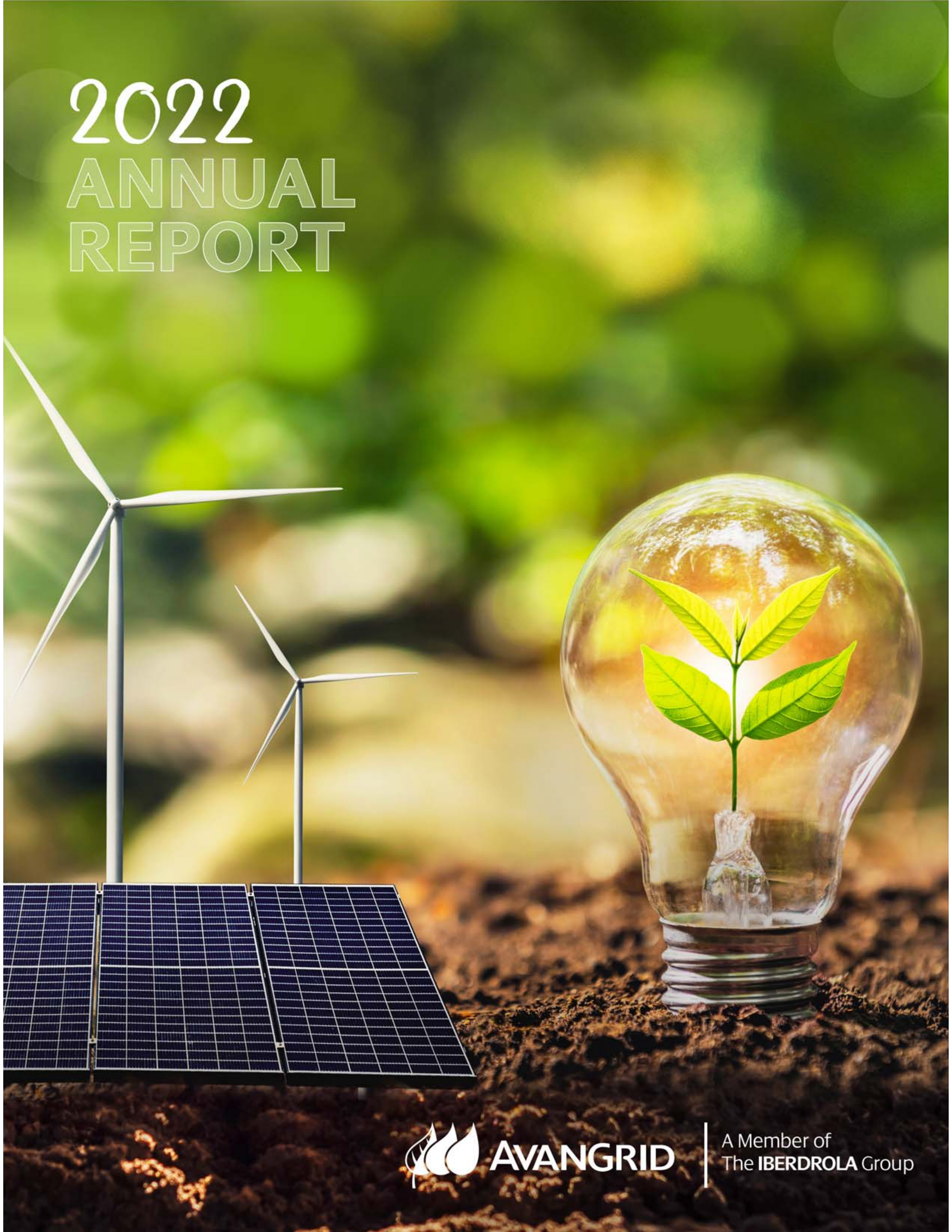
2022 ANNUAL REPORT



AVANGRID | A Member of The IBERDROLA Group



To our Shareholders:

Two years into what has been called our "decisive decade," we stand at a pivotal moment in the world's energy transition. In the midst of a global energy crisis and pandemic-related supply chain disruptions, it's become clear that the world needs more secure, sustainable, and affordable energy. By enhancing the electrification of our economies, we can meet these needs while creating jobs and economic growth, promoting environmental and social justice, and making transformative investments in our communities.

We are encouraged to see U.S. energy policy aligning to this vision. Historic federal legislation, including the Inflation Reduction Act, promises to generate a wave of investment in the grid and in various clean energy technologies.

AVANGRID is well positioned to contribute, with efforts underway to pioneer the U.S. offshore wind industry, modernize our networks to deliver cleaner power to customers and help electrify transit and buildings, and grow our onshore footprint while pursuing promising new opportunities, like green hydrogen.

These are positive steps forward, but we must continue to move faster. To accomplish this, having a stable and predictable framework is essential – including streamlined development processes and a constructive market design that supports the capital needed to build these projects.

With over two decades committed to clean energy as part of the Iberdrola Group, AVANGRID is proud to be at the forefront of this fundamental shift in how we generate and use energy. We are grateful for the leadership and contribution of our Chairman Ignacio Galán to our company and our Board of Directors, providing continued strategic guidance, expertise, and a focus on sustained value creation. Building on our successes from the past year, we are committed to further accelerating the clean energy transition in the years to come.

2022 IN REVIEW

In 2022, we invested $2.7 billion in our Networks and Renewables businesses and delivered financial success even in the face of a challenging economic and market environment.

> AVANGRID'S 2022 CONSOLIDATED U.S. GAAP NET INCOME INCREASED BY 25% YEAR-OVER-YEAR TO $881 MILLION, OR $2.28 PER SHARE. OUR NON-U.S. GAAP CONSOLIDATED ADJUSTED NET INCOME[1] INCREASED BY 16% YEAR-OVER-YEAR TO $901 MILLION, OR $2.33 PER SHARE.

Since AVANGRID's formation in 2015, we have grown net income and adjusted net income at strong compound annual growth rates of 9% and 10%, respectively. Furthermore, adjusted earnings per share has grown at a healthy 7% compound annual rate, returning significant value for our investors.[2]

In Networks, we invested $1.9 billion to support system reliability and resiliency, and to better serve the 3.3 million electric and gas customers who depend on us. These investments helped grow our rate base by 8% in 2022, to $12.7 billion. We took significant steps forward to ensure a secure and sustainable financial position for all our utilities with the filing of six rate cases and a successful settlement in Massachusetts.

In addition, our more than 7,500 employees continued to step up for our customers, responding to an active winter storm season and delivering double-digit improvements in average reliability across our electric utilities. On multiple occasions, our utilities were recognized with the Edison Electric Institute's Emergency Response Award, for recovery efforts in New York following a major snowstorm and for mutual aid provided to Nova Scotia and Louisiana.

In Renewables, we invested approximately $800 million and added nearly 400 megawatts (MW) of new onshore wind and solar, including AVANGRID's first large-scale solar project – our 194 MWdc Lund Hill Solar. Our team ensures exceptional operations across our 8.6 gigawatt (GW) fleet, delivering over 97% availability in 2022, an increase of nearly two percentage-points since 2019. We took action to manage a challenging market environment by renegotiating 780 MW of onshore Power Purchase Agreements (PPAs).

Furthermore, we advanced the construction of 1.4 GW of additional onshore and offshore capacity, which we expect to bring into operations over the next two years. This includes Vineyard Wind 1[3], AVANGRID's first-in-the-nation industrial wind farm, which successfully started manufacturing of all major components and began export cable installation in 2022. These major milestones keep Vineyard Wind 1 on track to deliver its first power by the end of this year and reach full commercial operations in 2024.

For our two other New England offshore wind projects – Commonwealth Wind and Park City Wind – we have taken important steps forward in permitting, including obtaining the Bureau of Ocean Energy Management's draft environmental impact statement. Additionally, we made the difficult decision to terminate non-viable PPAs for Commonwealth Wind after evaluating the project's economics and financeability in light of unprecedented shifts in energy and financial markets, which show the need for additional flexibility in auctions for long-lead projects like offshore wind farms, and determining it was the fastest way forward to deliver clean energy for Massachusetts by its 2030 climate target. As our shareholders, you have entrusted us as investors of your capital, and we owe you a duty to use that capital prudently. We hold this responsibility with the highest regard and will take the actions needed to ensure financial discipline. Despite these challenges, we are committed to reaching a path forwardto create value, and ultimately deliver the powerful sources of clean, reliable energy the region critically needs.

Finally, to truly decarbonize the economy, we need to develop solutions that work for all sectors – even those most difficult to electrify. To meet this challenge, we continue to explore green hydrogen opportunities, leveraging our expansive renewables footprint and development and operations expertise to add value to our business mix. In 2022, we announced an agreement with Sempra Infrastructure to support potential joint development efforts and we are engaged in seven coalitions for the Department of Energy's $7 billion Hydrogen Hubs program. We believe green hydrogen will be a powerful tool to fully decarbonize energy demand and are encouraged by the foundation we have set for future growth.

BUILDING ON OUR ESG+F ADVANTAGE

As one of the nation's cleanest utilities, our sustainable business practices have been a central part of our company since its inception. We are proud to have set the bar high and we continue to raise it. In addition to being the first U.S. utility to pledge to achieve carbon neutrality in our generation fleet, we have consistently maintained an emissions intensity that is at least six times lower[4] than the U.S. power sector average. Today, our generation mix is 91% emissions-free.

THIS PAST YEAR, WE ANNOUNCED A SIGNIFICANT EXPANSION TO OUR NEUTRALITY GOAL – NOW TARGETING CARBON NEUTRALITY IN SCOPES 1 AND 2 EMISSIONS[5] BY 2030, WHICH PUTS AVANGRID AHEAD OF MOST OTHER MAJOR U.S. UTILITIES AND IN LINE TO DELIVER ON NATIONAL AND STATE CLIMATE OBJECTIVES.

Importantly, AVANGRID is committed to excellence across a full range of environmental, social, governance and financial indicators. If we get the transition right, not only will our environment benefit, but so too will our society. Our operations help promote more vibrant communities, underpinned by broader economic opportunities, high-quality jobs, and healthy, more localized supply chains. Our investments support approximately 70,000 U.S. jobs and contribute an estimated $10 billion each year to U.S. GDP[6]. In addition, we made approximately $3.4 billion of purchases in 2022, helping sustain thousands of local companies. 94% of these purchases were from U.S. suppliers and two-thirds were from sustainable suppliers.

Furthermore, through our corporate and foundation giving, which increased in 2022 by nearly 30% to $5.7 million, we directly support hundreds of nonprofits and community organizations across our states – funds that help expand access to education, preserve arts and culture, promote biodiversity, combat food insecurity, and much more.

I am proud that our team's exceptional performance continues to earn recognition from a growing number of third parties. For five consecutive years, AVANGRID has been named as one of the World's Most Ethical Companies, and in 2022 was one of just nine honorees in the global Energy and Utilities sector. In addition, we are proud to have been listed for three consecutive years as one of America's Most Just Companies, ranking second among utilities and in the top 50 of all companies nationwide, and to have joined Bloomberg's Gender-Equality Index.

In these respects, if your drivers are green, sustainable investments, AVANGRID represents a unique opportunity to invest in a company with well-established credentials and a well-developed position. As we deliver transformative projects like offshore wind and execute on our long-term investment plans, we expect our ESG+F impact will only continue to grow.

DELIVERING CONTINUED GROWTH

Last year, we refreshed our Strategic Plan, defining a clear focus on regulated growth, consistent execution and value creation.

> THROUGH 2025, WE EXPECT TO INVEST $21.5 BILLION, PRIMARILY TO STRENGTHEN AND EXPAND OUR CORE REGULATED NETWORKS BUSINESS, AND IN TURN DRIVE 6% TO 7% COMPOUND ANNUAL GROWTH IN OUR ADJUSTED EARNINGS PER SHARE[7], AS COMPARED TO THE MIDPOINT OF OUR 2022 GUIDANCE.

Central to this plan is a disciplined capital management strategy, leveraging partnerships and asset rotation to deliver on our strategic vision while balancing the associated capital requirements. In addition, we have identified over $2 billion in asset rotation opportunities through 2025, which would materially reduce equity needs, while maintaining a firm commitment to balance sheet strength and solid financial metrics.

On top of this, our focus on operational excellence and continuous improvement is more important than ever. We must continue to think creatively, find ways to deliver the cost-effective, high quality service our customers expect, and run our operations as efficiently as possible. This is critical not only to ensure the financial sustainability of our business, but also to preserve customer affordability.

Our rate case proposals represent a balanced path forward, keeping rates among the lowest in New York and New England, while unlocking $10 billion in capital investments to drive clean energy transformation, strengthen reliability and resiliency, and better serve our customers.

Additionally, we remain committed to advancing our New England Clean Energy Connect (NECEC) transmission project and to completing our merger with PNM Resources (PNMR). Combined with PNMR, our two companies would serve 4.1 million customers across six states and provide the financial and operational strength needed to accelerate New Mexico's clean energy transition. NECEC will deliver 1.2 GW of clean, affordable hydropower to the New England grid while creating jobs and providing significant economic benefit to the region.

Heading into 2023 and beyond, we are well positioned to deliver on our commitments. While the energy landscape has been shaped by current events, AVANGRID's dedication to comprehensive climate action remains as strong as ever – even as other companies slow or abandon the call to action. We are committed to bringing all customers along in this transition.

There are huge growth opportunities ahead for both Networks and Renewables. Alongside continued growth in electric demand, electricity generation is projected to substantially expand by 2050, with renewables leading the charge – nearly doubling over the next decade alone to claim the largest share of the U.S. power mix[8]. Our top priority remains execution.

We know there will always be challenges to come. But if 2022 is any example, I am confident that this team is well equipped, capable, and fully committed to delivering continued success. This is who we've been since the start – a long-term company, committed to creating long-term value. We are persistent in pursuit of our goals, and we won't stop until we get the job done. Thank you for your continued support.

Sincerely,

Pedro Azagra Blázquez | Chief Executive Officer

1 Adjusted consolidated net income is a non-GAAP financial measure that excludes restructuring charges, mark-to-market earnings from changes in the fair value of derivative instruments, accelerated depreciation from repowering of wind farms, costs incurred related to the merger with PNM Resources, Inc., a legal settlement, an offshore contract provision and costs incurred in connection with the coronavirus (COVID-19) pandemic. For additional information, see "Non-GAAP Financial Measures" beginning on page 68 of our Annual Report on Form 10-K for the year ended December 31, 2022, included in this annual report.

2 2015 represents unaudited pro forma information reflecting the combined results of operations as if the UIL acquisition had been completed on January 1, 2015, as disclosed in AVANGRID's Annual Report on Form 10-K for the year ended December 31, 2015, updated for revisions in subsequent years. Refer to Appendix for reconciliation of Net Income to Adjusted Net Income. Weighted average number of shares: 310M in 2015.

3 Vineyard Wind 1 is a 50/50 joint venture between Avangrid Renewables and Copenhagen Infrastructure Partners.

4 Based on 2022 electric power sector emissions data from the U.S. Energy Information Administration.

5 Scope 1 emissions includes all direct greenhouse gas emissions from sources that are owned or controlled by the AVANGRID Group such as power generation facilities, offices and fleet vehicles. Scope 2 emissions includes indirect greenhouse gas emissions associated with the generation of purchased energy consumed by the AVANGRID Group, including grid losses during the distribution of third-party power. Greenhouse gases include carbon dioxide (CO_2), sulfur hexafluoride (SF_6), and methane (CH_4). Neutrality targets exclude PNM Resources (PNMR).

6 Jobs and GDP Impact include direct, indirect and induced impacts of AVANGRID's investments and operations in the United States, New York, Connecticut, Maine and Massachusetts based on an analysis by PricewaterhouseCoopers.

7 Networks investments through 2025 and earnings growth expectations include PNM Resources (PNMR).

8 Projections from the Energy Information Administration's Annual Energy Outlook 2022 (reference case); growth compared to 2021.

AVANGRID | A Member of The IBERDROLA Group

Accelerating America's clean energy transformation

OVER $41 BILLION
IN ASSETS WITH A PRESENCE IN 24 STATES

We are working together to deliver a more accessible clean energy model that promotes healthier, more sustainable communities *every day*

Our purpose, strategy and actions are inspired by and built on our three core values:

SUSTAINABLE: We seek to be a model of inspiration for creating economic, social and environmental value in our communities, and we act positively to effect local development, generate employment and give back to the community.

AGILE: We act efficiently and with passion to drive innovation and continuous improvement at both the local and global level.

COLLABORATIVE: We work together toward a common purpose and mutual benefit while valuing each other and our differences.

Financial and Operational
Highlights for 2022

9.5 GW
Installed Capacity

$12.7B
Rate Base

3.3M
Customers

91%
Emissions-free

26 GW
Renewables Pipeline

Selected Financial Data
(in millions, except per-share data)

Revenues	$7,923
Operating income	$852
Net income	$881
Adjusted net income*	$901
Earnings per share	$2.28
Adjusted earnings per share*	$2.33
Dividends declared per share	$1.76
Dividend yield (year-end)	4.36%
Market cap (year-end)	$16,617
Total assets	$41,123
Equity	$20,342
Non-current debt	$8,215
Accrued investments	$2,698

Selected Operational Data

Total customers	3,344,803
Electricity customers	2,310,881
Natural gas customers	1,033,922
Electricity delivered (GWh)	36,870
Natural gas delivered (DTh)	199,725,000
Electrical transmission and distribution lines (miles)	106,542
Gas distribution pipeline (miles)	23,559
Net electricity generation (GWh)	22,807
% emissions-free generation	89%
Installed capacity (MW)	9,541
% emissions-free capacity	91%
CO_2 emissions intensity (lbs CO_2/MWh)	102
Employees	7,579

Recognized Leader
in Sustainability

- In 2022, AVANGRID expanded its commitment to climate action with a target to achieve carbon neutrality in Scopes 1 and 2[1] emissions by 2030, and to develop a strategy to address Scope 3[1] emissions.
- By 2030, emissions-free installed capacity will increase by nearly 200% compared with base year 2015, reaching 16.9 GW. At the same time, emissions intensity associated with generation will fall 70% compared with base year 2015.

AVANGRID supports the U.N.'s 17 Sustainable Development Goals with focus on affordable and clean energy and climate action.

Main Focus

Direct Contribution

Indirect Contribution

* Adjusted consolidated net income excludes restructuring charges, mark-to-market earnings from changes in the fair value of derivative instruments, accelerated depreciation from repowering of wind farms, costs incurred related to the merger with PNM Resources, Inc., a legal settlement, an offshore contract provision and costs incurred in connection with the coronavirus (COVID-19) pandemic. For additional information, see "Non-GAAP Financial Measures" beginning on page 68 of our Annual Report on Form 10-K for the year ended December 31, 2022, included in this annual report.

1 Scope 1 emissions includes all direct greenhouse gas emissions from sources that are owned or controlled by the AVANGRID Group such as power generation facilities, offices and fleet vehicles. Scope 2 emissions include indirect greenhouse gas emissions associated with the generation of purchased energy consumed by the AVANGRID Group, including grid losses during the distribution of third-party power. Scope 3 emissions are all other indirect greenhouse gas emissions occurring in the AVANGRID Group value chain, such as emissions from supply chain, electricity purchased for end users, and gas supplied to final customers. Greenhouse gases include carbon dioxide (CO_2), Sulfur hexafluoride (SF_6), and methane (CH_4). Neutrality targets exclude PNM Resources (PNMR).

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2022

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

Avangrid, Inc.

(Exact name of registrant as specified in its charter)

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

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(s)	Name of exchange on which registered
Common Stock, par value $0.01 per share	AGR	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes ☐ No ☒

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, a smaller reporting company, or 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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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

The aggregate market value of the Avangrid, Inc.'s voting and non-voting common equity held by non-affiliates, computed by reference to the price at which the common equity was last sold as of the last business day of Avangrid, Inc.'s most recently completed second fiscal quarter (June 30, 2022) was $3,262 million based on a closing sales price of $46.12 per share.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: 386,637,276 shares of common stock, par value $0.01, were outstanding as of February 21, 2023.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the documents listed below have been incorporated by reference into the indicated parts of this report, as specified in the responses to the item numbers involved.

Designated portions of the Proxy Statement relating to the 2023 Annual Meeting of the Shareholders are incorporated by reference into Part III to the extent described therein.

TABLE OF CONTENTS

GLOSSARY OF TERMS AND ABBREVIATIONS

Unless the context indicates otherwise, references in this Annual Report on Form 10-K to "AVANGRID," the "Company," "we," "our," and "us" refer to Avangrid, Inc. and its consolidated subsidiaries.

2016 Joint Proposal	Joint proposal of NYSEG and RG&E and certain other signatory parties approved by the NYPSC on June 15, 2016, for a three-year rate plan for electric and gas service commencing May 1, 2016.
2020 Joint Proposal	Joint proposal of NYSEG and RG&E and certain other signatory parties approved by the NYPSC on November 19, 2020, for a three-year rate plan for electric and gas service commencing December 1, 2020.
AMI	Automated Metering Infrastructure
AOCI	Accumulated other comprehensive income
ARHI	Avangrid Renewables Holdings, Inc.
ARP	Alternative Revenue Programs
ASC	Accounting Standards Codification
Asnat	Asnat Realty, LLC
Army Corps	U.S. Army Corps of Engineers
ARO	Asset retirement obligation
AVANGRID	Avangrid, Inc.
Bcf	One billion cubic feet
BGC	The Berkshire Gas Company
BGEPA	Bald and Golden Eagle Protection Act
BLM	U.S. Bureau of Land Management
BOEM	U.S. Bureau of Ocean Energy Management
CAPM	Capital-asset pricing model
CfDs	Contracts for Differences
CFTC	Commodity Futures Trading Commission
CFIUS	Committee on Foreign Investment in the United States
CL&P	The Connecticut Light and Power Company
CLCPA	Climate Leadership and Community Protection Act
CMP	Central Maine Power Company
CNG	Connecticut Natural Gas Corporation
CPCN	Certificate of Public Convenience and Necessity
CSC	Connecticut Siting Council
DCF	Discounted cash flow
DEEP	Connecticut Department of Energy and Environmental Protection
DE&I	Diversity, Equity and Inclusion
DEQ	Oregon Department of Environmental Quality
DER	Distributed energy resources
DIMP	Distribution Integrity Management Program
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOE	Department of Energy
DOER	Massachusetts Department of Energy Resources
DOJ	Department of Justice
DPA	Deferred Payment Arrangements
DPU	Massachusetts Department of Public Utilities
DSIP	Distributed System Implementation Plan
DTh	Dekatherm
EAM	Earnings adjustment mechanism
EDC	Massachusetts electric distribution companies

English Station	Former generation site on the Mill River in New Haven, Connecticut
EPA	Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
ERCOT	Electric Reliability Council of Texas
ESA	Endangered Species Act
ESC	Energy Smart Community
ESM	Earnings sharing mechanism
Evergreen Power	Evergreen Power, LLC
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.
FPA	Federal Power Act
Gas	Enstor Gas, LLC
GE	General Electric
GenConn	GenConn Energy LLC
GenConn Devon	GenConn's peaking generating plant in Devon, Connecticut
GenConn Middletown	GenConn's peaking generating plant in Middletown, Connecticut
HLBV	Hypothetical Liquidation at Book Value
HQUS	H.Q. Energy Services (U.S) Inc.
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
IRA	Inflation Reduction Act
IRS	Internal Revenue Service
ISO	Independent system operator
ISO-NE	ISO New England, Inc.
ITC	Investment Tax Credit
Klamath Plant	The Klamath gas-fired cogeneration facility located in the city of Klamath, Oregon
kV	Kilovolts
kWh	Kilowatt-hour
LDC	Local distribution company
LIBOR	London Interbank Offer Rate
LNG	Liquefied natural gas
LUPC	Maine Land Use Planning Commission
MBTA	Migratory Bird Treaty Act
MBEP	Maine Board of Environmental Protection
MDEP	Maine Department of Environmental Protection
MEPCO	Maine Electric Power Corporation
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 January 3, 2022 among AVANGRID, PNMR and Merger Sub.
Merger Sub	NM Green Holdings, Inc., a New Mexico corporation and wholly-owned subsidiary of AVANGRID.

MGP	Manufactured gas plants
MHI	Mitsubishi Heavy Industries
MISO	Midcontinent Independent System Operator
MNG	Maine Natural Gas Corporation
MPRP	Maine Power Reliability Program
MPUC	Maine Public Utility Commission
MtM	Mark-to-market
MW	Megawatts
MWh	Megawatt-hours
NAV	Net asset value
NECEC	New England Clean Energy Connect
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NETOs	New England Transmission Owners
Networks	Avangrid Networks, Inc.
New York TransCo	New York TransCo, LLC.
NGA	Natural Gas Act of 1938
NMPRC	New Mexico Public Regulation Commission
NOL	Net operating loss
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
NYISO	New York Independent System Operator, Inc.
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
OATT	Open Access Transmission Tariff
OCI	Other comprehensive income
OSHA	Occupational Safety and Health Act, as amended
PA	Connecticut Public Act
PCB	Polychlorinated Biphenyls
PJM	PJM Interconnection, L.L.C.
PNMR	PNM Resources, Inc.
PPA	Power purchase agreement
PTC	Production tax credit
PUCT	Public Utility Commission of Texas
PUHCA 2005	Public Utility Holding Company Act of 2005
PURA	Connecticut Public Utilities Regulatory Authority
RAM	Rate Adjustment Mechanism
RCRA	Resource Conservation and Recovery Act
RDM	Revenue decoupling mechanism
REC	Renewable Energy Certificate
Renewables	Avangrid Renewables, LLC
REV	Reforming the Energy Vision
RFP	Request for Proposals
RG&E	Rochester Gas and Electric Corporation
ROE	Return on equity
ROU	Right-of-use
RPS	Renewable Portfolio Standards

RTO	Regional transmission organization
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 between AVANGRID and Iberdrola concerning items
SOX	Sarbanes-Oxley Act
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
TSA	Transmission Service Agreement
UI	The United Illuminating Company
UIL	UIL Holdings Corporation
U.S. GAAP	Generally accepted accounting principles for financial reporting in the United States.
VaR	Value-at-risk
VIEs	Variable interest entities
VW	Vineyard Wind LLC and its subsidiaries
WECC	Western Electricity Coordinating Council

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS AND SUMMARY OF RISK FACTORS

This Annual Report on Form 10-K 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 including regulatory approvals 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 that could cause actual results to differ materially from those indicated by such forward-looking statements include, without limitation, the following, which is also a summary of the principal risks set forth under Part I, Item 1A, "Risk Factors" in this Annual Report on Form 10-K:

- actions or inactions of local, state or federal regulatory agencies;
- the ability of our regulated utility operations to recover costs in a timely manner or at all or obtain a return on certain assets or invested capital through base rates, cost recovery clauses, other regulatory mechanism;
- potentially material adverse effect on our business, and financial condition due to the purchase and sales of energy commodities and related transportation and services by our operating subsidiaries;
- 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;
- the impact of any change to applicable laws and regulations, including those subject to referendums 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;
- efforts to maintain a responsive ESG program;
- new tariffs imposed on imported goods;
- 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;
- potential restrictions by interconnecting utility and/or RTO rules, policies, procedures and FERC tariffs and market conditions on renewable project operations and ability to generate revenue;
- our rights, and the rights of our subsidiaries to sites that projects are located may be subordinate to the rights of lienholders and leaseholders;
- strikes, work stoppages or an inability to negotiate future collective bargaining agreements on commercially reasonable terms
- technological developments;
- geopolitical instability could exacerbate existing risk factors;
- the future financial performance, anticipated liquidity and capital expenditures;
- weather conditions are unfavorable or below production forecasts;
- customary business and market related risks including warranty limitation and expiration as well as PPA expiration or early termination.
- impact of Iberdrola's influence over stock as well as the future sale of issuance of common stock by Iberdrola;
- the "controlled company" exemption to the corporate governance rules for NYSE-listed companies could make shares of our common stock less attractive to some investors or otherwise harm our stock price.
- our dividend policy is subject to the discretion of our board of directors and may be limited by our debt agreements and limitations under New York law;
- ability to meet our financial obligations and to pay dividends on our common stock if our subsidiaries are unable to pay dividends or repay loans from us;
- the ability to effectively implement and maintain internal control over financial reporting;
- our investments and cash balances are subject to the risk of loss;
- the cost and availability of capital to finance our business is inherently uncertain;
- litigation or administrative proceedings;
- inability to insure against all potential risks;
- 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;
- the impacts of climate change, fluctuations in weather patterns and extreme weather events;
- our ability to close the proposed Merger (as defined below), 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 such as risks associated with operating and maintaining a large transmission network, fossil-fueled and nuclear power plants;
- the impact of a catastrophic or geopolitical event, such as the Covid-19 pandemic, on business and economic conditions, including but not limited to impacts from consumer payment behavior and supply chain delays, and the pace of recovery from the pandemic or other similar events;
- the implementation of changes in accounting standards;
- adverse publicity or other reputational harm; and
- other presently unknown unforeseen factors.

Additional risks and uncertainties are set forth under Part I, Item 1A, “Risk Factors” in this Annual Report on Form 10-K. 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 Securities and Exchange Commission, or SEC, and we encourage you to consult such disclosures.

PART I

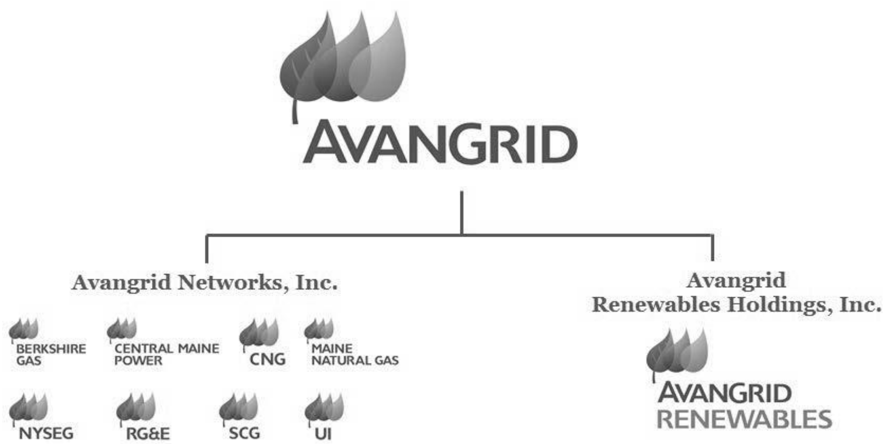
Item 1. *Business*

Overview

AVANGRID aspires to be the leading sustainable energy company in the United States. 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 $41 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 2022 for the fourth consecutive year by the Ethisphere Institute and is listed as a Forbes Best-In-State Employers 2022 and recognized by Just Capital as one of the 2022 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. 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. The following chart depicts our current organizational structure.



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 December 31, 2022. The interstate transmission and wholesale sale of electricity by these regulated utilities is regulated by the Federal Energy Regulatory Commission, or FERC, under the Federal Power Act, or FPA, including with respect to transmission rates. Further, Networks' electric and gas distribution utilities in New York, Maine, Connecticut and Massachusetts are subject to regulation by the New York State Public Service Commission, or NYPSC; the Maine Public Utilities Commission, or MPUC; the Connecticut Public Utilities Regulatory Authority, or PURA; and the Massachusetts Department of Public Utilities, or DPU, respectively. Networks strives to be a leader in safety, reliability and quality of service to its utility customers.

Through Renewables, we have a combined wind, solar and thermal installed capacity of 9,206 megawatts, or MW, as of December 31, 2022, 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 power purchase agreements, or PPAs, and hedges to limit market volatility. As of December 31, 2022, approximately 74% of the capacity was contracted with PPAs, for an average period of approximately 10 years, and an additional 15% of production was hedged. AVANGRID is one of the three largest wind operators in the United States based on installed capacity as of December 31, 2022 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 five solar facilities in 21 states across the United States.

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 was expected to merge with and into PNMR, with PNMR surviving the Merger as a direct wholly-owned subsidiary of AVANGRID, or the Merger. 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 set forth certain terms and conditions relating to the Funding Commitment Letter, or the Side Letter Agreement. The Side Letter Agreement provides that any drawing in the form of indebtedness made by AVANGRID pursuant to the Funding Commitment Letter shall bear interest at an interest rate equal to 3-month London Interbank Offer Rate, or LIBOR, 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, AVANGRID 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. On June 14, 2022, the NMPRC filed its Answer Brief. On June 13, 2022, New Energy Economy, an intervener in the Merger proceeding, filed its Answer Brief. AVANGRID's Reply Brief was filed on August 5, 2022. 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. On September 21, 2022, New Energy Economy filed a motion to show cause with the NMPRC alleging that AVANGRID and PNMR have engaged in a misleading joint advertising and sponsorship strategy and requesting an investigation. AVANGRID filed a reply to the motion to show cause on October 11, 2022. We cannot predict the outcome of this proceeding.

In addition, on January 3, 2022, AVANGRID, PNMR and Merger Sub entered into an Amendment to the Merger Agreement, or the 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 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 Amendment. As amended, the Merger Agreement may be terminated by each of AVANGRID and PNMR under certain circumstances, including if the Merger is not consummated by April 20, 2023 (subject to a three-month extension by AVANGRID and PNMR by mutual consent if all of the conditions to the closing, other than the conditions related to obtaining regulatory approvals, have been satisfied or waived). 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. In addition, the Closing of the Merger is subject to certain conditions including entry into agreements providing for, and to making filings required to, exit from all ownership interests in the Four Corners Power Plant and certain other customary closing conditions. For additional information, see Note 1 to our consolidated financial statements contained in this Annual Report on Form 10-K.

Further information regarding the amount of revenues from external customers, including revenues by products and services, a measure of profit or loss and total assets for each segment for each of the last three fiscal years is provided in Note 24 to our consolidated financial statements contained in this Annual Report on Form 10-K.

See "Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*" in this Annual Report for further details.

History

We were incorporated in 1997 as a New York corporation and named Energy East Corporation. In 2008, Iberdrola acquired Energy East Corporation and we changed our name to Iberdrola USA, Inc. In 2013, we completed an internal corporate reorganization to create a unified corporate presence for Iberdrola in the United States, bringing all of its U.S. energy companies under Iberdrola USA, Inc. The internal reorganization resulted in the concentration of our principal businesses in two major subsidiaries: Networks, which holds all of our regulated utilities; and Renewables, which holds our renewable and thermal generation businesses.

On December 16, 2015, we completed the acquisition of UIL Holdings Corporation, or UIL, and changed our name to Avangrid, Inc. Immediately following the completion of the acquisition, former UIL shareowners owned 18.5% of the outstanding shares of common stock of AVANGRID, and Iberdrola owned the remaining shares.

Networks

Overview

Networks, a Maine corporation, holds our regulated utility businesses, including electric distribution, transmission and generation 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;
- SCG, which serves natural gas customers in Connecticut;
- CNG, which serves natural gas customers in Connecticut;
- 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.

The demand for electric power and natural gas is affected by seasonal differences in the weather. Demand for electricity in each of the states in which Networks operates tends to increase during the summer months to meet cooling load or in winter months for heating load while demand for natural gas tends to increase during the winter to meet heating load.

The following table sets forth certain information relating to the rate base, number of customers and the amount of electricity or natural gas provided by each of Networks' regulated utilities as of and for the year ended December 31, 2022:

Utility	Rate Base(1) (in billions)	Electricity Customers	Electricity Delivered (in MWh)	Natural Gas Customers	Natural Gas Delivered (in DTh)
NYSEG	$ 3.9	916,521	15,412,000	271,623	55,590,000
RG&E	$ 2.7	390,455	7,361,000	322,926	58,884,000
CMP	$ 2.6	659,948	9,224,000	—	—
MNG	$ 0.1	—	—	5,935	2,202,000
UI	$ 2.0	343,957	4,873,000	—	—
SCG	$ 0.7	—	—	208,010	36,031,000
CNG	$ 0.6	—	—	184,678	36,799,000
BGC	$ 0.1	—	—	40,750	10,219,000
Total	**$ 12.7**	**2,310,881**	**36,870,000**	**1,033,922**	**199,725,000**

(1) "Rate base" means the net assets upon which a utility can receive a specified return, based on the carrying value of such assets. The rate base is set by the relevant regulatory authority and typically represents the value of specified property, such as plants, facilities and other investments of the utility. These rate base values have been calculated using the best estimates as of December 31, 2022.

During the last five years, Networks has invested $8.9 billion enhancing its delivery network with greater capacity and improved reliability, environmental security and sustainability, efficiency and automation. Networks continuously improves its grid to accommodate new requirements for advanced metering, demand response and enhanced outage management, while improving its flexibility for the integration and management of distributed energy resources, or DER.

New York

In 2022, the nine hydroelectric plants owned by NYSEG and RG&E generated approximately 187,800 megawatt-hours, or MWh of clean hydropower, which is enough energy to power approximately 26,000 homes across New York State, assuming an average electricity consumption of 600 kilowatt-hours, or kWh, per month per customer. See "—Properties—Networks" for more information regarding Networks' electric generation plants.

Networks also holds an approximate 20% ownership interest in the regulated New York TransCo, LLC, or New York TransCo. Through New York TransCo, Networks has formed a partnership with affiliates of Central Hudson Gas and Electric Corporation, Consolidated Edison, Inc., National Grid, plc, and Orange and Rockland Utilities, Inc. to develop a portfolio of interconnected transmission lines and substations to fulfill the objectives of the New York energy highway initiative, a proposal to install up to 3,200 MW of new electric generation and transmission capacity in order to deliver more power generated from upstate New York power plants to downstate New York.

Maine

CMP owns 78% of the Maine Electric Power Corporation, or MEPCO, a single-asset 182-mile 345kV electric transmission line from the Maine/New Brunswick border to Wiscasset, Maine.

In 2018, the New England Clean Energy Connect, or NECEC, transmission project, a joint bid proposed by CMP and Hydro-Québec, was selected by the Massachusetts electric utilities and the Massachusetts Department of Energy Resources, or DOER, in the Commonwealth of Massachusetts's 83D clean energy Request for Proposal. The proposed 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 $1.4 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. As of December 31, 2022, we have capitalized approximately $585 million on the NECEC project. For further discussion of the NECEC project, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in this Annual Report.

Connecticut

UI is a party to a joint venture with Clearway Energy, Inc., which is an affiliate of Global Infrastructure Partners, pursuant to which UI holds 50% of the membership interests in GCE Holding LLC, whose wholly-owned subsidiary, GenConn Energy LLC, or GenConn, operates peaking generation plants in Devon, Connecticut, or GenConn Devon, and Middletown, Connecticut, or GenConn Middletown.

Rate Base

The below rate base values were calculated using the best estimates as of December 31, 2022, 2021 and 2020. The rate base of Networks' regulated utilities, excluding utilities accounted for under the equity method, for the years indicated below were as follows:

Rate base	**2022**	**2021**	**2020**
		(in millions)	
NYSEG Electric	$ 3,181	$ 2,776	$ 2,408
NYSEG Gas	726	715	703
RG&E Electric	2,082	1,911	1,566
RG&E Gas	597	553	492
Subtotal New York	**6,586**	**5,955**	**5,169**
CMP Dist	1,120	1,014	982
CMP Trans	1,520	1,493	1,448
MNG	82	87	77
Subtotal Maine	**2,722**	**2,594**	**2,507**
UI Dist	1,253	1,240	1,170
UI Trans	730	699	662
SCG	673	602	588
CNG	559	515	524
Subtotal Connecticut	**3,215**	**3,056**	**2,944**
BGC	135	128	124
Total	**$ 12,658**	**$ 11,733**	**$ 10,744**

Renewables

The Renewables business, based in Portland, Oregon and Boston, Massachusetts, is engaged primarily in the design, development, construction, management and operation of generation plants that produce electricity using renewable resources and, with more than 70 renewable energy projects, is one of the leaders in renewable energy production in the United States based on installed capacity. Renewables' primary business is onshore wind energy generation, which represented approximately 95% of Renewables' combined installed capacity as of December 31, 2022. For the year ended December 31, 2022, Renewables produced 19,683,719 MWh of energy through wind power generation. Renewables had a pipeline of 25,584 MW (19,645 MW - onshore and 5,939 MW - offshore) of future renewable energy projects in various stages of development as of December 31, 2022.

A significant part of Renewables' strategic business is offshore wind. Renewables has rights to two federal offshore wind lease areas. One is located 20 miles off the coast of Massachusetts including 101,590 acres, which has the potential to generate up to 2,600 MW of renewable energy for one or more New England states and the other is located 27 miles off the coast of North Carolina including 122,405 acres, which has the potential to generate up to 3,500 MW of renewable energy for Virginia and North Carolina. In addition, Renewables holds a 50% indirect ownership interest in Vineyard Wind 1 LLC (Vineyard Wind 1), a joint venture with affiliates of Copenhagen Infrastructure Partners, or CIP, a fund management company based in Denmark, which has rights to a federal offshore wind lease area located 15 miles off the coast of Massachusetts including 65,296 acres.

Prior to a restructuring transaction that closed on January 10, 2022 (Restructuring Transaction), Vineyard Wind, LLC (Vineyard Wind) held acquired easements from the U.S. Bureau of Ocean Energy Management (BOEM) containing the rights to develop offshore wind generation. Vineyard Wind acquired two lease areas, 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. Refer to Note 22 to our consolidated financial statements contained in this Annual Report on Form 10-K.

Vineyard Wind 1 LLC is developing and has started onshore construction of the Vineyard Wind 1 project, an 806 MW utility-scale offshore wind project in Lease Area 501. The Vineyard Wind 1 project is expected to generate clean energy for over 400,000 households and businesses in Massachusetts and reduce carbon emissions by over 1.6 million tons per year. The project has 20-year PPAs with the electric distribution companies in Massachusetts with an average price of $88.77/MWh, which represents a price for 50% of the project that starts at $65/MWh and escalates 2.5% annually, and a price for the other 50% of the project that starts at $74/MWh and escalates 2.5% annually.

Renewables is developing the Park City Wind project, an 804 MW project located on Lease Area 534, that will deliver clean, reliable energy to the residents of Connecticut through contracts with the electric distribution companies in Connecticut. The project has 20-year PPAs with the electric distribution companies in Connecticut, including UI, with an average price of $79.83/MWh, which is based on a starting price of $62.50 that escalates at 2.5% annually. With respect to the Park City Wind project, Renewables has agreed to have good faith negotiations to adjust the price if the project benefits from any improvements to the profitability of the project for having access to investments tax credits, or ITCs, in excess of 18%. Both projects are expected to be commissioned in 2024 to 2026, subject to permitting and contract negotiation. In Connecticut, discussions remain ongoing with the EDCs, state and regulatory officials, and other stakeholders concerning a possible amendment to the Park City Wind PPAs.

In December 2021, the Commonwealth Wind project, which will also be located on Lease Area 534 was selected as part of Massachusetts' third offshore wind competitive procurement process. In April 2022, Commonwealth Wind signed 1200 MW of contracts with the Massachusetts electric distribution companies. The project has 20-year PPAs with an average price of $76.06/MWh, which is based on a starting price of $59.60 that escalates at 2.5% annually. Permitting for Commonwealth Wind is expected to be substantially completed in 2024. On October 20, 2022, Commonwealth Wind filed a motion with the DPU seeking a one-month suspension in the DPU's proceeding to review the contracts 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 contracts. This motion was denied by the DPU on November 4, 2022. In the November 4th order, the DPU directed Commonwealth Wind to indicate whether it wished to move forward with the contracts or file a request to dismiss the DPU proceedings. On November 14, 2022, Commonwealth Wind responded to the DPU order, indicating that while it strongly believed a pause in the proceedings was in the best interest of all parties, if the DPU did not support a pause, then the appropriate action was for the DPU to continue the proceeding such that the parties could continue ongoing discussions to achieve a financeable and economically viable project. On December 16, 2022, after concluding that the ongoing discussions were unlikely to result in a viable path that would allow the project to move forward under the contracts, Commonwealth Wind filed a motion to dismiss with the DPU, requesting that the DPU's proceeding be dismissed on the grounds that the contracts did not and could not satisfy the required statutory criteria for approval. Commonwealth Wind's motion further stated that the best path forward was for the contract capacity to be included in the next Massachusetts offshore wind solicitation, that Commonwealth Wind was committed to continuing development of the project, and that Commonwealth Wind would bid into that solicitation to offer Massachusetts a project with cost-effective pricing, a superior timeline for completion and exceptional development opportunities. On December 30, 2022, notwithstanding Commonwealth Wind's motion to dismiss, the DPU approved the contracts. On January 19, 2023, Commonwealth Wind filed an appeal of the December 30th DPU order to the Supreme Judicial Court of Massachusetts.

Typically, Renewables enters into long-term lease agreements with property owners who lease their property and other sites for onshore renewable energy projects, and with federal agencies for offshore renewables energy projects. Electricity generated at a wind project is then transmitted to customers through long-term agreements with purchasers. There are a limited number of turbine suppliers in the market. Renewables' largest turbine suppliers, Siemens-Gamesa and GE Wind, in the aggregate supplied turbines that accounted for 70% of Renewables' installed wind capacity as of December 31, 2022. Iberdrola had an 8.1% ownership interest in Siemens-Gamesa until it was sold in February 2020.

