an orderly termination of the PPAs, withdrawal of Commonwealth Wind's appeal, and payment by Commonwealth Wind of a $48 million termination payment to the EDCs an amount equal to the development period security provided for in the PPAs in connection with the regulatory approval that is under appeal. The DPU approved the termination agreements on August 2, 2023 and Commonwealth Wind dismissed its appeal of the DPU's December 30th order.

On October 2, 2023, Park City Wind entered into a first amendment, termination agreement and release with each of the Connecticut EDCs, providing for an orderly termination of the Park City Wind PPAs and payment by Park City Wind of an approximately $16 million termination payment to the EDCs, an amount equal to the development period security provided for in the PPAs. On October 13, 2023, PURA approved the termination agreements.

Results of Operations

The following tables set forth financial information by segment for each of the periods indicated:

	Three Months Ended September 30, 2023				Three Months Ended September 30, 2022			
	Total	Networks	Renewables	Other(1)	Total	Networks	Renewables	Other(1)
	(in millions)							
Operating Revenues	**$ 1,974**	**$ 1,587**	**$ 387**	**$ —**	**$ 1,838**	**$ 1,546**	**$ 293**	**$ (1)**
Operating Expenses								
Purchased power, natural gas and fuel used	482	377	105	—	535	479	56	—
Operations and maintenance	924	748	183	(7)	758	621	136	1
Depreciation and amortization	303	175	123	5	279	166	113	—
Taxes other than income taxes	176	153	21	2	154	139	15	—
Total Operating Expenses	**1,885**	**1,453**	**432**	**—**	**1,726**	**1,405**	**320**	**1**
Operating Income	**89**	**134**	**(45)**	**—**	**112**	**141**	**(27)**	**(2)**
Other Income (Expense)								
Other income (expense)	42	45	8	(11)	18	19	3	(4)
Earnings (losses) from equity method investments	(1)	3	(4)	—	2	3	(1)	—
Interest expense, net of capitalization	(107)	(76)	(6)	(25)	(76)	(60)	(2)	(14)
Income (Loss) Before Income Tax	**23**	**106**	**(47)**	**(36)**	**56**	**103**	**(27)**	**(20)**
Income tax expense (benefit)	(8)	12	(27)	7	(50)	13	(56)	(7)
Net Income (Loss)	**31**	**94**	**(20)**	**(43)**	**106**	**90**	**29**	**(13)**
Net (income) loss attributable to noncontrolling interests	28	(1)	29	—	(1)	(1)	—	—
Net Income (Loss) Attributable to Avangrid, Inc.	**$ 59**	**$ 93**	**$ 9**	**$ (43)**	**$ 105**	**$ 89**	**$ 29**	**$ (13)**

	Nine Months Ended September 30, 2023				Nine Months Ended September 30, 2022			
	Total	Networks	Renewables	Other(1)	Total	Networks	Renewables	Other(1)
	(in millions)							
Operating Revenues	**$ 6,027**	**$ 4,936**	**$ 1,092**	**$ (1)**	**$ 5,765**	**$ 4,945**	**$ 821**	**$ (1)**
Operating Expenses								
Purchased power, natural gas and fuel used	1,844	1,514	330	—	1,716	1,619	97	—
Operations and maintenance	2,319	1,910	414	(5)	2,102	1,728	369	5
Depreciation and amortization	868	524	338	6	811	491	319	1
Taxes other than income taxes	516	457	56	3	501	447	53	1
Total Operating Expenses	**5,547**	**4,405**	**1,138**	**4**	**5,130**	**4,285**	**838**	**7**
Operating Income	**480**	**531**	**(46)**	**(5)**	**635**	**660**	**(17)**	**(8)**
Other Income (Expense)								
Other income (expense)	96	110	13	(27)	38	40	5	(7)
Earnings (losses) from equity method investments	5	11	(6)	—	261	8	253	—
Interest expense, net of capitalization	(301)	(215)	(16)	(70)	(226)	(171)	(8)	(47)
Income (Loss) Before Income Tax	**280**	**437**	**(55)**	**(102)**	**708**	**537**	**233**	**(62)**
Income tax expense (benefit)	(17)	70	(87)	—	14	65	(35)	(16)
Net Income (Loss)	**297**	**367**	**32**	**(102)**	**694**	**472**	**268**	**(46)**
Net loss (income) attributable to noncontrolling interests	92	(3)	95	—	40	(2)	42	—
Net Income (Loss) Attributable to Avangrid, Inc.	**$ 389**	**$ 364**	**$ 127**	**$ (102)**	**$ 734**	**$ 470**	**$ 310**	**$ (46)**

(1) "Other" represents Corporate and intersegment eliminations.

Comparison of Period to Period Results of Operations

Three Months Ended September 30, 2023 Compared to Three Months Ended September 30, 2022

Operating Revenues

Our operating revenues increased by $136 million from $1,838 million for the three months ended September 30, 2022 to $1,974 million for the three months ended September 30, 2023, as detailed by segment below:

Networks

Operating revenues increased by $41 million from $1,546 million for the three months ended September 30, 2022 to $1,587 million for the three months ended September 30, 2023. Electricity and gas revenues increased by $22 million, primarily due to rate increases in New York effective December 1, 2020, and a $22 million favorable impact from deferrals mainly driven by the regulatory mechanism established in the current period to offset impacts from the regulatory amortization periods determined by current rate case in New York in anticipation of the amortization periods to be established in the future rate case. Additionally, electricity and gas revenues changed due to the following items that have offsets within the income statement: a decrease of $102 million in purchased power and purchased gas (offset in purchased power) driven by lower average pricing in commodities in the period and an increase of $100 million in flow through amortizations (offset in operating expenses).

Renewables

Operating revenues increased by $94 million from $293 million for the three months ended September 30, 2022 to $387 million for the three months ended September 30, 2023. The increase in operating revenues was primarily due to an increase of $29 million driven by 392 GWh higher wind and solar generation output, $34 million in favorable thermal and power trading due to higher average prices in the period primarily driven by weather, favorable MtM changes of $27 million on energy derivative transactions entered for economic hedging purposes and $3 million of other changes in the period.

Purchased Power, Natural Gas and Fuel Used

Our purchased power, natural gas and fuel used decreased by $53 million from $535 million for the three months ended September 30, 2022 to $482 million for the three months ended September 30, 2023, as detailed by segment below:

Networks

Purchased power, natural gas and fuel used decreased by $102 million from $479 million for the three months ended September 30, 2022 to $377 million for the three months ended September 30, 2023. The decrease is primarily driven by a $102 million decrease in average commodity prices and an overall decrease in electricity and gas units procured due to lower degree days in the period.

Renewables

Purchased power, natural gas and fuel used increased by $49 million from $56 million for the three months ended September 30, 2022 to $105 million for the three months ended September 30, 2023. The increase is primarily due to unfavorable MtM changes on derivatives of $27 million driven by market price changes in the period and an increase of $22 million in power and gas purchases due to higher average prices in the current period driven by weather.

Operations and Maintenance

Operations and maintenance expenses increased by $166 million from $758 million for the three months ended September 30, 2022 to $924 million for the three months ended September 30, 2023, as detailed by segment below:

Networks

Operations and maintenance expenses increased by $127 million from $621 million for the three months ended September 30, 2022 to $748 million for the three months ended September 30, 2023. The increase is primarily driven by increased business and corporate costs of $12 million and $15 million increase in personnel expenses primarily driven by higher headcount in the current period. In addition, there were increases of $100 million in flow-through amortizations (which is offset in revenue).

Renewables

Operations and maintenance expenses increased by $47 million from $136 million for the three months ended September 30, 2022 to $183 million for the three months ended September 30, 2023. The increase is primarily due to a $40 million increase in connection with offshore contract provision and $7 million increase in personnel costs driven primarily by increase in headcount in the period.

Depreciation and Amortization

Depreciation and amortization for the three months ended September 30, 2023 was $303 million compared to $279 million for the three months ended September 30, 2022, representing an increase of $24 million. The increase is driven by $19 million from plant additions in Networks and Renewables, and $5 million in Other in the current period.

Other Income (Expense) and Earnings (Losses) from Equity Method Investments

Other income (expense) and equity earnings (losses) increased by $21 million from $20 million for the three months ended September 30, 2022 to $41 million for the three months ended September 30, 2023. The change is primarily due to a $10 million favorable change in the non-service component of pension expense driven by the revised actuarial studies (which is partially offset in revenue) and $11 million favorable change in allowance for equity funds used during construction in the period.

Interest Expense, Net of Capitalization

Interest expense for the three months ended September 30, 2023 and 2022 was $107 million and $76 million, respectively. The change is primarily due to an increase of $4 million in carrying charges on regulatory deferrals and $11 million due to increased debt in the period at Networks and $31 million increase in Other mainly driven by increased outstanding balances on commercial paper, intragroup loan and unfavorable changes in the fair value hedges in the current period, offset by $15 million of capitalized interest driven by higher interest rates in the period.

Income Tax

The effective tax rates, inclusive of federal and state income tax, for the three months ended September 30, 2023 was (34.8)%, which is below the federal statutory tax rate of 21%, primarily due to the recognition of production tax credits associated with wind production, the effect of the excess deferred tax amortization resulting from the Tax Act, the equity component of allowance for funds used during construction and other property related flow through items. The effective tax rates, inclusive of federal and state income tax, for the three months ended September 30, 2022 was (89.3)%, which is below the federal statutory tax rate of 21%, primarily due to the recognition of production tax credits associated with wind production, the effect of the excess deferred tax amortization resulting from the Tax Act, the equity component of allowance for funds used during construction and the release of our federal valuation allowance in the third quarter of 2022 as a result of the Inflation Reduction Act enacted in August 2022 that will permit us to utilize tax attributes that were previously expected to expire.

Nine Months Ended September 30, 2023 Compared to Nine Months Ended September 30, 2022

Operating Revenues

Our operating revenues increased by $262 million from $5,765 million for the nine months ended September 30, 2022 to $6,027 million for the nine months ended September 30, 2023, as detailed by segment below:

Networks

Operating revenues decreased by $9 million from $4,945 million for the nine months ended September 30, 2022 to $4,936 million for the nine months ended September 30, 2023. Electricity and gas revenues changed due to the following items that have offsets within the income statement: a decrease of $105 million in purchased power and purchased gas (offset in purchased power) driven by lower average pricing in commodities in the period, offset by an increase of $47 million in flow through amortizations (offset in operating expenses). Electricity and gas revenues increased by $58 million, primarily due to rate increases in New York effective December 1, 2020, offset by a $9 million unfavorable impact from deferrals mainly driven by unfavorable changes in net plant reconciliation due to delays in the meters' installation schedules in New York and suspension of late payment charges collection in the current period.

Renewables

Operating revenues increased by $271 million from $821 million for the nine months ended September 30, 2022, to $1,092 million for the nine months ended September 30, 2023. The increase in operating revenues was primarily due to an increase of $31 million driven by 517 GWh higher wind and solar generation output, $104 million in favorable thermal and power trading due to higher average prices in the period primarily driven by weather, favorable MtM changes of $185 million on energy derivative transactions entered for economic hedging purposes, offset by a $50 million decrease in merchant prices driven by lower average prices in the current period.

Purchased Power, Natural Gas and Fuel Used

Purchased power, natural gas and fuel used increased by $128 million from $1,716 million for the nine months ended September 30, 2022 to $1,844 million for the nine months ended September 30, 2023, as detailed by segment below:

Networks

Purchased power, natural gas and fuel used decreased by $105 million from $1,619 million for the nine months ended September 30, 2022 to $1,514 million for the nine months ended September 30, 2023. The decrease is primarily driven by a $105 million decrease in average commodity prices and an overall decrease in electricity and gas units procured due to lower degree days in the period.