To monetize the tax benefits resulting from tax credits, or PTCs and ITCs, and accelerated tax depreciation available to qualifying wind and solar energy projects, Renewables has entered into "tax equity" financing structures with third party investors for a portion of its wind and solar farms. Renewables holds operating wind and solar farms under these structures through limited liability companies jointly owned by one or more third party investors. These investors generally provide an up-front investment and, in some cases, payments over time for their membership interests in the financing structures. In return, the investors receive specified cash distribution allocations and substantially all of the tax benefits generated by the wind and solar farms, until such benefits achieve a negotiated return on their investment. Upon attainment of this target return, the sharing of the cash flows and tax benefits flip, with Renewables receiving substantially all of these amounts thereafter. We also have an option to repurchase the investor's interest within a certain timeframe after the target return is met. Renewables maintains operational and management control over the wind and solar farm businesses, subject to investor approval of certain major decisions. See "—Properties—Renewables" for more information regarding Renewables' wind power generation properties.

Additionally, as part of the Renewables portfolio, Renewables operates two thermal generation facilities, with 636 MW of combined capacity as of December 31, 2022. Renewables worked closely with the City of Klamath Falls, Oregon to develop the Klamath Plant, which has a current capacity of 536 MW. The Klamath Plant operates by creating two useful forms of energy, electricity and process steam, from a single fuel source of natural gas. In addition, Renewables operates a highly flexible 100 MW Klamath Peaking Plant adjacent to the Klamath Plant, providing customers of Renewables additional capability to meet their peak summer and winter power needs.

In addition to its wind assets, Renewables operates five solar photovoltaic facilities with an installed capacity of 324 MW. The solar photovoltaic facilities produced over 317,580 MWh of renewable energy for the year ended December 31, 2022. Solar accounted for 2.0% of the total renewable energy generation from Renewables in 2022.

Renewables is pursuing the continued development of a large pipeline of wind and solar energy projects in various regions across the United States. Each site features a range of different atmospheric characteristics that ultimately drive the selection of technology for the proposed project. As part of Renewables' resource assessment investigation, critical atmospheric parameters such as mean wind speed, extreme wind speed, turbulence intensity, mean air density, and solar energy availability are characterized to represent long-term conditions. The summary wind and solar characteristics are then combined with a terrain analysis, or orography, and weather pattern analysis to assess siting and placement risks in order to mitigate any future operations and maintenance concerns that may arise due to improper siting or placement.

Renewables maintains close relationships with key turbine suppliers, including Siemens-Gamesa, GE, Vestas and others in order to identify the turbine technology that safely delivers the lowest cost of energy for each candidate project in its portfolio. See "—Properties—Renewables" for more information regarding Renewables' turbine technology.

Renewables focuses on ensuring solar projects deliver the lowest cost of energy safely. This requires detailed information on cost, long term performance and reliability of project components including solar panels, trackers and inverters – particularly as technology continues to advance. Renewables relies upon a wide network of experienced solar industry consultants to provide expert advice on project development, performance specifications, manufacturing quality assurance and equipment selection. These consultants range from Tetra Tech Inc. for environmental permitting support, to companies such as DNV GL, Clean Energy Associates, and PI Berlin to advise on energy estimation, equipment performance expectations, and equipment quality audits.

The Renewables meteorology team supports the commercial development of wind and solar energy projects in Renewables' pipeline by performing a wide variety of detailed investigations and analyses to characterize the expected wind and solar energy production from a proposed wind farm or solar plant in its pre-construction phase of development. These investigations include measuring the wind or solar resource with several well-equipped meteorological masts and using energy modeling software packages that characterize the gross energy and relevant losses. For wind projects, state of the art laser-based and acoustic-based remote sensing equipment and computational fluid dynamics modeling software are used. The Renewables fleet of measurement masts consists of approximately 40 wind meteorological towers and 15 solar meteorological stations that are currently in operation. Additionally, a total of three light detecting and ranging and six sonic detecting and ranging remote sensing devices are deployed or available for deployment at sites across the United States to support wind project development. These remote sensing devices allow hub-height wind speed measurement from a ground-based sensor that can be rapidly deployed and moved as the project matures or changes in nature. The resulting pre-construction energy production estimates that utilize these measurements have been shown to be accurate in a multi-year internal study that compares results to actual, operational data at wind plants in a benchmarking analysis. This study provides a critical feedback loop that is used to define methodology requirements for future pre-construction energy production estimates to ensure confidence in project investment. Renewables' commitment to obtaining robust atmospheric measurement is driven by a company culture that values business case confidence and understands the role that accurate meteorological data plays in the pursuit of this goal.

Regulatory Environment and Principal Markets

Federal Energy Regulatory Commission

Among other things, the FERC regulates the transmission and wholesale sales of electricity in interstate commerce and the transmission and sale of natural gas for resale in interstate commerce. Certain aspects of Networks' businesses and Renewables' competitive generation businesses are subject to regulation by the FERC.

Pursuant to the FPA, electric utilities must maintain tariffs and rate schedules on file with the FERC, which govern the rates, terms and conditions for the provision of the FERC-jurisdictional wholesale power and transmission services. Unless otherwise exempt, any person that owns or operates facilities used for the wholesale sale or transmission of power in interstate commerce is a public utility subject to the FERC's jurisdiction. The FERC regulates, among other things, the disposition of certain utility property, the issuance of securities by public utilities, the rates, the terms and conditions for the transmission or wholesale sale of power in interstate commerce, interlocking officer and director positions, and the uniform system of accounts and reporting requirements for public utilities.

With respect to Networks' regulated electric utilities in Maine, New York and Connecticut, the FERC governs the return on equity, or ROE, on all transmission assets in Maine and Connecticut and certain New York TransCo assets in New York. The FERC also oversees the rates, terms and conditions of the transmission of electric energy in interstate commerce, interconnection service in interstate commerce (which applies to independent power generators, for example) and the rates, terms and conditions of wholesale sales of electric energy in interstate commerce. This includes cost-based rates, market-based rates and the operations of regional capacity and electric energy markets in New England administered by an independent entity, ISO New England, Inc., or ISO-NE, and in New York, administered by the New York Independent System Operator, Inc., or NYISO. The FERC approves CMP's, UI's, MEPCO's and New York TransCo's regulated electric utilities transmission revenue requirements. Wholesale electric transmission revenues are recovered through stated or formula rates that are approved by the FERC. CMP's, MEPCO's and UI's electric transmission revenues are recovered from New England customers through charges that recover costs of transmission and other transmission-related services provided by all regional transmission owners. NYSEG's and RG&E's electric transmission revenues are recovered from New York customers through charges that recover the costs of transmission and other transmission-related services provided by all transmission owners in New York. Several of our affiliates have been granted authority to engage in sales at market-based rates and blanket authority to issue securities and have also been granted certain waivers of the FERC reporting and accounting regulations available to non-traditional public utilities; however, we cannot be assured that such authorizations or waivers will not be revoked for these affiliates or will be granted in the future to other affiliates.

Pursuant to a series of orders involving the ROE for regionally planned New England electric transmission projects, the FERC established a base-level transmission ROE of 11.14%, as well as providing a 50-basis point ROE adder on Pool Transmission Facilities for participation in the regional transmission organization, or RTO, for New England and a 100-basis point ROE incentive for projects included in the ISO-NE Regional System Plan that were completed and on line as of December 31, 2008. Certain other transmission projects received authorization for incentives up to 125 basis points.

Since 2011, several parties have filed four separate complaints with the FERC against ISO-NE and several New England transmission owners, or NETOs, including UI, CMP and MEPCO, claiming that the current approved base ROE of 11.14% was not just and reasonable, seeking a reduction of the base ROE and a refund 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).). For more information on this matter see Note 14 of our consolidated financial statements included in Part II, Item 8, "Financial Statements and Supplementary Data" of this Annual Report on Form 10-K, which information is incorporated herein by reference.

The FERC has the right to review books and records of "holding companies," as defined in the Public Utility Holding Company Act of 2005, or PUHCA 2005, that are determined by the FERC to be relevant to the companies' respective FERC-jurisdictional rates. We are a holding company, as defined in PUHCA 2005.

The FERC has civil penalty authority over violations of any provision of Part II of the FPA, as well as any rule or order issued thereunder. FERC is authorized to assess a maximum civil penalty of $1.39 million per violation for each day that the violation continues. The FPA also provides for the assessment of criminal fines and imprisonment for violations under Part II of the FPA. Pursuant to the Energy Policy Act of 2005, or EPAct 2005, the North American Electric Reliability Corporation, or NERC, has been certified by the FERC as the Electric Reliability Organization for North America responsible for developing and overseeing the enforcement of electric system reliability standards applicable throughout the United States. FERC-approved reliability standards may be enforced by the FERC independently, or, alternatively, by NERC and the regional reliability organizations with frontline responsibility for auditing, investigating and otherwise ensuring compliance with reliability standards, subject to the FERC oversight.

The gas distribution operations of NYSEG, RG&E, SCG, CNG and BGC are subject to the FERC regulation under the Natural Gas Act of 1938, or NGA, with respect to their gas purchases/sales and contracted transportation/storage capacity. FERC has civil penalty authority under the NGA to impose penalties for certain violations of up to $1.39 million per day for violations. FERC also has the authority to order the disgorgement of profits from transactions deemed to violate the NGA and EPAct 2005.

Market Anti-Manipulation Regulation

The FERC and the Commodity Futures Trading Commission, or CFTC, monitor certain segments of the physical and futures energy commodities market pursuant to the FPA, the Commodity Exchange Act and the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, including our businesses' energy transactions and operations in the United States. With regard to the physical purchases and sales of electricity and natural gas, the gathering storage, transmission and delivery of these energy commodities and any related trading or hedging transactions that some of our operating subsidiaries undertake, our operating subsidiaries are required to observe these anti-market manipulation laws and related regulations enforced by the FERC and CFTC. The FERC holds substantial enforcement authority, including the ability to assess civil penalties of up to $1.9 million per day per violation, to order disgorgement of profits and to recommend criminal penalties. The CFTC is authorized to issue monetary penalties for violations of the Commodity Exchange Act up to a maximum penalty per violation. Generally, penalties may be determined on a per violation basis or up to triple the monetary gain to the respondent, whichever is greater.

State Regulation

Networks' regulated utilities are subject to regulation by the applicable state public utility commissions, including with regard to their rates, terms and conditions of service, issuance of securities, purchase or sale of utility assets and other accounting and operational matters. NYSEG and RG&E are subject to regulation by the NYPSC; CMP and MNG are subject to regulation by the MPUC; UI, SCG and CNG are subject to regulation by the PURA; and BGC is subject to regulation by the DPU. The NYPSC, MPUC and the Connecticut Siting Council, or CSC, exercise jurisdiction over the siting of electric transmission lines in their respective states, and each of the NYPSC, MPUC, PURA and DPU exercise jurisdiction over the approval of certain mergers or other business combinations involving Networks' regulated utilities. In addition, each of the utility commissions has the authority to impose penalties on these regulated utilities, which could be substantial, for violating state utility laws and regulations and their orders.

Networks' regulated distribution utilities deliver electricity and/or natural gas to all customers in their service territory at rates established under cost of service regulation. Under this regulatory structure, Networks' regulated distribution utilities file rate cases to recover the cost of providing distribution service to their customers based on its costs and earn a return on their capital investment in utility assets. For more information on our regulated utilities' most recent rate cases and other regulatory matters see Note 5 of our consolidated financial statements included in Part II, Item 8, "Financial Statements and Supplementary Data" of this Annual Report on Form 10-K, which information is incorporated herein by reference.

As a result of a restructuring of the utility industry in New York, Maine, Connecticut and Massachusetts, most of Networks' distribution utilities' customers have the opportunity to purchase their electricity or natural gas supplies from third-party energy supply vendors. Most customers in New York, however, continue to purchase such supplies through the distribution utilities under regulated energy rates and tariffs. In Maine, CMP customers can also purchase electric supply from competitive providers, but the majority receive baseline standard offer service that is provided through a MPUC procurement process. Networks' regulated utilities in New York, Connecticut and Massachusetts and MNG purchase electricity or natural gas from unaffiliated wholesale suppliers and recover the actual approved costs of these supplies on a pass-through basis, as well as certain costs associated with industry restructuring, through reconciling rate mechanisms that are periodically adjusted.

State public utility commissions may also have jurisdiction over certain aspects of Renewables' competitive generation businesses. For example, in New York, certain Renewables' generation subsidiaries are electric corporations subject to "lightened" regulation by the NYPSC. As such, the NYPSC exercises its jurisdictional authority over certain non-rate aspects of the facilities, including safety, retirements and the issuance of debt secured by recourse to those generation assets located in New York. In Texas, Renewables' operations within the Electric Reliability Council of Texas, or ERCOT, footprint are not subject to regulation by FERC, as they are deemed to operate solely within the ERCOT market and not in interstate commerce. These operations are subject to regulation by the Public Utility Commission of Texas, or PUCT. In California, Renewables' generation subsidiaries are subject to regulation by the California Public Utilities Commission with regard to certain non-rate aspects of the facilities, including health and safety, outage reporting and other aspects of the facilities' operations.

RTOs and ISOs

Networks' regulated electric utilities in New York, Connecticut and Maine, as well as some of Renewables' generation fleet, operate in or have access to organized energy markets, known as RTOs or independent system operators, or ISOs, particularly NYISO and ISO-NE. Each organized market administers centralized bid-based energy, capacity and ancillary services markets pursuant to tariffs approved by the FERC, or in the case of ERCOT, market rules approved by the PUCT. These tariffs and rules dictate how the energy, capacity and ancillary service markets operate, how market participants bid, clear, are dispatched, make bilateral sales with one another, and how entities with market-based rates are compensated. Certain of these markets set prices, referred to as Locational Marginal Prices that reflect the value of energy, capacity or certain ancillary services, based upon geographic locations, transmission constraints and other factors. Each market is subject to market mitigation measures designed to limit the exercise of market power. Some markets limit the prices of the bidder based upon some level of cost justification. These market structures impact the bidding, operation, dispatch and sale of energy, capacity and ancillary services.

The RTOs and ISOs are also responsible for transmission planning and operations within their respective regions. Each of Networks' transmission-owning subsidiaries in New York, Connecticut and Maine has transferred operational control over certain of its electric transmission facilities to its respective ISOs, such as ISO-NE and NYISO.

Environmental, Health and Safety

Permitting and Other Regulatory Requirements

Networks. Networks' distribution utilities in New York, Maine, Connecticut and Massachusetts are subject to numerous federal, state and local laws and regulations in connection with the environmental, health and safety effects of its operations. The distribution utilities of Networks are subject to regulation by the applicable state public utility commission with respect to the siting and approval of electric transmission lines, with the exception of UI, the siting of whose transmission lines is subject to the jurisdiction of the Connecticut Siting Council, or the CSC, and with respect to pipeline safety regulations for intrastate gas pipeline operators.

The National Environmental Policy Act, or NEPA, requires that detailed statements of the environmental effect of Networks' facilities be prepared in connection with the issuance of various federal permits and licenses. Federal agencies are required by NEPA to make an independent environmental evaluation of the facilities as part of their actions during proceedings with respect to these permits and licenses.

Under the federal Toxic Substances Control Act, the Environmental Protection Agency, or EPA, has issued regulations that control the use and disposal of Polychlorinated Biphenyls, or PCBs. PCBs were widely used as insulating fluids in many electric utility transformers and capacitors manufactured before the federal Toxic Substances Control Act prohibited any further manufacture of such PCB equipment. Fluids with a concentration of PCBs higher than 500 parts per million and materials (such as electrical capacitors) that contain such fluids must be disposed of through burning in high temperature incinerators approved by the EPA. For our gas distribution companies, PCBs are sometimes found in the distribution system. Networks tests any distribution piping being removed or repaired for the presence of PCBs and complies with relevant disposal procedures, as needed.

Under the federal Resource Conservation and Recovery Act, or RCRA, the generation, transportation, treatment, storage and disposal of hazardous wastes are subject to regulations adopted by the EPA. All of Networks' subsidiaries have complied with the notification and application requirements of present regulations, and the procedures by which the subsidiaries handle, store, treat and dispose of hazardous waste products comply with these regulations.

Before the environmental best practices laws and regulations were implemented in the last quarter of the 20th century, utility companies, including Networks' subsidiaries, often disposed of residues from operations by depositing or burying them on-site or at off-site landfills or other facilities. Typical materials disposed of included coal gasification byproducts, fuel oils, ash and other materials that might contain PCBs or otherwise be hazardous. In recent years it was determined that such disposal practices, under certain circumstances, can cause groundwater contamination.

Renewables. Renewables' projects are subject to numerous federal, state and local environmental review and permitting requirements. Whether a project is sited onshore or offshore dictates the complexity of the permitting framework.

Many states where Renewables' projects are located have laws that require state agencies to evaluate the environmental impacts of a proposed project prior to granting state permits or approvals. Generally, state agencies evaluate similar issues as federal agencies, including the project's impact on wildlife, historic or cultural sites, aesthetics, wetlands and water resources, agricultural operations and scenic areas. States may impose different or additional monitoring or mitigation requirements than federal agencies. Additional approvals may be required for specific aspects of a project, such as stream or wetland crossings, impacts to designated significant wildlife habitats, storm water management and highway department authorizations for oversize loads and state road closings during construction. Permitting approvals related to transmission lines may be required in certain cases.

Renewables' projects also are subject to local environmental and regulatory requirements, including county and municipal land use, zoning, building and transportation requirements. Permitting at the local municipal or county level often consists of obtaining a special use or conditional use permit under a land use ordinance or code, or, in some cases, rezoning is required for a project. Obtaining a permit usually requires that Renewables demonstrate that the project will conform to certain development standards specified under the ordinance so that the project is compatible with existing land uses and protects natural and human environments. Local or state regulatory agencies may require modeling and measurement of permissible sound levels in connection with the permitting and approval of Renewables' projects. Local or state agencies also may require Renewables to develop decommissioning plans for dismantling the project at the end of its functional life and establish financial assurances for carrying out the decommissioning plan.

In addition to permits required under state and local laws, Renewables' projects may be subject to permitting and other regulatory requirements under federal law. For example, if an offshore wind project is sited in federal waters (beyond the 3 nautical mile state jurisdictional line), the project will require approval from the Department of Interior's Bureau of Ocean Energy Management, or BOEM as well as other federal cooperating agencies such as the National Oceanic and Atmospheric Administration's National Marine Fisheries Service, the U.S. Army Corps of Engineers, or Army Corps, the Federal Aviation Administration, the Department of Defense, the U.S. Environmental Protection Agency and the U.S. Coast Guard. If an onshore project is located near wetlands, a permit may be required from the Army Corps, with respect to the discharge of dredged or fill material into the waters of the United States. The Army Corps may also require the mitigation of any loss of wetland functions and values that accompanies the project's activities. Renewables may be required to obtain permits under the federal Clean Water Act for water discharges, such as storm water runoff associated with construction activities, and to follow a variety of best management practices to ensure that water quality is protected and impacts are minimized. Renewables' projects also may be located, or partially located, on lands administered by the U.S. Bureau of Land Management, or BLM. Therefore, Renewables may be required to obtain and maintain BLM right-of-way grants for access to, or operations on, such lands. To obtain and maintain a grant, there must be environmental reviews conducted, a plan of development implemented and a demonstration that there has been compliance with the plan to protect the environment, including measures to protect biological, archeological and cultural resources encountered on the grant.

Renewables' projects may be subject to requirements pursuant to the Endangered Species Act, or ESA, and analogous state laws. For example, federal agencies granting permits for Renewables' projects consider the impact on endangered and threatened species and their habitat under the ESA, which prohibits and imposes stringent penalties for harming endangered or threatened species and their habitats. Renewables' projects also need to consider the Migratory Bird Treaty Act, or MBTA, and the Bald and Golden Eagle Protection Act, or BGEPA, which protect migratory birds and bald and golden eagles and are administered by the U.S. Fish and Wildlife Service. Criminal liability can result from violations of the MBTA and the BGEPA. For example, the U.S. Department of Justice, or DOJ, has previously enforced substantial penalties and mitigation measures against two large wind farm operators, pursuant to which those operators pled guilty to criminal violations of the MBTA.

In addition to regulations, voluntary wind turbine siting guidelines for onshore wind projects established by the U.S. Fish and Wildlife Service, or USFWS, set forth siting, monitoring and coordination protocols that are designed to support wind development in the United States while also protecting both birds and bats and their habitats. These guidelines include provisions for specific monitoring and study conditions which need to be met in order for projects to be in adherence with these voluntary guidelines. Most states also have similar laws. Because the operation of wind turbines may result in injury or fatalities to birds and bats, federal and state agencies often recommend or require that Renewables conduct avian and bat risk assessments prior to issuing permits for its projects. They may also require ongoing monitoring or mitigation activities as a condition to approving a project.

Similarly, BOEM has established survey guidelines for renewable energy development, including avian surveys in coordination with the USFWS. BOEM will use the data from the offshore marine surveys to evaluate the impacts of construction, installation and operation of meteorological towers, buoys, export and inter-array cables, wind turbine generators and supporting structures on physical, biological, and socioeconomic resources, as well as the seafloor and sub-seafloor conditions. The information will be used by BOEM, other federal agencies and potentially affected states in the preparation of National Environmental Policy Act documents, for consultations and other regulatory requirements.

Global Climate Change and Greenhouse Gas Emission Issues

Global climate change and greenhouse gas emission, or GHG, issues continue to receive an increased focus from state governments and the federal government. In November 2010, the EPA published final rules for monitoring and reporting requirements for petroleum and natural gas systems that emit greenhouse gases under the authority of the Clean Air Act beginning in 2011. These regulations apply to facilities that emit greenhouse gases above the threshold level of 25,000 metric tons equivalent per year. SCG and CNG both exceed this threshold and are subject to reporting requirements. The liquefied natural gas, or LNG, facilities owned and/or contracted by SCG and CNG are also subject to the monitoring and reporting requirements under the regulations. Similarly, Networks is subject to reporting requirements under provisions of the greenhouse gases regulations, which regulate electric transmission and distribution equipment that emit sulfur hexafluoride.

We are continuously evaluating the regulatory risks and regulatory uncertainty presented by climate change and greenhouse gas emission. Such concerns could potentially lead to additional rules and regulations as well as requirements imposed through the ratemaking process that impact how we operate our business. We generally expect that any of Networks' costs for these rules, regulations and requirements would be recovered from customers.

For Klamath Plant Renewables performs annual GHG reporting to the EPA and to the Oregon Department of Environmental Quality, or DEQ. Emissions are reported by unit in CO2 equivalent for CO2 CH4 and NO2. Starting in 2022 Oregon DEQ requires a 3rd party verification of GHG reports.

OSHA and Certain Other Federal Safety Laws

We are subject to the requirements of the federal Occupational Safety and Health Act, as amended, or OSHA, and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard and standards administered by other federal as well as state agencies, including the Emergency Planning and Community Right to Know Act and the related implementing regulations require that information be maintained about hazardous materials used or produced in operations of our subsidiaries and that this information be provided to employees, state and local government authorities and citizens.

Management, Disposal and Remediation of Hazardous Substances

We own or lease real property and may be subject to federal, state and local requirements regarding the storage, use, transportation and disposal of petroleum products and toxic or hazardous substances, including spill prevention, control and counter-measure requirements. Project properties and materials stored or disposed thereon may be subject to the federal RCRA, the Toxic Substances Control Act, the Comprehensive Environmental Response, Compensation and Liability Act and analogous state laws. If any of our owned or leased properties are contaminated, whether during or prior to our ownership or operation, we could be responsible for the costs of investigation and cleanup and for any related liabilities, including claims for damage to property, persons or natural resources. Such responsibility may arise even if we were not at fault and did not cause the contamination. In addition, waste generated by our operating subsidiaries is at times sent to third party disposal facilities. If such facilities become contaminated, the operating subsidiary and any other persons who arranged for the disposal or treatment of hazardous substances at those sites may be jointly and severally responsible for the costs of investigation and remediation, as well as for any claims of damages to third parties, their property or natural resources.

In August 2016, a partial consent order was issued by the Connecticut Department of Energy and Environmental Protection, or DEEP, related to the investigation and remediation of the English Station site. The consent order 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 is required to remit to the State of Connecticut the difference between such cost and $30 million to be applied to 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. However, UI is obligated to comply with the consent order even if the cost of such compliance exceeds $30 million. The state may discuss options with UI on recovering or funding any cost above $30 million, such as through public funding or recovery from third parties, however it is not bound to agree to or support any means of recovery or funding. UI has initiated its process to investigate and remediate the environmental conditions within the perimeter of the English Station site pursuant to the consent order.

Environmental Management and Goals

In connection with our environmental, social, governance and financial stewardship strategy, we have established several environmental goals including a target to be carbon neutral for Scopes 1 and 2, as defined by the U.S. Environmental Protection Agency, by 2030. The AVANGRID Board has adopted a governance and sustainability system reflecting our environmental, social, governance and financial stewardship strategy including, without limitation, a Climate Action Policy that explicitly sets forth our Scope 1 and Scope 2 targets. Further, we have defined a set of goals to reduce the environmental impact of our facilities including that 100% of our corporate facilities will have renewable electricity by 2030, 100% of our light duty fleet will be clean energy vehicles by 2030 and an increase in our emission free generation capacity by more than 150% by 2030.

See information on infrastructure protection and cyber security measures in "Properties" in Item 1 of this Annual Report on Form 10-K.

Customers

Networks delivers natural gas and electricity to residential, commercial and institutional customers through its regulated utilities in New York, Maine, Connecticut and Massachusetts. Networks' customer payment terms are regulated by the state of New York, with respect to NYSEG and RG&E; Maine, with respect to CMP and MNG; Connecticut, with respect to UI, SCG and CNG; and Massachusetts, with respect to BGC, and each of the regulated utilities must provide extended payment arrangements to customers for past due balances. See "—Networks" for more information relating to the customers of Networks.

Renewables sells the majority of its energy output to large investor-owned utilities, public utilities and other credit-worthy entities. Additionally, Renewables generates and provides power, among other services, to federal and state agencies, institutional retail and joint action agencies. Offtakers typically purchase renewable energy from Renewables through long-term PPAs, allowing Renewables to limit its exposure to market volatility. As of December 31, 2022, approximately 74% of the capacity was contracted with PPAs, for an average period of approximately 10 years, and an additional 15% of production was hedged. Renewables also delivers thermal output to wholesale customers in the Western United States.

Competition

Networks' regulated utilities do not generally face competition from other companies that transmit and distribute electricity and natural gas. However, supply for electricity and natural gas may be negatively impacted by federal and state legislation mandating that certain percentages of power delivered to end users be produced from renewable resources, such as wind, thermal and solar energy, and demand for electricity and natural gas may be negatively impacted by federal and state legislation mandating energy efficiency programs and policy.

Networks faces competition from self-contained micro-grids that integrate renewable energy sources in the areas served by Networks. However, there has been limited development of these micro-grids in Networks' service areas to date, and Networks expects that growth in distributed generation of renewable energy will continue due to financial incentives being provided by federal and state legislation. In addition, Networks may face competition from government-controlled power initiatives in states where Networks operates in which states, municipalities or other local authorities attempt to use eminent domain to acquire privately-owned utility companies.

Renewables has competitive advantages, including a robust development pipeline, a management team with extensive experience, strong relationships with suppliers and clients, expert regulatory knowledge and brand awareness. However, Renewables faces competition throughout the life cycles of its renewable energy facilities, including during the development phase, in the identification and procurement of suitable sites with high wind resource availability, grid connection capacity and land availability. Renewables also competes with other suppliers in securing long-term renewable energy PPAs with power purchasers and participates in competitive bilateral and organized energy markets with other energy sources for power that is not sold under PPAs. Competitive conditions may be substantially affected by various forms of energy legislation and regulation considered from time to time by federal, state and local legislatures and administrative agencies.

Properties

Networks

The following table sets forth certain information relating to Networks' electricity generation facilities and their respective locations, type and installed capacity as of December 31, 2022. Unless noted otherwise, Networks owns each of these facilities and all our generating properties are regulated under cost of service regulation.

Operating Company	Facility Location	Facility Type	Installed Capacity (in MW)	Year(s) Commissioned
NYSEG	Newcomb, NY	Diesel Turbine	4.3	1967, 2017
NYSEG	Blue Mountain, NY	Diesel Turbine	2.0	2019
NYSEG	Long Lake, NY	Diesel Turbine	2.0	2019
NYSEG	Eastern New York (6 locations)	Hydroelectric	61.4	1921—1986
RG&E	Rochester, NY (3 locations)	Hydroelectric	57.1	1917—1960

UI is also party to a 50-50 joint venture with certain affiliates of Clearway Energy, Inc. in GCE Holding LLC, whose wholly-owned subsidiary, GenConn, operates two 188 MW peaking generation plants, GenConn Devon and GenConn Middletown, in Connecticut.

The following table sets forth certain operating data relating to the electricity transmission and distribution activities of each of Networks' regulated utilities as of December 31, 2022:

Utility	State	Substations	Transmission Lines (in miles)	Overhead Distribution Lines (in pole miles)	Underground Lines (in miles)	Total Distribution (in miles)
NYSEG	New York	430	4,549	39,725	3,555	43,280
RG&E	New York	156	1,116	8,746	3,381	12,127
CMP	Maine	205	2,907	29,364	3,432	32,796
UI	Connecticut	28	138	8,321	1,309	9,629
Total		**819**	**8,710**	**86,155**	**11,677**	**97,832**

The following table sets forth certain operating data relating to the natural gas transmission and distribution activities of each of Networks' regulated utilities, as of December 31, 2022:

Utility	State	Transmission Pipeline (in miles)	Distribution Pipeline (in miles)
NYSEG	New York	20	8,486
RG&E	New York	103	9,344
MNG	Maine	2	231
SCG	Connecticut	—	2,513
CNG	Connecticut	—	2,215
BGC	Massachusetts	—	770
Total		**126**	**23,559**

CNG owns and operates an LNG plant which can store up to 1.2 Bcf of natural gas and can vaporize up to 100,000 Dth per day of LNG to meet peak demand. SCG has contract rights to and operates a similar plant, which is owned by an affiliate that can also store up to 1.2 Bcf of natural gas. SCG's LNG facilities can vaporize up to 82,000 Dth per day of LNG to meet peak demand. SCG and CNG have also contracted for 20.6 Bcf of storage with a maximum peak day delivery capability of 216,000 Dth per day.

Renewables

The following table sets forth Renewables' portfolio of wind projects as of December 31, 2022. Unless noted otherwise, Renewables wholly owns each of these facilities.

Location	Wind Project	Turbines	Total Installed Capacity (MW)	Commercial Operation Date	North American Electric Reliability Corporation (NERC) Region
Arizona	Dry Lake I	30 (Suzlon S88, 2.1 MW)	63	2009	WECC
	Poseidon Wind (1)	15.5 (Suzlon, 2.1 MW)	33	2010	WECC
California	Dillon	45 (Mitsubishi, 1 MW)	45	2008	WECC
	Manzana	126 (GE, 1.5 MW)	189	2011	WECC
	Mountain View III	34 (Vestas V47, 0.66 MW)	22	2020	WECC
	Phoenix Wind Power	3 (Vestas, 0.66 MW)	2	1999	WECC
	Shiloh	100 (GE, 1.5 MW)	150	2006	WECC
	Tule	57 (GE, 2.3 MW)	131	2018	WECC
Colorado	Colorado Green	100 (GE, 1.5 SLE RP1.62 MW)	162	2003	WECC
	Twin Buttes	50 (GE, 1.5 MW)	75	2007	WECC
	Twin Buttes II	30 (Gamesa G114, 2.10 MW); 6 (Gamesa G114, 2.0 MW)	75	2017	WECC
Illinois	Providence Heights	36 (Gamesa G87, 2.0 MW)	72	2008	MRO
	Streator Cayuga Ridge South	150 (Gamesa, 2.0MW)	300	2010	MRO
	Otter Creek	38 (Vestas, 3.8 MW); 4 (Vestas, 3.5 MW)	158	2020	MRO
Iowa	Barton	79 (Gamesa, 2.0 MW)	158	2009	MRO
	Flying Cloud	29 (GE, 1.5 MW)	44	2003	MRO

Location	Wind Project	Turbines	Total Installed Capacity (MW)	Commercial Operation Date	North American Electric Reliability Corporation (NERC) Region
	New Harvest	50 (Gamesa G87, 2.0W)	100	2012	MRO
	Top of Iowa II	40 (Gamesa G87, 2.0 MW)	80	2007	MRO
	Winnebago I	10 (Gamesa G87, 2.0 MW)	20	2008	MRO
Kansas	Elk River	100 (GE, 1.5 MW)	150	2005	MRO
Massachusetts	Hoosac	19 (GE, 1.5 MW)	29	2012	NPCC
Minnesota	Elm Creek	66 (GE, 1.5 MW)	99	2008	MRO
	Elm Creek II	62 (Mitsubishi, 2.4)	149	2010	MRO
	MinnDakota	100 (GE, 1.5 MW)	150	2008	MRO
	Moraine I	34 (GE, 1.5 MW)	51	2003	MRO
	Moraine II	33 (GE, 1.5 MW)	50	2009	MRO
	Trimont	67 (GE, 1.5 SLE RP1.62 MW)	107	2020	MRO
Missouri	Farmers City	73 (Gamesa G87, 2.0 MW)	144	2009	MRO
New Hampshire	Groton	24 (Gamesa G87, 2.0 MW)	48	2012	NPCC
	Lempster	12 (Gamesa G87, 2 MW)	24	2008	NPCC
New Mexico	El Cabo	140 (Gamesa G114, 2.1 MW); 2 (Gamesa G114, 2.0 MW)	298	2017	WECC
	La Joya	76 (GE 2.85, 2.85 MW); 35 (Gamesa G114, 2.6 MW)	306	2021	WECC
New York	Hardscrabble	37 (Gamesa G90, 2.0 MW)	74	2011	NPCC
	Maple Ridge I(2)	70 (Vestas V82, 1.65 MW)	116	2006	NPCC
	Maple Ridge II(2)	27 (Vestas V82, 1.65 MW)	45	2006	NPCC
	Roaring Brook	5 (Gamesa G114, 2.625); 15 (Gamesa G145, 4.5)	80	2021	NPCC
North Carolina	Desert Wind	104 (Gamesa G114, 2.0 MW)	208	2017	SERC
North Dakota	Rugby	71 (Suzlon S88, 2.1 MW)	149	2009	MRO
Ohio	Blue Creek	152 (Gamesa G90 – 2.0 MW)	304	2012	RFC
Oregon	Hay Canyon	48 (Suzlon S88, 2.1 MW)	101	2009	WECC
	Klondike I	16 (GE, 1.5 S – 1.5 MW)	24	2001	WECC
	Klondike II	50 (GE, 1.5 SLE RP1.62 MW)	81	2020	WECC
	Klondike III	44 (Siemens, 2.3 MW); 80 (GE, 1.5 SLE, 1.5 MW); 1 (Mitsubishi, 2.4 MW)	224	2007	WECC
	Klondike IIIa	51 (GE, 1.5 MW)	77	2008	WECC
	Leaning Juniper II	74 (GE, 1.5 MW); 42 (Suzlon, 2.1 MW)	199	2011	WECC
	Montague	51 (Vestas, 3.6 MW); 5 (Suzlon, 3.45 MW)	201	2019	WECC
	Pebble Springs	47 (Suzlon, 2.1 MW)	99	2009	WECC
	Star Point	47 (Suzlon, 2.1 MW)	99	2010	WECC
	Golden Hills	51 (Vestas, 4.3 MW)	201	2021	WECC
Pennsylvania	Casselman	23 (GE, 1.5 MW)	35	2007	RFC
	Locust Ridge I	13 (Gamesa G87, 2.0)	26	2007	RFC
	Locust Ridge II	50 (Gamesa G87, 2.0 MW)	100	2009	RFC
	South Chestnut	22 (Gamesa, 2.0 MW)	44	2012	RFC
South Dakota	Buffalo Ridge I	24 (Suzlon, 2.1 MW)	50	2009	MRO
	Buffalo Ridge II	105 (Gamesa G87, 2.0 MW)	210	2010	MRO
	Coyote Ridge (3)	35 (GE, 2.52 MW); 4 (GE, 2.3 MW)	20	2019	MRO
	Tatanka Ridge (3)	50 (GE, 2.3 MW); 6 (GE, 2.3 MW)	23	2021	MRO
Texas	Baffin	101 (Gamesa G97, 2.0 MW)	202	2016	TRE
	Barton Chapel	60 (Gamesa, 2.0 MW)	120	2009	TRE
	Karankawa	93 (GE, 2.52 MW); 22 (GE, 2.3 MW); 9 (GE, 2.5 MW)	307	2019	TRE

Location	Wind Project	Turbines	Total Installed Capacity (MW)	Commercial Operation Date	North American Electric Reliability Corporation (NERC) Region
	Patriot	58 (Vestas, 3.6 MW); 5 (Vestas, 3.45 MW)	226	2019	TRE
	Peñascal I	84 (Mitsubishi, 2.4 MW)	202	2009	TRE
	Peñascal II	83 (Mitsubishi, 2.4 MW)	199	2010	TRE
Vermont	Deerfield	7 (Gamesa G87, 2.0 MW); 8 (Gamesa G97, 2.0 MW)	30	2017	NPCC
Washington	Big Horn I	133 (GE, 1.5 MW)	200	2006	WECC
	Big Horn II	25 (Gamesa, 2.0 MW)	50	2010	WECC
	Juniper Canyon	62 (Mitsubishi, 2.4 MW)	149	2011	WECC

(1) Jointly owned with Axium; capacity amounts represent only Renewables' share of the wind farm.
(2) Jointly owned with Horizon Wind Energy; capacity amounts represent only Renewables' share of the wind farm.
(3) Jointly owned with WEC Infrastructure; capacity amounts represent only Renewables' share of the wind farm.

Additionally, set forth below are the solar and thermal facilities operated by Renewables as of December 31, 2022. Unless otherwise noted, Renewables owns each facility.

Facility	Location	Type of Facility	Installed Capacity (MW) (3)	Commercial Operation Date
Poseidon Solar (1)	Pinal County, Arizona	Solar	12	2011
San Luis Valley Solar Ranch (2)	Alamosa County, Colorado	Solar	35	2012
Gala Solar	Deschutes County, Oregon	Solar	70	2017
Wy'East Solar	Sherman County, Oregon	Solar	13	2018
Lund Hill Solar	Klickitat County, Washington	Solar	194	2022
Klamath Cogeneration	Klamath Falls, Oregon	Thermal	536	2001
Klamath Peakers	Klamath Falls, Oregon	Thermal	100	2009

(1) Jointly owned with Axium; capacity amounts represent only Renewables' share of the solar project.
(2) Operated pursuant to a sale-and-leaseback agreement.
(3) Previously reported in MWac. Reported in MWdc starting in 2020.

Infrastructure Protection and Cyber Security Measures

We have risk-based security measures in place designed to protect our facilities, assets and cyber-infrastructure, such as our transmission and distribution system.

While we have not had any significant security breaches, a physical security intrusion could potentially lead to theft, damage, interruption of service and the release of critical operating information. In addition to physical security intrusions, a cyber breach could also potentially lead to theft, damage, interruption of service and the release of critical operating information or confidential customer information.

To manage these operational risks, pursuant to the cybersecurity risk policy and corporate security policy approved by the AVANGRID Board, we have implemented cyber and physical security measures and continue to strengthen our security posture by improving and expanding our physical and cyber security capabilities to protect critical assets. In addition, the Audit Committee of the AVANGRID Board (formerly known as the Audit and Compliance Committee) has responsibility for oversight of physical and cyber security matters, incident response management, and risks related to physical security, information security, cybersecurity, and technology, as well as the steps taken by management to mitigate such risks. Corporate Security maintains strong relationships with the U.S. Department of Homeland Security, or DHS, the Cybersecurity and Infrastructure Security Agency, or CISA, National Security Council, or NSC, the FBI, and the Department of Energy to ensure threat information is passed in a timely manner for situation awareness and that actions are taken to reduce risk.

The AVANGRID Board has appointed a senior officer responsible for security (Chief Security Officer) and established a dedicated corporate security office, responsible for improving and coordinating security across the company, who regularly reports to the Audit Committee of the AVANGRID board on security matters. We have adopted a comprehensive company-wide physical and cyber security program, which is supported by a governance program to manage, oversee and assist us in meeting our corporate, legal and regulatory responsibilities with regard to the protection of our cyber, physical and information assets.

However, as threats evolve and grow increasingly more sophisticated, we cannot ensure that a potential security breach may not occur or quantify the potential impact of such an event. We continue to invest in technology, processes, security measures and services to predict, detect, mitigate and protect our assets, both physical and cyber. These investments include upgrades to our cyber-infrastructure assets, network architecture and physical security measures, and compliance with emerging industry best practice and regulation. See the risk factor "Security breaches, acts of war or terrorism, grid disturbances or unauthorized access could negatively impact our business, financial condition and reputation" under Item 1A - Risk Factors.

Human Capital Resources

At AVANGRID, we aspire to be a company where talented and committed people want to build long-term careers.

We foster a culture that values continuous improvement and seeks diverse perspectives. We recognize and reward behavior and ideas that drive company performance and that prepare us to meet the challenges and opportunities of the future.

The overall health of our workforce is important to us – from physical safety and financial security, to diversity and inclusion and a respectful work environment. We invest in workforce programs that enable personal and professional growth, help employees build connections with one another, and meet the unique needs of our employees and their families.

In light of our committee to our employees, we have established several human-capital related goals including commitments to gender equity with a goal to have women represent 35% of our executive positions by 2030, 50% of our senior leaders to be women by 2030 and a 40% reduction in our employee accident rate by 2030.

As of December 31, 2022, we employed 7,579 employees, virtually all of whom are full-time. 91.5% of employees were based in five states – Connecticut, Massachusetts, Maine, New York, and Oregon. During fiscal year 2022, we hired and onboarded 1,243 employees.

Approximately 46.0% of our employees are represented by a collective bargaining agreement and we generally enjoy strong working relationships with all our labor unions. There are no union contracts that are scheduled to expire in 2023. There is mutual respect and collaboration when discussing the variety of issues we face on an ongoing basis, and the respective parties share the goal of supporting the business while helping to ensure a positive customer experience.

For the year ended December 31, 2022, the information on turnover rates is as follows:

Employee Turnover	**% of Total**
Voluntary Turnover as a percent of workforce	7.6 %
Involuntary Turnover as a percent of workforce	1.1 %
Retirement as a percent of workforce	4.8 %
Total Turnover as a percent of workforce	13.5 %

Diversity, Equity and Inclusion

Diversity, equity and inclusion are critical to our future success. We strive to build and sustain a diverse workforce with a rich mix of differences, inclusive workplaces where each of us feel valued and connected, and experiences equitable opportunities to grow and develop.

In this respect, we have prioritized initiatives in three areas: increasing diverse representation, especially in positions of authority; promoting equitable opportunities to grow and develop; and establishing pathways for community and connection with others.

In 2022, AVANGRID focused on building an inclusive culture, leveraging our Business Resource Groups, or BRGs, to launch the following initiatives:

- community volunteer initiatives across various locations
- engagement with senior leadership to discuss diversity awareness and inclusive leadership practice
- establishment of recruitment partnerships to deliver diversity pipeline expansion, and
- incentivizing senior leadership to demonstrate Diversity, Equity and Inclusion, or DE&I, outreach, active involvement in diverse mentorship, and leadership positions within BRGs.

As of December 31, 2022, 87% of AVANGRID employees completed unconscious bias training during the previous 24 months.

Our growing community of BRGs provide communities where our employees can discuss relevant issues and celebrate different cultures, ethnicities, and identities. Over 15% of our employees participate in one of our seven BRGs. The AVANGRID African-American Council for Excellence, the AVANGRID Coalition for Asian Pacific Americans, AVAN-Veterans, The AVANGRID Community for All Abilities and Resource for Excellence, The Hispanic Organization for

Leadership and Awareness, Pride@AVANGRID and WomENergy. Our BRGs hosted over 50 events in 2022, promoting inclusive conversations and diverse thinking throughout the organization. As of December 31, 2022, the approximate demographic breakdowns of our workforce are as follows:

Ethnicity	**% of Total**					
All Employees	**All**	**CT**	**MA**	**ME**	**NY**	**OR**
% of Employees in State		23.6 %	3.9 %	16.5 %	42.6 %	5.0 %
American Indian or Alaska Native	0.5 %	0.3 %	0.3 %	0.8 %	0.4 %	0.5 %
Asian	3.2 %	5.0 %	2.4 %	1.6 %	2.3 %	8.4 %
Black or African American	6.2 %	13.8 %	3.4 %	1.0 %	5.5 %	2.1 %
Hispanic or Latino	8.1 %	15.9 %	6.8 %	1.5 %	5.3 %	6.3 %
Hawaiian Native or other Pacific Islander	0.1 %	0.0 %	0.0 %	0.0 %	0.1 %	0.8 %
Two or more races	1.6 %	1.7 %	1.4 %	1.4 %	1.5 %	2.4 %
White	79.4 %	62.7 %	84.7 %	92.7 %	84.5 %	77.9 %
Did not provide	0.8 %	0.5 %	1.0 %	1.0 %	0.5 %	1.6 %

Senior Leadership	**All**	**CT**	**MA**	**ME**	**NY**	**OR**
% of Employees in State		29.8 %	8.3 %	15.3 %	19.2 %	17.1 %
American Indian or Alaska Native	— %	— %	— %	— %	— %	— %
Asian	2.7 %	4.0 %	— %	1.9 %	1.5 %	1.7 %
Black or African American	2.4 %	5.0 %	— %	— %	3.1 %	1.7 %
Hispanic or Latino	9.7 %	18.8 %	— %	5.8 %	10.8 %	3.4 %
Hawaiian Native or other Pacific Islander	— %	— %	— %	— %	— %	— %
Two or more races	2.4 %	2.0 %	— %	3.8 %	1.5 %	1.7 %
White	81.1 %	69.3 %	96.4 %	86.5 %	80.0 %	89.7 %
Did not provide	1.8 %	1.0 %	3.6 %	1.9 %	3.1 %	1.7 %

All Employees	**All**	**CT**	**MA**	**ME**	**NY**	**OR**
Female	27.5 %	30.1 %	28.9 %	29.8 %	27.6 %	26.6 %
Male	72.4 %	69.9 %	71.1 %	70.1 %	72.3 %	73.2 %
Undeclared	0.1 %	0.1 %	— %	0.1 %	0.1 %	0.3 %

Senior Leadership	**All**	**CT**	**MA**	**ME**	**NY**	**OR**
Female	30.1 %	33.7 %	25.0 %	34.6 %	27.7 %	31.0 %
Male	69.9 %	66.3 %	75.0 %	65.4 %	72.3 %	69.0 %
Undeclared	— %	— %	— %	— %	— %	— %

Health and Safety

Safety is a core value at AVANGRID. We are committed to providing a safe and healthy workplace for our employees, communities, customers, and investors. Daily emphasis on the importance of a safe workplace – and everyone's role in supporting it – builds employee confidence, motivation, and productivity. A safe workplace encourages an environment where innovation can flourish. All AVANGRID leaders have a portion of their variable compensation tied directly to health and safety goals.

We continuously work to embed a safety-first culture across the company. In addition to ongoing safety training and awareness programs, we use environmental, health & safety excellence awards and other recognition programs to spotlight exemplary and proactive safety behavior. In 2022, we elevated the "Good Catch" program to recognize five "Good Catches of the Year" at the annual EH&S Summit and initiated a reward program that highlights two winners each month for outstanding safety behavior. A Good Catch is the result of an employee recognizing a condition that had the potential to cause an incident but did not cause one, due to timely identification and mitigation by the employee. This past year, we also rolled out a Leadership Field Safety Observation Program, which is designed to improve employee engagement and increase field condition awareness throughout the organization. In 2022, employees and leaders completed more than 17,000 safety observations. These programs, in addition to monthly safety meetings, are dedicated to sharing critical safety updates and promoting a learning and improving safety culture, while also building critical skills for managers and supervisors to boost engagement for all employees. AVANGRID also launched "The Daily 5," which includes safety best practices videos and content posted on the company’s internal social media channel. These posts are shared with field supervisors and managers, who cascade the messages to all field employees. We also completed the rollout of AVANGRID’s Essential Controls designed to strengthen safety performance and focused on reducing the hazards most prevalent in our industry. For our Networks employees, we initiated an intensive “Alertdriving” training program with nearly 3,000 employees to promote safety and reduce company-related motor vehicle incidents.

A true culture of health and safety must also include employee wellbeing. Healthier employees are at lower risk of injury from industrial exposure and perform work more safely with lower rates of absenteeism. In 2022, wellbeing programming continued to place a strong emphasis on supporting employee mental health, with extensive resources offered including regular mental health webinars, mental health training for people managers, regular health and wellbeing content throughout the year, activities challenges, and digital emotional health programs using cognitive behavior therapy. In 2022, AVANGRID launched Daylight, an online anxiety management program, and Sleepio, a sleep improvement and fatigue management app. In addition, we held several onsite “Benefits & Wellbeing Fairs” and expanded our network of “mental health advocates” to include approximately 80 employees. Mental health advocates are employees who undergo certain training and volunteer their time to listen and provide guidance to others regarding available mental health resources. We also expanded our onsite prevention and risk reduction programs, including the early intervention program, which helps to prevent soft-tissue and musculoskeletal injuries, and onsite influenza vaccination clinics.

Growing our Talent

Varied learning options enable the personal and professional development of our employees – such as on-demand skill building platforms, leadership programs, mentoring programs, technical and on-the-job training, community outreach opportunities, and tuition assistance.

In 2022, we completed and launched the Leadership Essentials program for all new leaders at AVANGRID, focused on building management and leadership skills. We also enhanced our succession and talent management processes to target the identification and development of key talent within all business areas to enhance the sustainability of the business from a people perspective, with a focus on diverse representation. We expanded our early career pipeline to include a new Global Graduates Program alongside our Engineering Development Program as well as our ongoing Internship Program to continue building in-demand and emerging skillets.

Lastly, we continued the evolution of our technical training programs by leveraging new technologies such as virtual reality with the launch of a cross functional virtual reality town that will continue to be enhanced in the coming years. We also leveraged our digital platform for the tracking of on-the-job training hours in addition to traditional classroom instruction to further promote knowledge retention and skills mastery.

Total Rewards & Benefits

Our compensation, health, and retirement programs are designed to attract and retain the right people to meet business and customer needs across a variety of markets and locations, and within the increasingly competitive market in which we operate.

The following principles guide our compensation philosophy:

1. Pay for Performance. We believe that our compensation programs should motivate higher performance among our employees, and compensation levels should broadly reflect the achievement of short-term performance objectives, and for key leaders, long-term performance objectives as well.
2. Competitive Pay. To support our need to recruit, retain and motivate our workforce, we aim to ensure that our compensation, in terms of structure and total amount, is competitive with that of comparable entities. We regularly review market data to obtain a general understanding of current compensation practices to ensure that compensation offered is reasonably market competitive, including for the applicable geographic location.
3. Executives: Long-Term Focus on Total Direct Compensation. The compensation program for our executive officers is designed to mitigate excessive short-term decision making and risk taking, while encouraging the attainment of strategic goals through the inclusion of long-term incentives. We regularly evaluate the effectiveness and competitiveness of our executive compensation and benefit programs and benchmark ourselves against our peers within our industry.

We take a “Total Health” approach to benefits and wellbeing with inclusive programs designed to support employees’ physical, financial, emotional, and social health, as well as their families’, throughout various stages of life. Many of our programs are available to all union and non-union employees both full- and part-time.

Some 2022 examples of Company programs include:

- Comprehensive, high-quality health, dental, vision, life, and disability plans
- Generous 401(k) match and Paid Time Off programs
- Paid Parental Leave for those welcoming a new child through birth, surrogacy, adoption, or foster care placement
- Fertility and family-forming care and coverage
- Education and tuition reimbursement assistance programs
- Subsidized back-up care for children, elder family members, and those with special needs
- Programs that support local non-profits by offering a cash match for employee donations, as well as direct donations recognizing employee volunteer hours.
- A variety of value-added options that allow employees to make choices that meet their individual needs, including telemedicine, claims navigation, mental health and financial wellness and education programs, legal assistance, and pet insurance.

For information on the risks related to our human capital resources, see Item 1A - Risk Factors.

Available Information

Copies of our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed with the SEC may be requested, viewed or downloaded on-line, free of charge, on our website www.avangrid.com. Printed copies of these reports may be obtained free of charge by writing to our Investor Relations Department at 180 Marsh Hill Road, Orange, Connecticut, 06477.

Information about AVANGRID's environmental, social and governance performance and sustainability reporting is also available on our website www.avangrid.com. under the heading "Sustainability." Information contained on our website is not incorporated herein.

The Company may use its website and/or social media outlets, such as Facebook and Twitter, as distribution channels of material company information. Financial and other important information regarding the Company is routinely posted on and accessible through the Company's website at www.avangrid.com, its Facebook page at https://www.facebook.com/Avangrid/, its Twitter account @AVANGRID, and its LinkedIn page at www.linkedin.com/company/avangrid. The information contained on these sites is not incorporated by reference into this Form 10-K. In addition, you may automatically receive email alerts and other information about the Company when you enroll your email address by visiting the Investor Relations section of www.avangrid.com.

Item 1A. Risk Factors

You should carefully consider the following risks and all of the other information set forth in this report, including without limitation our consolidated financial statements and the notes thereto and "Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Estimates." The following risk factors have been organized by category for ease of use; however, many of the risks may have impacts in more than one category.

PNMR Merger Risk Factors

There is no assurance when or if the proposed PNMR Merger will be completed.

Completion of the proposed Merger is subject to the satisfaction or waiver of a number of conditions as set forth in the Merger Agreement, including certain regulatory approvals and other customary closing conditions. There can be no assurance that the conditions to completion of the proposed Merger will be satisfied or waived or that other events will not intervene to delay or result in the failure to close the proposed Merger. In addition, each of AVANGRID and PNMR may unilaterally terminate the Merger Agreement under certain circumstances set forth in the Merger Agreement and the Amendment, and AVANGRID and PNMR may agree at any time to terminate the Merger Agreement, even though PNMR's shareholders have already approved the proposed Merger and the other transactions contemplated by the Merger Agreement. The Merger Agreement provides for certain customary termination rights. If we were to terminate the Merger Agreement under certain circumstances, we could incur significant costs (including, without limitation, the payment of the termination fee and out-of-pocket fees and expenses).

AVANGRID and PNMR may be unable to obtain, extend or reapply for the regulatory approvals required to complete the proposed Merger.

In addition to other conditions set forth in the Merger Agreement, completion of the proposed Merger is conditioned upon the receipt of various state and U.S. federal regulatory approvals including, but not limited to, approval by the Public Utility Commission of Texas, or PUCT, the New Mexico Public Regulation Commission, or NMPRC, the FERC, the Federal

Communications Commission, or FCC, the Committee on Foreign Investment in the United States, or CFIUS, the Nuclear Regulatory Commission, or NRC, and under the Hart-Scott-Rodino Antitrust Improvements Act of 1976. AVANGRID and PNMR have made or will make various filings and submissions and are pursuing all required consents, orders and approvals in accordance with the Merger Agreement. The Merger has obtained all regulatory approvals other than the approval from the NMPRC. During the pendency of the appeal of the NMPRC order rejecting the amended stipulated agreement in the Merger 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. These consents, orders and approvals may impose conditions on or require divestitures relating to the divisions, operations or assets of AVANGRID and PNMR or may impose requirements, limitations or costs or place restrictions on the conduct of the combined company's business, and if such consents, orders and approvals require an extended period of time to be obtained, such extended period of time could increase the chance that an event occurs that constitutes a material adverse effect with respect to PNMR and thereby may allow AVANGRID an opportunity not to consummate the proposed Merger. Such extended period of time also may increase the chance that other adverse effects with respect to AVANGRID or PNMR could occur, such as the loss of key personnel.

The Merger Agreement requires AVANGRID and PNMR, among other things, to accept conditions, divestitures, requirements, limitations, costs or restrictions that may be imposed by regulatory entities, subject to the burdensome effect provisions in the Merger Agreement. Such conditions, divestitures, requirements, limitations, costs or restrictions may jeopardize or delay consummation of the proposed Merger, reduce the benefits that may be achieved from the proposed Merger or result in the abandonment of the proposed Merger. Further, no assurance can be given that the required consents, orders and approvals will be obtained or that the required conditions to closing the proposed Merger will be satisfied, and, even if all such consents, orders and approvals are obtained and such conditions are satisfied, no assurance can be given as to the terms, conditions and timing of such consents, orders and approvals.

The pendency of the proposed Merger could have an adverse effect on AVANGRID's businesses, results of operations, financial condition, cash flows or the market value of AVANGRID's common stock and debt securities.

The pendency of the proposed Merger could disrupt AVANGRID's businesses, and uncertainty about the timing and the effect of the proposed Merger may have an adverse effect on AVANGRID or the combined company following the proposed Merger. AVANGRID's employees may experience uncertainty regarding their roles after the proposed Merger, for example, employees may depart either before or after the completion of the proposed Merger because of such uncertainty and issues relating to the difficulty of coordination or a desire not to remain following the proposed Merger; and the pendency of the proposed Merger may adversely affect AVANGRID's ability to retain, recruit and motivate key personnel. Additionally, the attention of AVANGRID's management may be directed towards the completion of the proposed Merger including obtaining regulatory approvals and other transaction-related considerations and may be diverted from the day-to-day business operations of AVANGRID and matters related to the proposed Merger may require commitments of time and resources that could otherwise have been devoted to other opportunities that might have been beneficial to AVANGRID. Additionally, the Merger Agreement requires AVANGRID to obtain PNMR's consent prior to taking certain specified actions while the proposed Merger is pending. These restrictions may prevent AVANGRID and PNMR from pursuing otherwise attractive business opportunities and executing certain of its business strategies prior to the consummation of the proposed Merger. Further, the proposed Merger may give rise to potential liabilities, including as a result of pending and future shareholder lawsuits relating to the proposed Merger. Any of these matters could adversely affect the businesses of, or harm the results of operations, financial condition or cash flows of AVANGRID and the market value of AVANGRID common stock and debt securities.

AVANGRID will incur substantial transaction fees and costs in connection with the proposed PNMR Merger.

AVANGRID has incurred, and expects to incur additional, material non-recurring expenses in connection with the proposed Merger, obtaining various required consents, orders and approvals in connection with the Merger and consummation of the transactions contemplated by the Merger Agreement. Additional unanticipated costs have been incurred in connection with the delay in obtaining approval from the NMPRC including expenses related to the appeal of the NMPRC order rejecting the amended stipulated agreement in the Merger, the reapplication and extension of certain approval, and the Amended to the Merger Agreement and may be incurred in the course of coordinating the businesses of AVANGRID and PNMR after consummation of the proposed Merger. Even if the proposed Merger is not consummated, AVANGRID may need to pay certain pre-tax costs relating to the proposed Merger incurred prior to the date the proposed Merger was abandoned, such as legal, accounting, financial advisory and filing fees. Additionally, continued delay of the consummation of the Merger may materially adversely affect the benefits that AVANGRID may achieve as a result of the proposed Merger and could result in additional pre-tax transaction costs, loss of revenue or other effects associated with uncertainty about the proposed Merger. Satisfying the conditions to, and consummation of, the proposed Merger may take longer than, and could cost more than, AVANGRID expects.

AVANGRID may be unable to integrate PNMR successfully, and AVANGRID may not experience the growth being sought from the proposed Merger.

AVANGRID and PNMR have operated and, until the consummation of the proposed Merger will continue to operate, independently. Coordinating certain aspects of the operations and personnel of PNMR with AVANGRID after the consummation of the proposed Merger will involve complex operational, technological and personnel-related challenges. This process will be time-consuming and expensive, may disrupt the businesses of either or both of the companies and may reduce the growth opportunities sought from the Merger. The potential difficulties, and resulting costs and delays, include examples such as:

- managing a larger combined company;
- coordinating corporate and administrative infrastructures;
- unanticipated issues in coordinating information technology, communications, administration and other systems;
- difficulty addressing possible differences in corporate cultures and management philosophies;
- unforeseen and unexpected liabilities related to the proposed Merger or PNMR's business; and
- a deterioration of credit ratings.

While AVANGRID can refuse to consummate the proposed Merger if there is a material adverse effect (as defined in the Merger Agreement) affecting PNMR prior to the consummation of the proposed Merger, certain types of changes do not permit AVANGRID to refuse to consummate the proposed Merger, even if such changes would have a material adverse effect on PNMR. If adverse changes occur but AVANGRID must still consummate the proposed Merger, the market price of AVANGRID common stock may suffer. There can be no assurance that, if the proposed Merger is not consummated, these risks will not materialize and will not materially adversely affect the business and financial results of AVANGRID.

Failure by PNMR to successfully execute its business strategy and objectives may materially adversely affect the future results of the combined company and, consequently, the market value of AVANGRID's common stock and debt securities.

The success of the Merger will depend, in part, on the ability of PNMR to successfully execute its business strategy, including delivering electricity in a safe and reliable manner, minimizing service interruptions and investing in its transmission and distribution infrastructure to maintain its system, serve its growing customer base with a modernized grid and support energy production. These objectives are capital intensive and subject to substantial regulation by state and local regulatory agencies and PNMR's business, results of operations and prospects may be adversely affected by legislative or regulatory changes, as well as liability under, or any future inability to comply with, existing or future regulations or requirements. If PNMR is not able to achieve these objectives, is not able to achieve these objectives on a timely basis, or otherwise fails to perform in accordance with AVANGRID's expectations, the anticipated benefits of the Merger may not be realized fully or at all, and the Merger may materially adversely affect the results of operations, financial condition and prospects of the combined company and, consequently, the market value of AVANGRID common stock and debt securities.

The market value of AVANGRID common stock could decline if its existing shareholders sell large amounts of its common stock in anticipation of or following the PNMR Merger, and the market prices of AVANGRID common stock and debt securities may be affected by factors following the Merger that are different from those affecting the market prices for AVANGRID's common stock and debt securities prior to the Merger.

Current shareholders of AVANGRID may not wish to continue to invest in the combined company, or may wish to reduce their investment in the combined company, for a number of reasons, which may include loss of confidence in the ability of the combined company to execute its business strategies, to comply with institutional investing guidelines or to increase diversification. If, before or following the Merger, large amounts of AVANGRID common stock are sold, the market price of its common stock could decline. If the Merger is consummated, the risks associated with the combined company may affect the results of operations of the combined company and the market prices of AVANGRID common stock and debt securities following the Merger differently than they affected such results of operations and market prices prior to the Merger. Additionally, the results of operations of the combined company may be affected by additional or different risks than those that currently affect the results of operations of AVANGRID. Any of the foregoing matters could materially adversely affect the market prices of AVANGRID common stock and debt securities following the Merger.

The PNMR Merger may not positively affect AVANGRID's results of operations and/or may cause a decrease in its earnings per share and dividends, which may negatively affect the market price of AVANGRID common stock and debt securities.

AVANGRID anticipates that the Merger, if consummated, will have a positive impact on its consolidated results of operations. This expectation is based on current market conditions and is subject to a number of assumptions, estimates, projections and other uncertainties, including assumptions regarding the results of operations of the combined company after the Merger, and the financing necessary to fund the Merger Consideration. This expectation also assumes that PNMR will perform in accordance with AVANGRID's expectations, and there can be no assurance that this will occur. In addition, AVANGRID may encounter additional transaction costs and costs to manage its investment in PNMR, may fail to realize some or any of the benefits anticipated in the Merger, may be subject to currently unknown liabilities as a result of the Merger, or may be subject to other factors that affect preliminary estimates. As a result, there can be no assurance that the Merger will positively impact AVANGRID's results of operations, and it is possible that the Merger may have an adverse effect, which could be material, on AVANGRID's results of operations, financial condition and prospects and/or may cause its earnings per share and dividend payout ratio to decrease, any of which may materially adversely affect the market price of AVANGRID common stock and debt securities.

AVANGRID may incur additional indebtedness or issue additional equity securities in connection with the PNMR Merger. As a result, it may be more difficult for AVANGRID to pay or refinance its debts or take other actions, and AVANGRID may need to divert cash to fund debt service payments or AVANGRID shareholders may be further diluted.

AVANGRID may incur significant additional indebtedness or issues additional equity securities to finance the Merger Consideration and related transaction costs. AVANGRID expects to fund all or a portion of the Merger Consideration through sales of its common stock and, possibly, other equity securities, and to the extent it is unable to do so the amount of indebtedness it may incur to finance the Merger and associated transaction costs will likely increase, perhaps substantially. If AVANGRID is required to obtain more debt financing than anticipated to finance the Merger Consideration and associated transaction costs, whether through the issuance of debt securities or borrowings under the committed financing or otherwise, the required regulatory approvals to complete the Merger may be more difficult to obtain and the combined company's credit ratings and ability to service its debt could be materially adversely affected. The increase in AVANGRID's debt service obligations resulting from this additional indebtedness could have a material adverse effect on the results of operations, financial condition and prospects of AVANGRID.

AVANGRID's increased indebtedness could:

- make it more difficult and/or costly for AVANGRID to pay or refinance its debts as they become due, particularly during adverse economic and industry conditions, because a decrease in revenues or increase in costs could cause cash flow from operations to be insufficient to make scheduled debt service payments;
- limit AVANGRID's flexibility to pursue other strategic opportunities or react to changes in its business and the industry sectors in which it operates and, consequently, put AVANGRID at a competitive disadvantage to its competitors that have less debt;
- require a substantial portion of AVANGRID's available cash to be used for debt service payments, thereby reducing the availability of its cash to fund working capital, capital expenditures, development projects, acquisitions, dividend payments and other general corporate purposes, which could harm AVANGRID's prospects for growth and the market price of its common stock and debt securities, among other things;
- result in a downgrade in the credit ratings on AVANGRID's indebtedness, which could limit AVANGRID's ability to borrow additional funds, increase the interest rates under its credit facilities and under any new indebtedness it may incur, and reduce the trading prices of its outstanding debt securities and common stock;
- make it more difficult for AVANGRID to raise capital to fund working capital, make capital expenditures, pay dividends, pursue strategic initiatives or for other purposes;
- result in higher interest expense in the event of increases in interest rates on AVANGRID's current or future borrowings subject to variable rates of interest; and
- require that additional materially adverse terms, conditions or covenants be placed on AVANGRID under its debt instruments.

Based on the current and expected results of operations and financial condition of AVANGRID and its subsidiaries, AVANGRID believes that its cash flow from operations, together with the proceeds from borrowings, issuances of debt securities in the capital markets, distributions from its equity method investments, project financing and equity sales (including tax equity and partnering in joint ventures) will generate sufficient cash on a consolidated basis to make all of the principal and interest payments when such payments are due under AVANGRID's and its current subsidiaries' existing credit facilities, indentures and other instruments governing its outstanding indebtedness and under the indebtedness incurred to fund the Merger Consideration. However, AVANGRID's expectation is subject to numerous estimates, assumptions and uncertainties, and there can be no assurance that AVANGRID will be able to repay or refinance such borrowings and obligations when due. PNMR and its subsidiaries will not guarantee any indebtedness of AVANGRID, nor will any of them have any obligation to provide funds, whether in the form of dividends, loans or otherwise, to enable AVANGRID and its other subsidiaries to make required debt service payments. As a result, the Merger may substantially increase AVANGRID's debt service obligations without any assurance that AVANGRID will receive any cash from PNMR or any of its subsidiaries to assist AVANGRID in servicing its indebtedness or other cash needs.

The Merger will increase our goodwill and other intangible assets.

Following the Merger, we will have a significant amount of goodwill and other intangible assets on our consolidated financial statements that could be subject to impairment based upon future adverse changes in our business or prospects. The impairment of any goodwill and other intangible assets may have a negative impact on our consolidated results of operations.

Any litigation filed against PNMR and the members of the PNMR board of directors could result in the payment of damages following completion of the Merger or prevent or delay completion of the Merger.

In connection with the Merger, purported shareholders of PNMR have filed lawsuits against PNMR and the members of the PNMR board of directors under the federal securities laws, challenging the adequacy of the disclosures made in PNMR's proxy statement in connection with the Merger or otherwise.

The outcome of any such litigation is uncertain. If a dismissal is not granted or a settlement is not reached, the lawsuits could prevent or delay completion of the Merger and result in substantial costs to AVANGRID, including any costs associated with indemnification of PNMR's directors and officers. Additional lawsuits may be filed against PNMR or the directors and officers of PNMR in connection with the Merger. The defense or settlement of any lawsuit or claim that remains unresolved at the time the Merger is consummated may adversely affect the combined company's business, financial condition, results of operations and cash flows.

The impact of severe weather conditions, including brown-outs and black-outs, could negatively affect PNMR.

PNMR has large networks of electric transmission and distribution facilities. Weather conditions in the U.S. Southwest region and Texas vary and could contribute to severe weather conditions, such as wildfires or severe winter weather events, as have occurred over the past two years in Texas or result in brown-outs or black-outs, in or near PNMR's service territories. While PNMR may take certain proactive steps to mitigate the risks caused by severe weather conditions, brown-outs or black-outs, such risks are always present and PNMR could be held liable for damages incurred as a result of severe weather conditions, brown-outs or black-outs, or as a result of wildfires caused, or allegedly caused, by their transmission and distribution systems. In addition, wildfires could cause damage to PNMR's assets that could result in loss of service to customers or make it difficult to supply power in sufficient quantities to meet customer needs. These events could adversely affect PNMR and may materially adversely affect the results of operations, financial condition and prospects of the combined company and, consequently, the market value of AVANGRID's common stock and debt securities.

Costs of decommissioning, remediation and restoration of nuclear and fossil-fueled power plants, as well as reclamation of related coal mines, could exceed the estimates of PNMR as well as the amounts PNMR recovers from its ratepayers, which could negatively impact PNMR.

PNMR has interests in a nuclear power plant, two coal-fired power plants and several natural gas-fired power plants and is obligated to pay its share of the costs to decommission these facilities. PNMR is also obligated to pay for its share of the costs of reclamation of the mines that supply coal to the coal-fired power plants. Likewise, other owners or participants are responsible for their shares of the decommissioning and reclamation obligations and it is important to PNMR that those parties fulfill their obligations. Rates charged by PNMR to its customers, as approved by the NMPRC, include a provision for recovery of certain costs of decommissioning, remediation, reclamation and restoration. The NMPRC has established a cap on the amount of costs for the final reclamation of the surface coal mines that may be recovered from customers. PNMR records estimated liabilities for its share of the legal obligations for decommissioning and reclamation in accordance with GAAP. These estimates include many assumptions about future events and are inherently imprecise. In the event the costs to decommission those facilities or to reclaim the mines serving the plants exceed current estimates, or if amounts are not approved for recovery by the NMPRC, they could materially and adversely affect PNMR and may materially adversely affect the results of operations, financial condition and prospects of the combined company and, consequently, the market value of AVANGRID's common stock and debt securities.

The costs of decommissioning any nuclear or fossil power plant are substantial. PNMR is responsible for all decommissioning obligations related to its entire proportionate interest in Palo Verde Nuclear Generating Station, or PVNGS, San Juan Generating Station, or SJGS, and Four Corners Power Plant, or FCPP, including portions under lease both during and after termination of the leases, other than amounts after the consummation of PNMR's sale of its interest in the Four Corners Power Plant (assuming that transaction closes pursuant to the purchase and sale agreement on December 31, 2024). A delay or termination of the sale of PNMR's interest in the FCPP could have a negative impact on AVAGRID's sustainability reputation.

PNMR maintains trust funds and escrow accounts designed to provide adequate financial resources for decommissioning PVNGS, SJGS and FCPP and for reclamation of the coal mines serving SJGS and FCPP at the end of their expected lives. However, because the funds and accounts grow over time to meet decommissioning and reclamation responsibilities, if the PVNGS, SJGS or FCPP units are decommissioned before their planned dates or the coal mines are shut down sooner than expected, these funds may prove to be insufficient, which may materially adversely affect the results of operations, financial condition and prospects of the combined company and, consequently, the market value of AVANGRID's common stock and debt securities.

There are inherent risks in the ownership and operation of nuclear facilities.

While PNMR does not operate PVNGS, PNMR has an indirect 10.2% undivided interest in PVNGS, including interests in Units 1 and 2 held under leases. PVNGS is subject to environmental, health, and financial risks, including, but not limited to, the ability to obtain adequate supplies of nuclear fuel and water, the ability to dispose of spent nuclear fuel, decommissioning of the plant, securing the facilities against possible terrorist attacks, and unscheduled outages due to equipment failures.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. Events at nuclear facilities of other operators or which impact the industry generally may lead the NRC to impose additional requirements and regulations on all nuclear generation facilities, including PVNGS. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit and to promulgate new regulations that could require significant capital expenditures and/or increase operating costs.

In the event of noncompliance with its requirements, the NRC has the authority to impose a progressively increasing inspection regime that could ultimately result in the shutdown of a unit, civil penalties or both, depending upon the NRC's assessment of the severity of the situation, until compliance is achieved. Increased costs resulting from penalties, a heightened level of scrutiny, and/or implementation of plans to achieve compliance with NRC requirements could adversely affect the financial condition, results of operations, and cash flows of PNMR. Although PNMR has no reason to anticipate a serious nuclear incident at PVNGS, if an incident did occur, it could materially and adversely affect PNMR and may materially adversely affect the results of operations, financial condition and prospects of the combined company and, consequently, the market value of AVANGRID's common stock and debt securities.

Strategic Risk Factors

The success of AVANGRID depends on achieving our strategic objectives, which may be through acquisitions, joint ventures, dispositions and restructurings and failure to achieve these objectives could adversely affect our business, financial condition and prospects.

We are continuously reviewing the alternatives available to ensure that we meet our strategic objectives, which include, among other things, acquisitions, joint ventures, dispositions and restructuring. With respect to potential acquisitions, joint ventures and restructuring activities, we may not achieve expected returns, cost savings and other benefits as a result of various factors including integration and collaboration challenges such as personnel and technology. We also may participate in joint ventures with other companies or enterprises in various markets, including joint ventures where we may have a lesser degree of control over the business operations, which may expose us to additional operational, financial, legal or compliance risks. We also continue to evaluate the potential disposition of assets and businesses that may no longer help us meet our objectives or sell a stake of these assets as a way of maximizing the value of AVANGRID. When we decide to sell assets or a business, we may encounter difficulty in finding buyers or executing alternative exit strategies on acceptable terms in a timely manner, which could delay the accomplishment of our strategic objectives or be on terms less favorable than we anticipated.

We expect to invest in development opportunities in all segments of AVANGRID, but such opportunities may not be successful, projects may not commence operation as scheduled and/or within budget or at all, which could have an adverse effect on our business, financial condition and prospects.

We are pursuing additional development investment opportunities related to all segments of AVANGRID with a particular focus on additional opportunities in electric transmission, renewable energy generation and interconnections to generating resources. The development, construction and expansion of such projects involve numerous risks. Various factors could result in increased costs or result in delays or cancellation of these projects. Risks include regulatory approval processes, permitting, new legislation, citizen referendums or ballot initiatives, economic events, foreign currency risk, environmental and community concerns, negative publicity, design and siting issues, difficulties in obtaining required rights of way, difficulties in securing equipment orders, construction delays and cost overruns, including delays in equipment deliveries, increase in raw materials, severe weather, increase in financing cost, competition from incumbent facilities and other entities, and actions of strategic partners. There may be delays or unexpected developments in completing current and future construction projects. For example, the outcome of ongoing legal proceedings, cost overruns and construction delays could have an adverse effect on the success of the NECEC project and our financial condition and prospects. While most of Renewables' construction projects are constructed under fixed-price and fixed-schedule contracts with construction and equipment suppliers, these contracts provide for limitations on the liability of these contractors to pay liquidated damages for cost overruns and construction delays. These circumstances could prevent Renewables' construction projects from commencing operations or from meeting original expectations about how much electricity it will generate or the returns it will achieve. Project delays may also lead to an inability to utilize and monetize safe harbor equipment, negatively impacting project returns. Additionally, for Renewables' projects that are subject to PPAs contractual non-performance prior to construction could lead to payment of damages and potential project cancellation. During construction, substantial delays could cause defaults under the PPAs, which generally require the completion of project construction by a certain date at specified performance levels. A delay resulting in a wind project failing to qualify for federal PTCs or ITCs could result in losses that would be substantially greater than the amount of liquidated damages paid to Renewables.

AVANGRID may be materially adversely affected by negative publicity related to or in connection with the proposed PNMR Merger, the NECEC transmission project, government-controlled power initiatives and in connection with other matters.

From time to time, political and public sentiment in connection with the proposed Merger, the NECEC transmission project, government-controlled power initiatives and in connection with other matters may result in a significant amount of adverse press coverage and other adverse public statements affecting AVANGRID. Adverse press coverage and other adverse statements, whether or not driven by political or public sentiment, may also result in investigations by regulators, legislators and law enforcement officials or in legal claims. Responding to these investigations and lawsuits, regardless of the ultimate outcome of the proceeding, can divert the time and effort of senior management from the management of AVANGRID's businesses. Addressing any adverse publicity, legislative initiatives, governmental scrutiny or enforcement or other legal proceedings is time consuming and expensive and, regardless of the factual basis for the assertions being made, can have a negative impact on the reputation of AVANGRID, on the morale and performance of our employees and on our relationship with regulators. It may also have a negative impact on AVANGRID's ability to take timely advantage of various business and market opportunities. The direct and indirect effects of negative publicity, and the demands of responding to and addressing it, may have a material adverse effect on AVANGRID's business, financial condition, results of operations and cash flows and the market value of AVANGRID common stock and debt securities.

Regulatory and Legislative Risk Factors

AVANGRID is subject to substantial regulation by federal, state and local regulatory agencies and our business, results of operations and prospects may be adversely affected by legislative or regulatory changes, as well as liability under, or any future inability to comply with, existing or future regulations or requirements.

The operations of AVANGRID are subject to, and influenced by, complex and comprehensive federal, state and local regulation and legislation, including regulations promulgated by state utility commissions and the FERC. This extensive regulatory and legislative framework regulates our ability to own and operate utilities, the industries in which our subsidiaries operate, our business segments, rates for our products and services, financings, capital structures, cost structures, construction, environmental obligations, development and operation of our facilities, acquisition, disposal, depreciation and amortization of facilities and other assets, service reliability, customer service requirements, hedging, derivatives transactions and commodities trading. For example, in Maine efforts to place a citizen's referendum on the ballot affecting the ownership and operations of electric and gas utilities continue if affirmed could result in forced divestiture.

The federal, state and local political and economic environment has had, and may in the future have, an adverse effect on regulatory decisions with negative consequences for AVANGRID. These decisions may require AVANGRID to cancel, reduce, or delay planned development activities or other planned capital expenditures or investments or otherwise incur costs that we may not be able to recover through rates. We are unable to predict future legislative or regulatory changes, initiatives or interpretations, and there can be no assurance that we will be able to respond adequately or sufficiently quickly to such actions.

AVANGRID is subject to the jurisdiction of various regulatory agencies including, but not limited to, the FERC, the NERC, the CFTC, the DOE and the EPA. Further, Networks' regulated utilities are subject to the jurisdiction of the NYPSC, the MPUC, the New York State Department of Environmental Conservation, the Maine Department of Environmental Protection, the PURA, the CSC, the DEEP and the DPU. These regulatory agencies cover a wide range of business activities, including, among other items the retail and wholesale rates for electric energy, the transmission and distribution of energy, the setting of tariffs and rates including cost recovery clauses, procurement of electricity for Networks' customers, and certain aspects of the siting, construction and transmission and distribution systems. These regulatory agencies have the authority to initiate associated investigations or enforcement actions or impose penalties or disallowances, which could be substantial. Certain regulatory agencies have the authority to review and disallow recovery of costs that they consider excessive or imprudently incurred and to determine the level of return that AVANGRID is permitted to earn on invested capital.

The regulatory process, which may be adversely affected by the political, regulatory, and economic environment in the states we operate in may limit our earnings and does not provide any assurance with respect to the achievement of authorized or other earnings levels. The disallowance of the recovery of costs incurred by us or a decrease in the rate of return that we are permitted to earn on our invested capital could have a material adverse effect on our financial condition. In addition, certain of these regulatory agencies also have the authority to audit the management and operations of AVANGRID and its subsidiaries, which could result in operational changes or adversely impact our financial condition. Such audits and post-audit work require the attention of our management and employees and may divert their attention from other regulatory, operational or financial matters.

AVANGRID's operations are subject to, and influenced by, complex and comprehensive federal, state and local regulation and legislation. This is impactful for all areas of the business but particularly in the emerging development of offshore and solar generation. It is anticipated that members of House of Representatives will reintroduce legislation that would prohibit offshore wind construction by foreign flagged vessels in which the crew nationality does not match the nation in which the vessel is flagged. If passed, this legislation could affect expected timelines and returns on approved projects. Additionally, implementation of Uyghur Forced Labor Prevention Act has lead U.S. Customs and Border Control and Protection to detain import of products made with forced labor in certain areas of China, to date this has included solar panels, which is causing significant delay in panel delivery. There is the potential that additional products such as aluminum could face detentions under this authority in the future. This legislation could have an impact on solar project development, construction activities and project returns.

AVANGRID's regulated utility operations may not be able to recover costs in a timely manner or at all or obtain a return on certain assets or invested capital through base rates, cost recovery clauses, other regulatory mechanisms or otherwise.

Our regulated utilities are subject to periodic review of their rates and the retail rates charged to their customers through base rates and cost recovery clauses which are subject to the jurisdiction of the NYPSC, MPUC, PURA and DPU, as applicable. New rate proceedings can be initiated by the utilities or the regulators and are subject to review, modification and final authorization by the regulators. Networks' regulated utilities' business rate plans approved by state utility regulators limit the rates Networks' regulated utilities can charge their customers. The rates are generally designed for, but do not guarantee, the recovery of Networks' regulated utilities' respective cost of service and the opportunity to earn a reasonable rate of Return on Equity, or ROE. Actual costs may increase due to inflation, supply chain constraints, or other factors and exceed levels provided for such costs in the rate plans for Networks' regulated utilities. Utility regulators can initiate proceedings to prohibit Networks' regulated utilities from recovering from their customers the cost of service that the regulators determine to have been imprudently incurred, including service and management company charges. Networks' regulated utilities defer for future recovery certain costs as permitted by the regulators. Networks' regulated subsidiaries could be denied recovery of certain costs, or deferred recovery pending the next general rate case, including denials or deferrals related to major storm costs and construction expenditures. In some instances, denial of recovery may cause the regulated subsidiaries to record an impairment of assets. If Networks' regulated utilities' costs are not fully and timely recovered through the rates ultimately approved by regulators, our financial condition could be adversely affected.

Current electric and gas rate plans of Networks' regulated utilities include revenue decoupling mechanisms, or RDMs, and the provisions for the recovery of energy costs, including reconciliation of the actual amount paid by such regulated utilities. There is no guarantee that such decoupling mechanisms or recovery and reconciliation mechanism will apply in future rate proceedings.

Changes in regulatory and/or legislative policy could negatively impact Networks' transmission planning and cost allocation.

The existing FERC-approved ISO-NE transmission tariff allocates the costs of transmission facilities that provide regional benefits to all customers of participating transmission-owning utilities in New England. FERC is currently reviewing its policies regarding transmission planning, cost allocation and generation interconnection and could require substantial changes in RTO and transmission owner tariffs. Changes in RTO tariffs, transmission owners' agreements or legislative policy, or implementation of these new FERC planning rules, could adversely affect our transmission planning and financial condition.

For example, there are pending challenges at the FERC against New England transmission owners (including UI and CMP) seeking to lower the ROE that these transmission owners are allowed to receive for wholesale transmission service pursuant to the ISO-NE Open Access Transmission Tariff. Reductions to the ROE adversely impact the revenues that Networks' regulated utilities receive from wholesale transmission customers and could have a material effect on our financial condition.

AVANGRID's operating subsidiaries' purchases and sales of energy commodities and related transportation and services expose us to potential regulatory risks that could have a material adverse effect on our business, and financial condition.

Under the EPAct 2005 and the Dodd-Frank Act, AVANGRID is subject to enhanced FERC and CFTC statutory authority to monitor certain segments of the physical and financial energy commodities markets. Under these laws, the FERC and CFTC have promulgated regulations that have increased compliance costs and imposed reporting requirements on AVANGRID. These regulations require our operating subsidiaries to comply with certain margin requirements for our over-the-counter derivative contracts with certain CFTC- or SEC-registered entities that require us to post cash collateral with respect to swap transactions, that could potentially have an adverse effect on our liquidity or our ability to hedge commodity or interest rate risks.

With regard to the physical purchases and sales of energy commodities, the physical trading of energy commodities and any related transportation and/or hedging activities that some of our operating subsidiaries undertake, our operating subsidiaries are required to follow market-related regulations and certain reporting and other requirements enforced by the FERC, the CFTC and the SEC. Additionally, to the extent that operating subsidiaries enter into transportation contracts with natural gas pipelines or transmission contracts with electricity transmission providers that are subject to FERC regulation, the operating subsidiaries are subject to FERC requirements related to the use of such transportation or transmission capacity. Any failure on the part of our operating subsidiaries to comply with the regulations and policies of the FERC, the CFTC or the SEC relating to the physical or financial trading and sales of natural gas or other energy commodities, transportation or transmission of these energy commodities or trading or hedging of these commodities could result in the imposition of significant civil and criminal penalties, which could have a material adverse effect on our business.

Additionally, Avangrid faces fluctuations in the fair value of its derivative contracts over time due to the impact mark-to-market accounting.

The increased cost of purchasing natural gas during periods in which natural gas prices have increased significantly could adversely impact our earnings and cash flow.

Our regulated utilities are permitted to recover the costs of natural gas purchased for customers. Under the regulatory body-approved gas cost recovery pricing mechanisms, the gas commodity charge portion of gas rates charged to customers may be adjusted upward on a periodic basis. If the cost of purchasing natural gas increases and Networks' regulated natural gas utilities are unable to recover these costs from its customers immediately, or at all, Networks may incur increased costs associated with higher working capital requirements and/or realize increased costs. In addition, any increases in the cost of purchasing natural gas may result in higher customer bad debt expense for uncollectible accounts and reduced sales volume and related margins due to lower customer consumption.

Climate related proceedings and legislation may result in the alteration of the public utility model in the states we operate in and could materially and adversely impact our business and operations.

Clean energy and emission reduction legislation, proceedings, or executive orders have been issued within New York, Maine, Connecticut and Massachusetts that, among other things, set renewable energy and carbon emission goals and create incentive programs for energy efficiency and renewable energy programs. Climate vulnerability assessment regulation have also been issued in New York, Maine, and Connecticut. Additionally, new legislation can require significant change to the natural gas portion of AVANGRID including reduction in usage and restriction of the expansion of natural gas within our territories. We are unable to predict the impact these law and actions may have on the operations of our subsidiaries in New York, Maine, Connecticut and Massachusetts which could have an adverse effect on our business and financial condition.

Renewables relies in part on governmental policies that support utility-scale renewable energy. Any reductions to, or the elimination of, these governmental mandates and incentives or the imposition of additional taxes or other assessments on renewable energy, could adversely impact our growth prospects, our business and financial condition.

Renewables relies, in part, upon government policies that support the development and operation of utility-scale renewable energy projects and enhance the economic feasibility of these projects. The federal government and many state and local jurisdictions have policies or other mechanisms in place, such as tax incentives or Renewable Portfolio Standards, or RPS, that support the sale of energy from utility-scale renewable energy facilities. Federal, state and local governments may review their policies and mechanisms that support renewable energy and take actions that would make them less conducive to the development or operation of renewable energy facilities. Any reductions to, or the elimination of, governmental policies or other mechanisms that support renewable energy or the imposition of additional taxes or other assessments on renewable energy, could result in, among other items, the lack of a satisfactory market for new development, Renewables abandoning the development of new projects, a loss of Renewables' investments in the projects and reduced project returns.

New tariffs imposed on imported goods may increase capital expense in projects and negatively impact expected returns.

Changes in tariffs may affect the final cost of a significant portion of capital expenses in projects, with renewable projects being more exposed. Tariffs have been imposed in the recent years to imports of solar panels, aluminum and steel, among other goods or raw materials. Depending on the timing and contractual terms, tariff changes may have adverse impacts to the buyer of these goods which could affect expected returns on approved projects.

For example, in January 2023, members of the House of Representatives introduced a resolution under the Congressional Review Act to reverse the Biden's administrative two year pause on new tariffs on China related to solar imports from 4 Southeast Asian countries (AD-CVD) issued in June of 2022. Additionally, representatives from China have signaled that they may implement an export ban on wafers in retaliation to efforts in the U.S. and elsewhere to divest from the Chinese supply chain.

Operational, Environmental, Social and Legal Risk Factors

AVANGRID is subject to numerous environmental laws, regulations and other standards, including rules and regulations with respect to climate change, which could result in increased capital expenditures, operating costs and various liabilities, and could require us to cancel or delay planned projects or limit or eliminate certain operations, all of which could have an adverse effect on our business and financial condition.

AVANGRID is subject to environmental laws and regulations, including, but not limited to, extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality and usage, climate change, emissions of greenhouse gases, waste management, hazardous wastes, wildlife mortality and habitat protection, historical artifact preservation, natural resources and health and safety that could, among other things, prevent or delay the development of power generation, power or natural gas transmission, or other infrastructure projects, restrict the output of some existing facilities, limit the availability and use of some fuels required for the production of electricity, require additional pollution control equipment, and otherwise increase costs, increase capital expenditures and limit or eliminate certain operations. There are significant costs associated with compliance with these environmental statutes, rules and regulations, and those costs could be even more significant in the future as a result of new legislation. Violations of current or future laws, rules, regulations or other standards could expose our subsidiaries to regulatory and legal proceedings, disputes with, and legal challenges by, third parties, and potentially significant civil fines, criminal penalties and other sanctions.

Security breaches, acts of war or terrorism, grid disturbances or unauthorized access could negatively impact our business, financial condition and reputation.