Renewables

Purchased power, natural gas and fuel used increased by $233 million from $97 million for the nine months ended September 30, 2022 to $330 million for the nine months ended September 30, 2023. The increase is primarily due to unfavorable MtM changes on derivatives of $187 million driven by market price changes in the period and an increase of $46 million in power and gas purchases due to higher average prices in the current period driven by weather.

Operations and Maintenance

Operations and maintenance expenses increased by $217 million from $2,102 million for the nine months ended September 30, 2022 to $2,319 million for the nine months ended September 30, 2023, as detailed by segment below:

Networks

Operations and maintenance expenses increased by $182 million from $1,728 million for the nine months ended September 30, 2022 to $1,910 million for the nine months ended September 30, 2023. The increase is driven by increased business and corporate costs of $60 million, $39 million increase in personnel expenses primarily driven by higher headcount and $36 million increase in uncollectible expenses due to higher bad debt provision in the current period. In addition, there were increases of $47 million in flow-through amortizations (which is offset in revenue).

Renewables

Operations and maintenance expenses increased by $45 million from $369 million for the nine months ended September 30, 2022 to $414 million for the nine months ended September 30, 2023. The increase is primarily due to a $40 million increase in connection with offshore contract provision, a $10 million increase driven by the write-off of certain development projects and $3 million higher corporate charges in the current period, offset by a $8 million decrease in the bad debt provision in the current period driven by lower uncollectibles billed arising from the weather event in the PJM market in 2022.

Depreciation and Amortization

Depreciation and amortization for the nine months ended September 30, 2023 was $868 million compared to $811 million for the nine months ended September 30, 2022, an increase of $57 million. The increase is primarily driven by $52 million from plant additions in Networks and Renewables and $5 million in Other in the current period.

Other Income (Expense) and Earnings (Losses) from Equity Method Investments

Other income (expense) and equity earnings (losses) decreased by $198 million from $299 million for the nine months ended September 30, 2022 to $101 million for the nine months ended September 30, 2023. The decrease is primarily due to $256 million of unfavorable equity earnings, driven by a $246 million gain recognized in the same period of 2022 from the offshore joint venture restructuring transaction in Renewables, offset by a $40 million favorable change in non-service component of pension expense driven by revised actuarial studies (which is partially offset within revenue) and $18 million favorable carrying costs in Networks driven by higher regulatory deferrals and interest rates in the period.

Interest Expense, Net of Capitalization

Interest expense for the nine months ended September 30, 2023 and 2022 was $301 million and $226 million, respectively. The change is primarily due to an increase of $26 million in carrying charges on regulatory deferrals and $11 million due to increased debt in the period at Networks and $80 million increase in Other mainly driven by increased outstanding balances on commercial paper, intragroup loan and unfavorable changes in the fair value hedges in the current period, offset by $42 million of capitalized interest driven by higher interest rates in the period.

Income Tax

The effective tax rates, inclusive of federal and state income tax, for the nine months ended September 30, 2023 was (6.1)%, which is below the federal statutory tax rate of 21%, primarily due to the recognition of production tax credits associated with wind production, the effect of the excess deferred tax amortization resulting from the Tax Act, the equity component of allowance for funds used during construction and other property related flow through items. The effective tax rate, inclusive of federal and state income tax, for the nine months ended September 30, 2022 was 2.0%, which was below the federal statutory tax rate of 21%, primarily due to the recognition of production tax credits associated with wind production, the effect of the excess deferred tax amortization resulting from the Tax Act, the equity component of allowance for funds used during construction, and the release of our federal valuation allowance in the third quarter of 2022 as a result of the Inflation Reduction Act enacted in August 2022 permitting us to utilize tax attributes that were previously expected to expire, partially offset by the tax on gain from the offshore joint venture restructuring transaction, which is reflected in the first half of 2022.

Non-GAAP Financial Measures

To supplement our consolidated financial statements presented in accordance with U.S. GAAP, we consider adjusted net income and adjusted earnings per share, adjusted EBITDA and adjusted EBITDA with Tax Credits as financial measures that are not prepared in accordance with U.S. GAAP. The non-GAAP financial measures we use are specific to Avangrid and the non-GAAP financial measures of other companies may not be calculated in the same manner. We use these non-GAAP financial measures, in addition to U.S. GAAP measures, to establish operating budgets and operational goals to manage and monitor our business, evaluate our operating and financial performance and to compare such performance to prior periods and to the performance of our competitors. We believe that presenting such non-GAAP financial measures is useful because such measures can be used to analyze and compare profitability between companies and industries by eliminating the impact of certain non-cash charges. In addition, we present non-GAAP financial measures because we believe that they and other similar measures are widely used by certain investors, securities analysts and other interested parties as supplemental measures of performance.

We define adjusted net income as net income adjusted to exclude mark-to-market earnings from changes in the fair value of derivative instruments, costs incurred in connection with the COVID-19 pandemic, costs incurred related to the PNMR Merger and costs incurred in connection with offshore contract provision. We believe adjusted net income is more useful in understanding and evaluating actual and projected financial performance and contribution of Avangrid core lines of business and to more fully compare and explain our results. The most directly comparable U.S. GAAP measure to adjusted net income is net income. We also define adjusted earnings per share, or adjusted EPS, as adjusted net income converted to an earnings per share amount.

We define adjusted EBITDA as adjusted net income adjusted to fully exclude the effects of net (loss) income attributable to noncontrolling interests, income tax expense (benefit), depreciation and amortization, interest expense, net of capitalization, other (income) expense and (earnings) losses from equity method investments. We further define adjusted EBITDA with tax credits as adjusted EBITDA adding back the pre-tax effect of retained Production Tax Credits (PTCs) and Investment Tax Credits (ITCs) and PTCs allocated to tax equity investors. The most directly comparable U.S. GAAP measure to adjusted EBITDA and adjusted EBITDA with tax credits is net income.