Cyber breaches, acts of war or terrorism or grid disturbances resulting from internal or external sources could target our facilities or our information technology systems. In the ordinary course of business, we maintain sensitive customer, employee, financial and system operating information and are required by various laws to safeguard this information. Cyber or physical security intrusions could potentially lead to disabling damage to our facilities or to theft and the release of critical operating information or confidential customer or employee information, which could adversely affect our operations and/or reputation, and could result in significant costs, fines and litigation. Additionally, because our generation and transmission facilities are part of an interconnected regional grid, we face the risk of blackout due to a disruption on a neighboring interconnected system. As threats evolve and grow increasingly more sophisticated, we may incur significant costs to upgrade or enhance our security measures to protect against such risks and we may face difficulties in fully anticipating or implementing adequate preventive measures or mitigating potential harms.

A physical attack on our infrastructure could interfere with our normal business operations and affect our ability to control our transmission and distribution assets. A physical security intrusion could potentially lead to theft and the release of critical operating information and could result in significant costs, fines and litigation. Theft, vandalism or damages to our facilities and equipment can cause significant disruption to operations and can lead to operating losses.

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.

The impact of a catastrophic or geopolitical event, such as the Covid-19 pandemic, on the economy, labor and financial markets could adversely affect our business. The extent to which events like a pandemic may impact our business going forward will depend on factors such as public response, governmental actions, the duration, and its impact to economic activity and financial stability. Increased frequency or duration of events such as these may alter the fundamental demand for electricity particularly from businesses, commercial and industrial customers; cause us to experience an increase in costs as a result of our emergency measures, delayed payments from our customers and uncollectible accounts; cause delays and disruptions in the availability and timely delivery of materials and components used in our operations; cause delays and disruptions in the supply chain resulting in disruptions in the commercial operation dates of certain projects and impacting qualification criteria for certain tax credits and potential delay damages in our power purchase agreements; cause deterioration in credit quality of our counterparties, contractors or retail customers that could result in credit losses; cause impairment of goodwill or long-lived assets and impact our ability to develop, construct and operate facilities; result in our inability to meet the requirements of the covenants in our existing credit facilities, including covenants regarding the ratio of indebtedness to total capitalization; cause a deterioration in our financial metrics or the business environment that impacts our credit ratings; cause a delay in the permitting process of certain development projects, affecting the timing of final investment decisions and start of construction dates; cause employee turnover, labor shortages, and extended remote work, which could harm productivity, increase cybersecurity risk, strain our business continuity plans, give rise to claims by employees and otherwise negatively impact our business.

If Networks' electricity and natural gas transmission, transportation and distribution systems do not operate as expected or are not available for operation, they could require unplanned expenditures, including the maintenance, replacement, and refurbishment of Networks' facilities, which could adversely affect our business and financial condition.

Networks' ability to operate and have available its electricity and natural gas transmission, transportation and distribution systems is critical to the financial performance of AVANGRID. The ongoing operation of Networks' facilities involves risks customary to the electric and natural gas industry that include the breakdown, failure, loss of use or destruction of Networks' facilities, equipment or processes or the facilities, equipment or processes of third parties due to natural disasters, war or acts of terrorism, operational and safety performance below expected levels, errors in the operation or maintenance of these facilities and the inability to transport electricity or natural gas to customers in an efficient manner. Any unexpected failure, including failure associated with breakdowns, forced outages or any unanticipated capital expenditures, accident, failure of major equipment, shortage of or inability to acquire critical equipment, replacement or spare parts could result in reduced profitability, impacted cash flows, harm to our reputation or result in regulatory penalties.

Storing, transporting and distributing natural gas involves inherent risks that could cause us to incur significant costs that could adversely affect our business, financial condition and reputation.

There are inherent hazards and operational risks in gas distribution activities, such as leaks, explosions and mechanical problems that could cause the loss of human life, significant damage to property, environmental pollution and impairment of operations. The location of pipelines and storage facilities near populated areas could increase the level of damages resulting from these risks. These incidents may subject us to litigation and administrative proceedings that could result in substantial monetary judgments, fines or penalties and damage to our reputation.

If Renewables' equipment is not available for operation, Renewables projects' electricity generation and the revenue generated from its projects may fall below expectations and adversely affect our financial condition and reputation.

The revenues generated by Renewables' facilities depend upon the ability to maintain the working order of its projects. A natural disaster, severe weather, accident, failure of major equipment, failure of equipment supplier or shortage of or inability to acquire critical replacement of spare parts not held in inventory or maintenance services, including the failure of interconnection to available electricity transmission or distribution networks, could damage or require Renewables to shut down its turbines, panels or related equipment and facilities, leading to decreases in electricity generation levels and revenues.

Renewables' ability to generate revenue from renewable energy facilities depends on interconnecting utility and/or RTO rules, policies, procedures and FERC tariffs and market conditions that do not present restrictions to renewable project operations which could adversely impact our operations and financial condition.

If a transmission network connected to one or more generating facilities experiences outages or curtailments caused by interconnecting utility and/or RTO, the affected projects may lose revenue. In addition, certain Renewables' generation facilities have agreements that may allow for economic curtailment by the off-taker, which could negatively impact revenues. Furthermore, economic congestion on the transmission grid (for instance, a negative price difference between the location where power is put on the grid by a project and the location where power is taken off the grid by the project's customer) in certain of the bulk power markets in which Renewables operates may occur and its businesses may be responsible for those congestion costs. Similarly, negative congestion costs may require that the projects either not participate in the energy markets or bid and clear at negative prices which may require the projects to pay money to operate each hour in which prices are negative. If such businesses were liable for such congestion costs or if the projects are required to pay money to operate in any given hour when prices are negative, then our financial results could be adversely affected. Additionally, we are obligated to pay the FERC Tariff price, which can be adjusted from time to time, for Renewables' facilities interconnection agreements even if the project has been curtailed.

AVANGRID's subsidiaries do not own all the property and other sites on which their projects are located and our rights may be subordinate to the rights of lienholders and leaseholders, which could have an adverse effect on their business and financial condition.

Existing and future projects may be located on property on other sites occupied under long-term easements, leases and rights of way. The ownership interests in the property on other sites subject to these easements, leases and rights of way may be subject to mortgages securing loans or other liens and other easements, lease rights and rights of way of third parties that were created previously. As a result, some of these real property rights may be subordinate to the rights of these third parties, and the rights of our operating subsidiaries to use the property on other sites on which their projects are, or will be, located and their projects' rights to such easements, leases and rights of way could be lost or curtailed.

AVANGRID and our subsidiaries face risks of strikes, work stoppages or an inability to negotiate future collective bargaining agreements on commercially reasonable terms which could have an adverse effect on our business and financial condition.

The majority of employees at Networks' facilities are subject to collective bargaining agreements with various unions. Unionization activities, including votes for union certification, could occur among non-union employees. While we generally enjoy strong working relationships with all our labor unions, if union employees strike, participate in a work stoppage or slowdown or engage in other forms of labor strike or disruption, our subsidiaries could experience reduced power generation or outages if replacement labor is not procured. The ability to procure such replacement labor or the ability to negotiate future collective bargaining agreements on commercially reasonable terms is uncertain.

Advances in technology and rate design initiatives could impair or eliminate AVANGRID's competitive advantage or could result in customer defection, which could have an adverse effect on our growth prospects, business and financial condition.

Legislative and regulatory initiatives designed to reduce greenhouse gas emissions or limit the effects of global warming and overall climate change have increased the development of new technologies for renewable energy, energy efficiency and investment to make those technologies more efficient and cost effective. There is a potential that new technology or rate design incentives could adversely affect the demand for services of our regulated subsidiaries thus impacting our revenues, such as distributed generation. Similarly, future investments in Networks could be impacted if adequate rate making does not fully contemplate the characteristics of an integrated reliable grid from a unified perspective, regardless of customer disconnection. The interoperability, integration and standard connection of these distributed energy devices and systems could place a burden on the system of Networks' operating subsidiaries, without adequately compensating them. The technology and techniques used in the production of electricity from renewable sources are constantly evolving and becoming more complex. In order to maintain its competitiveness and expand its business, Renewables must adjust to changes in technology effectively and in a timely manner, which could impact our cash flow and/or reduce our profitability.

Avangrid's efforts to maintain a responsive ESG program may impact business operations and investor sentiment.

Avangrid's reputation around ESG is reliant on the company's actions around employee engagement, community relations, human rights, and areas that may impact perceptions on the company's ESG effectiveness. Avangrid's efforts to comply with increasing ESG reporting requirements to regulators, customers and third parties, and to track and provide accurate data may impact internal resources. Additionally, Avangrid's efforts to address climate change may increase operating costs. The company's performance relative to competitors in this aspect may impact investor outlook.

Geopolitical instability could exacerbate existing risk factors.

The recent geopolitical developments caused by the conflict in Ukraine as well as the increasingly strained relationship between China and the United States may further intensify risk factors highlighted in this Form 10-K for the fiscal year ended December 31, 2022 including, but not limited to, risks around inflation, interest rates, energy supply and price, supply chain delays and heightened cybersecurity and physical security threats.

Business and Market Risk Factors

AVANGRID's operations and power production may fall below expectations due to the impact of natural events, which could adversely affect our financial condition and reputation.

Weather conditions influence the supply and demand for electricity, natural gas and other fuels and affect the price of energy and energy-related commodities. Severe weather can result in power outages, bodily injury and property damage or affect the availability of fuel and water. Many of our facilities could be at greater risk of damage should climate change produce unusual variations in temperature and weather patterns, resulting in more intense, frequent and extreme weather events and conditions.

Recoverability of additional costs associated with restoration and/or repair of regulated utilities facilities is defined within their respective rate decision. Regulatory agencies have the authority to review and disallow recovery of costs that they consider excessive or imprudently incurred. Reliability metrics may be negatively affected resulting in a potential negative rate adjustment or other imposed penalty. Our regulated utilities are subject to adverse publicity focused on the reliability of their distribution services and the speed with which they are able to respond to electric outages, natural gas leaks and similar interruptions caused by storm damage or other unanticipated events. Adverse publicity of this nature could harm our reputations and the reputations of our subsidiaries. Renewables can incur damage to wind or solar equipment, either through natural events such as lightning strikes that damage blades or in-ground electrical systems used to collect electricity from turbines or panels; or may experience production shut-downs or delayed restoration of production during extreme weather conditions resulting from, among other things, icing on the blades or restricted access to sites.

If weather conditions are unfavorable or below production forecasts, Renewables projects' electricity generation and the revenue generated from its projects may fall below expectations and have an adverse effect on financial condition.

Changing weather patterns or lower than expected wind or solar resource could cause reductions in electricity generation at Renewables' projects, which could negatively affect revenues. These events could vary production levels significantly from period to period, depending on the level of available resources. To the extent that resources are not available at planned levels, the financial results from these facilities may be less than expected. Changing weather patterns could also degrade equipment, components, and/or shorten interconnection and transmission facilities' useful lives or increase maintenance costs.

Lower prices for other fuel sources may reduce the demand for wind and solar energy development, which could adversely affect Renewables' growth prospects and financial condition.

Wind and solar energy demand is affected by the price and availability of other fuels, including nuclear, coal, natural gas and oil, as well as other sources of renewable energy. To the extent renewable energy, particularly wind and solar, becomes less cost-competitive due to reduced government targets, increases in the costs, new regulations, incentives that favor other forms of energy, cheaper alternatives or otherwise, demand for renewable energy could decrease.

There are a limited number of purchasers of utility-scale quantities of electricity, which exposes Renewables' utility-scale projects to additional risk that could have an adverse effect on its business.

Since the transmission and distribution of electricity is highly concentrated in most jurisdictions, there are a limited number of possible purchasers for utility-scale quantities of electricity in a given geographic location, including transmission grid operators, state and investor-owned power companies, public utility districts and cooperatives. As a result, there is a concentrated pool of potential buyers for electricity generated by Renewables' businesses, which may restrict our ability to negotiate favorable terms under new PPAs and could impact our ability to find new customers for the electricity generated by our generation facilities should this become necessary. Renewables' PPA portfolio is mostly contracted with low risk regulated utility companies. In the past few years, there has been increased participation from commercial and industrial customers. The higher long-term business risk profile of these companies results in increased credit risk. Furthermore, if the financial condition of these utilities and/or power purchasers deteriorated or the RPS programs, climate change programs or other regulations to which they are currently subject and that compel them to source renewable energy supplies change, demand for electricity produced by Renewables' businesses could be negatively impacted.

The benefits of any warranties provided by the suppliers of equipment for Networks and Renewables' projects may be limited by the ability of a supplier to satisfy its warranty obligations, or if the term of the warranty has expired or has liability limits which could have an adverse effect on our business and financial condition.

Networks and Renewables expect to benefit from various warranties, including product quality and performance warranties, provided by suppliers in connection with the purchase of equipment by our operating subsidiaries. The suppliers may fail to fulfill their warranty obligations, or the warranty may not be sufficient to compensate for all losses or cover a particular defect. In addition, these warranties generally expire within two to five years after the date of equipment delivery or commissioning and are subject to liability limits. If installation is delayed, the operating subsidiaries may lose all or a portion of the benefit of warranty.

Renewables' revenue may be reduced upon expiration or early termination of PPAs if the market price of electricity decreases and Renewables is otherwise unable to negotiate favorable pricing terms which could have a negative effect on our business and financial condition.

Renewables' PPA portfolio primarily has fixed or otherwise predetermined electricity prices for the life of each PPA. A decrease in the market price of electricity could result in a decrease in revenues upon expiry or extension of a PPA. The majority of Renewables' energy generation projects become merchant upon the expiration of a PPA and are subject to market risks unless Renewables can negotiate an extension or replacement contract. If Renewables is not able to secure a replacement contract with equivalent terms and conditions or otherwise obtain prices that permit operation of the related facility on a profitable basis, the affected project may temporarily or permanently cease operations and trigger an asset value impairment.

Our risk management policies cannot fully eliminate the risk associated with some of our operating subsidiaries' commodity trading and hedging activities, which may result in significant losses and adversely impact our financial condition.

Our subsidiaries' commodity trading and hedging activities are inherently uncertain and involve projections and estimates of factors that can be difficult to predict such as future prices and demand for power and other energy-related commodities. In addition, Renewables has exposure to commodity price movements through their "natural" long positions in electricity and other energy-related commodities in addition to proprietary trading and hedging activities. We manage the exposure to risks of such activities through internal risk management policies, enforcement of established risk limits and risk management procedures but they may not be effective and, even if effective, cannot fully eliminate the risks associated with such activities.

Risk Factors Relating to Ownership of Our Common Stock

Iberdrola exercises significant influence over AVANGRID, and its interests may be different from yours. Additionally, future sales or issuances of our common stock by Iberdrola could have a negative impact on the price of our common stock.

Iberdrola owns approximately 81.6% of outstanding shares of our common stock and has the ability to exercise significant influence over AVANGRID’s policies and affairs, including the composition of our board of directors and any action requiring the approval of our shareholders, including the adoption of amendments to the certificate of incorporation and bylaws and the approval of a merger or sale of substantially all of our assets, subject to applicable law and the limitations set forth in the shareholder agreement to which we and Iberdrola are parties. The directors designated by Iberdrola may have significant authority to effect decisions affecting our capital structure, including the issuance of additional capital stock, incurrence of additional indebtedness, the implementation of stock repurchase programs and the decision of whether or not to declare dividends.

The interests of Iberdrola may conflict with the interests of our other shareholders. For example, Iberdrola may support certain long-term strategies or objectives for us that may not be accretive to shareholders in the short term. The concentration of ownership may also delay, defer or even prevent a change in control, even if such a change in control would benefit our other shareholders, and may make some transactions more difficult or impossible without the support of Iberdrola. This significant concentration of share ownership may adversely affect the trading price for shares of our common stock because investors may perceive disadvantages in owning stock in companies with shareholders who own significant percentages of a company’s outstanding stock.

Further, sales of our common stock by Iberdrola or the perception that sales may be made by it could significantly reduce the market price of shares of our common stock. Even if Iberdrola does not sell a large number of shares of our common stock into the market, its right to transfer such shares may depress the price of our common stock. Furthermore, pursuant to the shareholder agreement dated December 15, 2016, between AVANGRID and Iberdrola, Iberdrola is entitled to customary registration rights of our common stock, including the right to choose the method by which the common stock is distributed, a choice as to the underwriter and fees and expenses to be borne by us. Iberdrola also retains preemptive rights to protect against dilution in connection with issuances of equity by us. If Iberdrola exercises its registration rights and/or its preemptive rights, the market price of shares of our common stock may be adversely affected. Additionally, being a controlled company, relevant risks materializing at the ultimate parent level could have a negative impact on our share price, financial condition, credit ratings or reputation.

We have elected to take advantage of the “controlled company” exemption to the corporate governance rules for NYSE-listed companies, which could make shares of our common stock less attractive to some investors or otherwise harm our stock price.

Under the rules of the NYSE, a company in which over 50% of the voting power is held by an individual, a group or another company is a “controlled company” and may elect to take advantage of certain exemptions to the corporate governance rules for NYSE-listed companies. AVANGRID has elected to take advantage of these exemptions and, as a controlled company, is not required to have a majority of its board of directors be independent directors, a compensation committee and a nominating and corporate governance committee, or to have such committee composed entirely of independent directors. Because we are a “controlled company,” you will not have the same protections afforded to shareholders of companies that are subject to all the corporate governance requirements of the NYSE without regard to the exemptions available for “controlled companies.” Our status as a "controlled company" could make our shares of common stock less attractive to some investors or otherwise harm our stock price.

Our dividend policy is subject to the discretion of our board of directors and may be limited by our debt agreements and limitations under New York law.

Although we currently anticipate paying a regular quarterly dividend, any such determination to pay dividends is at the discretion of our board of directors and dependent on conditions such as our financial condition, earnings, legal requirements, including limitations under New York law and other factors the board of directors deem relevant. Our board of directors may, in its sole discretion, change the amount or frequency of dividends or discontinue the payment of dividends entirely. For these reasons, investors may not be able to rely on dividends to receive a return on their investments.

AVANGRID may be unable to meet our financial obligations and to pay dividends on our common stock if our subsidiaries are unable to pay dividends or repay loans from us.

We are a holding company and, as such, have no revenue-generating operations of our own. We are dependent on dividends and the repayment of loans from our subsidiaries and on external financings to provide the cash necessary to make future investments, service debt we have incurred, pay administrative costs and pay dividends. Our subsidiaries are separate legal entities and have no independent obligation to pay dividends. Our regulated utilities are restricted by regulatory decision from paying us dividends unless a minimum equity-to-total capital ratio is maintained. The future enactment of laws or regulations may prohibit or further restrict the ability of our subsidiaries to pay upstream dividends or to repay funds. In addition, in the event of a subsidiary's liquidation or reorganization, our right to participate in a distribution of assets is subject to the prior claims of the subsidiary's creditors. As a result, our ability to pay dividends on our common stock and meet our financial obligations is reliant on the ability of our subsidiaries to generate sustained earnings and cash flows and pay dividends to and repay loans from us.

General Risk Factors

If we are unable to implement and maintain effective internal control over financial reporting in the future, investors may lose confidence in the accuracy and completeness of our financial reports and the trading price of our common stock may be negatively affected.

As a public company, we are subject to reporting, disclosure control and other obligations in accordance with applicable laws and rules adopted, and to be adopted, by the SEC and the NYSE such as the requirement that our management report on the effectiveness of our internal control over financial reporting and our independent registered public accounting firm to attest to the effectiveness of our internal controls. Our management and other personnel devote a substantial amount of time to these compliance activities, and if we are not able to comply with these requirements in a timely manner or if we are unable to conclude that our internal control over financial reporting is effective, our ability to accurately report our cash flows, results of operations or financial condition could be inhibited and additional financial and management resources could be required. Any failure to maintain internal control over financial reporting or if our independent registered public accounting firm determines the we have a material weakness or significant deficiency in our internal control over financial reporting, could cause investors to lose confidence in the accuracy and completeness of our financial reports, a decline in the market price of our common stock, or subject us to sanctions or investigations by the NYSE, the SEC or other regulatory authorities. Failure to remedy any material weakness or significant deficiency in our internal control over financial reporting, or to implement or maintain other effective control systems required of public companies, could also restrict our future access to the capital markets and reduce or eliminate the trading market for our common stock.

Changes in tax laws, as well as judgments and estimates used in the determination of tax-related asset and liability amounts, could adversely affect our financial condition.

Our provision for income taxes and reporting of tax-related assets and liabilities require significant judgments and the use of estimates. Amounts of tax-related assets and liabilities involve judgments and estimates of the timing and probability of recognition of income, deductions and tax credits, including, but not limited to, estimates for potential adverse outcomes regarding tax positions that have been taken and the ability to utilize tax benefit carryforwards, such as net operating loss, or NOL, and tax credit carryforwards. Actual income taxes could vary significantly from estimated amounts due to the future impacts of, among other things, changes in tax laws, regulations and interpretations, our financial performance and results of operations.

Our investments and cash balances are subject to the risk of loss.

Our cash balances and the cash balances at our subsidiaries may be deposited in banks, may be invested in liquid securities such as commercial paper or money market funds or may be deposited in a liquidity agreement in which we are a participant along with other affiliates of the Iberdrola Group. Bank deposits in excess of federal deposit insurance limits would be subject to risks in the counterparty bank. Liquid securities and money market funds are subject to loss of principal, more likely in an adverse market situation, and to the risk of illiquidity.

The cost and availability of capital to finance our business is inherently uncertain and may adversely affect our financial condition.

AVANGRID and its subsidiaries are exposed to an increase in the general level of interest rates and to geopolitical and other macroeconomics factors and events affecting the capital markets that may increase the cost of capital or restrict its availability. In addition, AVANGRID's performance directly affects its financial strength and credit ratings and therefore its cost of, and ability to attract, capital. Significant increases in the cost of capital, whether caused by economic or capital market conditions or adverse company performance, would adversely impact our financial performance and may make certain potential business opportunities uneconomic. Prolonged inability to access capital would impair our ability to execute our business plan and could impair AVANGRID's ability to meet its financial obligations.

Moreover, certain of AVANGRID and its subsidiaries' debt securities and derivative contracts use the LIBOR as a benchmark for establishing the interest rate. In March 2021, the U.K. Financial Conduct Authority announced that all LIBOR settings will either cease to be provided by any administrator or no longer be representative immediately after December 31, 2021 for one-week and two-month U.S. dollar settings, as well as the sterling, euro, Swiss franc and Japanese yen settings, and immediately after June 30, 2023 for the remaining U.S. dollar settings. AVANGRID and its subsidiaries' existing debt securities and derivative contracts that reference LIBOR contain standard fallback language addressing the transition away from LIBOR. However, the discontinuation and replacement of LIBOR may have an unpredictable impact on the credit and financial markets. Additionally, uncertainty as to the nature of such potential discontinuation and replacement, including that any benchmark may not be the economic equivalent of LIBOR or not achieve market acceptance similar to LIBOR, may negatively impact the cost of our debt securities.

AVANGRID and our subsidiaries are subject to litigation or administrative proceedings, the outcome or settlement of which could adversely affect our business, financial condition and reputation.

AVANGRID and our operating subsidiaries have been and continue to be involved in legal proceedings, administrative proceedings, claims and other litigation that arise in the ordinary course of business. AVANGRID could experience unfavorable outcomes, developments or settlement of claims relating to these proceedings or future proceedings such as judgments for monetary damages, injunctions, unfavorable settlement terms, or denial or revocation of permits or approvals that could adversely impact our business, financial condition and reputation.

AVANGRID is not able to insure against all potential risks which could adversely affect our financial condition.

AVANGRID is exposed to certain risks inherent in our business such as equipment failure, manufacturing defects, natural disasters, terrorist attacks, cyber-attacks and sabotage, as well as affected by international, national, state or local events. Our insurance coverage may not continue to be offered or offered on an economically feasible basis and may not cover all events that could give rise to a loss or claim involving the assets or operations of our subsidiaries.

Pension and post-retirement benefit plans could require significant future contributions to such plan that could adversely impact our business and financial condition.

We provide defined benefit pension plans and other post-retirement benefits administered by our subsidiaries for a significant number of employees, former employees and retirees. Financial market disruptions and significant declines in the market values of the investments held to meet those obligations, discount rate assumptions, participant demographics and increasing longevity, and changes in laws and regulations may require us to make significant contributions to the plans.

AVANGRID and our subsidiaries may suffer the loss of key personnel or the inability to hire and retain qualified employees in a competitive labor market, which could have an adverse effect on our operations and financial condition.

The operations of AVANGRID depend on the continued efforts of our employees. Retaining key employees and attracting new employees are important to our financial performance and our operations. We cannot guarantee that any member of our management will continue to serve in any capacity for any length of time. We operate in an increasingly competitive labor market and an increasing percentage of our employees are retirement eligible. If employee turnover increases or our workforce continue to age without appropriate replacements, our efficiency and effectiveness, productivity, and ability to pursue growth opportunities may be impaired. In addition, a significant portion of our skilled workforce will be eligible to retire in the next five to ten years. Such highly skilled individuals cannot be quickly replaced due to the technically complex work they perform, the competitive labor market and changing workplace. This could lead to a loss in productivity and increased recruiting and training costs.

Item 1B. *Unresolved Staff Comments.*

None.

Item 2. *Properties.*

We have included descriptions of the location and general character of our principal physical operating properties by segment in "Item 1. *Business*", which is incorporated herein by reference. The principal offices of AVANGRID and Networks are located in Orange, Connecticut; Portland, Maine; and Rochester, New York, while Renewables' headquarters are located in Portland, Oregon and Boston, Massachusetts. In addition, AVANGRID and its subsidiaries have various administrative offices located throughout the United States. AVANGRID leases part of its administrative and local offices.

The following table sets forth the principal properties of AVANGRID, by location, type, lease or ownership and size as of December 31, 2022:

Location	Type of Facility	Leased/Owned	Size (square feet)
Orange, Connecticut	Office	Owned	123,159
Augusta, Maine	Office	Leased	215,832
Portland, Maine	Office	Leased	90,325
Rochester, New York	Office	Leased	116,472
Portland, Oregon	Office	Leased	43,634
Boston, Massachusetts	Office	Leased	39,215

We believe that our office facilities are adequate for our current needs and that additional office space can be obtained if necessary.

Item 3. *Legal Proceedings.*

For information with respect to this item see Notes 14 and 15 of our consolidated financial statements included in Part II, Item 8, "Financial Statements and Supplementary Data" of this Annual Report on Form 10-K, which information is incorporated herein by reference.

Item 4. *Mine Safety Disclosures.*

Not applicable.

Information about our Executive Officers

The names and ages of all executive officers of AVANGRID as of February 21, 2023 and a brief account of the business experience during the past five years of each executive officer are as follows:

Name	Age (1)	Title
Pedro Azagra Blázquez	54	Chief Executive Officer
Patricia C. Cosgel	57	Senior Vice President – Chief Financial Officer
Scott M. Tremble	43	Senior Vice President – Controller
Jose Antonio Miranda Soto	51	President and Chief Executive Officer of Renewables
R. Scott Mahoney	57	Senior Vice President – General Counsel and Corporate Secretary
Catherine Stempien	53	President and Chief Executive Officer of Networks

(1) Age as of December 31, 2022.

Pedro Azagra Blázquez. Mr. Azagra Blázquez has served as Chief Executive Officer of AVANGRID since May 29, 2022, and previously served as the Chief Development Officer of Iberdrola from 2008 until his appointment as AVANGRID Chief Executive Officer. Prior to his appointment as Chief Development Officer, Mr. Azagra Blázquez served as Iberdrola's Director of Strategy. He has also served as Professor of Corporate Finance and Mergers and Acquisitions at Universidad Pontificia de Comillas, in Madrid, Spain, since 1998. Mr. Azagra Blázquez formerly served on the board of directors of Siemens Gamesa Renewable Energy, S.A. He earned a business degree and a law degree from Universidad Pontificia de Comillas and an M.B.A. from the University of Chicago. Mr. Azagra Blázquez has served as a member of the Company's Board since 2019 and previously served as a member of the Board from 2014 until 2018. In addition, Mr. Azagra Blázquez serves as a member of the board of directors of Neoenergia, S.A., a member of the Iberdrola group of companies listed on the São Paulo Stock Exchange.

Patricia C. Cosgel. Ms. Cosgel was appointed Interim Chief Financial Officer on February 24, 2022, and was promoted to Senior Vice President – Chief Financial Officer on June 2, 2022. Ms. Cosgel previously served as Vice President of Investor and Shareholder Relations of AVANGRID from December 2015 until her appointment as Interim Chief Financial Officer. Prior to this role, Ms. Cosgel served as Vice President and Treasurer of UIL Holdings Corporation from May 2011 until its acquisition by the Corporation in December 2015. Prior to joining UIL Holdings Corporation, Ms. Cosgel served as Director of Enterprise Risk Management, Assistant Treasurer and Manager-Corporate Finance of Eversource Energy. Ms. Cosgel earned a Bachelor of Arts in Economics from Dickinson College and a Master of Arts in Economics from University of Iowa.

Scott M. Tremble. Mr. Tremble was appointed Senior Vice President – Controller of AVANGRID on May 1, 2018, and is responsible for the execution and recording of AVANGRID's transactional processes while meeting mandatory reporting requirements and tax obligations. Mr. Tremble also serves as a director of AVANGRID's subsidiaries Networks, Renewables and UIL. Mr. Tremble joined the Company as chief accounting officer of Avangrid Management Company, LLC, a wholly-owned subsidiary of AVANGRID, in 2015, and was responsible for oversight in the areas of consolidation, financial reporting, internal controls, technical accounting and corporate accounting for the Company. From 2014 to 2015, he served as the international controller of Cole Haan LLC. Mr. Tremble started his career at PricewaterhouseCoopers in October 2002 and served various roles, including, most recently, as senior manager in the assurance practice. Mr. Tremble received his B.S. in Accountancy from Bentley University and is a Certified Public Accountant.

Jose Antonio Miranda Soto. Mr. Miranda Soto was appointed as Co-Chief Executive Officer and President-Onshore of Renewables on October 12, 2021, responsible for leading the growth and development of the company's onshore wind and solar pipeline in the United States. On October 12, 2022, Mr. Miranda Soto became the sole President and Chief Executive Officer of Renewables. Prior to joining AVANGRID, he served as Chief Executive Officer of Onshore in the Americas region for Siemens Gamesa and Chairman of its boards in US, Mexico and Brazil. He also served as Secretary of the Board and Executive Committee member of the American Wind Energy Association (AWEA). Prior to his fourteen-year tenure at Siemens Gamesa where he held roles in Europe, Asia and the Americas, he held a variety of roles over a ten-year period at the multinational engineering firm, ABB. Mr. Miranda Soto holds a Master of Business Administration ICADE (Universidad Pontificia de Comillas, Madrid, Spain) and a Maser degree in Industrial Engineering from the Superior Technical Institute of Industrial Engineers of Gijón (Oviedo University, Spain).

R. Scott Mahoney. Mr. Mahoney was appointed Senior Vice President – General Counsel of AVANGRID on December 17, 2015. He was appointed Secretary of AVANGRID on January 27, 2016, and previously served as vice president-general counsel and secretary of Networks. Mr. Mahoney previously served as Deputy General Counsel and Chief FERC Compliance Officer for AVANGRID from January 2007 to June 2012, and served in legal and senior executive positions at AVANGRID subsidiaries from October 1996 until January 2007. Mr. Mahoney also serves on the board of directors of the Gulf of Maine Research Institute. Mr. Mahoney earned a B.A. from St. Lawrence University, a J.D. from the University of Maine, a master's degree in environmental law from the Vermont Law School, and a postgraduate diploma in business administration from the University of Warwick. He has received bar admission to the State of Maine, the State of New York, the U.S. Court of Appeals, the U.S. District Court and the U.S. Court of Military Appeals and is a State of Connecticut Authorized House Counsel.

Catherine Stempien. Ms. Stempien was appointed President and Chief Executive Officers of Networks on March 15, 2021. Prior to joining AVANGRID, Ms. Stempien served in various roles for Duke Energy Corporation, a publicly-traded energy company, including as the President of Duke Energy Florida, as senior vice president of corporate development with responsibility for Duke Energy's corporate development activities, and as vice president legal for Duke Energy. Ms. Stempien has more than 25 years of legal and financial experience, predominantly in the energy and telecommunications fields. Ms. Stempien previously served as associate general counsel for Cinergy Corp., senior attorney for AT&T Corporation and AT&T Broadband, and associate with Covington & Burling LLP. Ms. Stempien earned a Juris Doctor degree, magna cum laude, from Boston University School of Law and a Bachelor of Arts degree in government from Dartmouth College. She also completed a joint Dartmouth/London School of Economics program in comparative political studies and participated in the Advanced Management Program at Harvard Business School. She is a member of the Bar in the District of Columbia, Colorado, the U.S. Supreme Court, and the U.S. Court of Appeals for the Third Circuit.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Market Information and Holders

Our shares of common stock began trading on the NYSE on December 17, 2015, under the symbol "AGR." Prior to that time, there was no public market for shares of our common stock.

As of February 21, 2023, there were 2,989 shareholders of record.

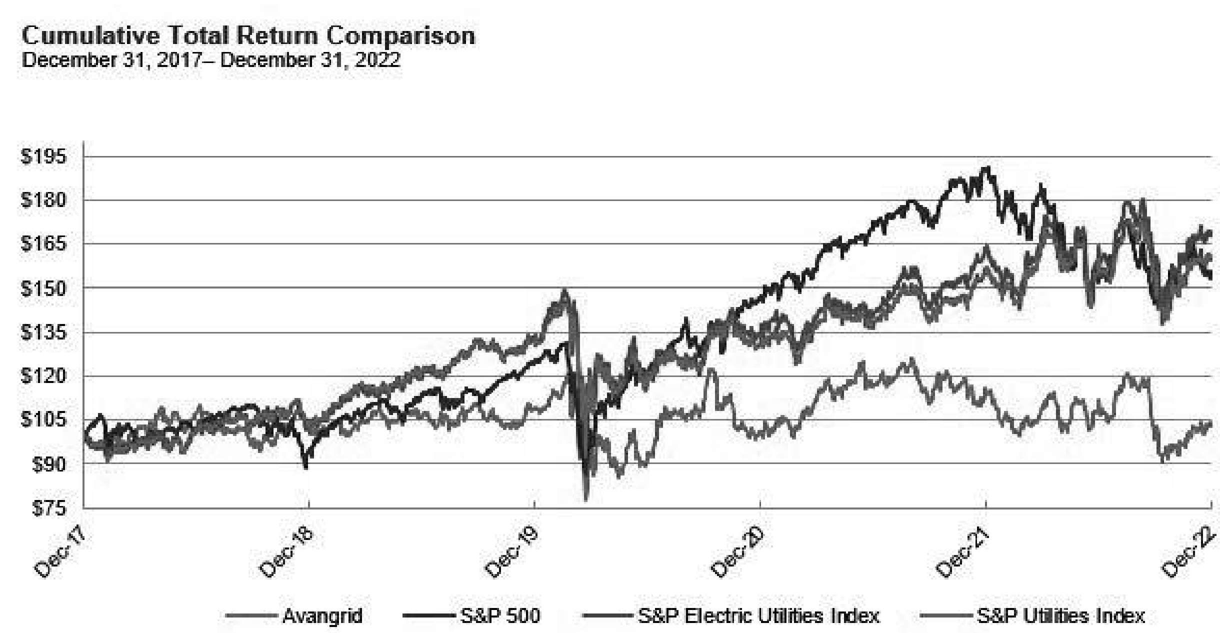
Dividends

AVANGRID expects to continue paying quarterly cash dividends, although there is no assurance as to the amount of future dividends, which depends on future earnings, capital requirements and financial condition.

Further information regarding payment of dividends is provided in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" of this Annual Report on Form 10-K.

Performance Graph

The line graph appearing below compares the change in AVANGRID's total shareowner return on its shares of common stock with the return on the S&P Composite-500 Stock Index, the S&P Electric Utilities Index and the S&P Utilities Index for the period December 31, 2017 through December 31, 2022.



	December 31, 2017	December 31, 2018	December 31, 2019	December 31, 2020	December 31, 2021	December 31, 2022
AVANGRID	$ 100.00	$ 102.52	$ 164.50	$ 142.64	$ 156.48	$ 102.66
S&P 500	$ 100.00	$ 95.61	$ 171.70	$ 202.96	$ 231.31	$ 155.48
S&P Electric Utilities Index	$ 100.00	$ 104.21	$ 170.89	$ 174.91	$ 182.51	$ 167.88
S&P Utilities Index	$ 100.00	$ 104.11	$ 172.56	$ 172.38	$ 174.96	$ 159.42

The above information assumes that the value of the investment in shares of AVANGRID's common stock and each index was $100 on December 31, 2017, including dividend reinvestment during this time period. The changes displayed are not necessarily indicative of future returns.

Recent Sales of Unregistered Securities

None.

Issuer Repurchases of Equity Securities

There were no repurchases of common stock of AVANGRID during the fourth quarter of the year ended December 31, 2022.

Equity Compensation Plan Information

For information regarding securities authorized for issuance under equity compensation plans, see Part III, Item 12 of this Annual Report on Form 10-K.

Item 6. [Reserved]

Item 7. 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 consolidated financial statements and the notes thereto included elsewhere in this Annual Report on Form 10-K. In addition to historical 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. Factors that could cause or contribute to these differences include those discussed below and elsewhere in this Annual Report on Form 10-K, particularly in Part I, Item 1A, "Risk Factors."

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 $41 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 2022 for the fourth consecutive year by the Ethisphere Institute and is listed as a Forbes Best-In-State Employers 2022 and recognized by Just Capital as one of the 2022 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 18.4% 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 December 31, 2022.

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 9,206 megawatts, or MW, as of December 31, 2022, 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 December 31, 2022, approximately 74% of the capacity was contracted with PPAs for an average period of approximately 10 years and an additional 15% of production was hedged. AVANGRID is one of the three largest wind operators in the United States based on installed capacity as of December 31, 2022, 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 five 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. 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 was 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 set forth certain terms and conditions relating to the Funding Commitment Letter (the Side Letter Agreement). The Side Letter Agreement provides that any drawing in the form of indebtedness made by AVANGRID pursuant to the Funding Commitment Letter shall bear interest at an interest rate equal to 3-month LIBOR 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 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. On June 14, 2022, the NMPRC filed its Answer Brief. On June 13, 2022, New Energy Economy, an intervener in the Merger proceeding, filed its Answer Brief. AVANGRID's Reply Brief was filed on August 5, 2022. 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. On September 21, 2022, New Energy Economy filed a motion to show cause with the NMPRC alleging that AVANGRID and PNMR have engaged in a misleading joint advertising and sponsorship strategy and requesting an investigation. AVANGRID filed a reply to the motion to show cause on October 11, 2022. We cannot predict the outcome of this proceeding.

In addition, on January 3, 2022, AVANGRID, PNMR and Merger Sub entered into an Amendment to the Merger Agreement, or the 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 Amendment that the required regulatory approval from the New Mexico Public Regulation Commission, or 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 Amendment. As amended, the Merger Agreement may be terminated by each of Avangrid and PNMR under certain circumstances, including if the Merger is not consummated by April 20, 2023 (subject to a three-month extension by Avangrid and PNMR by mutual consent if all of the conditions to the closing, other than the conditions related to obtaining regulatory approvals, have been satisfied or waived). 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 this proceeding for the outstanding approvals.

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 April 20, 2023 (subject to a three-month extension by Avangrid and PNMR by mutual consent if all of the conditions to the closing, other than the conditions related to obtaining regulatory approvals, have been satisfied or waived). 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 (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.

For additional information on the Merger, see Note 1 - Background and Nature of Operations.

Business Environment

The COVID-19 pandemic has caused global economic 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, including the COVID-19 pandemic and the Russia and Ukraine conflict described below. For example, we recently announced that Commonwealth Wind and Park City Wind would seek to renegotiate 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 Connecticut, discussions remain ongoing with the EDCs, state and regulatory officials, and other stakeholders concerning a possible amendment to the PPAs. While we have not yet experienced a materially adverse impact to our business, results of operations or financial condition, given the uncertain scope and duration of the COVID-19 outbreak or global economic trends and its potential effects on our business, we currently cannot predict if there will be materially adverse impacts to our business, results of operations or financial condition in the future.

In February 2022, Russia invaded Ukraine resulting in the United States, Canada, the European Union and other countries imposing economic sanctions on Russia. We continue to monitor the broader economic impact of this conflict, which may include further sanctions, supply chain instability, and potential retaliatory action by the Russian government. We are taking steps intended to mitigate the potential risks from this continued conflict, including without limitation, communication with suppliers to ensure that the supply chains are free from sanctioned materials, 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 the conflict; however, we cannot predict the extent of these effects, given the evolving nature of the conflict, on our business, results of operations or financial condition.

We are also 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 and cells and could be retroactive to the filing date. In June 2022, President Biden's Administration announced a 24-month tariff exemption on any potential tariff resulting from the anti-circumvention investigation. 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 the final resolution by the DOC and 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 March 2022, the United States House of Representatives passed the Coast Guard Authorization Act of 2022 and the National Defense Authorization Act that was passed by the United States House of Representatives in mid-July. If enacted, the bills 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, are 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. To date, there has been no material impact on Renewables' operations or turbine procurement; however, we are monitoring this dispute and we cannot predict if there will be materially adverse impacts to our business, results of operations or financial condition.

For more information, see the risk factor under the heading "The outbreak of COVID-19 and its impact on business and economic conditions could negatively affect our business, results of operations or financial condition." in Item 1A. Risk Factors in this Form 10-K.

Summary of Results of Operations

Our operating revenues increased by 14%, from $6,974 million for the year ended December 31, 2021, to $7,923 million for the year ended December 31, 2022.

Networks business revenues increased mainly due to rate increases in New York effective December 1, 2020. Renewables revenues decreased mainly due to decrease in merchant prices driven primarily by lower demand as compared to the same period of 2021 when demand was higher during the Texas weather event.

Net income attributable to AVANGRID increased by 25% from $707 million for the year ended December 31, 2021, to $881 million for the year ended December 31, 2022, primarily due to a gain recognized in the current period from the offshore joint venture restructuring transaction in Renewables.

Adjusted net income (a non-GAAP financial measure) increased by 16%, from $780 million for the year ended December 31, 2021 to $901 million for the year ended December 31, 2022. The increase is primarily due to a $233 million increase in Renewables driven by a gain recognized in the current period from the offshore joint venture restructuring transaction and favorable tax expense from valuation allowances and state tax rate changes which are primarily offset in Corporate, offset by a $33 million decrease in Networks driven primarily by higher business costs and uncollectible expenses in the period, $79 million decrease in Corporate mainly driven by unfavorable tax expense from unitary rate changes in the period which are primarily offset in Renewables.

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 year.

Our financial condition and financing capability will be dependent on many factors, including the level of income and cash flow of its subsidiaries, conditions in the bank and capital markets, economic conditions, interest rates and legislative and regulatory developments.

Networks

Electric Transmission and Distribution and Natural Gas Distribution

The operating subsidiaries of Networks are regulated electric distribution and transmission and natural gas transportation and distribution utilities whose structure and operations are significantly affected by legislation and regulation. The FERC regulates, under the FPA, the interstate transmission and wholesale sale of electricity by these regulated utilities, including transmission rates and allowed ROE on transmission assets. Further, the distribution rates and allowed ROEs for Networks' regulated utilities in New York, Maine, Connecticut and Massachusetts are subject to regulation by the NYPSC, the MPUC, PURA and DPU, respectively. Legislation and regulatory decisions implementing legislation establish a framework for Networks' operations. Other factors affecting Networks' financial results are operational matters, such as the ability to manage expenses, uncollectibles and capital expenditures, in addition to weather disturbances, equipment failures and environmental regulation. Networks expects to continue to make significant capital investments in its distribution and transmission infrastructure.

Pursuant to Maine law, CMP earns revenue for the delivery of energy to its retail customers, but is prohibited from selling power to them. CMP generally does not enter into purchase or sales arrangements for power with ISO-NE, the New England power pool, or any other ISO or similar entity. CMP generally sells all of its power entitlements under its nonutility generator and other PPAs to unrelated third parties under bilateral contracts. If the MPUC does not approve the terms of bilateral contracts, it can direct CMP to sell power entitlements that it receives from those contracts on the spot market through ISO-NE. NYSEG and RG&E enter into power purchase and sales transactions with the NYISO to have adequate supplies for their customers who choose to purchase energy directly from them. Customers may also choose to purchase energy from other energy supply companies.

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

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

For additional information regarding Networks, including a comprehensive overview of our regulated businesses, please see the section entitled, "Business—Networks" in Part I, Item 1 in this report.

Revenues

Networks obtains its operating revenues primarily from the sale of electricity and natural gas at rates established by the state utilities commissions and the FERC in its jurisdictions through base rates and cost recovery deferral mechanisms, including reconciling differences between actual revenue received or cost incurred with the rate allowances provided under the approved tariffs. Cost recovery deferral mechanisms create regulatory assets and liabilities under the FERC, consistent with generally accepted accounting principles for financial reporting in the United States, or U.S. GAAP.