The use of non-GAAP financial measures is not intended to be considered in isolation or as a substitute for, or superior to, Avangrid's U.S. GAAP financial information, and investors are cautioned that the non-GAAP financial measures are limited in their usefulness, may be unique to Avangrid, and should be considered only as a supplement to Avangrid's U.S. GAAP financial measures. The non-GAAP financial measures may not be comparable to other similarly titled measures of other companies and have limitations as analytical tools.

Non-GAAP financial measures are not primary measurements of our performance under U.S. GAAP and should not be considered as alternatives to operating income, net income or any other performance measures determined in accordance with U.S. GAAP.

The following tables provide a reconciliation between Net Income attributable to Avangrid and non-GAAP measures Adjusted Net Income, Adjusted EBITDA and Adjusted EBITDA with Tax Credits by segment for the three and nine months ended September 30, 2023 and 2022, respectively:

	Three Months Ended September 30, 2023				Nine Months Ended September 30, 2023			
	Total	Networks	Renewables	Corporate*	Total	Networks	Renewables	Corporate*
	(in millions)				*(in millions)*			
Net Income Attributable to Avangrid, Inc.	**$ 59**	**$ 92**	**$ 9**	**$ (43)**	**$ 389**	**$ 364**	**$ 127**	**$ (102)**
Adjustments:								
Mark-to-market earnings – Renewables	23	—	23	—	19	—	19	—
Merger costs	1	—	—	1	2	—	—	2
Offshore contract provision	40	—	40	—	40	—	40	—
Income tax impact of adjustments (1)	(17)	—	(17)	—	(16)	—	(16)	(1)
Adjusted Net Income (2)	**$ 105**	**$ 92**	**$ 55**	**$ (42)**	**$ 434**	**$ 364**	**$ 170**	**$ (100)**
Net (loss) income attributable to noncontrolling interests	(28)	1	(29)	—	(92)	3	(95)	—
Income tax expense (benefit)	9	12	(10)	7	(1)	70	(71)	1
Depreciation and amortization	303	175	123	5	868	524	338	6
Interest expense, net of capitalization	107	76	6	25	301	215	16	70
Other (income) expense	(42)	(45)	(8)	11	(96)	(110)	(13)	27
(Earnings) losses from equity method investments	1	(3)	4	—	(5)	(11)	6	—
Adjusted EBITDA (3)	**$ 455**	**$ 308**	**$ 141**	**$ 6**	**$ 1,409**	**$ 1,055**	**$ 351**	**$ 3**
Retained PTCs and ITCs	35	—	35	—	125	—	125	—
PTCs allocated to tax equity investors	34	—	34	—	113	—	113	—
Adjusted EBITDA with Tax Credits (3)	**$ 524**	**$ 308**	**$ 210**	**$ 6**	**$ 1,647**	**$ 1,055**	**$ 589**	**$ 3**

	Three Months Ended September 30, 2022				Nine Months Ended September 30, 2022			
	Total	Networks	Renewables	Corporate*	Total	Networks	Renewables	Corporate*
	(in millions)				*(in millions)*			
Net Income Attributable to Avangrid, Inc.	**$ 105**	**$ 88**	**$ 29**	**$ (13)**	**$ 734**	**$ 470**	**$ 310**	**$ (46)**
Adjustments:								
Mark-to-market earnings – Renewables	22	—	22	—	17	—	17	—
Impact of COVID-19	—	—	—	—	2	2	—	—
Merger costs	1	—	—	1	3	—	—	3
Income tax impact of adjustments (1)	(6)	—	(6)	—	(6)	—	(4)	(1)
Adjusted Net Income (2)	**$ 122**	**$ 89**	**$ 45**	**$ (13)**	**$ 749**	**$ 471**	**$ 322**	**$ (44)**
Net (loss) income attributable to noncontrolling interests	1	1	—	—	(40)	2	(42)	—
Income tax expense (benefit)	(44)	13	(50)	(7)	20	65	(31)	(15)
Depreciation and amortization	279	166	113	—	811	491	319	1
Interest expense, net of capitalization	76	60	2	14	226	171	8	47
Other (income) expense	(18)	(19)	(3)	4	(38)	(40)	(5)	7
Earnings from equity method investments	(2)	(3)	1	—	(261)	(8)	(253)	—
Adjusted EBITDA (3)	**$ 414**	**$ 306**	**$ 108**	**$ (1)**	**$ 1,467**	**$ 1,153**	**$ 319**	**$ (4)**
Retained PTCs and ITCs	32	—	32	—	123	—	123	—
PTCs allocated to tax equity investors	25	—	25	—	89	—	89	—
Adjusted EBITDA with Tax Credits (3)	**$ 470**	**$ 306**	**$ 165**	**$ (1)**	**$ 1,679**	**$ 1,153**	**$ 531**	**$ (4)**

(1) Income tax impact of adjustments: 2023 - $(6) million and $(5) million from MtM earnings, $(1) and $(1) from merger costs, and $(10) million and $(10)

million from offshore contract provision for the three and nine months ended September 30, 2023, respectively; 2022 - $(6) million and $(4) million from MtM earnings and $0 and $0 from impact of COVID-19 and $0 and $(1) million from merger costs for the three and nine months ended September 30, 2022, respectively.

(2) Adjusted Net Income is a non-GAAP financial measure and is presented after excluding costs incurred in connection with the COVID-19 pandemic, the impact from mark-to-market activities in Renewables, costs incurred related to the PNMR Merger and offshore contract provision.

(3) Adjusted EBITDA is a non-GAAP financial measure defined as adjusted net income adjusted to fully exclude the effects of net (loss) income attributable to noncontrolling interests, income tax expense (benefit), depreciation and amortization, interest expense, net of capitalization, other (income) expense and (earnings) losses from equity method investments. We further define adjusted EBITDA with tax credits as adjusted EBITDA adding back the pre-tax effect of retained PTCs and ITCs and PTCs allocated to tax equity investors.

* Includes corporate and other non-regulated entities as well as intersegment eliminations.