Regulatory deferrals in New York include electric and gas supply costs, PPAs, net plant reconciliations (downward only), revenue decoupling, system benefit charges, RPS, energy efficiency programs, including heat pumps, economic development programs, earnings sharing mechanism, electric vehicle program costs, labor FTE's, low income programs, pension costs, other post-employment benefits costs, environmental remediation costs, major storm costs, distribution vegetation management costs (downward only), gas research and development, incremental maintenance initiatives (downward only), management audit consultant and implementation costs, property taxes, Reforming the Energy Vision, or REV, initiatives, Nuclear Electric Insurance Limited credits, credit and debit card fees, debt costs, power tax, 2017 Tax Act, exogenous costs and certain legislative, accounting, regulatory and tax related actions.

Regulatory deferrals in Maine include stranded costs, distribution revenue decoupling, power tax regulatory asset, 2017 Tax Act, environmental remediation, storm reserve accounting, electric thermal storage pilot costs, standard offer retainage costs, AMI opt-out program costs, AMI deferral costs, AMI legal/health proceeding costs, conservation program costs, demand side management costs, low income program costs, electric lifeline program costs, make-ready line extension costs, electric vehicle pilot program costs and transmission planning and related cost allocation.

Regulatory deferrals in Connecticut include electric and gas supply costs, PPAs, revenue decoupling, earnings sharing mechanism, system benefit charges, certain hardship bad debt expense, transmission revenue requirements, gas distribution integrity management program costs, gas system expansion costs, certain public policy costs, certain environmental remediation costs, major storm costs and certain legislative, accounting, regulatory and tax related actions.

Regulatory deferrals in Massachusetts include gas supply costs, gas supply-related bad debt costs, environmental remediation costs, arrearage management program costs, gas system enhancement program costs, energy efficiency program costs, 2017 Tax Act and certain other public policy costs.

Each of Networks' regulated utilities' rate plans, other than MNG, contain an RDM under which their actual energy delivery revenues are compared on a periodic basis with the authorized delivery revenues and the difference accrued, with interest, for refund to or recovery from customers, as applicable.

NYSEG, RG&E and UI are energy delivery companies and also provide energy supply as providers of last resort. Energy costs that are set on the wholesale markets are passed on to consumers. The difference between actual energy costs that are incurred and those that are initially billed are reconciled in a process that results in either immediate or deferred tariff adjustments. These procedures apply to other costs, which are in most cases exceptional, such as the effects of extreme weather conditions, environmental factors, regulatory and accounting changes and treatment of vulnerable customers, that are offset in the tariff process.

Pursuant to agreements with, or decisions of the NYPSC and the MPUC, Networks’ Maine and New York regulated utilities are each subject to a minimum equity ratio requirement that is tied to the capital structure assumed in establishing revenue requirements. Pursuant to these requirements, each of NYSEG, RG&E, CMP and MNG must maintain a minimum equity ratio equal to the ratio in its currently effective rate plan or decision measured using a trailing 13-month average. On a monthly basis, each utility must maintain a minimum equity ratio of no less than 300 basis points below the equity ratio used to set rates. The minimum equity ratio requirement has the effect of limiting the amount of dividends that can be paid if the minimum equity ratio is not maintained and can, under certain circumstances, require that AVANGRID contribute equity capital. For CMP and MNG, equity distributions that would result in equity falling below the minimum level are prohibited. For NYSEG and RG&E, equity distributions that would result in a 13-month average common equity less than the maximum equity ratio utilized for the earnings sharing mechanism, or ESM, are prohibited if the credit rating of NYSEG, RG&E, AVANGRID or Iberdrola are downgraded by a nationally recognized rating agency to the lowest investment grade with a negative watch or downgraded to noninvestment grade. UI, SCG, CNG and BGC may not pay dividends if paying such dividend would result in a common equity ratio lower than 300 basis points below the equity percentage used to set rates in the most recent distribution rate proceeding as measured using a trailing 13-month average calculated as of the most recent quarter end. In addition, UI, SCG, CNG and BGC are prohibited from paying dividends to their parent if the utility’s credit rating, as rated by any of the three major credit rating agencies, falls below investment grade, or if the utility’s credit rating, as determined by two of the three major credit rating agencies, falls to the lowest investment grade and there is a negative watch or review downgrade notice. We believe that these minimum equity ratio requirements do not present any material risk with respect to our performance, cash flow or ability to pay quarterly dividends. In the ordinary course, Networks utilities manage their capital structures to allow the maximum level of returns consistent with the levels of equity authorized to set rates, and accordingly, compliance with these requirements does not alter ordinary equity level management. The regulated utility subsidiaries are also prohibited by regulation from lending to unregulated affiliates.

Rates

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

In December 2017, PURA approved new tariffs for 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 will be first applied against any environmental regulatory asset balance as defined in the settlement agreement (if one exists at that time) or refunded to customers through a bill credit if such environmental regulatory asset balance does not exist.

In December 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 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 October 27, 2022, the DPU approved new distribution rates for BGC. The distribution rate increase is based on an ROE of 9.70% and 54.00% common equity ratio. New rates went into effect January 1, 2023.

On June 15, 2016, the NYPSC approved NYSEG's and RG&E's 2016 Joint Proposal for a three-year rate plan for electric and gas service which balanced the varied interests of the signatory parties including but not limited to maintaining the companies’ credit quality and mitigating the rate impacts to customers. The 2016 Joint Proposal reflected many customer benefits including: acceleration of the companies’ natural gas leak prone main replacement programs and increased funding for electric vegetation management to provide continued safe and reliable service. The delivery rate increases for the last year of the 2016 Joint Proposal can be summarized as follows:

	May 1, 2018	
Utility	**Rate Increase (Millions)**	**Delivery Rate Increase %**
NYSEG Electric	$ 30	4.10 %
NYSEG Gas	$ 15	7.30 %
RG&E Electric	$ 26	5.70 %
RG&E Gas	$ 10	5.20 %

The allowed rate of return on common equity for NYSEG Electric, NYSEG Gas, RG&E Electric and RG&E Gas was 9.00%. The equity ratio for each company was 48.00%; however, the equity ratio was set at the actual up to 50.00% for earnings sharing calculation purposes. The customer share of any earnings above allowed levels increased as the ROE increased, with customers receiving 50.00%, 75.00% and 90.00% of earnings in rate year three (May 1, 2018 – April 30, 2019) above 9.75%, 10.25% and 10.75% ROE, respectively. The rate plans also included the implementation of a rate adjustment mechanism (RAM) designed to return or collect certain defined reconciled revenues and costs, new depreciation rates and continuation of the existing RDM for each business. The 2016 Joint Proposal reflected the recovery of deferred NYSEG Electric storm costs of approximately $262 million, of which $123 million is being amortized over ten years and the remaining $139 million is being amortized over five years. The proposal also continues reserve accounting for qualifying Major Storms ($26 million annually for NYSEG Electric and $3 million annually for RG&E Electric). Incremental maintenance costs incurred to restore service in qualifying divisions will be chargeable to the Major Storm Reserve provided they meet certain thresholds.

On June 22, 2020, NYSEG and RG&E filed a joint proposal with the NYPSC for a new three-year rate plan (the "2020 Joint Proposal"). On November 19, 2020, the NYPSC approved the 2020 Joint Proposal, with modifications to the rate increases at the two electric businesses. The modifications were made to limit the overall bill impacts, to a level at or below 2.00% per year, in consideration of the current impacts of COVID-19 on the economic climate. The effective date of new tariffs was December 1, 2020 with a make-whole provision back to April 17, 2020. The new rates help to facilitate the companies' transition to a cleaner energy future while allowing for important initiatives such as COVID-19 relief for customers and additional funding for vegetation management, hardening/resiliency and emergency preparedness. The rate plans continue the RAM designed to return or collect certain defined reconciled revenues and costs, have new depreciation rates and continue existing RDMs for each business. The 2020 Joint Proposal bases delivery revenues on an 8.80% ROE and 48.00% equity ratio; however, for the proposed ESM, the equity ratio is the lower of the actual equity ratio or 50.00%. The below table provides a summary of the approved delivery rate increases and delivery rate percentages, including rate levelization and excluding energy efficiency, which is a pass-through, for all four businesses. Rate years two and three commence on May 1, 2021 and 2022, respectively.

	Year 1		Year 2		Year 3	
Utility	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %
NYSEG Electric	$ 34	4.6 %	$ 46	5.9 %	$ 36	4.2 %
NYSEG Gas	$ —	— %	$ 2	0.8 %	$ 3	1.6 %
RG&E Electric	$ 17	3.8 %	$ 14	3.2 %	$ 16	3.3 %
RG&E Gas	$ —	— %	$ —	— %	$ 2	1.3 %

On May 26, 2022, NYSEG and RG&E filed for a new rate plan with the NYPSC. The rate filings are based on test year 2021 financial results adjusted to the rate year May 1, 2023 – April 30, 2024. Since these rate filings were submitted on May 26, 2022, the effective date of new rates, assuming an approximately 11-month approval period, will be May 1, 2023. 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. In their filings, the following revenue changes were requested:

	Requested Revenue Change		
Utility	May 26, 2022 (Millions)	August 12, 2022 (Millions)	Difference (Millions)
NYSEG Electric	$ 274	$ 274	$ —
NYSEG Gas	$ 43	$ 30	$ (13)
RG&E Electric	$ 94	$ 93	$ (1)
RG&E Gas	$ 38	$ 32	$ (6)

On September 16, 2022, the NYPSC suspended new tariffs and rates through April 21, 2023. On October 19, 2022, consistent with the Administrative Law Judge's July 1, 2022 Ruling on Schedule and Party Status, NYSEG and RG&E voluntarily agreed to 60-day extension of maximum suspension period through June 20, 2023, subject to a make-whole provision. On December 21, 2022, NYSEG and RG&E voluntarily agreed to further 60-day extension of maximum suspension period to postpone through August 19, 2023, subject to a make-whole provision. During this time, the parties have conducted multi-party rate case settlement negotiations. We cannot predict the outcome of this proceeding.

In an order issued on February 19, 2020, the MPUC authorized an increase in CMP's distribution revenue requirement of $17 million, or approximately 7.00%, based on an allowed ROE of 9.25% and a 50.00% equity ratio. The rate increase was effective March 1, 2020. The MPUC also imposed a 1.00% ROE reduction (to 8.25%) for management efficiency associated with CMP's customer service performance following the implementation of its new billing system in 2017. The management efficiency adjustment was ordered to remain in effect until CMP demonstrated satisfactory customer service performance on four specified service quality measures for a rolling average period of 18 months, which commenced on March 1, 2020. CMP met the required rolling average benchmarks for all four of these quality measures and effective February 18, 2022, the MPUC approved CMP's request to remove the management efficiency adjustment and CMP's accounting order to allow it to defer for future recovery the revenues it would effectively lose by not having the adjustment starting from September 1, 2021.

The February 19, 2022 MPUC order provided additional funding for staffing increases, vegetation management programs and storm restoration costs, while retaining the basic tiered structure for storm cost recovery implemented in the 2014 stipulation, and retained the RDM implemented in 2014. The order denied CMP's request to increase rates for higher costs associated with services provided by its affiliates and ordered the initiation of a management audit to evaluate whether CMP's current management structure, and the management and other services from its affiliates, are appropriate and in the interest of Maine customers. The management audit was commenced in July 2020 by the MPUC's consultants and culminated with a report issued by the MPUC's consultants in July 2021. On February 18, 2022, the MPUC opened a narrowly tailored follow-on investigation examining how CMP and its customers are affected by decisions made at the CMP corporate parent level about earnings, capital budgeting, and planning. In this context, the investigation will also examine regulatory approaches and structures including ratemaking and performance mechanisms. We cannot predict the outcome of this investigation.

On August 11, 2022, CMP filed a three-year rate plan, with adjustments to the distribution revenue requirement in each year. In its filing, CMP has set the three rate years as May 10, 2023 to May 9, 2024, or Rate Year 1; May 10, 2024 to May 9, 2025, or Rate Year 2; and May 10, 2025 to May 9, 2026, or Rate Year 3. The requested Rate Year revenue requirement increases for the rate years are $48 million, $28 million and $23 million, respectively. The revenue requirement adjustments are based on a test year ending December 31, 2021. The requested revenue changes for each rate year of the proposal are subject to four adjustment mechanisms: (1) a yearly review of plant additions with potential downward reconciliation in the event of an underspend, (2) a capital adjustment mechanism for certain incremental pole replacements, broadband work, electric vehicle work, energy storage projects, and metering system upgrades, (3) a symmetrical inflation reconciliation adjustment, and (4) reconciliation of the benefits associated with the tax basis repair deduction. Other parties filed direct testimony in this proceeding on December 2, 2022 and CMP filed rebuttal testimony on February 7, 2023. New rates are expected to take effect on or around August 2023. We cannot predict the outcome of this matter.

On May 17, 2016, the MPUC approved MNG's ten-year rate plan through April 30, 2026. The settlement structure for non-Augusta customers includes a 34.60% delivery revenue increase over five years with an allowed 9.55% ROE and 50.00% common equity ratio. The settlement structure for Augusta customers includes a ten-year rate plan with existing Augusta customers being charged rates equal to non-Augusta customers plus a surcharge which increases annually for five years. New Augusta customers will have rates set based on an alternate fuel market model. In year seven of the rate plan MNG will submit a cost of service filing for the Augusta area to determine if the rate plan should continue. This cost of service filing will exclude $15 million of initial 2012/2013 gross plant investment, however the stipulation allows for accelerated depreciation of these assets. If the Augusta area's cost of service filing illustrates results above a 14.55% ROE then the rate plan may cease, otherwise the rate plan would continue.

CMP's and UI's electric transmission rates are determined by a tariff regulated by the FERC and administered by ISO-NE. Transmission rates are set annually pursuant to a FERC authorized formula that allows for recovery of direct and allocated transmission operating and maintenance expenses, including return of and on investment in assets. The FERC currently provides an initial base ROE of 10.57% and additional incentive adders applicable to assets based upon vintage, voltage and other factors.

In September 2011, several New England governmental entities, including PURA, the Connecticut Attorney General and the Connecticut Office of Consumer Counsel filed a joint complaint with the FERC against ISO-NE and several New England Transmission Owners, or NETOs, (including CMP and UI) claiming that the current approved base ROE used in calculating formula rates for transmission service under the ISO-NE Open Access Transmission Tariff, or OATT, by the NETOs of 11.14% 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).

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, or the October 2018 Order. The FERC proposed to use this new methodology to resolve Complaints I, II, III and IV filed by the New England state consumer advocates.

The proposed ROE methodology set forth in the October 2018 Order considers more than just the two-step discounted cash flow, or DCF, analysis adopted in the FERC order on Complaint I vacated by the Court. It uses four financial analyses (i.e., DCF, the capital-asset pricing model, or CAPM, expected earnings analysis and risk premium analysis) to produce a range of returns to narrow the zone of reasonableness when assessing whether a complainant has met its initial burden of demonstrating that the utility's existing ROE is unjust and unreasonable. The proposed ROE methodology establishes a range of just and reasonable ROEs of 9.60% to 10.99% and proposes a just and reasonable base ROE of 10.41% with a new ROE cap of 13.08%. Pursuant to the October 2018 Order, the NETOs filed 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 CAPM 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. On May 21, 2020, FERC issued a ruling, which, among other things, adjusted the methodology to determine the MISO transmission owners' ROE, resulting in an increase in ROE from 9.88% to 10.02% by utilizing the risk premium model in addition to the DCF model and capital-asset pricing model under both prongs of Section 206 of the FPA, and calculated the zone of reasonableness into equal thirds rather than employing the quartile approach. On November 19, 2020, FERC issued an order addressing arguments raised on the rehearing of its May 21, 2020 order, making minor adjustments to certain typographical errors with regard to some of the case inputs it included in its Risk Premium model analysis. However, those minor adjustments did not affect the outcome of the case, leaving the 10.02% ROE established by the May 21, 2020 order in place. Parties to these orders affecting the MISO transmission owners' base ROE petitioned for their review at the D.C. Circuit Court of Appeals in January 2021. The NETO's submitted an amici curia brief in support of the MISO transmission owners on March 17, 2021. On August 9, 2022, the court vacated the MISO ROE orders and remanded the case back to FERC for further proceedings. In particular, the court found that FERC failed to offer a reasoned explanation for its inclusion of the Risk Premium model after initially (and forcefully) rejecting it, and thus its development of the new ROE-setting methodology was arbitrary and capricious. We cannot predict the outcome or timing of these proceedings, including the potential impact the MISO transmission owners' ROE proceeding may have in establishing a precedent for our pending four Complaints, or whether a continued MISO ROE proceeding will precede the issuance of an order on our pending Complaints.

Legislative and Regulatory Update

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 $1.4 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. Their appeals are 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.

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.

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 it's 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.

On November 23, 2021, the MDEP issued an Order finding that the Initiative constitutes a changed circumstance justifying the suspension of the MDEP permits for the NECEC project. This MDEP-ordered suspension will remain effective unless and until a court grants Networks and NECEC Transmission LLC’s request for a preliminary injunction and allows continued construction of the NECEC project pending the final outcome of the legal challenge to the Initiative, or, if a court does not grant a preliminary injunction, until final disposition of the legal challenge in favor of Networks and NECEC Transmission LLC. 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.

On December 16, 2021, the Maine Business & Consumer Court denied Networks and NECEC Transmission LLC’s request for a preliminary injunction temporarily precluding application of the Initiative to the NECEC transmission project. 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. On December 28, 2021, 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 the Initiative provisions requiring legislative approval for the construction of any high impact transmission line anywhere in Maine and prohibiting high impact transmission lines in the Upper Kennebec Region 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 vested rights analysis to the Business & Consumer Court with guidance on how to conduct it.

On October 21, 2022, the Business and Consumer denied Owner's request for reconsideration of its December 16, 2021 Order that denied Owner's preliminary injunction request, declining to issue a preliminary injunction to allow construction of the NECEC to resume while the litigation against the Initiative proceeds.

The trial in the Initiative challenge is currently expected to take place in April 2023.

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.

Construction of the NECEC project started in January 2021 and was halted in November 2021. Construction remains stopped pending the outcome of NECEC Transmission LLC's challenge to the Initiative. There are potentially adverse implications arising out of the suspension of the MDEP permit, the Initiative, and the pending challenge, which may have negative impacts on the NECEC project, including impacts related to increased project construction costs, disputes with third party vendors regarding contracts and certain change orders, and a decrease in expected returns. The company is evaluating the construction schedule for the NECEC project for a commercial operation date in August 2025. As of December 31, 2022, we have capitalized approximately $585 million for the NECEC project. The outcome of the ongoing legal proceedings could have an adverse effect on the success of the NECEC project indicating that the carrying amount may not be recoverable. We cannot predict the outcome of these proceedings and the results of such evaluation, if any.

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 have made statements that they intend to continue to collect sufficient signatures to present the referendum in a 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. We cannot predict the outcome of the lawsuit or any Citizen's Initiative.

In February 2022, a bill, L.D. 1959, An Act To Ensure Transmission and Distribution Utility Accountability was introduced in the Maine Legislature. The bill provides additional Maine PUC requirements on Maine large electric utilities, including CMP, to ensure customer service and reliability. The bill imposes penalties for poor performance, adds more protection for whistleblowers who report illegal or improper behavior by a utility, authorizes the PUC to audit utilities' financial information, requires utilities to submit regular plans to address the impact of climate change on their infrastructure, and initiates a proceeding for divestiture subject to constitutional protections due process and just compensation should the large electric utilities fail to meet to be determined standards. The bill, as amended, passed the Maine Legislature in April 2022 and became law.

CMP System Upgrades Due to Distributed Generation Demand

CMP has entered into certain interconnection agreements with distributed generation operators and/or developers. Due to the increased demand for solar distribution-side connections, certain reconfigurations of the grid and substation and systems upgrades may be necessary to prevent potential safety issues. CMP is analyzing the anticipated costs of the necessary upgrades and the distributed generation operations and/or developers responsibility for such costs under the interconnection agreements. We cannot predict the outcome of this matter, including any potential proceedings before the MPUC.

New England Clean Energy Request for Proposals

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

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

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

On December 28, 2018, DEEP issued a directive to UI to negotiate and enter into PPAs with twelve projects, totaling approximately 12 million MWh, selected as a result of the Zero Carbon RFP issued by DEEP pursuant to PA 17-3, which provides that the net costs of the PPAs are recoverable through electric rates. One of the selected projects is the Millstone nuclear facility located in Waterford, Connecticut which is owned by Dominion Energy, Inc. The PPA with Dominion was executed and approved by PURA in September 2019. Of the eleven other projects, one dropped out and PPAs with nine other projects were executed and approved by PURA in November 2019. The PPA for the final project was approved in August 2020.

Pursuant to Connecticut Act Concerning the Procurement of Energy Derived from Offshore Wind, DEEP solicited proposals from providers of energy derived from offshore wind facilities that are Class I renewable energy sources for up to 2,000 MW in the aggregate and selected Vineyard Wind, an affiliate of UI, to provide 804 MW of offshore wind through the development of its Park City Wind Project. In 2020, UI entered into a PPA with Vineyard Wind for the offshore wind energy. Similar to the case with the zero carbon PPAs discussed above, the net costs of the PPAs are recoverable through electric rates.

Reforming the Energy Vision

In 2014, the NYPSC instituted its REV proceeding, the goals of which are to improve electric system efficiency and reliability, encourage renewable energy resources, support distributed energy resources, or DER, and empower customer choice. In this proceeding, the NYPSC is examining the establishment of a Distributed System Platform to manage and coordinate DER, and provide customers with market data and tools to manage their energy use. The NYPSC is also examining how its regulatory practices should be modified to incentivize utility practices to promote REV objectives. REV has been divided into two tracks, Track 1 for market design and technology, and Track 2 for regulatory reform. REV proposes regulatory changes that are intended to promote more efficient use of energy, deeper penetration of renewable energy resources such as wind and solar, and wider deployment of DER, such as micro grids, on-site power supplies and storage. Track 2 was undertaken in parallel with Track 1, and examines changes in current regulatory, tariff, market design and incentive structures to better align utility interests with achieving NYPSC’s policy objectives. Our New York utilities are addressing related regulatory issues in their individual rate cases. A Track 2 order was issued in 2016 which included guidance related to the potential for earnings adjustment mechanisms, or EAMs, platform service revenues, innovative rate designs, and data utilization and security. In 2016, NYSEG and RG&E filed a proposal for the implementation of EAMs in the areas of system efficiency, energy efficiency, interconnections and clean air. The EAM is reflected in the rate plan approved in 2020.

In 2016, an initial DSIP was filed by NYSEG and RG&E and included information regarding the potential deployment of Automated Metering Infrastructure, or AMI. A separate petition for the cost recovery associated with full deployment of AMI was filed by NYSEG and RG&E. In March 2017, the NYPSC issued three separate REV-related orders. The three orders involved: 1) modifications to the electric utilities’ proposed interconnection EAM framework; 2) further DSIP requirements, including the filing of an updated DSIP plan by mid-2018 and implementing two energy storage projects at NYSEG by the end of 2018; and 3) Net Energy Metering Transition including implementation of Phase One of VDER. NYSEG and RG&E submitted biannual updates of the DSIP plan on July 31, 2018 and June 30, 2020, consistent with guidance received from the NY Department of Public Service. The next DISP update is scheduled for June 2022. As of the end of 2018, both NYSEG and RG&E had deployed two energy storage projects each, consistent with the March 2017 NYPSC order requirements. In

December 2018, the NYPSC staff submitted whitepapers on standby and buyback service rate design, future value stack compensation and capacity value compensation. The NYPSC ruled on the proposals set forth in the whitepapers on May 16, 2019. NYSEG and RG&E filed proposed standby and buyback rates with the NYPSC on September 24, 2019. A final Commission Order is expected in 2022. The NYPSC also issued an order on value stack compensation for high-capacity-factor resources on December 12, 2019 modifying the treatment of certain high-capacity-factor DER in the Value Stack compensation framework. The modification per the December 12, 2019 Order became effective February 1, 2020. On March 19, 2020, the Commission issued an additional Order regarding Value Stack Compensation. The Order directs National Grid, NYSEG and RGE to reallocate capacity from closed tranches where available capacity remained due to projects being canceled since the issuance of the VDER Compensation Order, and to assign that capacity to a new Community Credit Tranche with compensation at 2 cents per kWh. The utilities must also continue to reallocate capacity to this new Tranche for the next six months when there are cancellations of projects that have received a Market Transition Credit (MTC) or Community Credit allocation. The new provisions per the March 19, 2020 Order became effective on May 1, 2020. On July 16, 2020, the Commission issued an Order establishing a net metering successor tariff. The Order continues Phase One NEM for all eligible mass market and commercial projects under 750 kW interconnected after January 1, 2022 and implements a modest customer benefit contribution (CBC) for onsite DERs to address cost recovery of certain public benefit programs. Customers that install DERs interconnected after January 1, 2022 shall be charged a monthly per kW fee based on the nameplate rating of the DER. Draft tariff leaves implementing the Commission’s Order and proposed CBC calculations were filed on November 1, 2020. A final Commission Order was issued on August 13, 2021, implementing the CBC effective January 1, 2022 for new mass market net metering customers.

On May 14, 2020, the Commission issued an Order extending and expanding distributed solar incentives. In addition to authorizing the extension of and additional funding for the NY-Sun program, the Commission modified certain program rules related to the NY-Sun program and the VDER policy. As part of the ordered modifications, the Commission directed the electric utilities with VDER tariffs to add tariff language for a Remote Crediting program that will allow Value-Stack-eligible generation resources to distribute the credits they receive for generation injected into the utility system to the utility bills of multiple, separately sited, non-residential customers. The Commission ordered the utilities to submit tariff leaves that implement the modifications associated with the Remote Crediting program to become effective November 1, 2020. Given the complexity of the program changes, the utilities petitioned the Commission for an extension. Tariffs were filed on August 16, 2021, becoming effective on September 1, 2021.

On April 24, 2018, the Commission instituted a proceeding to consider the role of utilities in providing infrastructure and rate design to encourage the adoption of electric vehicles and expansion of electric vehicle supply equipment. The Commission issued an Order on February 2, 2019 to establish a Direct Current Fast Charger incentive program, and subsequently clarified its Order on July 12, 2019 and March 3, 2020. A Whitepaper was issued by DPS Staff on January 13, 2020, proposing a make-ready infrastructure program with a budget estimated at $582 million. An order in this proceeding was issued on July 16, 2020 approving a $700 million statewide program (NYSEG and RG&E combined share is approximately $118 million) funded by customers to accelerate the deployment of electric vehicle charging stations in an effort to increase the number of electric vehicles.

On February 11, 2021, the Commission issued an Order to implement an Integrated Energy Data Resource platform, where NYSERDA was designated as the Program Sponsor of the platform. The development of the platform will be an iterative process, currently separated into two phases. Utilities will be expected to transmit data to the platform through processes to be established with the Program Manager (to be determined). The Order established a combined cost cap of $12 Million for NYSEG and RG&E for Phase 1, to be deferred and recovered in the next rate case filing after Phase 1 is complete. On April 15, 2021, the Commission issued an Order Adopting a Data Access Framework and Establishing Further Process (“DAF Order”). The DAF Order establishes a centralized data access certification process. On May 14, 2021, a stakeholder (Mission:data Coalition) filed a petition for rehearing on the DAF Order citing concerns with the audit requirements. The NY utilities also jointly filed a petition for rehearing on May 17, 2021 regarding the Commission’s directive to remove fees for certain requests for data. The Commission issued an Order on November 18, 2021 denying both requests for rehearing.

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

In March 2018, following two severe winter storms that impacted more than a million electric utility customers in New York, including 520,000 NYSEG and RG&E customers, the NYDPS commenced a comprehensive investigation of the preparation and response to those events by New York's major electric utility companies. The investigation was expanded in the spring of 2018 to include other 2018 New York spring storm events.

On April 18, 2019, the NYDPS staff issued a report or the 2018 Staff Report, of the findings from their investigation. The 2018 Staff Report identified 94 recommendations for corrective actions to be implemented in the utilities Emergency

Response Plans, or ERPs. The report also identified potential violations by several of the utilities, including NYSEG and RG&E.

Also on April 18, 2019, the NYPSC issued an Order Instituting Proceeding and to Show Cause directed to all major electric utilities in New York, including NYSEG and RG&E. The order directs the utilities, including NYSEG and RG&E, to show cause why the NYPSC should not pursue civil and/or administrative penalties for the apparent failure to follow their respective ERPs as approved and mandated by the NYPSC. The NYPSC also directed the utilities, within 30 days, to address whether the NYPSC should mandate, reject or modify in whole or in part, the 94 recommendations contained in the 2018 Staff Report. On May 20, 2019, NYSEG and RG&E responded to the portion of the Order to Show Cause with respect to the recommendations contained in the 2018 Staff Report. A petition requesting Commission approval of a joint settlement agreement was filed with the Commission on December 17, 2019. On February 6, 2020, the Commission approved the joint settlement agreement, which allows the companies to avoid litigation and provides for payment by the companies of a $10.5 million penalty ($9.0 million by NYSEG and $1.5 million by RG&E). The settlement reached as part of the NYSEG Electric and RG&E Electric three-year rate plan provides for utilization of these penalties as rate modifiers by the establishment of regulatory liabilities that will be amortized over the three-year term of the rate plans for both NYSEG Electric and RG&E Electric.

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

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

RG&E, Greenlight and Frontier filed respective notices to initiate settlement negotiations with respect to the alleged violations and to extend the deadline for filing a response to the Show Cause Order. The NYPSC granted the extension requests initiating settlement discussions. On or about August 12, 2021, the NYPSC approved a settlement entered into by NYDPS and RG&E providing for, among other things, RG&E's payment of $3 million, which will be used to support the State of New York's broadband initiative for underserved areas. This settlement amount could increase to a maximum of $5 million if RG&E does not resolve certain identified safety violations caused by Greenlight's pole attachments on or before December 31, 2021. We have met all compliance requirements of the settlement and filed the final compliance statement with the NYPSC on January 12, 2022.

CMP Customer Billing Class Action

On August 16, 2018, an amended class action lawsuit was filed against CMP and the Company in the Cumberland County Superior Court on behalf of all CMP customers alleging that CMP's new billing software and metering system improperly overcharged customers. The plaintiff asserts claims based on unjust enrichment, breach of contract, and fraudulent and intentional misrepresentation and seeks damages, punitive damages, attorney fees and costs. CMP and the Company removed the case to federal court and filed a Motion to Dismiss on September 30, 2019. On November 22, 2019, upon agreement of the parties, CMP and the Company withdrew its motion to dismiss without prejudice and the plaintiffs were granted leave to file an amended complaint on or before January 31, 2020 to allow for the conclusion of the MPUC investigation into CMP's metering, billing, and customer communications practices. On January 31, 2020, the plaintiffs filed their Third Amended Complaint. On February 28, 2020, CMP and the Company filed a Motion to Dismiss Plaintiff's Third Amended Complaint Without Prejudice or to Stay Proceedings Pending Plaintiffs' Exhaustion of Administrative Remedies. The plaintiffs filed an opposition to the Motion to Dismiss and CMP and the Company filed a reply. Oral Argument on the Motion to Dismiss was held on September 8, 2020. On November 25, 2020, the Court denied CMP's motion to stay the proceeding or dismiss the proceeding without prejudice. On February 1, 2021, CMP and the Company filed its Motion to Dismiss with prejudice for all claims except the breach of contract claim, which under the rules cannot be dismissed via this motion. The plaintiffs' opposition was filed on March 9, 2021, and CMP filed its reply on March 29, 2021. Oral argument on the Motion to Dismiss was held on May 20, 2021. On August 6, 2021, the Court ruled on the Motion to Dismiss, granting dismissal of all counts against the Company and all counts against CMP except for certain fraud claims. On August 27, 2021, CMP filed its answer to the Third Amended Complaint as to the breach of contract and fraud claims. Thereafter the parties commenced discovery.

In late June 2022, Plaintiffs' counsel informed Defendants that Plaintiffs' lead law firm was disbanding and would be withdrawing as counsel, and that a new lead firm was being identified. Plaintiffs sought a four-month extension of all deadlines, which Defendants opposed. The Court entered a stay of all deadlines until August 1, 2022. On July 26, 2022, the Court issued a new scheduling order, setting among other deadlines, November 21, 2022 as the deadline for Plaintiffs' to file its motion for class certification and April 28, 2023 as the deadline to complete discovery.

On September 2, 2022, Plaintiffs informed CMP and the Company that they were unable to identify a new lead law firm, and that they intend to dismiss the class allegations with the intent to continue pursuing individual claims. On September 30, 2022, the Court granted a consented-to motion to strike the class allegations from the complaint, such that the lawsuit now only involves the individual claims of the five named Plaintiffs. On October 21, 2022, the parties filed the Stipulation of Dismissal of all remaining claims without prejudice, and the Court closed the docket.

Tax Act Proceedings

The Tax Act significantly changed the federal taxation of business entities including, among other things, implementing a federal corporate tax rate decrease from 35% to 21% for tax years beginning after December 31, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates 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. With regard to SCG, we expect Tax Act savings to be deferred until they are reflected in tariffs in a future rate case, unless PURA determines otherwise.

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 $137 million and $142 million, respectively, at December 31, 2022 and December 31, 2021.

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. The NYPSC audit report is expected to be completed during 2023.

Weather Impact

The demand for electric power and natural gas is affected by seasonal differences in the weather. Statewide demand for electricity in New York, Connecticut and Maine tends to increase during the summer months to meet cooling load or in winter months for heating load while statewide demand for natural gas tends to increase during the winter to meet heating load. Market prices for both electricity and natural gas reflect the demand for these products and their availability at that time. Overall operating results of Networks do not fluctuate due to commodity costs as the regulated utilities generally recover those costs coincident with their expense or defer any differences for future recovery. Networks has historically sold less power when weather conditions are milder and may also be affected by severe weather, such as ice and snow storms, hurricanes and other natural disasters which may result in additional cost or loss of revenues that may not be recoverable from customers. However, Networks' regulated utilities, other than MNG, have approved RDMs as part of the NYPSC, PURA and MPUC rate plans in place for the period ended December 31, 2022. The RDM allows the regulated utilities to defer for future recovery and shortfall from projected revenues whether due to weather, economic conditions, conservation or other factors.

New Renewable Source Generation

Under Connecticut Public Act 11-80, or PA, Connecticut electric utilities are required to enter into long-term contracts to purchase Connecticut Class I Renewable Energy Certificates, or RECs, from renewable generators located on customer premises. Under this program, UI is required to enter into contracts totaling approximately $200 million in commitments over approximately 21 years. The obligations were initially expected to phase in over a six-year solicitation period and to peak at an annual commitment level of about $13.6 million per year after all selected projects are online. PA 17-144, PA 18-50 and PA 19-35 extended the original six-year solicitation period of the program by adding seventh, eighth, ninth, and tenth years, and increased the original funding level of this program by adding up to $64 million in additional commitments by UI. UI expects to partially mitigate the cost of these contracts through the resale of the RECs. PA 11-80 provides that the remaining costs (and any benefits) of these contracts, including any gain or loss resulting from the resale of the RECs, are fully recoverable from (or credited to) customers through electric rates.

Pursuant to Connecticut statute, in January 2017, UI entered into a master agreement with the Connecticut Green Bank to procure Connecticut Class I RECs produced by residential solar installations in 15-year tranches, with a final tranche to commence no later than 2022. UI's contractual obligation is to procure 20% of RECs produced by about 255 MW of residential solar installations. Connecticut statutes provides that the net costs (and any benefits) of these contracts, including any gain or loss resulting from the resale of the RECs, are fully recoverable from (or credited to) customers through electric rates.

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

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

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 were consolidated. On October 17, 2022, the court denied UI's appeal and affirmed PURA's decisions in their entirety. UI filed a notice of appeal to Connecticut's Appellate court on November 7, 2022. We cannot predict the outcome of this proceeding.

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.

Also, 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.

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

In August 2020, following Tropical Storm Isaias, the NYDPS commenced a comprehensive investigation of the preparation and response to this event by New York's major electric utility companies. In addition, on August 20, 2020, the New York State Senate and Assembly held a joint hearing to examine the response of various utility companies during the aftermath of Tropical Storm Isaias. On December 31, 2020, NYSEG and NYDPS Staff entered into a settlement agreement regarding three alleged violations by NYSEG of its emergency response plan pursuant to which NYSEG agreed to make a payment of a penalty of approximately $1.5 million. The settlement was approved by the NYPSC on January 21, 2021.

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.

Summary Investigation of Management Issues Identified in Management Audit of CMP

As noted above, on February 19, 2020, the MPUC issued its final order in CMP's distribution revenue case. As part of that order, the MPUC initiated a management audit of CMP and its affiliates to evaluate whether CMP's current management structure, and the management and other services from its affiliates, are appropriate and in the interest of Maine customers. The management audit was commenced in July 2020 by the MPUC's consultants and on July 12, 2021, the independent auditor released its final report. On September 28, 2021, the MPUC opened a summary investigation to follow up on the management audit report. The MPUC directed CMP to file a plan to incorporate feedback from the management audit. CMP filed a Performance Improvement Plan and parties commented on the plan. CMP provided responsive comments on January 6, 2022. On February 18, 2022, the MPUC opened a narrowly tailored follow-on investigation examining how CMP and its customers are affected by decisions made at the CMP corporate parent level about earnings, capital budgeting, and planning. In this context, the investigation will also examine regulatory approaches and structures including ratemaking and performance mechanisms. We cannot predict the outcome of this investigation.

Late Payment Charge Order

Due to the COVID-19 pandemic, the State of New York previously issued an executive order on March 20, 2020 which, among other items, resulted in the suspension of recovery of unbilled fees, including late payment fees and other fees associated with customer non-payment including, but not limited to, connection fees and reconnection fees. On June 17, 2022, the NYPSC issued an order authorizing NYSEG and RG&E to establish a surcharge to recover unbilled fees for Rate Year One and a surcharge/surcredit for Rate Years Two and Three, subject to the offsetting cost reductions resulting from the COVID-19 pandemic, starting on July 1, 2022.

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 $2.2 billion, including participation with other upstate utilities on certain projects.

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 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 provisions of the IRA will be effective for periods beginning after December 31, 2022. Given the complexity and uncertainty around the applicability of the legislation to our specific facts and circumstances, we continue to analyze the IRA provisions while waiting on pending Department of Treasury regulatory guidance.

Renewables

Renewable Energy Incentives

Renewables relies, in part, upon government policies that support utility-scale renewable energy and enhance the economic feasibility of development and operating wind energy projects in regions in which Renewables operates or plans to develop and operate renewable energy facilities.

The IRA extended and enhanced solar and wind tax incentives. The IRA also added certain prevailing wage and apprenticeship rules for projects to claim the full credit value unless construction started prior to January 29, 2023. The IRA provides other credit enhancements for qualifying projects that meet domestic content and/or energy community siting requirements.

The 2020 Consolidated Appropriations Act provided favorable extensions to renewable income tax incentives. Onshore and offshore wind projects could claim a 60% PTC for projects commencing construction in 2020 and 2021 and placed in service prior to 2022. Previously, the Setting Every Community up for Retirement Enhancement Act of 2019 extended the PTC and ITC options for wind facilities to 60% of the full credit for facilities commencing construction in 2020 and placed in service prior to 2022.

Solar projects commencing construction before 2020 and placed in service before 2022 could claim a 30% ITC. Solar projects commencing construction in 2020 and 2021 and placed in service before 2022, could claim a 26% ITC.

The Internal Revenue Service, or IRS, provided continuity safe harbor guidance that requires renewable projects to be completed within four years of the year construction commences. Any projects that do not meet this requirement will fall outside of the safe harbor and be subject to IRS scrutiny with regard to the date construction commenced. In 2020, the IRS allowed projects beginning construction in 2016 or 2017 an additional year (five years total) to complete construction. In late December 2020, the IRS issued a notice giving onshore wind projects on federal lands, with transmission permit requirements, and offshore wind projects 10 years to complete construction.

Vineyard Wind 1 Federal Approval

On May 11, 2021, the U.S. Bureau of Ocean Energy Management, or BOEM, issued its Record of Decision, or ROD, approving Vineyard Wind 1, an 806 MW offshore wind project that is a joint venture with CIP.

Lawsuits were filed in July 2021, August 2021, September 2021 and January 2022 against the federal permitting agencies and related officials, including BOEM, the U.S. Fish and Wildlife Service, NOAA Fisheries Directorate, U.S. Army Corps of Engineers and the U.S. Department of the Interior challenging the approval of the proposed Vineyard Wind 1 Project. Vineyard Wind 1 has intervened in these lawsuits to support the federal defense and protect its rights. We cannot predict the outcome of these proceedings.

Results of Operations

The following table sets forth financial information by segment for each of the periods indicated.

	Year Ended December 31, 2022			
	Total	**Networks**	**Renewables**	**Other(1)**
	(in millions)			
Operating Revenues	**$ 7,923**	**$ 6,782**	**$ 1,141**	**$ —**
Operating Expenses				
Purchased power, natural gas and fuel used	2,456	2,295	161	—
Operations and maintenance	2,872	2,338	526	8
Depreciation and amortization	1,085	660	424	1
Taxes other than income taxes	658	588	66	4
Total Operating Expenses	**7,071**	**5,881**	**1,177**	**13**
Operating Income	**852**	**901**	**(36)**	**(13)**
Other Income (Expense)				
Other income (expense)	30	33	10	(13)
Earnings (losses) from equity method investments	262	11	251	—
Interest expense, net of capitalization	(303)	(220)	(16)	(67)
Income Before Income Tax	**841**	**725**	**209**	**(93)**
Income tax expense (benefit)	20	94	(114)	40
Net Income (Loss)	**821**	**631**	**323**	**(133)**
Net loss (income) attributable to noncontrolling interests	60	(3)	63	—
Net Income (Loss) Attributable to Avangrid, Inc.	**$ 881**	**$ 628**	**$ 386**	**$ (133)**

	Year Ended December 31, 2021							
	Total		Networks		Renewables		Other(1)	
	(in millions)							
Operating Revenues	**$**	**6,974**	**$**	**5,754**	**$**	**1,220**	**$**	**—**
Operating Expenses								
Purchased power, natural gas and fuel used		1,719		1,489		230		—
Operations and maintenance		2,706		2,198		495		13
Depreciation and amortization		1,014		616		397		1
Taxes other than income taxes		640		575		72		(7)
Total Operating Expenses		**6,079**		**4,878**		**1,194**		**7**
Operating Income		**895**		**876**		**26**		**(7)**
Other Income (Expense)								
Other income (expense)		60		66		(4)		(2)
Earnings (losses) from equity method investments		7		12		(5)		—
Interest expense, net of capitalization		(298)		(217)		(1)		(80)
Income Before Income Tax		**664**		**737**		**16**		**(89)**
Income tax expense (benefit)		21		98		(48)		(29)
Net Income (Loss)		**643**		**639**		**64**		**(60)**
Net loss (income) attributable to noncontrolling interests		64		(3)		67		—
Net Income (Loss) Attributable to Avangrid, Inc.	**$**	**707**	**$**	**636**	**$**	**131**	**$**	**(60)**

	Year Ended December 31, 2020							
	Total		Networks		Renewables		Other(1)	
	(in millions)							
Operating Revenues	**$**	**6,320**	**$**	**5,188**	**$**	**1,132**	**$**	**—**
Operating Expenses								
Purchased power, natural gas and fuel used		1,379		1,125		254		—
Operations and maintenance		2,466		2,038		429		(1)
Depreciation and amortization		987		592		394		1
Taxes other than income taxes		619		556		71		(8)
Total Operating Expenses		**5,451**		**4,311**		**1,148**		**(8)**
Operating Income (Loss)		**869**		**877**		**(16)**		**8**
Other Income (Expense)								
Other (expense) income		18		15		15		(12)
Losses (earnings) from equity method investments		(3)		10		(13)		—
Interest expense, net of capitalization		(316)		(234)		(7)		(75)
Income Before Income Tax		**568**		**668**		**(21)**		**(79)**
Income tax expense (benefit)		29		120		(80)		(11)
Net Income (Loss)		**539**		**548**		**59**		**(68)**
Net loss (income) attributable to noncontrolling interests		42		(2)		44		—
Net Income (Loss) Attributable to Avangrid, Inc.	**$**	**581**	**$**	**546**	**$**	**103**	**$**	**(68)**

(1)Other amounts represent Corporate and intersegment eliminations.

Comparison of Period to Period Results of Operations

Operating revenues increased by 14%, from $6,974 million for the year ended December 31, 2021, to $7,923 million for the year ended December 31, 2022.

Purchased power, natural gas and fuel used increased by 43%, from $1,719 million for the year ended December 31, 2021, to $2,456 million for the year ended December 31, 2022.

Operations and maintenance increased by 6%, from $2,706 million for the year ended December 31, 2021, to $2,872 million for the year ended December 31, 2022.

Details of the period to period comparison are described below at the segment level.

Year Ended December 31, 2022 Compared to the Year Ended December 31, 2021

Networks

Operating revenues for the year ended December 31, 2022 increased by $1,028 million, or 18%, from $5,754 million for the year ended December 31, 2021, to $6,782 million. Electricity and gas revenues increased by $116 million, primarily due to rate increases in New York effective December 1, 2020, $10 million increase in late payment fees, and favorable $16 million of other various deferrals primarily driven by sales use tax payments in the period. Electricity and gas revenues changed due to the following items that have offsets within the income statement: an increase of $806 million in purchased power and purchased gas (offset in purchased power) driven by higher average pricing in commodities in the period, $25 million increase from deferral of pension settlement charges (offset in other income) as a result of freezing of pension benefit accruals and contribution credits for non-union employees in 2022 and an increase of $55 million in flow through amortizations (offset in operating expenses).