Three Months Ended September 30, 2023 Compared to Three Months Ended September 30, 2022

Adjusted net income

Our adjusted net income decreased by $16 million from $122 million for the three months ended September 30, 2022 to $105 million for the three months ended September 30, 2023. The decrease is primarily due to a $29 million decrease in Corporate mainly driven by higher interest expenses and unfavorable taxes from applying the annual consolidated estimated tax rate, offset by a $10 million increase in Renewables driven primarily by higher wind and solar generation output and favorable thermal and power trading due to higher average prices in the period primarily driven by weather and $3 million increase in Networks driven primarily by rate increases in New York effective December 1, 2020 in the period.

Nine Months Ended September 30, 2023 Compared to Nine Months Ended September 30, 2022

Adjusted net income

Our adjusted net income decreased by $316 million from $749 million for the nine months ended September 30, 2022 to $434 million for the nine months ended September 30, 2023. The decrease is primarily due to a $152 million decrease in Renewables driven by a gain recognized in the same period of 2022 from the offshore joint venture restructuring transaction, a $107 million decrease in Networks driven primarily by higher business costs, uncollectible and personnel expenses in the period, and a $56 million decrease in Corporate mainly driven by higher interest expenses in the period.

The following tables reconcile Net Income attributable to Avangrid to Adjusted Net Income (non-GAAP), and EPS attributable to Avangrid to adjusted EPS (non-GAAP) for the three and nine months ended September 30, 2023 and 2022, respectively:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Millions)	**2023**	**2022**	**2023**	**2022**
Networks	$ 92	$ 88	$ 364	$ 470
Renewables	9	29	127	310
Corporate (1)	(43)	(13)	(102)	(46)
Net Income	**$ 59**	**$ 105**	**$ 389**	**$ 734**
Adjustments:				
Mark-to-market earnings - Renewables (2)	23	22	19	17
Impact of COVID-19 (3)	—	—	—	2
Merger costs (4)	1	1	2	3
Offshore contract provision (5)	40	—	40	—
Income tax impact of adjustments	(17)	(6)	(16)	(6)
Adjusted Net Income (6)	**$ 105**	**$ 122**	**$ 434**	**$ 749**

(Millions)	Three Months Ended September 30, 2023	Three Months Ended September 30, 2022	Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022
Networks	$ 0.24	$ 0.23	$ 0.94	$ 1.21
Renewables	0.02	0.08	0.33	0.80
Corporate (1)	(0.11)	(0.03)	(0.26)	(0.12)
Earnings Per Share	**$ 0.15**	**$ 0.27**	**$ 1.00**	**$ 1.90**
Adjustments:				
Mark-to-market earnings - Renewables (2)	0.06	0.06	0.05	0.04
Impact of COVID-19 (3)	—	—	—	—
Merger costs (4)	—	—	0.01	0.01
Offshore contract provision (5)	0.10	—	0.10	—
Income tax impact of adjustments	(0.04)	(0.02)	(0.04)	(0.01)
Adjusted Earnings Per Share (6)	**$ 0.27**	**$ 0.31**	**$ 1.12**	**$ 1.94**

(1) Includes corporate and other non-regulated entities as well as intersegment eliminations.

(2) Mark-to-market earnings relates to earnings impacts from changes in the fair value of Renewables' derivative instruments associated with electricity and natural gas.

(3) Represents costs incurred in connection with the COVID-19 pandemic, mainly related to bad debt provisions.

(4) Pre-merger costs incurred.

(5) Costs incurred in connection with offshore contract provision.

(6) Adjusted net income and adjusted earnings per share are non-GAAP financial measures and are presented after excluding costs incurred in connection with the COVID-19 pandemic, the impact from mark-to-market activities in Renewables and costs incurred related to the PNMR Merger and offshore contract provision.

Liquidity and Capital Resources

Our operations, capital investment and business development require significant short-term liquidity and long-term capital resources. Historically, we have used cash from operations and borrowings under our credit facilities and commercial paper program as our primary sources of liquidity. Our long-term capital requirements have been met primarily through retention of earnings and borrowings in the investment grade debt capital markets. Continued access to these sources of liquidity and capital are critical to us. Risks may increase due to circumstances beyond our control, such as a general disruption of the financial markets and adverse economic conditions.

We and our subsidiaries are required to comply with certain covenants in connection with our respective loan agreements. The covenants are standard and customary in financing agreements, and we and our subsidiaries were in material compliance with such covenants as of and throughout the nine months ended September 30, 2023.

Liquidity Position

We optimize our liquidity within the United States through a series of arms-length intercompany lending arrangements with our subsidiaries and among our regulated utilities to provide for lending of surplus cash to subsidiaries with liquidity needs, subject to the limitation that the regulated utilities may not lend to unregulated affiliates. These arrangements minimize overall short-term funding costs and maximize returns on the temporary cash investments of the subsidiaries. As of September 30, 2023, we have the capacity to borrow up to $3,575 million from the lenders committed to the Avangrid Credit Facility described below.

The following table provides the components of our liquidity position as of September 30, 2023 and December 31, 2022, respectively:

	As of September 30, 2023	As of December 31, 2022
	(in millions)	
Cash and cash equivalents	$ 75	$ 69
Avangrid Credit Facility	3,575	3,575
Iberdrola Group Credit Facility	750	500
Less: borrowings	(954)	(397)
Total	**$ 3,446**	**$ 3,747**

Avangrid Commercial Paper Program

Avangrid has a commercial paper program with a limit of $2 billion that is backstopped by the Avangrid Credit Facility (described below). As of September 30, 2023 and October 25, 2023, there was $954 million and $1,386 million of commercial paper outstanding.

Avangrid Credit Facility

Avangrid and its subsidiaries, NYSEG, RG&E, CMP, UI, CNG, SCG and BGC, each of which are joint borrowers, have a revolving credit facility with a syndicate of banks, or the Avangrid Credit Facility, that provides for maximum borrowings of up to $3,575 million in the aggregate, which was executed on November 23, 2021. The agreement contained a commitment from lenders, which expired on April 20, 2022 to increase maximum borrowings to $4,000 million upon the joinder of PNM and TNMP as borrowers under the Avangrid Credit Facility.