Purchased power, natural gas and fuel used for the year ended December 31, 2022 increased by $806 million, or 54%, from $1,489 million for the year ended December 31, 2021, to $2,295 million. The increase is primarily driven by a $806 million increase in average commodity prices and an overall increase in electricity and gas units procured due to higher degree days in the period.

Operations and maintenance during the year ended December 31, 2022 increased by $140 million, or 6%, from $2,198 million for the year ended December 31, 2021, to $2,338 million. The increase is driven by increased business costs of $41 million, an increase of $27 million in uncollectible expenses driven primarily by higher bad debt provisions in New York, a $17 million increase in personnel expenses primarily driven by higher headcount in the period. In addition, there were increases of $55 million in flow-through amortizations (which is offset in revenue).

Renewables

Operating revenues for the year ended December 31, 2022 decreased by $79 million, or 6% from $1,220 million for the year ended December 31, 2021, to $1,141 million. The decrease in operating revenues was primarily due to a $128 million decrease in merchant prices driven mainly by lower demand as compared to the same period of 2021 when demand was higher during the Texas storm, $15 million from the sale of assets in 2021 and unfavorable MtM changes of $5 million on energy derivative transactions entered for economic hedging purposes, offset by $42 million in favorable thermal and power trading driven by higher average prices in the period, $24 million increase driven by higher demand during the weather event in the PJM market and $3 million from production, including new assets in service and curtailment payments in the current period.

Purchased power, natural gas and fuel used for the year ended December 31, 2022 decreased by $69 million, or 30%, from $230 million for the year ended December 31, 2021, to $161 million. The decrease is primarily due to a decrease of $11 million in power and gas purchases due to lower average prices in 2022 compared to 2021 and favorable MtM changes on derivatives of $58 million driven by market price changes in the period.

Operations and maintenance for the year ended December 31, 2022 increased by $31 million, or 6%, from $495 million for the year ended December 31, 2021, to $526 million. The increase is primarily due to a $13 million increase in the bad debt provision driven mainly by provisions during the weather event in the PJM market in 2022, a $24 million increase in connection with an offshore contract provision, $13 million increase in personnel costs driven primarily by increase in headcount in the period, $9 million increase in other operating costs primarily driven by increase in corporate charges in the period, $5 million driven by settlement of liquidated damage claims recorded in 2021, offset by a decrease of $33 million primarily driven by the write-off of certain development projects in the same period of 2021.

Depreciation, Amortization and Impairment

Depreciation, amortization and impairment expenses for the year ended December 31, 2022 increased by $71 million, or 7%, from $1,014 million for the year ended December 31, 2021, to $1,085 million. The increase is driven by $65 million from plant additions in Networks and Renewables in the period and $6 million increase driven by amortization of a deferred gain recorded in 2021.

Other Income and (Expense) and Equity Earnings

Other income and (expense) and equity earnings for the year ended December 31, 2022 increased by $225 million, or 336%, from $67 million for the year ended December 31, 2021, to $292 million. The increase is primarily due to a $246 million gain recognized in the current period from the offshore joint venture restructuring transaction in Renewables, offset by a $21 million unfavorable change in the non-service component of pension expense driven by revised actuarial studies in Networks (which is partially offset within revenue).

Interest Expense, Net of Capitalization

Interest expense for the year ended December 31, 2022 increased by $5 million or 2% from $298 million for the year ended December 31, 2021, to $303 million. The change is primarily due to an increase of $2 million of interest expense at Networks (unfavorable $11 million interest expense from increased debt, offset by $5 million of favorable carrying charges and $4 million favorable regulatory amortizations primarily driven by lower regulatory deferrals from the rate case in New York that was approved November 19, 2020) and $4 million increase in Other mainly driven by increased outstanding balances on commercial papers.

Income Tax Expense

The effective tax rate, inclusive of federal and state income tax, for the year ended December 31, 2022 was 2.4%, 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 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. The effective tax rate, inclusive of federal and state income tax, for the year ended December 31, 2021, was 3.2%, 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 and the equity component of allowance for funds used during construction.

Year Ended December 31, 2021 Compared to the Year Ended December 31, 2020

Networks

Operating revenues for the year ended December 31, 2021 increased by $566 million, or less than 1%, from $5,188 million for the year ended December 31, 2020, to $5,754 million. Electricity and gas revenues increased by $125 million, primarily due to the New York rate plan that was approved November 19, 2020, and rate increases in Maine, $19 million favorable impact from a COVID-19 deferral during the period in New York and Connecticut (in Connecticut this is included in the revenue decoupling mechanism), and $11 million favorable impact from transmission. These were offset by a $8 million unfavorable impact from negative revenue adjustments and $1 million of other decreases. Electricity and gas revenues changed due to the following items that have offsets within the income statement: an increase of $364 million in purchased power and purchased gas (offset in purchased power), an increase of $109 million in flow-through amortizations (offset in operating expenses), offset by a decrease of $54 million in flow-through amortizations ($32 million offset in income tax expense and $21 million offset in other income).

Purchased power, natural gas and fuel used for the year ended December 31, 2021 increased by $364 million, or 32%, from $1,125 million for the year ended December 31, 2020, to $1,489 million. The increase is primarily driven by a $364 million increase in average commodity prices and an overall increase in electricity and gas units procured due to higher degree days in the period.

Operations and maintenance during the year ended December 31, 2021 increased by $160 million, or 8%, from $2,038 million for the year ended December 31, 2020, to $2,198 million. The increase is driven by $34 million of increased personnel expenses primarily driven by an increase in headcount, increased business costs of $10 million, a $4 million increase in uncollectible expenses and $3 million unfavorable other. In addition, there were increases of $109 million in flow-through amortizations (which is offset in revenue).

Renewables

Operating revenues for the year ended December 31, 2021 increased by $88 million, or 8% from $1,132 million for the year ended December 31, 2020, to $1,220 million. The increase in operating revenues was primarily due to a $159 million increase in merchant prices driven mainly by higher demand during the Texas storm in the first quarter of 2021, $58 million in favorable thermal and power trading driven by higher average prices in the period, $23 million from curtailment payments, and $15 million from the sale of assets, offset by unfavorable MtM changes of $132 million on energy derivative transactions entered for economic hedging purposes, and a decrease of $35 million driven by 997 GWh lower wind generation output in the current period.

Purchased power, natural gas and fuel used for the year ended December 31, 2021 decreased by $24 million, or 9%, from $254 million for the year ended December 31, 2020, to $230 million. The decrease is primarily due to favorable MtM changes on derivatives of $43 million due to market price changes in the period, offset by an increase of $21 million in power and thermal purchases in the period driven by higher average prices in the period.

Operations and maintenance for the year ended December 31, 2021 increased by $66 million or 15% from $429 million for the year ended December 31, 2020, to $495 million. The increase is primarily due to a $6 million increase in the bad debt provision driven mainly by provisions during the Texas storm in the first quarter of 2021, $16 million of higher land rents driven by new sites, $19 million increase driven by higher personnel costs primarily attributable to new capacity, $40 million due to the write-off of certain development projects and casualty losses in the period, offset by a $15 million decrease driven mainly by settlement of liquidated damage claims in the period.

Depreciation, Amortization and Impairment

Depreciation, amortization and impairment expenses for the year ended December 31, 2021 increased by $27 million or 3% from $987 million for the year ended December 31, 2020, to $1,014 million. The increase is driven by $42 million from plant additions in Networks and Renewables in the period, offset by a $9 million decrease driven by accelerated depreciation from the repowering of wind farms recorded in the same period of 2020 and $6 million decrease driven by amortization of a deferred gain.

Other Income and (Expense) and Equity Earnings

Other income and (expense) and equity earnings for the year ended December 31, 2021 increased by $52 million, or 347%, from $15 million for the year ended December 31, 2020, to $67 million. The change is primarily due to a $31 million favorable increase in allowance for equity funds used during construction, a $24 million favorable change in the non-service component of pension expense driven by revised actuarial studies in Networks (which is partially offset within revenue), and $10 million of favorable equity earnings in the period, offset by $11 million of unfavorable carrying charges and $2 million other decreases.

Interest Expense, Net of Capitalization

Interest expense for the year ended December 31, 2021 decreased by $18 million or 6% from $316 million for the year ended December 31, 2020, to $298 million. The change is primarily due to a decrease of $23 million of interest expense at Networks ($16 million of favorable carrying charges and $12 million favorable regulatory amortizations primarily driven by lower regulatory deferrals from the rate case in New York that was approved November 19, 2020, offset by unfavorable $5 million interest expense from increased debt), offset by a $5 million increase in Other due to increased debt.

Income Tax Expense

The effective tax rate, inclusive of federal and state income tax, for the year ended December 31, 2021 was 3.2%, 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 and the equity component of allowance for funds used during construction. The effective tax rate, inclusive of federal and state income tax, for the year ended December 31, 2020, was 5.1%, which is below the federal statutory tax rate of 21%, primarily due to the recognition of production tax credits associated with wind production and the effect of the excess deferred tax amortization resulting from the Tax Act.

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 restructuring charges, mark-to-market earnings from changes in the fair value of derivative instruments, accelerated depreciation derived from repowering of wind farms, costs incurred related to the PNMR Merger, a legal settlement, an offshore contract provision and costs incurred in connection with the COVID-19 pandemic. 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 years ended December 31, 2022, 2021 and 2020, respectively:

	Year Ended December 31, 2022			
	Total	Networks	Renewables	Corporate *
	(in millions)			
Net Income Attributable to Avangrid, Inc.	**$ 881**	**$ 628**	**$ 386**	**$ (133)**
Adjustments:				
Mark-to-market adjustments - Renewables	—	—	—	—
Offshore contract provision	24	—	24	—
Impact of COVID-19	—	—	—	—
Merger costs	4	—	—	4
Income tax impact of adjustments (1)	(7)	—	(6)	(1)
Adjusted Net Income (2)	**$ 901**	**$ 628**	**$ 403**	**$ (130)**
Net (loss) income attributable to noncontrolling interests	(60)	3	(63)	—
Income tax (benefit) expense	27	94	(108)	41
Depreciation and amortization	1,085	660	424	1
Interest expense, net of capitalization	303	220	16	67
Other (income) expense	(30)	(33)	(10)	13
Losses (earnings) from equity method investments	(262)	(11)	(251)	—
Adjusted EBITDA (3)	**$ 1,964**	**$ 1,561**	**$ 411**	**$ (8)**
Retained PTCs and ITCs	162	—	162	—
PTCs allocated to tax equity investors	119	—	119	—
Adjusted EBITDA with Tax Credits (3)	**$ 2,246**	**$ 1,561**	**$ 693**	**$ (8)**

	Year Ended December 31, 2021			
	Total	Networks	Renewables	Corporate *
		(in millions)		
Net Income Attributable to Avangrid, Inc.	**$ 707**	**$ 636**	**$ 131**	**$ (60)**
Adjustments:				
Mark-to-market adjustments - Renewables	53	—	53	—
Impact of COVID-19	34	34	—	—
Merger costs	12	—	—	12
Income tax impact of adjustments (1)	(26)	(9)	(14)	(3)
Adjusted Net Income (2)	**$ 780**	**$ 661**	**$ 170**	**$ (51)**
Net (loss) income attributable to noncontrolling interests	(64)	3	(67)	—
Income tax (benefit) expense	47	107	(34)	(26)
Depreciation and amortization	1,014	616	397	1
Interest expense, net of capitalization	298	217	1	80
Other (income) expense	(60)	(66)	4	2
Losses (earnings) from equity method investments	(7)	(12)	5	—
Adjusted EBITDA (3)	**$ 2,008**	**$ 1,526**	**$ 476**	**$ 7**
Retained PTCs and ITCs	175	—	175	—
PTCs allocated to tax equity investors	80	—	80	—
Adjusted EBITDA with Tax Credits (3)	**$ 2,263**	**$ 1,526**	**$ 731**	**$ 7**

	Year Ended December 31, 2020			
	Total	Networks	Renewables	Corporate *
	(in millions)			
Net Income (Loss) Attributable to Avangrid, Inc.	**$ 581**	**$ 546**	**$ 103**	**$ (67)**
Adjustments:				
Mark-to-market adjustments - Renewables	5	—	5	—
Restructuring charges	6	5	1	—
Accelerated depreciation from repowering	9	—	9	—
Impact of COVID-19	29	26	1	2
Merger costs	6	—	—	6
Legal settlement - Gas storage	5	—	—	5
Income tax impact of adjustments (1)	(16)	(8)	(4)	(3)
Adjusted Net Income (2)	**$ 625**	**$ 568**	**$ 115**	**$ (58)**
Net (loss) income attributable to noncontrolling interests	(42)	2	(44)	—
Income tax (benefit) expense	45	128	(76)	(8)
Depreciation and amortization	978	592	385	1
Interest expense, net of capitalization	316	234	7	75
Other (income) expense	(18)	(15)	(15)	12
Losses (earnings) from equity method investments	3	(10)	13	—
Adjusted EBITDA (3)	**$ 1,907**	**$ 1,499**	**$ 385**	**$ 23**
Retained PTCs and ITCs	153	—	153	—
PTCs allocated to tax equity investors	63	—	63	—
Adjusted EBITDA with Tax Credits (3)	**$ 2,123**	**$ 1,499**	**$ 601**	**$ 23**

(1) Income tax impact of adjustments: For the year ended December 31, 2022, $(6) from an offshore contract provision and $(1) million from merger costs. For the year ended December 31, 2021, $14 million from MtM adjustment, $9 million from COVID-19 impacts and $3 million from merger costs. For the year ended December 31, 2020, $(1) million from MtM adjustment, $(2) million from accelerated depreciation, $(2) million from restructuring charges, $(8) million from COVID-19 impacts, $(1) million from legal settlement - gas storage and $(2) million from merger costs.

(2) Adjusted Net Income is a non-GAAP financial measure and is presented after excluding restructuring charges, accelerated depreciation derived from the repowering wind farms, MtM activities in Renewables, costs incurred related to the PNMR Merger, a legal settlement, an offshore contract provision and costs incurred in connection with the COVID-19 pandemic.

(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.

Comparison of Period to Period Results of Operations

Year Ended December 31, 2022 Compared to the Year Ended December 31, 2021

Adjusted net income

Adjusted net income increased by $121 million, or 16%, from $780 million for the year ended December 31, 2021 to $901 million for the year ended December 31, 2022. The increase is primarily due to a $233 million increase in Renewables driven by a gain recognized in the current period from the offshore joint venture restructuring transaction and favorable tax expense from valuation allowances and state tax rate changes which are primarily offset in Corporate, offset by a $33 million decrease in Networks driven primarily by higher business costs and uncollectible expenses in the period, $79 million decrease in Corporate mainly driven by unfavorable tax expense from unitary rate changes in the period which are primarily offset in Renewables.

Year Ended December 31, 2021 Compared to the Year Ended December 31, 2020

Adjusted net income

Adjusted net income increased by $155 million, or 25%, from $625 million for the year ended December 31, 2020 to $780 million for the year ended December 31, 2021. The increase is primarily due to a $93 million increase in Networks driven primarily by a new rate plan in New York that was approved on November 19, 2020, a $55 million increase in Renewables driven by higher merchant pricing mainly from the Texas weather event and a $7 million increase in Corporate mainly driven by favorable tax expense 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 years ended December 31, 2022, 2021 and 2020, respectively:

	Year Ended December 31,		
	2022	2021	2020
		(in millions)	
Networks	$ 628	$ 636	$ 546
Renewables	386	131	103
Corporate (1)	(133)	(60)	(67)
Net Income	**881**	**707**	**581**
Adjustments:			
Mark-to-market adjustments - Renewables (2)	—	53	5
Offshore contract provision (3)	24	—	—
Restructuring charges (4)	—	—	6
Accelerated depreciation from repowering (5)	—	—	9
Impact of COVID-19 (6)	—	34	29
Merger costs (7)	4	12	6
Legal settlement - Gas storage (8)	—	—	5
Income tax impact of adjustments	(7)	(26)	(16)
Adjusted Net Income (9)	**$ 901**	**$ 780**	**$ 625**

	Year Ended December 31,		
	2022	2021	2020
Networks	$ 1.62	$ 1.78	$ 1.76
Renewables	1.00	0.37	0.33
Corporate (1)	(0.34)	(0.17)	(0.22)
Earnings Per Share	**2.28**	**1.97**	**1.88**
Adjustments:			
Mark-to-market adjustments - Renewables (2)	—	0.15	0.02
Offshore contract provision (3)	0.06	—	—
Restructuring charges (4)	—	—	0.02
Accelerated depreciation from repowering (5)	—	—	0.03
Impact of COVID-19 (6)	—	0.10	0.09
Merger costs (7)	0.01	0.03	0.02
Legal settlement - Gas storage (8)	—	—	0.01
Income tax impact of adjustments	(0.02)	(0.07)	(0.05)
Adjusted Earnings Per Share (9)	**$ 2.33**	**$ 2.18**	**$ 2.02**

(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) Costs incurred in connection with an offshore contract provision.
(4) Restructuring and severance related charges relate to costs resulting from restructuring actions involving initial targeted voluntary workforce reductions and related costs in our plan to vacate a lease, predominantly within the Networks segment and costs to implement an initiative to mitigate costs and achieve sustainable growth.
(5) Represents the amount of accelerated depreciation derived from the repowering of wind farms in Renewables.

(6) Represents costs incurred in connection with the COVID-19 pandemic, mainly related to bad debt provisions.
(7) Pre-merger costs incurred.
(8) Removal of the impact from Gas activity in the reconciliation to AVANGRID Net Income.
(9) Adjusted Net Income and Adjusted Earnings Per Share are non-GAAP financial measures and are presented after excluding restructuring charges, accelerated depreciation derived from the repowering wind farms, MtM activities in Renewables, costs incurred related to the PNMR Merger, a legal settlement, an offshore contract provision and costs incurred in connection with the COVID-19 pandemic.

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, equity issuances 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.

Liquidity

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. At December 31, 2022, we had cash and cash equivalents of $69 million, as compared to $1,474 million at December 31, 2021. We have the capacity to borrow up to $3,575 million from the lenders committed to the AVANGRID Credit Facility and $500 million from an Iberdrola Group Credit Facility, each of which are described below.

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 December 31, 2022 and February 21, 2023, there was $397 million and $1,151 million, respectively, of commercial paper outstanding, presented net of discounts on the balance sheet. As of December 31, 2022, the weighted-average interest rate on outstanding commercial paper was 4.66%.

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. As of December 31, 2022, 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 December 31, 2022 and February 21, 2023, was $3,178 million and $2,424 million, respectively.

Iberdrola Group Credit Facility

AVANGRID has a credit facility with Iberdrola Financiacion, S.A.U., a company of the Iberdrola Group. The facility has a limit of $500 million and matures on June 18, 2023. AVANGRID pays a facility fee of 10.5 basis points annually. As of both December 31, 2022 and February 21, 2023, there was no outstanding amount under this credit facility.

Supplier Financing Arrangements

To manage cash flow and related liquidity, we operate a supplier financing arrangement under which certain suppliers can obtain accelerated settlement on invoices from the banking provider. This is a form of reverse factoring which has the objective of serving the group's suppliers by giving them early access to funding. This supplier financing program allows participating suppliers the ability to voluntarily elect to sell our payment obligations to a designated third-party financial institution. We have no economic interest in a supplier's decision to enter into the arrangements. Our obligations to our suppliers, including amounts due and scheduled payment terms, are not impacted by our suppliers' decisions to sell amounts under these arrangements. As of December 31, 2022 and 2021, the amount of notes payable under supplier financing arrangements was $171 million and $161 million, respectively. As of December 31, 2022 and 2021, the weighted average interest rate on the balance was 5.48% and 0.82%, respectively.

Group Cash Pool

We are a party to a liquidity agreement with Bank of America, N.A. along with certain members of the Iberdrola Group. The liquidity agreement aids the Iberdrola Group in efficient cash management and reduces the need for external borrowing by the pool participants. Parties to the agreement, including us, may deposit funds with or borrow from the financial institution, provided that the net balance of funds deposited or borrowed by all pool participants in the aggregate is not less than zero. As of both December 31, 2022 and 2021, the balance was $0. Any deposit amounts would be reflected in our consolidated balance sheets under cash and cash equivalents because our deposited surplus funds under the cash pooling agreement are highly-liquid short-term investments.

Off-Balance Sheet Arrangements

At December 31, 2022, we had approximately $4,726 million of standby letters of credit, surety bonds, guarantees and indemnifications outstanding, which includes guarantees of our own performance. These instruments provide financial assurance to the business and trading partners of AVANGRID and its subsidiaries 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 December 31, 2022, neither we nor our subsidiaries have any liabilities recorded for these instruments.

Long-Term Capital Resources

We expect to meet our long-term capital requirements through the use of our cash balances, credit facilities, cash from operations, long-term borrowings and new equity capital. We have investment grade ratings from Standard and Poor's, Moody's and Fitch and we believe that we can raise capital on competitive terms in the investment grade debt capital and/or bank markets.

Our long-term debt issuances during 2022 were as follows:

Company	Issue Date	Type	Amount (Millions)	Interest rate	Maturity
UI	1/31/2022	Unsecured Notes	$ 150	2.25%	2032
NYSEG	4/6/2022	Tax Exempt Bond	$ 67	4.00%	2028
NYSEG	12/15/2022	Unsecured Notes	$ 150	4.62%	2032
NYSEG	12/15/2022	Unsecured Notes	$ 125	4.96%	2052
RG&E	12/15/2022	First Mortgage Bonds	$ 125	4.86%	2052
CMP	12/15/2022	Green First Mortgage Bonds	$ 75	4.37%	2032
CMP	12/15/2022	Green First Mortgage Bonds	$ 50	4.76%	2052
UI	12/15/2022	Unsecured Notes	$ 50	4.62%	2032

At December 31, 2022, Networks had $6,651 million of debt, including the current portion thereof, consisting of first mortgage bonds, senior unsecured notes, tax-exempt bonds and various other forms of debt. Networks' regulated utilities are required by regulatory order to maintain a minimum ratio of common equity to total capital that is tied to the capital structure used in the establishment of their revenue requirements. Pursuant to these requirements, each of NYSEG, RG&E, CMP and MNG must maintain a minimum equity ratio equal to the ratio in its currently effective rate plan or decision measured using a trailing 13-month average. On a monthly basis, each utility must maintain a minimum equity ratio of no less than 300 basis points below the equity ratio used to set rates. UI, SCG, CNG and BGC are restricted from paying dividends if paying such dividend would result in their respective common equity ratio being lower than 300 basis points below the equity percentage used to set rates in the most recent distribution rate proceeding as measured using a trailing 13-month average calculated as of the most recent quarter end. The regulated utilities periodically pay dividends to, or receive capital contributions from, AVANGRID in order to maintain the minimum equity ratio requirement. They each independently incur indebtedness by issuing investment grade debt securities. Networks' regulated utilities were in compliance with these regulatory orders as of December 31, 2022.

At December 31, 2022, we had a $41 million finance lease liability outstanding in the Renewables segment relating to a sale-leaseback arrangement on a solar generation facility. Renewables has also sourced capital through tax equity financing arrangements associated with certain wind farm projects. The arrangements allocate substantially all of the projects' taxable income and PTCs to the tax equity investor, along with a percentage of cash generated by the projects, in exchange for investor contributions. 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. A further investment from our investor is expected shortly after the project's commercial operations in the estimated amount of $58 million, expected in 2023. Lund Hill is owned by Solis Solar Power I, LLC (Solis I). In June 2022 we received an additional $109 million from a tax equity investor for the addition of Golden Hill wind farms under Aeolus Wind Power VIII, LLC (Aeolus VIII). Montague solar was contributed to Aeolus VIII at the same time, with a future investment from our investor in the estimated amount of $87 million expected after Montague solar project reaches commercial operations, expected in the second quarter of 2023.

At December 31, 2022, corporate had $1,976 million of long-term debt, including the current portion thereof, outstanding. Long-term debt in corporate consists mainly of $600 million of 3.15% notes due in 2024, $750 million of 3.20% notes due in 2025 and $750 million of 3.80% notes due in 2029.

In our credit facilities, long-term borrowings, financing leases and tax-equity partnerships, we and our affiliates that are parties to the agreements are subject to covenants that are standard for such agreements. Affirmative covenants impose certain obligations on the borrower and negative covenants limit certain activities by the borrower. The agreements also define certain events of default, including but not limited to non-compliance with the covenants that may automatically in some circumstances, or at the option of the lenders in other circumstances, trigger acceleration of the obligations. We and our affiliates were in compliance with all such covenants at December 31, 2022 and throughout 2022.

Iberdrola Loan

On December 14, 2020, AVANGRID and Iberdrola entered into an intra-group loan agreement which provided AVANGRID with an unsecured subordinated loan in an aggregate principal amount of $3,000 million (the Iberdrola Loan). The Iberdrola Loan was repaid with the proceeds of the common share issuance described in Note 1 - Background and Nature of Operations.

Capital Requirements

Funding Future Common Dividend Payments

Funding of our dividend payments is considered in the context of our overall operating and investment cash flows and our long-term funding. 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.

Capital Expenditures

The regulated utilities' capital expenditures over the last three years have been as follows:

	2022	2021	2020
		(in millions)	
NYSEG	$ 759	$ 743	$ 689
RG&E	374	394	387
CMP*	338	682	389
UI	226	186	204
SCG	101	86	88
CNG	66	63	60
BGC	22	17	17
MNG	3	4	3
Corporate	23	55	23
Total	**$ 1,912**	**$ 2,230**	**$ 1,860**

*In 2021, includes NECEC Transmission LLC's capital expenditures in the NECEC project.

Networks continued its capital expenditures during 2022 to upgrade and expand electricity and natural gas transmission and distribution infrastructure. In 2022, we continued capital investments in a number of programs in Maine, New York and Connecticut, including substation modernization, grid automation, new transmission investments, pole replacement program, projects related to improvement of system operations, reliability and resiliency, replacement of aging infrastructure, and new customer connections. In 2021, we continued capital investments in a number of programs in Maine, including NECEC, substation modernization and new transmission investments. NYSEG and RG&E continued their capital investments in a number of programs, including the grid automation project, pole replace program, distribution line project, Binghamton Area Brightline, or BES, program.

Renewables' capital expenditures for the years set forth below were as follows:

	2022	2021	2020
		(in millions)	
Wind & solar	$ 662	$ 928	$ 822
Thermal	28	18	8
Corporate (1)	13	12	15
Other capitalized costs (2)	83	106	39
Total capital expenditures	**$ 786**	**$ 1,064**	**$ 884**

(1) Includes information technology and facilities and safety (security).

(2) Includes capitalized interests, labor and other costs.

In 2022, Renewables made capital expenditures of $662 million on construction of Lundhill Solar, Bakeoven Solar, Montague Solar, La Joya, Golden Hills, Midland, DayBreak Solar and other wind and solar assets and $28 million in capital expenditures on the Klamath gas-fired cogeneration facility, or the Klamath Plant.

In 2021, Renewables made capital expenditures of $928 million on construction of Lundhill Solar, Bakeoven Solar, Montague Solar, La Joya, Golden Hills, Midland and other wind and solar assets and $18 million in capital expenditures on the Klamath Plant.

Capital Projects

An important part of our business strategy involves capital projects. Networks plans to invest a total of approximately $10.9 billion from 2023 to 2027 to upgrade and expand electricity and natural gas transmission and distribution infrastructure. In the next 12 months, Networks plans to invest $764 million in Maine, including Distribution Line Inspection Repairs Program, Transmission Line Asset Condition Replacements Program, Substation Modernization Program, Storm Resiliency Program and Grid Automation. MEPCO plans to invest $17 million in the next 12 months primarily on the Strategic Rebuild of Transmission Structures. NECEC plans to invest $461 million in the next 12 months. NYSEG plans to invest $664 million in the next 12 months, including Advanced Meter Infrastructure Project, BES Program, Distribution Line Inspection Repairs Program, Grid Automation Program, Transmission Line Asset Condition Replacements Program, Storm Resiliency Program, Make Ready, Pole Replacement Program and Gas Distribution Mains and Leak Prone Main replacements. RG&E plans to invest $327 million in the next 12 months, including Advanced Meter Infrastructure Project, BES Program, Webster Area

Reliability Program, Pole Replacement Program, Grid Automation Program, Storm Resiliency Program, Gas Distribution Mains and Leak Prone Main Replacement programs. UIL plans to invest $535 million in the next 12 months, including a number of programs and projects related to improvement of system operations, reliability and resiliency, replacement of aging infrastructure, and new customer connections. For gas operations, the most notable investments include distribution main replacements, leak prone replacements, the connection of new customers, and infrastructure improvements.

Renewables plans to invest at least a total of approximately $7.4 billion from 2023 to 2027 and add at least approximately 1,990 MW of onshore and offshore generation capacity.

We expect to fund these capital projects through a combination of cash provided by operations and access to the capital markets, including debt borrowings at either the subsidiary or holding company level and equity issuances as needed. Additionally, we have revolving credit facilities, as described above, to fund short-term liquidity needs.

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 years ended December 31, 2022, 2021 and 2020, respectively:

	Year Ended December 31,		
	2022	2021	2020
		(in millions)	
Cash Flows			
Net cash provided by operating activities	$ 1,035	$ 1,561	$ 1,288
Net cash used in investing activities	(2,548)	(2,440)	(2,858)
Net cash provided by financing activities	108	889	2,853
Net (decrease) increase in cash, cash equivalents and restricted cash	**$ (1,405)**	**$ 10**	**$ 1,283**

Operating Activities

Our primary sources of operating cash inflows are proceeds from transmission and distribution of electricity and natural gas and sales of wholesale energy and energy related products and services. Our primary operating cash outflows are power and natural gas purchases and transmission operating and maintenance expenses, as well as personnel costs and other employee-related expenditures. As our business has expanded, our working capital requirements have grown. We expect our working capital to grow as we continue to grow our business.

The cash from operating activities for the year ended December 31, 2022 compared to the year ended December 31, 2021 decreased by $526 million, primarily attributable to a net decrease in current assets and liabilities driven by timing of cash collections and cash disbursements during the period.

The cash from operating activities for the year ended December 31, 2021 compared to the year ended December 31, 2020 increased by $273 million, primarily attributable to higher operating revenues in the period.

The cash from operating activities for the year ended December 31, 2020 compared to the year ended December 31, 2019 decreased by $300 million, primarily attributable to higher operations and maintenance expenses including from storm and other activities, delays in the timing of the approval of the 2020 Joint Proposal and increased overdue receivables as a result of COVID-19 in Networks.

Investing Activities

Our investing activities have primarily focused on enhancing, automating and reinforcing our asset base to support safety, reliability and customer growth in accordance with the regulatory markets within which we operate, as well as constructing solar and wind assets.

In 2022, net cash used in investing activities was $2,548 million, which primarily was comprised of $2,519 million of capital expenditures and $168 million of payment for the offshore joint venture restructuring transaction, partially offset by $123 million of contributions in aid of construction.

In 2021, net cash used in investing activities was $2,440 million, which was comprised of $2,976 million of capital expenditures, partially offset by $222 million of other investments and equity method investments, $155 million of distributions received from equity method investments, $130 million of contributions in aid of construction and $24 million of proceeds from the sale of assets.

In 2020, net cash used in investing activities was $2,858 million, which was comprised of $2,781 million of capital expenditures and $370 million of other investments and equity method investments, partially offset by $48 million of contributions in aid of construction and $238 million of proceeds from the sale of assets.

Financing Activities

Our financing activities have consisted of raising equity, using our credit facilities and long-term debt issued or redeemed by AVANGRID and our regulated Networks subsidiaries.

In 2022, financing activities provided $108 million in cash reflecting primarily a net increase in non-current debt and current notes payable of $662 million and contribution from non-controlling interests of $147 million in the period, offset by distributions to non-controlling interests of $10 million and dividends of $681 million.

In 2021, financing activities provided $889 million in cash reflecting primarily $4 billion in proceeds from private placements of equity in connection with share issuance, an issuance of non-current debt at our regulated subsidiaries with the net proceeds of $833 million and contribution from non-controlling interests, principally related to TEFs, of $330 million in the period, offset by a net decrease in non-current debt, including with affiliate, and current notes payable of $3.6 billion, dividends of $613 million and distributions to non-controlling interests of $10 million.

In 2020, financing activities used $2,853 million in cash reflecting primarily an issuance of non-current debt at AVANGRID and our regulated subsidiaries with the net proceeds of $1,367 million, receipt of the Iberdrola Loan of $3,000 million and tax equity financing contributions from non-controlling interests, principally related to TEFs, of $312 million, offset by a net decrease in non-current debt and current notes payable of $1,264 million, distributions to non-controlling interests of $5 million, payments on capital leases of $9 million and dividends of $545 million.

Contractual Obligations

As of December 31, 2022, our contractual obligations (excluding any tax reserves) were as follows:

	Total	2023	2024	2025	2026	2027	Thereafter
				(in millions)			
Leases (1)	$ 495	$ 25	$ 44	$ 22	$ 23	$ 25	$ 356
Easements (2)	1,068	29	30	31	30	28	920
Projected future pension benefit plan contributions (3)	357	10	51	18	42	40	196
Long-term debt (including current maturities) (4)	8,635	412	612	1,107	660	484	5,360
Interest payments (5)	3,266	312	302	260	243	217	1,932
Material purchase commitments (6)	1,455	1,037	170	81	56	38	73
Total Contractual Obligations	**$ 15,276**	**$ 1,825**	**$ 1,209**	**$ 1,519**	**$ 1,054**	**$ 832**	**$ 8,837**

(1) Represents lease contracts relating to operational facilities, office building leases and vehicle and equipment leases. These amounts represent our expected unadjusted portion of the costs to pay as amounts related to contingent payments are predominantly linked to electricity generation at the respective facilities.

(2) Represents easement contracts which are not classified as leases.

(3) The qualified pension plans' contributions are generally based on the estimated minimum pension contributions required under the Employee Retirement Income Sensitivity Act of 1974, as amended, and the Pension Protection Act of 2006, as well as contributions necessary to avoid benefit restrictions and at-risk status and agreements with state regulatory agencies. These amounts represent estimates that are based on assumptions that are subject to change.

(4) See debt payment discussion in "Long-term Capital Resources."

(5) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2022, and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2022.

(6) Represents forward purchase commitments under power, gas and other arrangements and contractual obligations for material and services on order but not yet delivered at December 31, 2022.

Critical Accounting Policies and Estimates

We have prepared the financial statements provided herein in accordance with U.S. GAAP and they include the accounts of AVANGRID and its consolidated subsidiaries. We describe our significant accounting policies in Note 3 to the consolidated financial statements.

In preparing the accompanying financial statements, our management has made certain estimates and assumptions that affect the reported amounts of assets, liabilities, shareholder's equity, revenues and expenses and the disclosures thereof. The following accounting policies represent those that management believes are particularly important to the consolidated financial statements and that require the use of estimates, assumptions and judgments to determine matters that are inherently uncertain.

Accounting for Regulated Public Utilities

U.S. GAAP allows regulated entities to give accounting recognition to the actions of regulatory authorities. We must meet certain criteria in order to apply such regulatory accounting treatment and record regulatory assets and liabilities. In determining whether we meet the criteria for our operations, our management makes significant judgments, which involve (i) determining whether rates for services provided to customers are subject to approval by an independent, third-party regulator, (ii) determining whether the regulated rates are designed to recover specific costs of providing the regulated service, (iii) considering relevant historical precedents and recent decisions of the regulatory authorities and (iv) considering the fact that decisions made by regulatory commissions or legislative changes at a later date could vary from earlier interpretations made by management and that the impact of such variations could be material. Our regulated subsidiaries have deferred recognition of costs (a regulatory asset) or have recognized obligations (a regulatory liability) if it is probable that such costs will be recovered or obligations relieved in the future through the ratemaking process. Management regularly reviews our regulatory assets and liabilities to determine whether we need to make adjustments to our previous conclusions based on the current regulatory environment as well as recent rate orders. If our regulated subsidiaries, or a portion of their assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for unregulated businesses in general would become applicable and immediate recognition of any previously deferred costs would be required in the year in which such criteria are no longer met.

Accounting for Pensions and Other Post-Retirement Benefits

We provide pensions and other post-retirement benefits for a significant number of employees, former employees and retirees. We account for those benefits in accordance with the accounting rules for retirement benefits. In accounting for our pension and other post-retirement benefit plans, or the AVANGRID plans, we make assumptions regarding the valuation of benefit obligations and the performance of plan assets. The primary assumptions include the discount rate, the expected long-term return on plan assets, health care cost trend rates, mortality assumptions, demographic assumptions and other factors. We apply consistent estimation techniques regarding our actuarial assumptions, where appropriate, across the AVANGRID plans of our operating subsidiaries. The estimation technique we use to develop the discount rate for the AVANGRID plans is based upon the settlement of such liabilities as of December 31, 2022, using a hypothetical portfolio of actual, high quality bonds, that would generate cash flows required to settle the liabilities. We believe such an estimate of the discount rate accurately reflects the settlement value for plan obligations and results in cash flows that closely match the expected payments to participants. The estimation technique we use to develop the long-term rate of return on plan assets is based on a projection of the long-term rates of return on plan assets that will be earned over the life of the plan, including considerations of investment strategy, historical experience and expectations for long-term rates of return.

The weighted-average discount rates used in accounting for qualified pension obligations in 2022 was 2.85%, representing an increase of 51 basis points from 2021. The expected rate of return on plan assets for qualified pension benefits in 2022 was 6.33%, representing a decrease of 0.97 basis points from 2021. The following table reflects the estimated sensitivity associated with a change in certain significant actuarial assumptions (each assumption change is presented mutually exclusive of the other assumption changes):

		Impact on 2022 Pension Expense Increase (Decrease)	
	Change in Assumption	**Pension Benefits**	**Post Retirement Benefits**
		(in millions)	
Increase in discount rate	50 basis points	$ (17)	$ (2)
Decrease in discount rate	50 basis points	$ 17	$ 2
Increase in return on plan assets	50 basis points	$ (15)	$ (1)
Decrease in return on plan assets	50 basis points	$ 15	$ 1

We reflect unrecognized prior service costs and credits and unrecognized actuarial gains and losses for the regulated utilities of Networks as regulatory assets or liabilities if it is probable that such items will be recovered through the ratemaking process in future periods. Certain nonqualified plan expenses are not recoverable through the ratemaking process and we present the unrecognized prior service costs and credits and unrecognized actuarial gains and losses in Accumulated Other Comprehensive Loss.

Business Combinations and Assets Acquisitions

We apply the acquisition method of accounting to account for business combinations. The consideration transferred for an acquisition is the fair value of the assets transferred, the liabilities incurred, including contingent consideration, and the equity interests issued by the acquirer. We measure identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination initially at their fair values at the acquisition date. For material transactions where valuations require significant assumptions and judgements, we utilize independent third-party valuation specialists and review their work prior to recording the transaction.

In contrast to a business combination (disposal), we classify a transaction as an asset acquisition (disposal) when substantially all the fair value of the gross assets acquired (disposed) is concentrated in a single identifiable asset or group of similar identifiable assets or otherwise does not meet the definition of a business. Similar to business combinations, we may utilize third-party valuation specialists for material asset transactions that require significant judgement in the valuation process.

Goodwill

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

In assessing goodwill for impairment, we have the option to first perform a qualitative assessment to determine whether a quantitative assessment is necessary. If we determine, based on qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If we bypass the qualitative assessment, or perform the qualitative assessment but determine it is more likely than not that its fair value is less than its carrying amount, we perform a quantitative test to compare the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, we record an impairment loss as a reduction to goodwill and a charge to operating expenses, but the loss recognized would not exceed the total amount of goodwill allocated to the reporting unit. For 2022, we utilized a qualitative assessment for the Networks reporting units and a quantitative assessment for the Renewables reporting unit.

Our qualitative assessment involves evaluating key events and circumstances that could affect the fair value of our reporting units, as well as other factors. Events and circumstances evaluated include macroeconomic conditions, industry, regulatory and market considerations, cost factors and their effect on earnings and cash flows, overall financial performance as compared with projected results and actual results of relevant prior periods, other relevant entity specific events, and events affecting a reporting unit.

Our quantitative assessment utilizes a discounted cash flow model under the income approach and includes critical assumptions, primarily the discount rate and internal estimates of forecasted cash flows. We use a discount rate that is developed using market participant assumptions, which consider the risk and nature of the respective reporting unit’s cash flows and the rates of return market participants would require in order to invest their capital in our reporting units. We test the reasonableness of the conclusions of our quantitative impairment testing using a range of discount rates and a range of assumptions for long-term cash flows.

Impairment of Long-Lived Assets

We evaluate property, plant and equipment and other long-lived assets for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. If indicators of impairment are present, a recoverability test is performed based on undiscounted cash flow analysis at the lowest level to which cash flows of the long-lived assets or asset groups are largely independent of the cash flows of other assets and liabilities. An impairment loss is required to be recognized if the carrying amount of the asset exceeds the undiscounted future net cash flows associated with that asset. The impairment loss to be recognized is the amount by which the carrying value of the long-lived asset exceeds the asset’s fair value.

We determine the fair value of a long-lived asset by applying the income approach prescribed under the fair value measurement accounting framework. We develop the underlying assumptions consistent with a market participant’s view of the exit price of our assets. We use an internal discounted cash flow, or DCF, valuation model based on the principles of present value techniques to estimate the fair value of our long-lived assets under the income approach. The DCF model estimates fair value by discounting AVANGRID’s cash flow forecasts at an appropriate market discount rate. Management applies a considerable amount of judgment in the estimation of the discount rate used in the DCF model and in selecting several input assumptions during the development of our cash flow forecasts. Examples of the input assumptions that our forecasts are sensitive to include macroeconomic factors such as growth rates, industry demand, inflation, power prices and commodity prices. Many of these input assumptions are dependent on other economic assumptions, which are often derived from statistical economic models with inherent limitations such as estimation differences. Further, several input assumptions are based on historical trends which often do not recur. The input assumptions that include significant unobservable inputs most significant to our cash flows are based on expectations of macroeconomic factors, which may be volatile. The use of a different set of input assumptions could produce significantly different cash flow forecasts.

The fair value of a long-lived asset is sensitive to both input assumptions related to our cash flow forecasts and the market discount rate. Further, estimates of long-term growth and terminal value are often critical to the fair value determination. As part of the impairment evaluation process, management analyzes the sensitivity of fair value to various underlying assumptions. The level of scrutiny increases as the gap between fair value and carrying amount decreases. Changes in any of these assumptions could result in management reaching a different conclusion regarding the potential impairment, which could be material. Our impairment evaluations inherently involve uncertainties from uncontrollable events that could positively or negatively impact the anticipated future economic and operating conditions.

Income Taxes

AVANGRID files a consolidated federal income tax return and various state income tax returns, some of which are unitary as required or permitted.

Our income tax expense and related balance sheet amounts involve management judgment and use of estimates. Amounts of deferred income tax assets and liabilities, current and noncurrent accruals, and determination of uncertain tax positions involve judgements and estimates of the timing and probability of recognition of income and deductions by taxing authorities. In making these judgements, we consider the status of any income tax examinations that are in progress, historical resolutions of tax issues, positions taken by the taxing authorities on similar issues with other taxpayers, among other criteria. Our actual income taxes could vary from estimated amounts because of the actual resolution of tax issues, forecasts of financial condition and changes in tax laws and regulations.

Our tax positions are evaluated under a more-likely-than-not recognition threshold before they are recognized for financial reporting purposes. The term more-likely-than-not means a likelihood of more than 50%. We use judgement to determine when a tax position reaches this threshold.

Our assessment regarding the realizability of deferred tax assets involves judgements and estimates including the impact of forecasted taxable income and tax planning strategies to utilize tax attributes before they expire.

New Accounting Standards

For discussion of new accounting pronouncements that affect AVANGRID, refer to Note 3 to our consolidated financial statements contained in this Annual Report on Form 10-K.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk.*

We are exposed to risks associated with adverse changes in commodity prices, interest rates and equity prices. Financial instruments and positions affecting our financial statements described below are held primarily for purposes other than trading. Market risk is measured as the potential loss in fair value resulting from hypothetical reasonably possible changes in commodity prices, interest rates or equity prices over the next year. Management has established risk management policies to monitor and manage such market risks, as well as credit risks.

Commodity Price Risk

Renewables faces a number of energy market risk exposures, including fixed price, basis (both location and time) and heat rate risk.

Long-term supply contracts reduce our exposure to market fluctuations. We have electricity commodity purchases and sales contracts for energy (physical contracts) that have been designated and qualify for the normal purchase normal sale exemption in accordance with the accounting requirements concerning derivative instruments and hedging activities.

Renewables merchant wind facilities are subject to price risk, which is hedged with fixed price power trades. Our combined cycle power plant is subject to heat rate risk, which is hedged with fixed price power and fixed price gas and basis positions. Those measures mitigate our commodity price exposure, but do not completely eliminate it. Some long-term hedges do not qualify for hedge accounting. This introduces some MtM volatility into yearly profit and loss accounts.