Under the terms of the Avangrid Credit Facility, each joint borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit contained in the agreement. On November 23, 2021, the executed Avangrid Credit Facility increased Avangrid's maximum sublimit from $1,500 million to $2,500 million. The Avangrid Credit Facility contains pricing that is sensitive to Avangrid's consolidated greenhouse gas emissions intensity. The Credit Facility also contains negative covenants, including one that sets the ratio of maximum allowed consolidated debt to consolidated total capitalization at 0.65 to 1.00, for each borrower. Under the Avangrid Credit Facility, each of the borrowers will pay an annual facility fee that is dependent on their credit rating. The initial facility fees will range from 10 to 22.5 basis points. The maturity date for the Avangrid Credit Facility is November 22, 2026. On July 17, 2023, the Avangrid Credit Facility was amended and restated to, among other things, provide for the replacement of LIBOR-based rates with SOFR-based rates and remove provisions related to the extension of credit to the Public Service Company of New Mexico and Texas-New Mexico Power Company.

As of both September 30, 2023 and October 25, 2023, we had no borrowings outstanding under this credit facility.

Since the Avangrid credit facility is also a backstop to the Avangrid commercial paper program, the total amount available under the facility as of September 30, 2023 and October 25, 2023, was $2,618 million and $2,186 million, respectively.

Iberdrola Group Credit Facility

On June 18, 2023, Avangrid's credit facility with Iberdrola Financiación, S.A.U., a subsidiary of Iberdrola, matured. The facility had a limit of $500 million. On July 19, 2023, we replaced this credit facility with an increased limit of $750 million and maturity date of June 18, 2028. Avangrid pays a quarterly facility fee of 22.5 basis points (rate per annum) on the facility based on Avangrid's current Moody's and S&P ratings for senior unsecured long-term debt. As of both September 30, 2023 and October 25, 2023, we had no borrowings outstanding under this credit facility.

Capital Resources

On July 3, 2023, NYSEG remarketed $100 million aggregate principal amount of unsecured notes maturing in 2034 at a fixed interest rate of 4.00%.

On July 19, 2023, we entered into a green term loan agreement with Iberdrola Financiación, S.A.U., with an aggregate principal amount of $800 million maturing on July 13, 2033 at an interest rate of 5.45% (the Intragroup Green Loan).

On July 3, 2023, we entered into a deposit agreement with Iberdrola Financiación, S.A.U., pursuant to which a deposit of $250 million was made on July 3, 2023, which matured on July 24, 2023 at an interest rate of 5.50%. The deposit was paid out on July 24, 2023 with the proceeds of the Intragroup Green Loan.

On August 3, 2023, NYSEG issued $350 million aggregate principal amount of unsecured notes maturing in 2028 at a fixed interest rate of 5.65%.

On August 3, 2023, NYSEG issued $400 million aggregate principal amount of unsecured notes maturing in 2033 at a fixed interest rate of 5.85%.

On October 2, 2023, UI remarketed $65 million aggregate principal amount of unsecured notes maturing in 2033 at a fixed interest rate of 4.50%.

Capital Requirements

We expect to fund our capital requirements, including, without limitation, any quarterly shareholder dividends and capital investments primarily from the cash provided by operations of our businesses and through the access to the capital markets in the future. We have revolving credit facilities, as described above, to fund short-term liquidity needs and we believe that we will continue to have access to the capital markets as long-term growth capital is needed. While taking into consideration the current economic environment, management expects that we will continue to have sufficient liquidity and financial flexibility to meet our business requirements.

We expect to incur approximately $1.1 billion in capital expenditures through the remainder of 2023. This estimate is subject to continuing review and actual capital expenditures may vary significantly. For example, the U.S. Department of Commerce's anti-circumvention petition alleging that solar panels and cells shipped from Vietnam, Thailand, Malaysia and Cambodia could result in higher than expected costs for projects beyond 2023. As a result, the timing and ultimate cost associated with solar panels and cells and related project capital expenditures may vary from our current expectations.

Cash Flows

Our cash flows depend on many factors, including general economic conditions, regulatory decisions, weather, commodity price movements and operating expense and capital spending control.

The following is a summary of the cash flows by activity for the nine months ended September 30, 2023 and 2022, respectively:

	Nine Months Ended September 30,	
	2023	2022
	(in millions)	
Net cash provided by operating activities	$ 757	$ 894
Net cash used in investing activities	(2,024)	(2,020)
Net cash provided by (used in) financing activities	1,279	(288)
Net increase (decrease) in cash, cash equivalents and restricted cash	**$ 12**	**$ (1,414)**

Operating Activities

The cash from operating activities for the nine months ended September 30, 2023 compared to the nine months ended September 30, 2022 decreased by $137 million, primarily attributable to a net decrease in current assets and liabilities driven by timing of cash collections and cash disbursements, and higher interest payments during the period.

Investing Activities

For the nine months ended September 30, 2023, net cash used in investing activities was $2,024 million, which was comprised of $2,078 million of capital expenditures and $99 million of capital contributions to the equity method investments, partially offset by $101 million of contributions in aid of construction.

For the nine months ended September 30, 2022, net cash used in investing activities was $2,020 million, which was comprised of $1,940 million of capital expenditures and $168 million of payment for the offshore joint venture restructuring transaction, partially offset by $90 million of contributions in aid of construction.

Financing Activities

For the nine months ended September 30, 2023, financing activities provided $1,279 million in cash reflecting primarily a net increase in non-current debt and current notes payable of $1,729 million, contribution from non-controlling interests of $79 million, offset by distributions to non-controlling interests of $13 million and dividends of $510 million in the period.

For the nine months ended September 30, 2022, financing activities used $288 million in cash reflecting primarily distributions to non-controlling interests of $8 million and dividends of $510 million, offset by a net increase in non-current debt and current notes payable of $93 million and contribution from non-controlling interests of $146 million in the period.

Off-Balance Sheet Arrangements

There have been no material changes in our off-balance sheet arrangements during the nine months ended September 30, 2023 as compared to those reported for the fiscal year ended December 31, 2022 in our Form 10-K.

Contractual Obligations

There have been no material changes in contractual and contingent obligations during the nine months ended September 30, 2023 as compared to those reported for the fiscal year ended December 31, 2022 in our Form 10-K.

Critical Accounting Policies and Estimates

We have prepared the accompanying condensed consolidated financial statements provided herein in accordance with U.S. GAAP. In preparing the accompanying condensed consolidated financial statements, our management has made certain estimates and assumptions that affect the reported amounts of assets, liabilities, stockholders' equity, revenues and expenses and the disclosures thereof. While we believe that these policies and estimates used are appropriate, actual future events can and often do result in outcomes that can be materially different from these estimates. As of September 30, 2023, the only notable changes to the significant accounting policies described in our Form 10-K for the fiscal year ending December 31, 2022, are with respect to our adoption of the new accounting pronouncements described in the Note 3 of our condensed consolidated financial statements for the nine months ended September 30, 2023.

New Accounting Standards

We review new accounting standards to determine the expected financial effect, if any, that the adoption of each such standard will have. The new accounting pronouncements we have adopted as of January 1, 2023, and reflected in our condensed consolidated financial statements are described in Note 3 of our condensed consolidated financial statements for the nine months ended September 30, 2023.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q contains a number of forward-looking statements. Forward-looking statements may be identified by the use of forward-looking terms such as “may,” “will,” “should,” “would,” “could,” “can,” “expect(s),” “believe(s),” “anticipate(s),” “intend(s),” “plan(s),” “estimate(s),” “project(s),” “assume(s),” “guide(s),” “target(s),” “forecast(s),” “are (is) confident that” and “seek(s)” or the negative of such terms or other variations on such terms or comparable terminology. Such forward-looking statements include, but are not limited to, statements about our plans, objectives and intentions, outlooks or expectations for earnings, revenues, expenses or other future financial or business performance, strategies or expectations, or the impact of legal or regulatory matters on business, results of operations or financial condition of the business and other statements that are not historical facts. Such statements are based upon the current reasonable beliefs, expectations, and assumptions of our management and are subject to significant risks and uncertainties that could cause actual outcomes and results to differ materially. Important factors are discussed and should be reviewed in our Form 10-K and other subsequent filings with the SEC. Specifically, forward-looking statements include, without limitation:

- the future financial performance, anticipated liquidity and capital expenditures;
- actions or inactions of local, state or federal regulatory agencies;
- the ability to recruit and retain a highly qualified and diverse workforce in the competitive labor market;
- changes in amount, timing or ability to complete capital projects;
- adverse developments in general market, business, economic, labor, regulatory and political conditions including, without limitation, the impacts of inflation, deflation, supply-chain interruptions and changing prices and labor costs, including the Department of Commerce's anti-circumvention petition that could adversely impact renewable solar energy projects;
- the impacts of climate change, fluctuations in weather patterns and extreme weather events;
- technological developments;
- the impact of extraordinary external events, such as any cyber breaches or other incidents, grid disturbances, acts of war or terrorism, civil or social unrest, natural disasters, pandemic health events or other similar occurrences, including the ongoing geopolitical conflict with Russia and Ukraine;
- the impact of any change to applicable laws and regulations, including those subject to referendums and legal challenges, affecting the ownership and operations of electric and gas utilities and renewable energy generation facilities, respectively, including, without limitation, those relating to the environment and climate change, taxes, price controls, regulatory approval and permitting;
- our ability to close the proposed Merger (as defined in "Note 1 - Background and Nature of Operations" to the accompanying unaudited condensed consolidated financial statements under Part I, Item 1 of this report), the anticipated timing and terms of the proposed Merger, our ability to realize the anticipated benefits of the proposed Merger and our ability to manage the risks of the proposed Merger;
- the impact of a catastrophic or geopolitical event on business and economic conditions;
- the implementation of changes in accounting standards;
- adverse publicity or other reputational harm; and
- other presently unknown unforeseen factors.

Should one or more of these risks or uncertainties materialize, or should any of the underlying assumptions prove incorrect, actual results may vary in material respects from those expressed or implied by these forward-looking statements. You should not place undue reliance on these forward-looking statements. We do not undertake any obligation to update or revise any forward-looking statements to reflect events or circumstances after the date of this report, whether as a result of new information, future events or otherwise, except as may be required under applicable securities laws. Other risk factors are detailed from time to time in our reports filed with the SEC, and we encourage you to consult such disclosures.

Item 3. *Quantitative and Qualitative Disclosures about Market Risk*

There have been no material changes in our market risk during the nine months ended September 30, 2023, as compared to those reported for the fiscal year ended December 31, 2022 in our Form 10-K.

Item 4. *Controls and Procedures*

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our Chief Executive Officer, or CEO, and our Chief Financial Officer, or CFO, has evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a- 15(e) and 15d- 15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act)), as of the end of the period covered by this Quarterly

Report on Form 10-Q. Based on such evaluation, our CEO and CFO have concluded that as of such date, our disclosure controls and procedures were effective.

Changes in Internal Control

There has been no change in our internal control over financial reporting identified in management's evaluation pursuant to Rules 13a-15(d) or 15d-15(d) of the Exchange Act during the period covered by this Quarterly Report on Form 10-Q that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Limitations on Effectiveness of Controls and Procedures

In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives. In addition, the design of disclosure controls and procedures must reflect the fact that there are resource constraints and that management is required to apply judgment in evaluating the benefits of possible controls and procedures relative to their costs.

PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings***

Please read “Note 8—Contingencies” and “Note 9—Environmental Liabilities” to the accompanying unaudited condensed consolidated financial statements under Part I, Item 1 of this report for a discussion of legal proceedings that we believe could be material to us.