Renewables uses a Monte Carlo simulation value-at-risk, or VaR, technique to measure and control the level of risk it undertakes. VaR is a statistical technique used to measure and quantify the level of risk within a portfolio over a given timeframe and within a specified level of confidence. VaR is primarily composed of three variables: the measured amount of potential loss, the probability of not exceeding the amount of potential loss and the portfolio holding period.

Renewables uses a 95% probability level over a one-day holding period, indicating that it can be 95% confident that losses over one day would not exceed that value. The average VaR for 2022 was $13.6 million compared to a 2021 average of $11.3 million.

As noted above, VaR is a statistical technique and is not intended to be a guarantee of the maximum loss Renewables may incur.

Networks also experiences commodity price risk, due to volatility in the wholesale energy markets. Networks manages that risk through a combination of regulatory mechanisms, such as the pass-through of the market price of electricity and natural gas to customers, and through comprehensive risk management processes. Those measures mitigate our commodity price exposure, but do not completely eliminate it. Networks also uses electricity contracts as deemed appropriate, both physical and financial, to manage fluctuations in electricity commodity prices in order to provide price stability to customers. It also uses natural gas futures and forwards to manage fluctuations in natural gas commodity prices in order to provide price stability to customers. It includes the cost or benefit of those contracts in the amount expensed for electricity or natural gas purchased when the related electricity is sold.

Because all gains or losses on Networks' commodity contracts will ultimately be passed on to retail customers, no sensitivity analysis is performed for Networks. Further information regarding the derivative financial instruments and sensitivity analysis is provided in Notes 11 and 12 of our consolidated financial statements contained in this Annual Report on Form 10-K.

Interest Rate Risk

Total debt outstanding was $9,024 million at December 31, 2022, of which $1,146 million had a floating interest rate. A change of 25 basis points in this interest rate would result in an interest expense or income fluctuation of approximately $3 million annually. The estimated fair value of our long-term debt at December 31, 2022 was $7,991 million, in comparison to a book value of $8,627 million.

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. Further information regarding our interest rate derivative financial instruments is provided in Note 12 of our consolidated financial statements contained in this Annual Report on Form 10-K. There was one interest rate derivative contract outstanding at December 31, 2022.

Credit Risk

This risk is defined as the risk that a third party will not fulfill its contractual obligations and, therefore, generate losses for AVANGRID. Networks is exposed to nonpayment of customer bills. Standard debt recovery procedures are in place, in accordance with best practices and in compliance with applicable state regulations and embedded tariff mechanisms to manage uncollectible expense. Our credit department, based on guidelines approved by our board, establishes and manages its counterparty credit limits. We have developed a matrix of unsecured credit thresholds that are dependent on a counterparty's or the counterparty guarantor's applicable credit rating. Credit risk is mitigated by contracting with multiple counterparties and limiting exposure to individual counterparties or counterparty families to clearly defined limits based upon the risk of counterparty default. At the counterparty level, we employ specific eligibility criteria in determining appropriate limits for each prospective counterparty and supplement this with netting and collateral agreements, including margining, guarantees, letters of credit and cash deposits, where appropriate.

Renewables is also exposed to credit risk through its energy management operations. Counterparty credit risk is managed through established credit policies by a credit department that is independent of the energy management function. Prospective and existing customers are reviewed for creditworthiness based upon established criteria. Credit limits are set in accordance with board approved guidelines, with counterparties not meeting minimum standards providing various credit enhancements such as cash prepayments, letters of credit, cash and other collateral and guarantees. Master netting agreements are used, where appropriate, to offset cash and non-cash gains and losses arising from derivative instruments with the same counterparty. Trade receivables and other financial instruments are predominately with energy, utility and financial services-related companies, as well as municipalities, cooperatives and other trading companies in the U.S., although there is a growing segment of long-term power sales (PPAs) signed with commercial and industrial customers of high credit quality.

Based on our policies and risk exposures related to credit risk from its management in Renewables, we do not anticipate a material adverse effect on our financial statements as a result of counterparty nonperformance. As of December 31, 2022, approximately 97% of our energy management counterparty credit risk exposure is associated with companies that have investment grade credit ratings.

Treasury Management (including Liquidity Risk)

We optimize our liquidity through a series of arms-length intercompany lending arrangements with our subsidiaries and among the 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. We have the capacity to borrow from third parties through a $2 billion commercial paper program, the $3.575 million AVANGRID Credit Facility, which backstops the commercial paper program, and $500 million from an Iberdrola Group Credit Facility. For more information, see the section entitled "—Liquidity and Capital Resources—Liquidity Resources" of this Annual Report on Form 10-K.

Networks

Networks' regulated utilities fund their operations independently, except to the extent that they borrow on a short-term basis from AVANGRID and from each other when circumstances warrant in order to minimize short-term funding costs and maximize returns on temporary cash investments. The regulated utilities are prohibited by regulatory order from lending to unregulated affiliates. Networks' regulated utilities each independently accesses the investment grade debt capital markets for long-term funding and each are borrowers under the AVANGRID Credit Facility described in "—Liquidity and Capital Resources—Liquidity Resources" of this Annual Report on Form 10-K.

Networks' regulated utilities are subjected by regulatory order to certain credit quality maintenance measures, including minimum equity ratios, that are linked to the level of equity assumed in the establishment of revenue requirements. The companies maintain their equity ratios at or above the minimum through dividend declarations or, when necessary, capital contributions from AVANGRID.

Renewables

Renewables historically has been financed through equity contributions, intercompany loans during construction, tax equity partnerships and, to a lesser extent, sale-leaseback arrangements. The outstanding balance of its financing lease was $41 million at December 31, 2022.

Renewables is a party to a cash pooling arrangement with Avangrid, Inc. All Renewables revenues are concentrated in and all Renewables disbursements are made from Avangrid, Inc. Net cash surpluses or deficits at Renewables are recorded as intercompany receivables or payables and these balances are periodically reduced to zero through dividends or capital contributions. In March 2022, Renewables recorded a net non-cash dividend of $568 million to Avangrid, Inc. to zero out account balances that had principally accumulated prior to January 2022.

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
Avangrid, Inc.:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Avangrid, Inc. and subsidiaries (the Company) as of December 31, 2022 and 2021, the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for each of the years in the three-year period ended December 31, 2022, and the related notes and financial statement schedule 1 (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2022, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 22, 2023 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Evaluation of the impairment of the carrying value of goodwill in the Renewables reporting unit

As discussed in Notes 3(g) and 7 to the consolidated financial statements, the goodwill balance as of December 31, 2022 was \$3,119 million, of which \$372 million related to the Renewables reporting unit. The Company performs goodwill impairment testing on an annual basis or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

We identified the evaluation of the impairment of the carrying value of goodwill in the Renewables reporting unit as a critical audit matter due to certain estimates and assumptions the Company made to determine the fair value of the Renewables reporting unit. As a result, a higher degree of auditor judgment was required to evaluate certain assumptions used in the Company's estimate of the fair value of the Renewables reporting unit. Specifically, the Company's determination of the forecasted power production and forecasted market prices, which are used to develop the revenue forecast, and the determination of the discount rates, required subjective and challenging auditor judgment.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls over the Company's goodwill impairment assessment process, including controls related to the determination of the forecasted power production, forecasted market prices and discount rates used to estimate the fair value of the Renewables reporting unit. To assess the Company's ability to forecast revenues, we compared the Renewables reporting unit's historical revenue forecasts to actual revenues. We compared the Renewables reporting unit's forecasted power production to historical power production. We also evaluated the forecasted power production and forecasted market prices by comparing them to third-party reports published by industry analysts. In addition, we involved valuation professionals with specialized skills and knowledge, who assisted in testing the selected discount rates by independently developing discount rates using publicly available market data for comparable entities and comparing them to the Company's discount rates.

Evaluation of regulatory assets and liabilities

As discussed in Notes 3(c) and 6 to the consolidated financial statements, the Company accounts for their regulated operations in accordance with Financial Accounting Standards Board Accounting Standard Codification Topic 980, Regulated Operations (ASC Topic 980). Pursuant to the requirements of ASC Topic 980, the financial statements of a rate-regulated enterprise reflect the actions of regulators. The Company capitalizes, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric and natural gas rates. In addition, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs are recorded as regulatory liabilities. The Company's regulated utilities are subject to complex and comprehensive federal, state and local regulation and legislation, including regulations promulgated by state utility commissions and the Federal Energy Regulatory Commission.

We have identified the evaluation of regulatory assets and liabilities as a critical audit matter. This was due to the extent of audit effort required in the evaluation of regulatory assets and liabilities in each of the relevant jurisdictions. The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls over the Company's regulatory accounting process, including controls related to the Company's application of ASC Topic 980 in each jurisdiction and the Company's calculation and review of regulatory assets and liabilities. We selected regulatory assets and liabilities and assessed the Company's application of ASC Topic 980 in the relevant jurisdiction by evaluating the underlying orders, statutes, rulings, memorandums, filings or publications issued by the respective regulators. We selected a sample of the regulatory assets and liabilities activity and using the methodologies approved by the relevant regulatory commissions, recalculated the activity and agreed the data used in the calculations to the Company's underlying books and records. We compared the amounts calculated by the Company to the amounts recorded in the consolidated financial statements.

Fair value of liquidating distribution

As discussed in Note 22 to the consolidated financial statements, the Company restructured and effectively dissolved the Vineyard Wind joint venture on January 10, 2022. As part of the dissolution, the Company and Copenhagen Infrastructure Partners (CIP) each acquired full ownership of certain legal entities and lease areas that were previously held within the joint venture. The Company received a non-cash liquidating distribution which was recorded at fair value and made an incremental payment of approximately $168 million to CIP. The Company recognized a pretax gain of $246 million during the year ended December 31, 2022, driven by the increase in the fair value of its acquired interest in the leases and related development activities.

We identified the evaluation of the fair value of the liquidating distribution as a critical audit matter. Subjective auditor judgment was required to evaluate certain assumptions used in the Company's estimate of the fair value of the liquidating distribution, specifically the Company's determination of the forecasted power production, which was used to develop the revenue forecast, and the discount rate.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the Company's process to determine the fair value of the liquidating distribution, including controls related to the determination of the forecasted power production and discount rate. To assess the forecasted power production, we compared the Company's forecasted generation to third-party reports published by industry analysts. In addition, we involved valuation professionals with specialized skills and knowledge, who assisted in testing the selected discount rate by comparing it to an independently-developed range of discount rates using publicly-available market data for comparable companies.

/s/ KPMG LLP

We have served as the Company's auditor since 2017.

New York, New York
February 22, 2023

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
Avangrid, Inc.:

Opinion on Internal Control Over Financial Reporting

We have audited Avangrid, Inc. and subsidiaries' (the Company) internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2022 and 2021, the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for each of the years in the three-year period ended December 31, 2022, and the related notes and financial statement schedule I (collectively, the consolidated financial statements), and our report dated February 22, 2023 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Report of Management on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ KPMG LLP

New York, New York
February 22, 2023

Avangrid, Inc. and Subsidiaries
Consolidated Statements of Income

Years Ended December 31,	2022	2021	2020
(Millions, except for number of shares and per share data)			
Operating Revenues	**$ 7,923**	**$ 6,974**	**$ 6,320**
Operating Expenses			
Purchased power, natural gas and fuel used	2,456	1,719	1,379
Operations and maintenance	2,872	2,706	2,466
Depreciation and amortization	1,085	1,014	987
Taxes other than income taxes, net	658	640	619
Total Operating Expenses	**7,071**	**6,079**	**5,451**
Operating Income	**852**	**895**	**869**
Other Income and (Expense)			
Other income (expense)	30	60	18
Earnings (losses) from equity method investments	262	7	(3)
Interest expense, net of capitalization	(303)	(298)	(316)
Income Before Income Tax	**841**	**664**	**568**
Income tax expense	20	21	29
Net Income	**821**	**643**	**539**
Net loss attributable to noncontrolling interests	60	64	42
Net Income Attributable to Avangrid, Inc.	**$ 881**	**$ 707**	**$ 581**
Earnings Per Common Share, Basic:	**$ 2.28**	**$ 1.97**	**$ 1.88**
Earnings Per Common Share, Diluted:	**$ 2.27**	**$ 1.97**	**$ 1.88**
Weighted-average Number of Common Shares Outstanding:			
Basic	386,727,246	358,086,621	309,494,939
Diluted	387,215,785	358,578,608	309,559,387

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

Avangrid, Inc. and Subsidiaries
Consolidated Statements of Comprehensive Income

Years Ended December 31,	2022	2021	2020
(Millions)			
Net Income	**$ 821**	**$ 643**	**$ 539**
Other Comprehensive Income			
Gain for defined benefit plans, net of income taxes of $3, $0 and $0, respectively	14	2	—
Amortization of pension cost, net of income taxes of $1, $(1) and $3, respectively	4	(8)	(13)
Unrealized gain (loss) from equity method investment, net of income taxes of $6, $(3) and $0, respectively	22	(9)	—
Unrealized loss during the year on derivatives qualifying as cash flow hedges, net of income taxes of $0, $(44) and $(7), respectively	(1)	(159)	(22)
Reclassification to net income of losses (gains) on cash flow hedges, net of income taxes of $19, $(3) and $2, respectively	54	12	19
Other Comprehensive Income (Loss)	**93**	**(162)**	**(16)**
Comprehensive Income	914	481	523
Net loss attributable to noncontrolling interests	60	64	42
Comprehensive Income Attributable to Avangrid, Inc.	**$ 974**	**$ 545**	**$ 565**

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

Avangrid, Inc. and Subsidiaries
Consolidated Balance Sheets

As of December 31,	2022	2021
(Millions)		
Assets		
Current Assets		
Cash and cash equivalents	$ 69	$ 1,474
Accounts receivable and unbilled revenues, net	1,737	1,269
Accounts receivable from affiliates	5	11
Notes receivable from affiliates	3	—
Derivative assets	60	35
Fuel and gas in storage	268	139
Materials and supplies	235	204
Prepayments and other current assets	386	245
Regulatory assets	447	400
Total Current Assets	**3,210**	**3,777**
Total Property, Plant and Equipment ($2,707 and $1,959 related to VIEs, respectively)	**30,994**	**28,866**
Operating lease right-of-use assets	159	148
Equity method investments	437	560
Other investments	49	61
Regulatory assets	2,321	2,247
Other Assets		
Goodwill	3,119	3,119
Intangible assets	281	293
Derivative assets	140	59
Other	413	374
Total Other Assets	**3,953**	**3,845**
Total Assets	**$ 41,123**	**$ 39,504**

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

Avangrid, Inc. and Subsidiaries
Consolidated Balance Sheets

As of December 31,	2022	2021
(Millions, except share information)		
Liabilities		
Current Liabilities		
Current portion of debt	$ 412	$ 372
Notes payable	566	159
Notes payable to affiliate	2	2
Interest accrued	66	69
Accounts payable and accrued liabilities	2,007	1,586
Accounts payable to affiliates	39	61
Dividends payable	170	170
Taxes accrued	61	43
Operating lease liabilities	13	12
Derivative liabilities	133	64
Other current liabilities	593	484
Regulatory liabilities	354	307
Total Current Liabilities	**4,416**	**3,329**
Regulatory liabilities	2,915	3,022
Other Non-current Liabilities		
Deferred income taxes	2,234	2,016
Deferred income	1,062	1,130
Pension and other postretirement	491	684
Operating lease liabilities	161	149
Derivative liabilities	164	160
Asset retirement obligations	273	253
Environmental remediation costs	279	298
Other	563	580
Total Other Non-current Liabilities	**5,227**	**5,270**
Non-current debt	8,215	7,922
Non-current debt to affiliate	8	—
Total Non-current Liabilities	**16,365**	**16,214**
Total Liabilities	**20,781**	**19,543**
Commitments and Contingencies	—	—
Equity		
Stockholders' Equity:		
Common stock, $.01 par value, 500,000,000 shares authorized, 387,734,757 and 387,678,630 shares issued; 386,628,586 and 386,568,104 shares outstanding, respectively	3	3
Additional paid-in capital	17,694	17,679
Treasury stock	(47)	(47)
Retained earnings	1,910	1,714
Accumulated other comprehensive loss	(180)	(273)
Total Stockholders' Equity	**19,380**	**19,076**
Noncontrolling interests	962	885
Total Equity	**20,342**	**19,961**
Total Liabilities and Equity	**$ 41,123**	**$ 39,504**

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

Avangrid, Inc. and Subsidiaries
Consolidated Statements of Cash Flows

Years Ended December 31,	**2022**	**2021**	**2020**
(Millions)			
Cash Flow from Operating Activities			
Net income	**$ 821**	**$ 643**	**$ 539**
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	1,085	1,014	987
Accretion expenses	14	12	11
Regulatory assets/liabilities amortization and carrying cost	(65)	(72)	(13)
Pension cost	11	52	82
Earnings from equity method investments	(262)	(7)	3
Distribution of earnings from equity method investments	23	17	19
Unrealized losses on marked to market derivative contracts	—	86	5
Loss (gain) from divestment and disposal of property	2	24	(10)
Deferred taxes	18	11	17
Other non-cash items	(48)	(82)	(83)
Changes in operating assets and liabilities:			
Current assets	(837)	(275)	(173)
Noncurrent assets	(123)	(45)	(170)
Current liabilities	385	286	160
Noncurrent liabilities	11	(103)	(86)
Net Cash Provided by Operating Activities	**1,035**	**1,561**	**1,288**
Cash Flow from Investing Activities			
Capital expenditures	(2,519)	(2,976)	(2,781)
Contributions in aid of construction	123	130	48
Proceeds from sale of equity method and other investment	—	—	238
Proceeds from sale of property, plant and equipment	31	24	7
(Payments to) receipts from affiliates	(3)	5	(3)
Cash distribution from equity method investments	18	155	3
Other investments and equity method investments, net	(198)	222	(370)
Net Cash Used in Investing Activities	**(2,548)**	**(2,440)**	**(2,858)**
Cash Flow from Financing Activities			
Non-current debt issuances	791	833	1,367
Non-current debt issuance with affiliate	—	—	3,000
Repayments of non-current debt	(365)	(304)	(1,011)
Repayment of non-current debt with affiliate	—	(3,000)	—
Receipts (Repayments) of other short-term debt, net	236	(306)	(253)
Repayments of financing leases	(9)	(6)	(9)
Repurchase of common stock	—	(33)	(2)
Issuance of common stock	(1)	3,998	(1)
Distributions to noncontrolling interests	(10)	(10)	(5)
Contributions from noncontrolling interests	147	330	312
Dividends paid	(681)	(613)	(545)
Net Cash Provided by Financing Activities	**108**	**889**	**2,853**
Net (Decrease) Increase in Cash, Cash Equivalents and Restricted Cash	**(1,405)**	**10**	**1,283**
Cash, Cash Equivalents and Restricted Cash, Beginning of Year	**1,477**	**1,467**	**184**
Cash, Cash Equivalents and Restricted Cash, End of Year	**$ 72**	**$ 1,477**	**$ 1,467**
Supplemental Cash Flow Information			
Cash paid for interest, net of amounts capitalized	$ 273	$ 279	$ 278
Cash paid for income taxes	$ 15	$ 2	$ 8

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

Avangrid, Inc. and Subsidiaries
Consolidated Statements of Changes in Equity

	Avangrid, Inc. Stockholders								
(Millions, except for number of shares)	**Number of shares (*)**	**Common Stock**	**Additional paid-in capital**	**Treasury Stock**	**Retained Earnings**	**Accumulated Other Comprehensive Income (Loss)**	**Total Stockholders' Equity**	**Non-controlling Interests**	**Total Equity**
Balances, December 31, 2019	**309,005,272**	**$ 3**	**$ 13,660**	**$ (12)**	**$ 1,634**	**$ (95)**	**$ 15,190**	**$ 349**	**$ 15,539**
Adoption of accounting standards	—	—	—	—	(1)	—	(1)	—	(1)
Net income	—	—	—	—	581	—	581	(42)	539
Other comprehensive loss, net of tax of $(2)	—	—	—	—	—	(16)	(16)	—	(16)
Comprehensive income									523
Dividends declared, $1.76/share	—	—	—	—	(545)	—	(545)	—	(545)
Release of common stock held in trust	72,028	—	—	—	—	—	—	—	—
Issuance of common stock	42,777	—	(1)	—	—	—	(1)	—	(1)
Repurchase of common stock	(42,777)	—	—	(2)	—	—	(2)	—	(2)
Stock-based compensation	—	—	6	—	—	—	6	—	6
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(5)	(5)
Contributions from noncontrolling interests	—	—	—	—	(3)	—	(3)	315	312
Balances, December 31, 2020	**309,077,300**	**3**	**13,665**	**(14)**	**1,666**	**(111)**	**15,209**	**617**	**15,826**
Net income	—	—	—	—	707	—	707	(64)	643
Other comprehensive loss, net of tax of $(51)	—	—	—	—	—	(162)	(162)	—	(162)
Comprehensive income									481
Dividends declared, $1.76/share	—	—	—	—	(647)	—	(647)	—	(647)
Release of common stock held in trust	301,239	—	—	—	—	—	—	—	—
Issuance of common stock	77,883,713	—	3,998	—	—	—	3,998	—	3,998
Repurchase of common stock	(694,148)	—	—	(33)	—	—	(33)	—	(33)
Stock-based compensation	—	—	16	—	—	—	16	—	16
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(10)	(10)
Contributions from noncontrolling interests	—	—	—	—	(12)	—	(12)	342	330
Balances, December 31, 2021	**386,568,104**	**3**	**17,679**	**(47)**	**1,714**	**(273)**	**19,076**	**885**	**19,961**
Net income	—	—	—	—	881	—	881	(60)	821
Other comprehensive income, net of tax of $29	—	—	—	—	—	93	93	—	93
Comprehensive income									914
Dividends declared, $1.76/share	—	—	—	—	(681)	—	(681)	—	(681)
Release of common stock held in trust	4,355	—	—	—	—	—	—	—	—
Issuance of common stock	56,127	—	(1)	—	—	—	(1)	—	(1)
Stock-based compensation	—	—	16	—	—	—	16	—	16
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(10)	(10)
Contributions from noncontrolling interests	—	—	—	—	(4)	—	(4)	147	143
Balances, December 31, 2022	**386,628,586**	**$ 3**	**$ 17,694**	**$ (47)**	**$ 1,910**	**$ (180)**	**$ 19,380**	**$ 962**	**$ 20,342**

(*) Par value of share amounts is $.01

The accompanying notes are an integral part of our 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 18.4% 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 was 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. On June 14, 2022, the NMPRC filed its Answer Brief. On June 13, 2022, New Energy Economy, an intervener in the Merger proceeding, filed its Answer Brief. AVANGRID's Reply Brief was filed on August 5, 2022. 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. On May 20, 2022, the NRC issued an order extending the effectiveness of its approval until May 25, 2023. On September 21, 2022, New Energy Economy filed a motion to show cause with the NMPRC alleging that AVANGRID and PNM have engaged in a misleading joint advertising and sponsorship strategy and requesting an investigation. AVANGRID and PNM filed a reply to the motion to show cause on October 11, 2022. On December 14, 2022, the NMPRC issued an order denying the motion.

In addition, on January 3, 2022, AVANGRID, PNMR and Merger Sub entered into an Amendment to the Merger Agreement (the 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 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 Amendment. As amended, the Merger Agreement may be terminated by each of AVANGRID and PNMR under certain circumstances, including if the Merger is not consummated by April 20, 2023 (subject to a three-month extension by AVANGRID and PNMR by mutual consent if all of the conditions to the closing, other than the conditions related to obtaining regulatory approvals, have been satisfied or waived). 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. For example, AVANGRID and PNMR are preparing new filings under HSR. We cannot predict the outcome of these re-applications or requests for extensions of such approvals.

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 April 20, 2023 (subject to a three-month extension by AVANGRID and PNMR by mutual consent if all of the conditions to the closing, other than the conditions related to obtaining regulatory approvals, have been satisfied or waived). 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 (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 set 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 3-month LIBOR 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, AVANGRID 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 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 approximately $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 consolidated financial statements have been prepared in accordance with U.S. GAAP and are presented on a consolidated basis, and therefore include the accounts of AVANGRID and its consolidated subsidiaries, Networks and ARHI. All intercompany transactions and accounts have been eliminated in consolidation in all periods presented.

Note 3. Summary of Significant Accounting Policies, New Accounting Pronouncements and Use of Estimates

Significant Accounting Policies

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

(a) Principles of consolidation

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

(b) Revenue recognition

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

(c) Regulatory accounting

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

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

(d) Business combinations and assets acquisitions (disposals)

We apply the acquisition method of accounting to account for business combinations. The consideration transferred for an acquisition is the fair value of the assets transferred, the liabilities incurred, including contingent consideration, and the equity interests issued by the acquirer. We measure identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination initially at their fair values at the acquisition date. We record as goodwill the excess of the consideration transferred over the fair value of the identifiable net assets acquired. We recognize adjustments to provisional amounts relating to a business combination that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. For business combinations, we expense acquisition-related costs as incurred.

In contrast to a business combination (disposal), we classify a transaction as an asset acquisition (disposal) when substantially all the fair value of the gross assets acquired (disposed) is concentrated in a single identifiable asset or group of similar identifiable assets or otherwise does not meet the definition of a business. For asset acquisitions, we capitalize acquisition-related costs as a component of the cost of the assets acquired and liabilities assumed.

(e) Noncontrolling interests

Noncontrolling interests represent the portion of our net income (loss), comprehensive income (loss) and net assets that is not allocable to us and is calculated based on our ownership percentage. For holdings where the economic allocations are not based pro rata on ownership percentages, we use the balance sheet-oriented hypothetical liquidation at book value (HLBV) method, to reflect the substantive profit sharing arrangement.

Under the HLBV method, the amounts we report as "Noncontrolling interests" and "Net income (loss) attributable to noncontrolling interests" in our consolidated balance sheets and consolidated statements of income represent the amounts the noncontrolling interest would hypothetically receive at each balance sheet reporting date under the liquidation provisions of each holding's ownership agreement assuming we were to liquidate the net assets of the projects at recorded amounts determined in accordance with U.S. GAAP and distribute those amounts to the investors. We determine the noncontrolling interest in our statements of income and comprehensive income as the difference in noncontrolling interests on our consolidated balance sheets at the start, or at inception of the noncontrolling interest if applicable, and end of each reporting period, after taking into account any capital transactions between the holdings and the third party. We report the noncontrolling interest balances in the holdings as a component of equity on our consolidated balance sheets.

(f) Equity method investments

We account for joint ventures and other equity investments that do not meet consolidation criteria using the equity method. We reflect earnings (losses) recognized under the equity method in the consolidated statements of income as "Earnings (losses) from equity method investments." We recognize dividends received from equity method investments as a reduction in the carrying amount of the investment and not as dividend income. When an equity method investee executes derivative transactions that have cash flow hedge accounting treatment, we recognize our share of the OCI in our consolidated balance sheet. We assess and record an impairment of our equity method investments in earnings for a decline in value that we determine to be other than temporary.

(g) Goodwill and other intangible assets

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

Goodwill is not amortized, but is subject to an assessment for impairment performed in the fourth quarter or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of a reporting unit to which goodwill is assigned below its carrying amount. A reporting unit is an operating segment or one level below an operating segment and is the level at which we test goodwill for impairment. In assessing goodwill for impairment, we have the option to first perform a qualitative assessment to determine whether a quantitative assessment is necessary. If we determine, based on qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If we bypass the qualitative assessment, or perform the qualitative assessment but determine it is more likely than not that its fair value is less than its carrying amount, we perform a quantitative test to compare the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, we record an impairment loss as a reduction to goodwill and a charge to operating expenses, but the loss recognized would not exceed the total amount of goodwill allocated to the reporting unit.

Intangible assets acquired separately are measured on initial recognition at cost. The cost of intangible assets acquired in a business combination is their fair value at the date of acquisition. Following initial recognition, intangible assets are carried at cost less any accumulated amortization and impairment losses. The useful lives of intangible assets are assessed as either finite or indefinite.

Intangible assets with finite lives are amortized on a straight-line basis over the useful economic life, which ranges from four to forty years, and assessed for impairment whenever there is an indication that the intangible asset may be impaired. The amortization expense on intangible assets with finite lives is recognized in our consolidated statements of income within the expense category that is consistent with the function of the intangible assets.

(h) Property, plant and equipment

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

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

We transfer assets from “Construction work in progress” to “Property, plant and equipment” when they are available for service.

We capitalize wind turbine and related equipment costs, other project construction costs and interest costs related to the project during the construction period through substantial completion. We record AROs at the date projects achieve commercial operation.

We depreciate the cost of plant and equipment in use on a straight-line basis, less any estimated residual value. The main asset categories are depreciated over the following estimated useful lives:

Major class	Asset Category	Estimated Useful Life (years)
Plant	Combined cycle plants	35-75
	Hydroelectric power stations	45-90
	Wind power stations	25-40
	Solar power stations	30
	Transmission and transport facilities	41-80
	Distribution facilities	4-80
Equipment	Conventional meters and measuring devices	7-85
	Computer software	3-37
Other	Buildings	30-82
	Operations offices	3-75

Networks determines depreciation expense using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal, in service at each operating company. Networks charges the original cost of utility plant retired or otherwise disposed to accumulated depreciation. Networks' composite rate of depreciation was 2.8% of average depreciable property for both 2022 and 2021.

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

Allowance for funds used during construction (AFUDC), applicable to Networks' entities that apply regulatory accounting, is a noncash item that represents the allowed cost of capital, including a return on equity (ROE), used to finance construction projects. We record the portion of AFUDC attributable to borrowed funds as a reduction of interest expense and record the remainder as other income.

(i) Leases

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

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

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

(j) Impairment of long-lived assets

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

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

(k) Fair value measurement

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

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

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

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

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

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

(l) Equity investments with readily determinable fair values

We measure equity investments with readily determinable fair values at fair value, with changes in fair value reported in net income.

(m) Derivatives and hedge accounting

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

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

Changes in conditions or the occurrence of unforeseen events could require discontinuance of the hedge accounting or could affect the timing of the reclassification of gains or losses on cash flow hedges from OCI into earnings. For our regulated operations, we record changes in the fair value of electric and natural gas hedge contracts derivative assets or liabilities with an offset to regulatory assets or regulatory liabilities.

We offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement.

(n) Cash and cash equivalents

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

(o) Trade receivables and unbilled revenues, net of allowance for credit losses

We record trade receivables at amounts billed to customers and we record unbilled revenues based on an estimate of energy delivered or services provided to customers. Certain trade receivables and payables related to our wholesale activities associated with generation and delivery of electric energy and associated environmental attributes, origination and marketing, natural gas storage, hub services and energy management, are subject to master netting agreements with counterparties, whereby we have the legal right to offset the balances and they are settled on a net basis. We present receivables and payables subject to such agreements on a net basis on our consolidated balance sheets.

Trade receivables include amounts due under Deferred Payment Arrangements (DPA). A DPA allows the account balance to be paid in installments over an extended period without interest, which generally exceeds one year, by negotiating mutually acceptable payment terms. The utility companies generally must continue to serve a customer who cannot pay an account balance in full if the customer (i) pays a reasonable portion of the balance; (ii) agrees to pay the balance in installments; and (iii) agrees to pay future bills within 30 days until the DPA is paid in full. Failure to make payments on a DPA results in the full amount of a receivable under a DPA being due. These accounts are part of the regular operating cycle and we classify them as short term. Due to COVID-19, the UIL companies’ regulators required them to offer to customers a 24-month repayment plan through June 30, 2022.

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

(p) Variable interest entities

An entity is considered to be a variable interest entity (VIE) when its total equity investment at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support, or its equity investors, as a group, lack the characteristics of having a controlling financial interest. A reporting company is required to consolidate a VIE as its primary beneficiary when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance, and the obligation to absorb losses of or the right to receive benefits from the VIE that could potentially be significant to the VIE. We evaluate whether an entity is a VIE whenever reconsideration events occur as defined by the accounting guidance (See Note 20).

We have undertaken several structured institutional partnership investment transactions that bring in external investors in certain of our wind farms in exchange for cash. Following an analysis of the economic substance of these transactions, we classify the consideration received at the inception of the arrangement as noncontrolling interests on our consolidated balance sheets. Subsequently, we use the HLBV method to allocate earnings to the noncontrolling interest, taking into consideration the cash and tax benefits provided to the tax equity investors.

(q) Debentures, bonds and bank borrowings

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

(r) Inventory

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

We also have materials and supplies inventories that we use for construction of new facilities and repairs of existing facilities. These inventories are carried and withdrawn at the lower of cost and net realizable value and reported on our consolidated balance sheets within “Materials and supplies.”

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

(s) Government grants

Our unregulated subsidiaries record government grants related to depreciable assets within deferred income and subsequently amortize them to earnings as an offset to depreciation and amortization expense over the useful life of the related asset. Our regulated subsidiaries record government grants as a reduction to the related utility plant to be recovered through rate base, in accordance with the prescribed FERC accounting.

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

(t) Deferred income

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

(u) Asset retirement obligations

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

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

We record AROs for the decommissioning of the wind and solar farms and thermal facilities. Projected removal costs are based on engineering estimates which are updated on an annual basis based on the relevant inflation and discount rate factors.

Our regulated utilities meet the requirements concerning accounting for regulated operations and we recognize a regulatory liability for the difference between removal costs collected in rates and actual costs incurred. We classify these as accrued removal obligations.

(v) Environmental remediation liability

In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. We record our environmental liabilities on an undiscounted basis.

(w) Post-employment and other employee benefits

We sponsor defined benefit pension plans that cover eligible employees. We also provide health care and life insurance benefits through various postretirement plans for eligible retirees.

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

We account for defined benefit pension or other postretirement plans, recognizing an asset or liability for the overfunded or underfunded plan status. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. Our utility operations generally reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in other comprehensive income, as management believes it is probable that such items will be recoverable through the ratemaking process. If a plan meets settlement or curtailment criteria, we recognize a regulatory asset of liability if these costs are probable of recovery from ratepayers. Certain nonqualified plan expenses are not recoverable through the ratemaking process and we present the unrecognized prior service costs and credits and unrecognized actuarial gains and losses in Accumulated Other Comprehensive Loss. We use a December 31st measurement date for our benefits plans.

We amortize prior service costs for both the pension and other postretirement benefits plans on a straight-line basis over the average remaining service period of participants expected to receive benefits. Unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans are amortized over the average remaining service period or 10 years, considering any requirement by the regulators for our Networks subsidiaries. Our policy is to calculate the expected return on plan assets using the market related value of assets. That value is determined by recognizing the difference between actual returns and expected returns over a five-year period.

(x) Income taxes

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

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

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

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

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

Federal production tax credits applicable to our renewable energy facilities, that are not part of a tax equity financing arrangement, are recognized as a reduction in income tax expense with a corresponding reduction in deferred income tax liabilities.

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

(y) Stock-based compensation

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

Adoption of New Accounting Pronouncements

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

In March 2020, the FASB issued amendments for recognizing the effects of reference rate reform on financial reporting, from the cessation of the London Interbank Offered Rate (LIBOR). The guidance provides optional expedients and exceptions to contract modifications, hedging relationships, and other transactions that reference LIBOR, subject to meeting certain criteria. Our adoption of reference rate reform did not materially affect our consolidated results of operations, financial position and cash flows.

(b) Disclosures by business entities about government assistance

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

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements not yet adopted that we have evaluated or are evaluating to determine their effect on our consolidated financial statements.

(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. The guidance is effective for disclosures starting in 2023, including interim periods, except for the roll forward information, which is effective for annual periods starting in 2024. Our adoption of the guidance on January 1, 2023 will not materially affect our disclosures.

Use of Estimates and Assumptions

The preparation of our consolidated financial statements in conformity with U.S. GAAP requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the reporting periods. Significant estimates and assumptions are used for, but not limited to: (1) allowance for credit losses and unbilled revenues; (2) asset impairments, including goodwill; (3) investments in equity instruments; (4) depreciable lives of assets; (5) income tax valuation allowances; (6) uncertain tax positions; (7) reserves for professional, workers' compensation and comprehensive general insurance liability risks; (8) contingency and litigation reserves; (9) fair value measurements; (10) earnings sharing mechanisms; (11) environmental remediation liabilities; (12) AROs; (13) pension and other postretirement employee benefits and (14) noncontrolling interest balances derived from HLBV (hypothetical liquidation at book value) accounting. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates we use in the preparation of our consolidated financial statements will change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes.

We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside specialists to assist in our evaluations, as necessary. Actual results could differ from those estimates.

Union collective bargaining agreements

We have approximately 46.0% of our employees covered by a collective bargaining agreement. There are no union contracts that are scheduled to expire in 2023.

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 24.

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, Contract Liabilities and Practical Expedient

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 December 2022 upon commercial operation. Contract assets totaled $9 million as of both December 31, 2022 and 2021, and are presented in "Other non-current assets" on our 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 $33 million and $16 million at December 31, 2022 and 2021, respectively, and are presented in "Other current liabilities" on our consolidated balance sheets. We recognized $33 million, $22 million and $21 million as revenue related to contract liabilities for the years ended December 31, 2022, 2021 and 2020, respectively.

We apply a practical expedient to expense as incurred costs to obtain a contract when the amortization period is one year or less. We record costs incurred to obtain a contract within operating expenses, including amortization of capitalized costs.

Revenues disaggregated by major source for our reportable segments for the years ended December 31, 2022, 2021 and 2020 are as follows:

	Year Ended December 31, 2022			
	Networks	Renewables	Other (b)	Total
(Millions)				
Regulated operations – electricity	$ 4,610	$ —	$ —	$ 4,610
Regulated operations – natural gas	1,931	—	—	1,931
Nonregulated operations – wind	—	947	—	947
Nonregulated operations – solar	—	36	—	36
Nonregulated operations – thermal	—	96	—	96
Other (a)	117	48	—	165
Revenue from contracts with customers	**6,658**	**1,127**	**—**	**7,785**
Leasing revenue	8	—	—	8
Derivative revenue	—	4	—	4
Alternative revenue programs	68	—	—	68
Other revenue	48	10	—	58
Total operating revenues	**$ 6,782**	**$ 1,141**	**$ —**	**$ 7,923**

	Year Ended December 31, 2021			
	Networks	Renewables	Other (b)	Total
(Millions)				
Regulated operations – electricity	$ 4,015	$ —	$ —	$ 4,015
Regulated operations – natural gas	1,516	—	—	1,516
Nonregulated operations – wind	—	1028	—	1028
Nonregulated operations – solar	—	20	—	20
Nonregulated operations – thermal	—	63	—	63
Other (a)	67	84	—	151
Revenue from contracts with customers	**5,598**	**1195**	**—**	**6,793**
Leasing revenue	7	—	—	7
Derivative revenue	—	3	—	3
Alternative revenue programs	115	—	—	115
Other revenue	34	22	—	56
Total operating revenues	**$ 5,754**	**$ 1,220**	**$ —**	**$ 6,974**

	Year Ended December 31, 2020			
	Networks	Renewables	Other (b)	Total
(Millions)				
Regulated operations – electricity	$ 3,642	$ —	$ —	$ 3,642
Regulated operations – natural gas	1,311	—	—	1,311
Nonregulated operations – wind	—	822	—	822
Nonregulated operations – solar	—	19	—	19
Nonregulated operations – thermal	—	39	—	39
Other (a)	58	101	—	159
Revenue from contracts with customers	**5,011**	**981**	**—**	**5,992**
Leasing revenue	6	—	—	6
Derivative revenue	—	136	—	136
Alternative revenue programs	157	—	—	157
Other revenue	14	15	—	29
Total operating revenues	**$ 5,188**	**$ 1,132**	**$ —**	**$ 6,320**

(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 December 31, 2022 and 2021, accounts receivable balances related to contracts with customers were approximately $1,622 million and $1,220 million, respectively, including unbilled revenues of $541 million and $405 million, which are included in "Accounts receivable and unbilled revenues, net" on our consolidated balance sheets.

As of December 31, 2022, the aggregate amount of the transaction price allocated to performance obligations that are unsatisfied (or partially unsatisfied) were as follows:

As of December 31, 2022	2023	2024	2025	2026	2027	Thereafter	Total
(Millions)							
Revenue expected to be recognized on multiyear retail energy sales contracts in place	$ 1	$ 1	$ —	$ —	$ —	$ —	$ 2
Revenue expected to be recognized on multiyear renewable energy credit sale contracts	46	45	17	5	1	2	116
Revenue expected to be recognized on multiyear capacity and carbon-free energy sale contracts	81	34	12	10	7	60	204
Total operating revenues	**$ 128**	**$ 80**	**$ 29**	**$ 15**	**$ 8**	**$ 62**	**$ 322**

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. Industry Regulation

Electricity and Natural Gas Distribution – Maine, New York, Connecticut and Massachusetts

Each of Networks' eight regulated utility companies must comply with regulatory procedures that differ in form but in all cases conform to the basic framework outlined below. Generally, tariff reviews cover various years and provide for a reasonable ROE, protection from, and automatic adjustments for, exceptional costs incurred and efficiency incentives. The distribution rates and allowed ROEs for Networks' regulated utilities in New York are subject to regulation by the New York Public Service Commission (NYPSC), in Maine by the Maine Public Utilities Commission (MPUC), in Connecticut by the Connecticut Public Utilities Regulatory Authority (PURA) and in Massachusetts by the Department of Public Utilities (DPU).

The revenues of Networks companies are essentially regulated, being based on tariffs established in accordance with administrative procedures set by the various regulatory bodies. The tariffs applied to the Networks companies are approved by the regulatory commissions of the different states and are based on the cost of providing service. The revenues of each of the Networks companies are set to be sufficient to cover its operating costs, including energy costs, finance costs and the costs of equity, the last of which reflects our capital ratio and a reasonable ROE.

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

The NYSEG and RG&E rate plans, the Maine distribution rate plan and associated proceedings, the Federal Energy Regulatory Commission (FERC) Transmission Return on Equity (ROE) case, the Connecticut rate plans, Reforming Energy Vision (REV), the storm proceedings in New York and the Tax Act are some of the most important specific regulatory processes that currently affect Networks.

CMP Distribution Rate Case

In an order issued on February 19, 2020, the MPUC authorized an increase in CMP's distribution revenue requirement of $17 million, or approximately 7.00%, based on an allowed ROE of 9.25% and a 50.00% equity ratio. The rate increase was effective March 1, 2020. Commencing on March 1, 2020, the MPUC also imposed a 1.00% ROE reduction (to 8.25%) for management efficiency associated with CMP's customer service performance following the implementation of its new billing system in 2017 which would be removed after demonstrating satisfactory customer service performance. In September 2021, CMP met the 18-month required rolling average satisfactory customer service benchmarks and filed with the MPUC a request for removal of the management efficiency adjustment, which was approved by the MPUC effective as of its February 18, 2022 order.

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

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

On August 11, 2022, CMP filed a three-year rate plan, with adjustments to the distribution revenue requirement in each year. In its filing, CMP has set the three rate years as May 10, 2023 to May 9, 2024 ("Rate Year 1"); May 10, 2024 to May 9, 2025 ("Rate Year 2"); and May 10, 2025 to May 9, 2026 ("Rate Year 3"). The requested Rate Year revenue requirement increases for the rate years are $48 million, $28 million and $23 million, respectively. The revenue requirement adjustments are based on a test year ending December 31, 2021. The requested revenue changes for each rate year of the proposal are subject to four adjustment mechanisms: (1) a yearly review of plant additions with potential downward reconciliation in the event of an underspend, (2) a capital adjustment mechanism for certain incremental pole replacements, broadband work, electric vehicle work, energy storage projects, and metering system upgrades, (3) a symmetrical inflation reconciliation adjustment, and (4) reconciliation of the benefits associated with the tax basis repair deduction. Other parties filed direct testimony in this proceeding on December 2, 2022 and CMP filed rebuttal testimony on February 7, 2023. New rates are expected to take effect on or around August 2023. We cannot predict the outcome of this matter.

NYSEG and RG&E Rate Plans

2016 Joint Proposal

On June 15, 2016, the NYPSC approved NYSEG's and RG&E's 2016 Joint Proposal for a three-year rate plan for electric and gas service which balanced the varied interests of the signatory parties including but not limited to maintaining the companies' credit quality and mitigating the rate impacts to customers. The 2016 Joint Proposal reflected many customer benefits including: acceleration of the companies' natural gas leak prone main replacement programs and increased funding for electric vegetation management to provide continued safe and reliable service. The delivery rate increases for the last year of the 2016 Joint Proposal can be summarized as follows:

	May 1, 2018	
Utility	Rate Increase (Millions)	Delivery Rate Increase %
NYSEG Electric	$ 30	4.10 %
NYSEG Gas	$ 15	7.30 %
RG&E Electric	$ 26	5.70 %
RG&E Gas	$ 10	5.20 %

The allowed rate of return on common equity for NYSEG Electric, NYSEG Gas, RG&E Electric and RG&E Gas was 9.00%. The equity ratio for each company was 48%; however, the equity ratio was set at the actual up to 50% for earnings sharing calculation purposes. The customer share of any earnings above allowed levels increased as the ROE increased, with customers receiving 50%, 75% and 90% of earnings in rate year three (May 1, 2018 – April 30, 2019) above 9.75%, 10.25% and 10.75% ROE, respectively. The rate plans also included the implementation of a rate adjustment mechanism (RAM) designed to return or collect certain defined reconciled revenues and costs, new depreciation rates and continuation of the existing RDM for each business. The 2016 Joint Proposal reflected the recovery of deferred NYSEG Electric storm costs of approximately $262 million, of which $123 million is being amortized over ten years and the remaining $139 million is being amortized over five years. The proposal also continues reserve accounting for qualifying Major Storms ($26 million annually for NYSEG Electric and $3 million annually for RG&E Electric). Incremental maintenance costs incurred to restore service in qualifying divisions will be chargeable to the Major Storm Reserve provided they meet certain thresholds.