Item 1A. ***Risk Factors***

Shareholders and prospective investors should carefully consider the risk factors disclosed in our Form 10-K for the fiscal year ended December 31, 2022.

Item 2. ***Unregistered Sales of Equity Securities and Use of Proceeds***

None.

Item 3. ***Defaults Upon Senior Securities***

None.

Item 4. ***Mine Safety Disclosures***

Not applicable.

Item 5. ***Other Information***

Securities Trading Plans of Directors and Executive Officers

In order to align our executive officers’ interests with the long-term interests of our shareholders, we grant long-term incentive awards in the form of performance stock units, phantom share units, and restricted stock units. Following the delivery of shares of our common stock under those equity awards, once any applicable service-, time- or performance-based vesting standards have been satisfied, our executive officers from time to time engage in the open-market sale of some of those shares. Additionally, our directors may purchase or sell shares of our common stock in the market from time to time. We encourage our executive officers and directors to make these transactions through plans that comply with Rule 10b5-1 under the Exchange Act, which provides an affirmative defense that enables prearranged transactions in securities in a manner that avoids concerns about initiating transactions at a future date while possibly in possession of material nonpublic information.

During the quarterly period ended September 30, 2023, no directors or executive officers entered into trading plans intended to comply with Exchange Act Rule 10b5-1 or other non-Rule 10b5-1 trading arrangements.

Item 6. *Exhibits*

The following documents are included as exhibits to this Form 10-Q:

Exhibit Number	Description
3.1	Avangrid, Inc. Amended and Restated By-Laws (incorporated herein by reference to Annex B to Avangrid's Proxy Statement filed with the Securities and Exchange Commission on June 6, 2023).
10.1	Offer Letter, dated July 18, 2023, between Justin Lagasse and Avangrid Management Company, LLC (incorporated herein by reference to Exhibit 10.1 to Form 8-K/A filed with the Securities and Exchange Commission on July 21, 2023).
10.2	Amendment No. 2, dated July 17, 2023, to the Revolving Credit Agreement, dated as of November 21, 2021 among Avangrid, Inc., New York State Electric & Gas Corporation, Rochester Gas and Electric Corporation, Central Maine Power Company, The United Illuminating Company, Connecticut Natural Gas Corporation, The Southern Connecticut Gas Company, The Berkshire Gas Company, the several lenders from time to time parties thereto, Mizuho Bank, Ltd., as Administrative Agent, MUFG Bank, LTD., Banco Bilbao Vizcaya Argentaria, S.A. New York Branch and Santander Bank, N.A., as Co-Documentation Agents, Bank of America, N.A. and JPMorgan Chase Bank, N.A., as Co-Syndication Agents, Banco Bilbao Vizcaya Argentaria, S.A. New York Branch, as Sustainability Agent, and Mizuho Bank, Ltd., BOFA Securities, Inc., JPMorgan Chase Bank, N.A., MUFG Bank, LTD., BBVA Securities Inc., and Santander Bank, N.A., as Joint Lead Arrangers and Joint Bookrunners (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed with the Securities and Exchange Commission on July 21, 2023).
10.3	Intra-Group Green Loan Agreement, dated July 19, 2023, between Avangrid, Inc. and Iberdrola Financiación, S.A.U. (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed with the Securities and Exchange Commission on July 21, 2023).
10.4	Intra-Group Credit Agreement, dated July 19, 2023, between Avangrid, Inc. and Iberdrola Financiación, S.A.U. (incorporated herein by reference to Exhibit 10.3 to Form 8-K filed with the Securities and Exchange Commission on July 21, 2023).
10.5	Side Letter to Platinum Commitment Letter, dated June 30, 2023, between Avangrid, Inc. and Iberdrola Financiación, S.A.U. (incorporated herein by reference to Exhibit 10.4 to Form 8-K filed with the Securities and Exchange Commission on July 21, 2023).
31.1	Chief Executive Officer Certification pursuant to Rule 13a-14(a) and 15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
31.2	Chief Financial Officer Certification pursuant to Rule 13a-14(a) and 15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
32	Certification pursuant to 18 United States Code Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*
101.INS	XBRL Instance Document.*
101.SCH	XBRL Taxonomy Extension Schema Document.*
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.*
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.*
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.*
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.*

*Filed herewith.
†Compensatory plan or agreement.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

		Avangrid, Inc.
Date: October 26, 2023	By:	/s/ Pedro Azagra Blázquez
		Pedro Azagra Blázquez
		Director and Chief Executive Officer
Date: October 26, 2023	By:	/s/ Patricia C. Cosgel
		Patricia C. Cosgel
		Senior Vice President - Chief Financial Officer

EXHIBIT 31.1

CERTIFICATION

I, Pedro Azagra Blázquez, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Avangrid, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 26, 2023	/s/ Pedro Azagra Blázquez
	Pedro Azagra Blázquez
	Director and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Patricia C. Cosgel, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Avangrid, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 26, 2023	/s/ Patricia C. Cosgel
	Patricia C. Cosgel
	Senior Vice President - Chief Financial Officer

EXHIBIT 32

CERTIFICATION OF CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER
Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

Pursuant to 18 U.S.C. Section 1350, the undersigned, Pedro Azagra Blázquez and Patricia C. Cosgel, the Chief Executive Officer and Chief Financial Officer, respectively, of Avangrid, Inc. (the "issuer"), do each hereby certify that the issuer's quarterly report on Form 10-Q for the quarter ended September 30, 2023, to which this certification is attached as an exhibit (the "report"), fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)) and that information contained in the report fairly presents, in all material respects, the financial condition and results of operations of the issuer.

/s/ Pedro Azagra Blázquez

Pedro Azagra Blázquez
Director and Chief Executive Officer
Avangrid, Inc.
October 26, 2023

/s/ Patricia C. Cosgel

Patricia C. Cosgel
Senior Vice President - Chief Financial Officer
Avangrid, Inc.
October 26, 2023