The 2016 Joint Proposal maintained NYSEG's and RG&E's current electric reliability performance measures (and associated potential negative revenue adjustments for failing to meet established performance levels) which include the system average interruption frequency index (SAIFI) and the customer average interruption duration index (CAIDI). The 2016 Joint Proposal also modified certain gas safety performance measures at the companies, including those relating to the replacement of leak prone mains, leak backlog management, emergency response and damage prevention. The proposal established threshold performance levels for designated aspects of customer service quality and continued and expanded NYSEG's and RG&E's bill reduction and arrears forgiveness Low Income Programs with increased funding levels. The 2016 Joint Proposal provided for the implementation of NYSEG's Energy Smart Community (ESC) Project in the Ithaca region which serves as a test-bed for implementation and deployment of Reforming the Energy Vision (REV) initiatives. The ESC Project is supported by NYSEG's planned Distribution Automation upgrades and Advanced Metering Infrastructure (AMI) implementation for customers on circuits in the Ithaca region. The companies also are pursuing Non-Wires Alternative projects as described in the proposal. Other REV-related incremental costs and fees were included in the RAM to the extent cost recovery is not provided for elsewhere. Under the proposal, the RAM was applicable to all customers and serves to return or collect RAM Eligible Deferrals and Costs, including: (1) property taxes; (2) Major Storm deferral balances; (3) gas leak prone pipe replacement; (4) REV costs and fees which are not covered by other recovery mechanisms; and (5) NYSEG Electric Pole Attachment revenues. RG&E implemented a RAM in July 2018 since certain eligibility thresholds were exceeded.

The 2016 Joint Proposal provided for partial or full reconciliation of certain expenses including, but not limited to: pensions and other postretirement benefits; property taxes; variable rate debt and new fixed rate debt; gas research and development; environmental remediation costs; major storms; nuclear electric insurance limited credits; economic development; and low income programs. The 2016 Joint Proposal also included a downward-only Net Plant reconciliation. In addition, the 2016 Joint Proposal included downward-only reconciliations for the costs of electric distribution and gas vegetation management, pipeline integrity and incremental maintenance. The 2016 Joint Proposal provided that NYSEG and RG&E continue their electric RDMs on a total revenue per class basis and their gas RDMs on a revenue per customer basis.

2020 Joint Proposal

On November 19, 2020, the NYPSC approved a new three-year rate plan for NYSEG & RG&E (2020 Joint Proposal), with modifications to the rate increases at the two electric businesses. The effective date of new tariffs was December 1, 2020 with a make-whole provision back to April 17, 2020. The proposed rates facilitate the companies' transition to a cleaner energy future while allowing for important initiatives such as COVID-19 relief for customers and additional funding for vegetation management, hardening/resiliency and emergency preparedness. The rate plans continue the RAM designed to return or collect certain defined reconciled revenues and costs, have new depreciation rates and continue existing RDMs for each business. The 2020 Joint Proposal bases delivery revenues on an 8.80% ROE and 48.00% equity ratio; however, for the proposed ESM, the equity ratio is the lower of the actual equity ratio or 50.00%. The below table provides a summary of the approved delivery rate increases and delivery rate percentages, including rate levelization and excluding energy efficiency, which is a pass-through, for all four businesses. Rate years two and three commence on May 1, 2021 and 2022, respectively.

	Year 1		Year 2		Year 3	
Utility	**Rate Increase (Millions)**	**Delivery Rate Increase %**	**Rate Increase (Millions)**	**Delivery Rate Increase %**	**Rate Increase (Millions)**	**Delivery Rate Increase %**
NYSEG Electric	$ 34	4.6 %	$ 46	5.9 %	$ 36	4.2 %
NYSEG Gas	$ —	— %	$ 2	0.8 %	$ 3	1.6 %
RG&E Electric	$ 17	3.8 %	$ 14	3.2 %	$ 16	3.3 %
RG&E Gas	$ —	— %	$ —	— %	$ 2	1.3 %

On May 26, 2022, NYSEG and RG&E filed for a new rate plan with the NYPSC. The rate filings are based on test year 2021 financial results adjusted to the rate year May 1, 2023 – April 30, 2024. Since these rate filings were submitted on May 26, 2022, the effective date of new rates, assuming an approximately 11-month approval period, will be May 1, 2023. 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. In their filings, the following revenue changes were requested:

	Requested Revenue Change					
Utility	May 26, 2022 (Millions)		August 12, 2022 (Millions)		Difference (Millions)	
NYSEG Electric	$	274	$	274	$	—
NYSEG Gas	$	43	$	30	$	(13)
RG&E Electric	$	94	$	93	$	(1)
RG&E Gas	$	38	$	32	$	(6)

On September 16, 2022, the NYPSC suspended new tariffs and rates through April 21, 2023. On October 19, 2022, consistent with the Administrative Law Judge's' July 1, 2022 Ruling on Schedule and Party Status, NYSEG and RG&E voluntarily agreed to 60-day extension of maximum suspension period through June 20, 2023, subject to a make-whole provision. On December 21, 2022, NYSEG and RG&E voluntarily agreed to further 60-day extension of maximum suspension period to postpone through August 19, 2023, subject to a make-whole provision. During this time, the parties have conducted multi-party rate case settlement negotiations. We cannot predict the outcome of this proceeding.

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 half of 2023, 70% of the second half of 2023, and 20% of the first half of 2024. Supplier of last resort service is procured on a quarterly basis and UI is self-managing the last resort service for the first quarter of 2023 and has a wholesale power supply agreement in place for second quarter 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. UI's filing proposes a three-year rate plan commencing September 1, 2023 through August 31, 2026. The filing is based on a test year ending December 31, 2021, for the rate years beginning September 1, 2023 ("UI Rate Year 1"), September 1, 2024 ("UI Rate Year 2"), and September 1, 2025 ("UI Rate Year 3"). UI is requesting that PURA approve new distribution rates to recover an increase in revenue requirements of approximately $102 million in UI Rate Year 1, an incremental approximately $17 million in UI Rate Year 2, and an incremental approximately $17 million in UI Rate Year 3, compared to total revenues that would otherwise be recovered under UI's current rate schedules. UI's Rate Plan also includes several measures to moderate the impact of the proposed rate update for all customers, including, without limitation a rate levelization proposal to spread the proposed total rate increase over the three rate years, which would result in a change in revenue in UI Rate Year 1 of approximately $54 million. Other parties filed direct testimony on December 13, 2022 and UI filed its rebuttal testimony on January 6, 2023. Litigation of the case is expected to take approximately one year with new rates expected to go into effect on or around September 2023. We cannot predict the outcome of this matter.

In 2017, PURA approved new tariffs for the Southern Connecticut Gas Company (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 will be first applied against any environmental regulatory asset balance as defined in the settlement agreement (if one exists at that time) or refunded to customers through a bill credit if such environmental regulatory asset balance does not exist.

In December 2018, PURA approved new tariffs for Connecticut Natural Gas Corporation (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 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.

REV

In April 2014, the NYPSC commenced a proceeding entitled REV, which is a wide-ranging initiative to reform New York State's energy industry and regulatory practices. REV has been divided into two tracks, Track 1 for Market Design and Technology, and Track 2 for Regulatory Reform. REV and its related proceedings have and will continue to propose regulatory changes that are intended to promote more efficient use of energy, deeper penetration of renewable energy resources such as wind and solar and wider deployment of distributed energy resources (DER), such as micro grids, on-site power supplies and storage.

REV is also intended to promote greater use of advanced energy management products to enhance demand elasticity and efficiencies. Track 1 of this initiative involves a collaborative process to examine the role of distribution utilities in enabling market-based deployment of DER to promote load management and greater system efficiency, including peak load reductions. NYSEG is participating in the initiative with other New York utilities. The NYPSC issued a 2015 order in Track 1, which acknowledges the utilities' role as a Distribution System Platform provider, and required the utilities to file an initial Distribution System Implementation Plan (DSIP) by June 30, 2016, followed by bi-annual updates. The companies filed the initial DSIP, which also included information regarding the potential deployment of Automated Metering Infrastructure (AMI) across its entire service territory. In December 2016, the companies filed a petition to the NYPSC requesting approval for cost recovery associated with the full deployment of AMI. A collaborative associated with this petition began in the first quarter of 2017, was suspended in the second quarter of 2017, subsequently resumed in the first quarter of 2018 and then further suspended and was been included in the companies' May 20, 2019 rate filing. The companies also filed their first bi-annual update of the DSIP on July 31, 2018 and filed their next bi-annual update on June 30, 2020.

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

Track 2 of the REV initiative is also underway, and through a NYPSC staff whitepaper review process, is examining potential changes in current regulatory, tariff, market design and incentive structures that could better align utility interests with achieving New York state and NYPSC's policy objectives. New York utilities will also be addressing related regulatory issues in their individual rate cases. A Track 2 order was issued in May 2016, and includes guidance related to the potential for Earnings Adjustment Mechanisms (EAMs), Platform Service Revenues, innovative rate designs and data utilization and security. The companies, in December 2016, filed a proposal for the implementation of EAMs in the areas of System Efficiency, Energy Efficiency, Interconnections and Clean Air. A collaborative process to review the companies' petition was suspended in 2017. The approved 2020 Joint Proposal includes EAMs.

In March 2017, the NYPSC issued three separate REV-related orders. These orders created a series of filing requirements for NYSEG and RG&E beginning in March 2017 and extending through the end of 2018. The three orders involve: 1) modifications to the electric utilities' proposed interconnection EAM framework; 2) further DSIP requirements, including filing of an updated DSIP plan by mid-2018 and implementing two energy storage projects at each company by the end of 2018; and 3) Net Energy Metering Transition including implementation of Phase One of the Value of DER. In September 2017, the NYPSC issued another order related to the Value of DER, requiring tariff filings, changes to Standard Interconnection Requirements and planning for the implementation of automated consolidated billing. As of the end of 2018, both NYSEG and RG&E had deployed two energy storage projects each, consistent with the March 2017 NYPSC order requirements. In December 2018, the NYPSC staff submitted whitepapers on standby and buyback service rate design, future value stack compensation and capacity value compensation. The NYPSC ruled on the proposals set forth in the whitepapers on May 16,

2019. NYSEG and RG&E filed proposed standby and buyback rates with the NYPSC in September 2019. On November 25, 2020, DPS Staff, jointly with NYSERDA, issued a whitepaper on further recommendations regarding standby and buyback rates that were based on the electric utilities' September 23, 2019 filings. Comments on the recommendations in the whitepaper are due February 22, 2021, and reply comments are due March 8, 2021. A final Commission Order is expected in 2022.

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

On May 14, 2020, the Commission issued an Order extending and expanding distributed solar incentives. In addition to authorizing the extension of and additional funding for the NY-Sun program, the Commission modified certain program rules related to the NY-Sun program and the VDER policy. As part of the ordered modifications, the Commission directed the electric utilities with VDER tariffs to add tariff language for a Remote Crediting program that will allow Value-Stack-eligible generation resources to distribute the credits they receive for generation injected into the utility system to the utility bills of multiple, separately sited, non-residential customers. The Commission ordered the utilities to submit tariff leaves that implement the modifications associated with the Remote Crediting program to become effective November 1, 2020. Given the complexity of the program changes, the utilities have petitioned the Commission for an extension. Tariffs were filed on August 16, 2021, becoming effective on September 1, 2021.

On July 16, 2020, the Commission issued an Order establishing a net metering successor tariff. The Order continues Phase One NEM for all eligible mass market and commercial projects under 750 kW interconnected after January 1, 2022 and implements a modest customer benefit contribution (CBC) for onsite DERs to address cost recovery of certain public benefit programs. Customers that install DERs interconnected after January 1, 2022 shall be charged a monthly per kW fee based on the nameplate rating of the DER. Draft tariff leaves implementing the Commission's Order and proposed CBC calculations were filed on November 1, 2020. A final Commission Order was issued on August 13, 2021, implementing the CBC effective January 1, 2022 for new mass market net metering customers.

On April 24, 2018, the NYPSC instituted a proceeding to consider the role of utilities in providing infrastructure and rate design to encourage the expansion electric vehicles and electric vehicle supply equipment. The Commission issued an Order on February 2, 2019 to establish a Direct Current Fast Charger incentive program, with subsequent clarifications provided in Orders issued on July 12, 2019 and March 3, 2020. On July 16, 2020, the NYPSC issued an Order approving a $700 million statewide program (NYSEG and RG&E combined share is approximately $118 million). The make-ready program will be funded by investor-owned utilities in New York State and creates a cost-sharing program that incentivizes utilities and charging station developers to site electric vehicle charging infrastructure in places that will provide a maximal benefit to consumers.

Tax Cuts and Jobs Act

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Tax Act) was signed into law. The Tax Act significantly changed the federal taxation of business entities including, among other things, implementing a federal corporate tax rate decrease from 35% to 21% for tax years beginning after December 31, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates 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. With regard to SCG, we expect Tax Act savings to be deferred until they are reflected in tariffs in a future rate case, unless PURA determines otherwise.

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 $137 million and $142 million, respectively for this item at December 31, 2022 and 2021.

In 2017, audits of the power tax regulatory assets were commenced by the NYPSC and MPUC. On January 11, 2018, the NYPSC issued an order opening an operations audit on NYSEG and RG&E and certain other New York utilities regarding tax accounting. The NYPSC audit report is expected to be completed during 2023. In January 2018, the MPUC published the Power Tax audit report with respect to CMP, which indicated the auditor was unable to verify the asset “acquisition value” used to calculate the Power Tax regulatory asset. The audit report requires that CMP must provide support for the beginning balance of the regulatory assets or it will be unable to recover the value of the assets, which is approximately $11 million, excluding carrying costs. CMP responded to the audit report in its rate case filing by providing additional acquisition value support and, therefore, requested full recovery of the Power Tax regulatory asset. MPUC staff expressed concerns about the value CMP has attributed to this issue. The MPUC had an outside firm conduct an audit of CMP's filing and acquisition values, and the auditor found CMP's information was reasonable. In September 2019, CMP filed a report in response to the audit report and addressed MPUC staff concerns. On December 17, 2019, CMP filed a stipulation with the MPUC providing for recovery of the Power Tax regulatory asset and adjusting the carrying costs values for the period of July 1, 2017 through June 30, 2019. The MPUC approved the stipulation on January 21, 2020, which allowed CMP to start collecting the Power Tax Regulatory asset over the next 32.5 years beginning in July 2020.

Minimum Equity Requirements for Regulated Subsidiaries

Our regulated utility subsidiaries of Maine and New York (NYSEG, RG&E, CMP and MNG) are each subject to a minimum equity ratio requirement that is tied to the capital structure assumed in establishing revenue requirements. Pursuant to these requirements, each of NYSEG, RG&E, CMP and MNG must maintain a minimum equity ratio equal to the ratio in its currently effective rate plan or decision measured using a trailing 13-month average. On a monthly basis, each utility must maintain a minimum equity ratio of no less than 300 basis points below the equity ratio used to set rates. The minimum equity ratio requirement has the effect of limiting the amount of dividends that may be paid and may, under certain circumstances, require that the parent contribute equity capital. In addition, NYSEG and RG&E equity distributions that would result in a 13-month average common equity less than the maximum equity ratio utilized for the earnings sharing mechanism, or ESM, are prohibited if the credit rating of NYSEG, RG&E, AVANGRID or Iberdrola are downgraded by a nationally recognized rating agency to the lowest investment grade with a negative watch or downgraded to non-investment grade. These regulated utility subsidiaries are prohibited by regulation from lending to unregulated affiliates. These regulated utility subsidiaries have also agreed to minimum equity ratio requirements in certain borrowing agreements. These requirements are lower than the regulatory requirements.

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

We had restricted net assets of approximately $6,241 million associated with the minimum equity requirements as of December 31, 2022.

Movement of capital from our wholly owned unregulated subsidiaries is unrestricted.

New Renewable Source Generation

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

In October of 2018, UI entered into five PPAs totaling approximately 50 MW from developers of offshore wind and fuel cell generation pursuant to state law that provides the net costs of the PPAs are recoverable through electric rates. On December 19, 2018, PURA approved the PPAs, and approved UI's use of the non-bypassable federally mandated congestion charges for all customers to recover the net costs of the PPAs.

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

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

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

Connecticut Energy Legislation

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

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

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

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

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

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. We cannot predict the outcome of this proceeding.

Note 6. 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. The total net amount of these items is approximately $977 million.

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 December 31, 2022 and 2021 consisted of:

As of December 31,	2022	2021
(Millions)		
Pension and other post-retirement benefits	$ 365	$ 545
Pension and other post-retirement benefits cost deferrals	93	95
Storm costs	671	448
Rate adjustment mechanism	41	68
Revenue decoupling mechanism	52	68
Transmission revenue reconciliation mechanism	11	15
Contracts for differences	56	73
Hardship programs	33	24
Plant decommissioning	1	2
Deferred purchased gas	56	52
Deferred transmission expense	—	13
Environmental remediation costs	248	256
Debt premium	64	71
Unamortized losses on reacquired debt	19	23
Unfunded future income taxes	492	424
Federal tax depreciation normalization adjustment	137	142
Asset retirement obligation	20	20
Deferred meter replacement costs	55	46
COVID-19 cost recovery and late payment surcharge	17	21
Low income arrears forgiveness	31	—
Excess generation service charge	24	6
System Expansion	21	12
Non-bypassable charge	14	10
Other	247	213
Total regulatory assets	**2,768**	**2,647**
Less: current portion	447	400
Total non-current regulatory assets	**$ 2,321**	**$ 2,247**

“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.

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

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

“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.

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

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

As of December 31,	2022	2021
(Millions)		
Energy efficiency portfolio standard	$ 30	$ 45
Gas supply charge and deferred natural gas cost	15	7
Pension and other post-retirement benefits cost deferrals	117	73
Carrying costs on deferred income tax bonus depreciation	9	23
Carrying costs on deferred income tax - Mixed Services 263(a)	3	7
2017 Tax Act	1,232	1,327
Rate change levelization	25	99
Revenue decoupling mechanism	13	13
Accrued removal obligations	1,178	1,192
Asset sale gain account	—	2
Economic development	20	26
Positive benefit adjustment	16	22
Theoretical reserve flow thru impact	3	6
Deferred property tax	17	22
Net plant reconciliation	11	16
Debt rate reconciliation	32	49
Rate refund – FERC ROE proceeding	36	35
Transmission congestion contracts	31	23
Merger-related rate credits	10	12
Accumulated deferred investment tax credits	22	24
Asset retirement obligation	18	18
Earning sharing provisions	13	13
Middletown/Norwalk local transmission network service collections	17	17
Low income programs	18	25
Non-firm margin sharing credits	27	15
New York 2018 winter storm settlement	1	5
Hedges gains	—	19
Non by-passable charges	76	11
Transmission revenue reconciliation mechanism	75	9
Other	204	174
Total regulatory liabilities	**3,269**	**3,329**
Less: current portion	354	307
Total non-current regulatory liabilities	**$ 2,915**	**$ 3,022**

“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.

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

“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 to five 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 14 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. In both of the years ended December 31, 2022 and 2021, $2 million 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 collections" represents allowance for funds used during construction of the Middletown/Norwalk transmission line, which is being amortized over the useful life of the project.

“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.

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

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

Note 7. Goodwill and Intangible assets

Goodwill by reportable segment as of December 31, 2022 and 2021 consisted of:

As of December 31,	2022	2021
(Millions)		
Networks	$ 2,747	$ 2,747
Renewables	372	372
Total	**$ 3,119**	**$ 3,119**

During 2022, there were no changes in gross amounts and accumulated losses of goodwill for the Networks and Renewables reportable segments.

Goodwill Impairment Assessment

For impairment testing purposes, our reporting units are the same as operating segments, except for Networks, which contains three reporting units, Maine, New York and UIL. Goodwill for the Maine reporting unit is $325 million from the purchase of CMP by Energy East Corporation in 2000. Goodwill for the New York reporting unit is $654 million primarily from the purchase of RG&E by Energy East in 2002. Goodwill for the UIL reporting unit is $1,768 million from the 2015 acquisition of UIL.

We perform our annual impairment testing in the fourth quarter, as of October 1. Our qualitative assessment involves evaluating key events and circumstances that could affect the fair value of our reporting units, as well as other factors. Events and circumstances evaluated include macroeconomic conditions, industry, regulatory and market considerations, cost factors and their effect on earnings and cash flows, overall financial performance as compared with projected results and actual results of relevant prior periods, other relevant entity specific events and events affecting a reporting unit.

Our quantitative assessment utilizes a discounted cash flow model under the income approach and includes critical assumptions, primarily the discount rate and internal estimates of forecasted cash flows. We use a discount rate that is developed using market participant assumptions, which consider the risk and nature of the respective reporting unit's cash flows and the rates of return market participants would require in order to invest their capital in our reporting units. We test the reasonableness of the conclusions of our quantitative impairment testing using a range of discount rates and a range of assumptions for long-term cash flows.

For 2022, we utilized a qualitative assessment for the Networks reporting units and a quantitative assessment for the Renewables reporting unit. We had no impairment of goodwill in 2022 and 2021 as a result of our impairment testing.

Intangible assets

Intangible assets include those assets acquired in business acquisitions and intangible assets acquired and developed from external third parties and from affiliated companies. Following is a summary of intangible assets as of December 31, 2022 and 2021:

As of December 31, 2022	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
(Millions)			
Wind development	$ 590	$ (313)	$ 277
Other	22	(18)	4
Total Intangible Assets	**$ 612**	**$ (331)**	**$ 281**

As of December 31, 2021	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
(Millions)			
Wind development	$ 592	$ (301)	$ 291
Other	18	(16)	2
Total Intangible Assets	**$ 610**	**$ (317)**	**$ 293**

Wind development costs, with the exception of future 'pipeline' development costs, are amortized on a straight-line basis in accordance with the life of the related assets once placed in service. Amortization expense was $14 million, $13 million and $14 million for the years ended December 31, 2022, 2021 and 2020, respectively. We believe our future cash flows will support the recoverability of our intangible assets.

We expect amortization expense for the five years subsequent to December 31, 2022, to be as follows:

Year ending December 31,	Amount
(Millions)	
2023	$ 14
2024	$ 14
2025	$ 14
2026	$ 13
2027	$ 13

Note 8. Property, Plant and Equipment

Property, plant and equipment as of December 31, 2022, consisted of:

As of December 31, 2022	Regulated	Nonregulated	Total
(Millions)			
Electric generation, distribution, transmission and other	$ 18,634	$ 14,096	$ 32,730
Natural gas transportation, distribution and other	5,392	14	5,406
Other common operating property	—	317	317
Total Property, Plant and Equipment in Service	**24,026**	**14,427**	**38,453**
Total accumulated depreciation	(6,277)	(5,265)	(11,542)
Total Net Property, Plant and Equipment in Service	**17,749**	**9,162**	**26,911**
Construction work in progress	2,225	1,858	4,083
Total Property, Plant and Equipment	**$ 19,974**	**$ 11,020**	**$ 30,994**

Property, plant and equipment as of December 31, 2021, consisted of:

As of December 31, 2021	Regulated	Nonregulated	Total
(Millions)			
Electric generation, distribution, transmission and other	$ 17,392	$ 13,446	$ 30,838
Natural gas transportation, distribution and other	5,032	13	5,045
Other common operating property	—	286	286
Total Property, Plant and Equipment in Service	**22,424**	**13,745**	**36,169**
Total accumulated depreciation	(5,806)	(4,783)	(10,589)
Total Net Property, Plant and Equipment in Service	**16,618**	**8,962**	**25,580**
Construction work in progress	2,064	1,222	3,286
Total Property, Plant and Equipment	**$ 18,682**	**$ 10,184**	**$ 28,866**

Capitalized interest costs were $53 million, $33 million and $51 million for the years ended December 31, 2022, 2021 and 2020, respectively. Accrued liabilities for property, plant and equipment additions were $481 million, $297 million and $285 million as of December 31, 2022, 2021 and 2020, respectively.

We impaired or wrote off amounts of $11 million, $20 million and $7 million for the years ended December 31, 2022, 2021 and 2020, respectively, resulting from reassessment of the economic feasibility of our various Renewables development projects under construction.

Depreciation expense for the years ended December 31, 2022, 2021 and 2020, amounted to $1,071 million, $1,001 million and $973 million, respectively.

In November 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 effectively prohibits the construction of the NECEC project. Subsequently, in November 2021, Networks and NECEC Transmission LLC filed a lawsuit challenging the constitutionality of the Initiative. At December 31, 2021, an indicator of impairment was identified and we performed a test of recoverability using estimated undiscounted expected project cash flows and compared to our estimated project costs and determined no impairment loss was required. In August 2022, the Maine Law Court ruled that the Initiative provisions requiring legislative approval for the construction of any high impact transmission line anywhere in Maine and prohibiting high impact transmission lines in the Upper Kennebec Region would infringe on NECEC's constitutionally protected vested rights if NECEC Transmission LLC can demonstrate it engaged in substantial construction of the project in good-faith reliance. The case was remanded to the Maine Business & Consumer Court for further proceedings, which are ongoing. The outcome of this ongoing legal proceedings could have an adverse effect on the success of the NECEC project indicating that the carrying amount may not be recoverable. On November 29, 2022, the Maine Law Court vacated the trial court's prior decision to reverse the Bureau of Public Land's (BPL) decision to grant the lease over a small area of Maine public lands to house a 0.9-mile section of the NECEC. The Maine Law Court confirmed that BPL acted within its constitutional and statutory authority when granting the lease and the lease was not voided by the Initiative. As a result of these positive developments in 2022, there was no indicator of impairment identified. As of December 31, 2022 and 2021, we have capitalized approximately $585 million and $546 million, respectively, for the NECEC project.

Note 9. Asset retirement obligations

AROs are intended to meet the costs for dismantling and restoration work that we have committed to carry out at our operational facilities.

The reconciliation of ARO carrying amounts for the years ended December 31, 2022 and 2021 consisted of:

(Millions)		
As of December 31, 2020	**$**	**210**
Liabilities settled during the year		(2)
Liabilities incurred during the year		7
Accretion expense		12
Revisions in estimated cash flows (a)		26
As of December 31, 2021	**$**	**253**
Liabilities settled during the year		(1)
Liabilities incurred during the year		13
Accretion expense		14
Revisions in estimated cash flows (a)		(6)
As of December 31, 2022	**$**	**273**

(a) Represents an increase (decrease) in our estimate of expected cash flows required for retirement activities related to our renewable energy facilities.

Several of the wind generation facilities have restricted cash for purposes of settling AROs. As of both December 31, 2022 and 2021, restricted cash related to AROs was $3 million. These amounts have been included in "Other Assets" on our consolidated balance sheets. Accretion expenses are included in "Operations and maintenance" in our consolidated statements of income.

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

Note 10. Debt

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

As of December 31,		2022		2021	
	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
(Millions)					
First mortgage bonds - fixed (a)	2025-2052	$ 2,882	1.85%-8.00%	$ 2,759	1.85%-8.00%
Unsecured pollution control notes - fixed	2023-2029	545	1.40%-4.00%	478	1.40%-4.00%
Other various non-current debt - fixed	2023-2052	5,276	1.95%-6.66%	5,110	1.95%-6.66%
Unamortized debt issuance costs and discount		(76)		(53)	
Total Debt		**8,627**		**8,294**	
Less: debt due within one year, included in current liabilities		412		372	
Total Non-current Debt		**$ 8,215**		**$ 7,922**	

(a) The first mortgage bonds have pledged collateral of substantially all the respective utility's in service properties of approximately $8,331 million.

2022 Long-Term Debt Issuances

Company	Issue Date	Type	Amount (Millions)	Interest rate	Maturity
UI	1/31/2022	Unsecured Notes	$ 150	2.25%	2032
NYSEG	4/6/2022	Tax Exempt Bond	$ 67	4.00%	2028
NYSEG	12/15/2022	Unsecured Notes	$ 150	4.62%	2032
NYSEG	12/15/2022	Unsecured Notes	$ 125	4.96%	2052
RG&E	12/15/2022	First Mortgage Bonds	$ 125	4.86%	2052
CMP	12/15/2022	Green First Mortgage Bonds	$ 75	4.37%	2032
CMP	12/15/2022	Green First Mortgage Bonds	$ 50	4.76%	2052
UI	12/15/2022	Unsecured Notes	$ 50	4.62%	2032

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

2023	2024	2025	2026	2027	Total
(Millions)					
$ 412	$ 612	$ 1,107	$ 660	$ 484	$ 3,275

We make certain standard covenants to lenders in our third-party debt agreements, including, in certain agreements, covenants regarding the ratio of indebtedness to total capitalization. A breach of any covenant in the existing credit facilities or the agreements governing our other indebtedness would result in an event of default. Certain events of default may trigger automatic acceleration. Other events of default may be remedied by the borrower within a specified period or waived by the lenders and, if not remedied or waived, give the lenders the right to accelerate. Neither we nor any of our subsidiaries were in breach of covenants or of any obligation that could trigger the early redemption of our debt as of both December 31, 2022 and 2021 and throughout 2022 and 2021.

Fair Value of Debt

As of December 31, 2022 and 2021, the estimated fair value of long-term debt, was $7,991 million and $9,155 million, respectively. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the electricity industry and the credit ratings of the borrowers in each case. The fair value of debt is considered Level 2 within the fair value hierarchy.

Iberdrola Loan

On December 14, 2020, AVANGRID and Iberdrola entered into an intra-group loan agreement which provided AVANGRID with an unsecured subordinated loan in an aggregate principal amount of $3,000 million (the Iberdrola Loan). The Iberdrola Loan was repaid with the proceeds of the common share issuance described in Note 1.

Short-term Debt

AVANGRID had $566 million and $159 million of notes payable as of December 31, 2022 and 2021, respectively.

AVANGRID has a commercial paper program with a limit of $2 billion which is backstopped by the AVANGRID credit facilities described below. As of December 31, 2022 and 2021, the amount of notes payable under the commercial paper program was $397 million and $0, respectively, presented net of discounts on the balance sheet. As of December 31, 2022, the weighted-average interest rate on outstanding commercial paper was 4.66%.

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. As of both December 31, 2022 and 2021, 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 December 31, 2022 was $3,178 million.

Iberdrola Group Credit Facility

AVANGRID has a credit facility with Iberdrola Financiacion, S.A.U., a company of the Iberdrola Group. The facility has a limit of $500 million and matures on June 18, 2023. AVANGRID pays a facility fee of 10.5 basis points annually on the facility. As of both December 31, 2022 and 2021, there was no outstanding amount under this credit facility.

Supplier Financing Arrangements

We operate a supplier financing arrangement. During 2021, 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. As of December 31, 2022 and 2021, the amount of notes payable under supplier financing arrangements was $171 million and $161 million, respectively. As of December 31, 2022 and 2021, the weighted average interest rate on the balance was 5.48% and 0.82%, respectively.

Note 11. 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.
- NYSEG, RG&E and CMP may enter into fuel derivative contracts to hedge their unleaded and diesel fuel requirements for their fleet vehicles. Exchange-based forward market prices are used, but because an unobservable basis adjustment is added to the forward prices, we include the fair value measurement for these contracts in Level 3.
- 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 12 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 historical volatilities and correlations for tolling arrangements and extrapolated values for certain power swaps. 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 the London Interbank Offered Rate (LIBOR) the Secured Overnight Financing Rate (SOFR), forward interest rate curves or other relevant benchmark. We include the fair value measurement for these contracts in Level 2 (See Note 12 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 $3 million as of both December 31, 2022 and 2021, respectively and is included in “Other Assets” on our consolidated balance sheets.

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

As of December 31, 2022	Level 1	Level 2	Level 3	Netting	Total
(Millions)					
Equity and other 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)**

As of December 31, 2021	Level 1	Level 2	Level 3	Netting	Total
(Millions)					
Equity and other investments with readily determinable fair values	**$ 45**	**$ 15**	**$ —**	**$ —**	**$ 60**
Derivative assets					
Derivative financial instruments - power	$ 31	$ 39	$ 85	$ (78)	$ 77
Derivative financial instruments - gas	4	34	9	(32)	15
Contracts for differences	—	—	2	—	2
Total	**$ 35**	**$ 73**	**$ 96**	**$ (110)**	**$ 94**
Derivative liabilities					
Derivative financial instruments - power	$ (16)	$ (137)	$ (90)	$ 176	$ (67)
Derivative financial instruments - gas	(1)	(22)	—	18	(5)
Contracts for differences	—	—	(75)	—	(75)
Derivative financial instruments – Other	—	(77)	—	—	(77)
Total	**$ (17)**	**$ (236)**	**$ (165)**	**$ 194**	**$ (224)**

The reconciliation of changes in the fair value of financial instruments based on Level 3 inputs for the years ended December 31, 2022, 2021 and 2020 consisted of:

(Millions)	2022	2021	2020
Fair value as of January 1,	**$ (69)**	**$ 13**	**$ 25**
Gains for the year recognized in operating revenues	108	21	8
Losses for the year recognized in operating revenues	(30)	(34)	(2)
Total gains or losses for the period recognized in operating revenues	78	(13)	6
Gains recognized in OCI	2	2	1
Losses recognized in OCI	(57)	(52)	(3)
Total gains or losses recognized in OCI	(55)	(50)	(2)
Net change recognized in regulatory assets and liabilities	17	13	6
Purchases	10	(17)	(2)
Settlements	8	(13)	(15)
Transfers out of Level 3 (a)	27	(2)	(5)
Fair value as of December 31,	**$ 16**	**$ (69)**	**$ 13**
Gains for the year included in operating revenues attributable to the change in unrealized gains relating to financial instruments still held at the reporting date	$ 78	$ (13)	$ 6

(a) Transfers out of Level 3 were the result of increased observability of market data.

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 December 31, 2022.

Index	Avg.	Max.	Min.
NYMEX ($/MMBtu)	$ 4.18	$ 9.86	$ 2.27
AECO ($/MMBtu)	$ 3.05	$ 10.80	$ 1.53
Ameren ($/MWh)	$ 46.29	$ 225.62	$ 18.01
COB ($/MWh)	$ 58.96	$ 400.10	$ 9.15
ComEd ($/MWh)	$ 42.57	$ 222.49	$ 14.98
ERCOT N hub ($/MWh)	$ 46.94	$ 324.49	$ 13.66
ERCOT S hub ($/MWh)	$ 45.44	$ 320.63	$ 13.88
Indiana hub ($/MWh)	$ 49.02	$ 230.14	$ 20.74
Mid C ($/MWh)	$ 55.72	$ 400.10	$ 5.15
Minn hub ($/MWh)	$ 39.75	$ 183.54	$ 15.23
NoIL hub ($/MWh)	$ 42.22	$ 222.18	$ 14.64
PJM W hub ($/MWh)	$ 48.80	$ 227.60	$ 17.78

Our Level 3 valuations primarily consist of NYMEX gas and fixed price power swaps with delivery periods extending through 2024 and 2032, respectively. The gas swaps are used to hedge uncontracted wind positions. The power swaps are used to hedge uncontracted wind production in the West and Midwest.

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 only material 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 gas swaps are economic hedges of uncontracted generation, with decreases in gas prices resulting in unrealized gains and increases 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 models themselves. 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 price, correlation and volatility curves. 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 12 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 December 31, 2022
Risk of non-performance	0.84% - 0.89%
Discount rate	3.99% - 4.22%
Forward pricing ($ per KW-month)	$2.00 - $3.80

Note 12. 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 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 December 31, 2022 and 2021, respectively, including those subject to master netting agreements and the location of the net derivative positions on our consolidated balance sheets:

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)

As of December 31, 2021	Current Assets	Noncurrent Assets	Current Liabilities	Noncurrent Liabilities
(Millions)				
Not designated as hedging instruments				
Derivative assets	$ 29	$ 7	$ 12	$ 4
Derivative liabilities	(12)	(4)	(27)	(64)
	17	3	(15)	(60)
Designated as hedging instruments				
Derivative assets	—	—	—	—
Derivative liabilities	—	—	(1)	—
	—	—	(1)	—
Total derivatives before offset of cash collateral	17	3	(16)	(60)
Cash collateral receivable	—	—	—	—
Total derivatives as presented in the balance sheet	$ 17	$ 3	$ (16)	$ (60)

The net notional volumes of the outstanding derivative instruments associated with Networks' activities as of December 31, 2022 and 2021, respectively, consisted of:

As of December 31,	2022	2021
(Millions)		
Wholesale electricity purchase contracts (MWh)	5.7	5.7
Natural gas purchase contracts (Dth)	9.6	9.4
Fleet fuel purchase contracts (Gallons)	—	2.0

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 December 31, 2022 and 2021 and amounts reclassified from regulatory assets and liabilities into income for the years ended December 31, 2022, 2021 and 2020 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				**For the Year Ended December 31,**	
December 31, 2022	**Electricity**	**Natural Gas**	**2022**	**Electricity**	**Natural Gas**
Regulatory assets	$ 9	$ 4	Purchased power, natural gas and fuel used	$ (127)	$ (16)
Regulatory liabilities	$ —	$ —			
December 31, 2021			**2021**		
Regulatory assets	$ —	$ —	Purchased power, natural gas and fuel used	$ (23)	$ (11)
Regulatory liabilities	$ (16)	$ (3)			
			2020		
			Purchased power, natural gas and fuel used	$ 55	$ 4

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 December 31, 2022, 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 $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. As of December 31, 2021, UI has recorded a gross derivative asset of $2 million ($0 of which is related to UI's portion of the CfD signed by CL&P), a regulatory asset of $73 million, a gross derivative liability of $75 million ($72 million of which is related to UI's portion of the CfD signed by CL&P) and a regulatory liability of $0.

The unrealized gains and losses from fair value adjustments to these derivatives, which are recorded in regulatory assets, for the years ended December 31, 2022, 2021 and 2020, respectively, were as follows:

	Years Ended December 31,		
	2022	**2021**	**2020**
(Millions)			
Derivative Assets	$ (1)	$ —	$ —
Derivative Liabilities	$ 18	$ 13	$ 6

Certain foreign currency exchange contracts are not designated as hedging instruments. For the years ended December 31, 2020, we recorded a gain of $4 million, related to our foreign currency contracts not designated as hedging instruments, included in "Other income" in our consolidated statements of income.

Derivatives designated as hedging instruments

The effect of derivatives in cash flow hedging relationships on OCI and income for the years ended December 31, 2022, 2021 and 2020, respectively, consisted of:

Year Ended December 31,	(Loss) Gain Recognized in OCI on Derivatives (a)	Location of Loss Reclassified from Accumulated OCI into Income	Loss (Gain) Reclassified from Accumulated OCI into Income	Total amount per Income Statement
(Millions)				
2022				
Interest rate contracts	$ —	Interest expense	$ 4	$ 303
Commodity contracts	2	Purchased power, natural gas and fuel used	(3)	2,456
Total	**$ 2**		**$ 1**	
2021				
Interest rate contracts	$ —	Interest expense	$ 4	$ 298
Commodity contracts	2	Purchased power, natural gas and fuel used	(1)	1,719
Foreign currency exchange contracts	(5)		—	
Total	**$ (3)**		**$ 3**	
2020				
Interest rate contracts	$ —	Interest expense	$ 4	$ 316
Commodity contracts	(1)	Purchased power, natural gas and fuel used	1	1,379
Foreign currency exchange contracts	1		—	
Total	**$ —**		**$ 5**	

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

On June 20, 2019, Networks entered into a forward contract to hedge the foreign currency exchange risk of approximately $100 million in forecasted capital expenditures through June 2023. The forward foreign currency contracts, which were designated and qualified as cash flow hedges, were settled in December 2021. The net loss of $5 million in accumulated OCI on the foreign exchange derivative will be reclassified into earnings over the useful life of the underlying capital expenditures.

The net loss in accumulated OCI related to previously settled forward starting swaps and accumulated amortization is $43 million and $47 million as of December 31, 2022 and 2021, respectively. We recorded $4 million in net derivative losses related to discontinued cash flow hedges during each of the years ended December 31, 2022, 2021 and 2020, respectively. We will amortize approximately $4 million of discontinued cash flow hedges in 2023.

(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 December 31, 2022 and 2021, respectively, consisted of:

As of December 31,	2022	2021
(MWh/Dth in Millions)		
Wholesale electricity purchase contracts	2	4
Wholesale electricity sales contracts	7	10
Natural gas and other fuel purchase contracts	15	20
Financial power contracts	6	9
Basis swaps - purchases	22	30

The fair values of derivative contracts associated with Renewables' activities as of December 31, 2022 and 2021, respectively, consisted of:

As of December 31,	2022	2021
(Millions)		
Wholesale electricity purchase contracts	$ 149	$ 36
Wholesale electricity sales contracts	(200)	(77)
Natural gas and other fuel purchase contracts	2	6
Financial power contracts	8	35
Total	**$ (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 22, this hedge was novated to the lending institutions and the notional value changed to $956 million. As of December 31, 2022 and 2021, the fair value of the interest rate swap was $116 million and $(58) million, respectively, as a non-current asset and non-current liability. 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 December 31, 2022 and 2021, respectively, including those subject to master netting agreements and the location of the net derivative position on our consolidated balance sheets:

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 payable	—	—	105	54
Total derivatives as presented in the balance sheet	$ 60	$ 139	$ (87)	$ (37)

As of December 31, 2021	**Current Assets**	**Noncurrent Assets**	**Current Liabilities**	**Noncurrent Liabilities**
(Millions)				
Not designated as hedging instruments				
Derivative assets	$ 29	$ 70	$ 52	$ 9
Derivative liabilities	(11)	(14)	(65)	(11)
	18	56	(13)	(2)
Designated as hedging instruments				
Derivative assets	—	—	5	6
Derivative liabilities	—	—	(67)	(142)
	—	—	(62)	(136)
Total derivatives before offset of cash collateral	18	56	(75)	(138)
Cash collateral (payable) receivable	—	—	27	57
Total derivatives as presented in the balance sheet	$ 18	$ 56	$ (48)	$ (81)

Derivatives not designated as hedging instruments

The effects of trading and non-trading derivatives associated with Renewables' activities for the years ended December 31, 2022, 2021 and 2020 consisted of:

	Year Ended December 31, 2022		
	Trading	Non-trading	Total amount per income statement
(Millions)			
Operating Revenues			
Wholesale electricity purchase contracts	$ 9	$ 6	
Wholesale electricity sales contracts	1	(63)	
Financial power contracts	1	(52)	
Financial and natural gas contracts	1	(6)	
Total loss included in operating revenues	$ 12	$ (115)	$ 7,923
Purchased power, natural gas and fuel used			
Wholesale electricity purchase contracts	$ —	$ 98	
Financial and natural gas contracts	—	5	
Total gain included in purchased power, natural gas and fuel used	$ —	$ 103	$ 2,456
Total Gain (Loss)	$ 12	$ (12)	

	Year Ended December 31, 2021		
	Trading	Non-trading	Total amount per income statement
(Millions)			
Operating Revenues			
Wholesale electricity purchase contracts	$ 1	$ (1)	
Wholesale electricity sales contracts	(2)	(33)	
Financial power contracts	4	(42)	
Financial and natural gas contracts	(1)	(25)	
Total (loss) gain included in operating revenues	$ 2	$ (101)	$ 6,974
Purchased power, natural gas and fuel used			
Wholesale electricity purchase contracts	$ —	$ 32	
Financial and natural gas contracts	—	12	
Total gain included in purchased power, natural gas and fuel used	$ —	$ 44	$ 1,719
Total Loss	$ 2	$ (57)	

	Year Ended December 31, 2020		
	Trading	Non-trading	Total amount per income statement
(Millions)			
Operating Revenues			
Wholesale electricity purchase contracts	$ (1)	$ —	
Wholesale electricity sales contracts	(1)	6	
Financial power contracts	2	—	
Financial and natural gas contracts	—	(13)	
Total (loss) gain included in operating revenues	$ —	$ (7)	$ 6,320
Purchased power, natural gas and fuel used			
Wholesale electricity purchase contracts	$ —	$ (4)	
Financial and natural gas contracts	—	6	
Total gain included in purchased power, natural gas and fuel used	$ —	$ 2	$ 1,379
Total (Loss) Gain	$ —	$ (5)	

Derivatives designated as hedging instruments

The effect of derivatives in cash flow hedging relationships on accumulated OCI and income for the years ended December 31, 2022, 2021 and 2020 consisted of:

Years Ended December 31,	Gain (Loss) Recognized in OCI on Derivatives (a)	Location of Loss (Gain) Reclassified from Accumulated OCI into Income	Loss (Gain) Reclassified from Accumulated OCI into Income	Total amount per Income Statement
(Millions)				
2022				
Interest rate contracts	$ 116	Interest Expense	$ —	$ 303
Commodity contracts	$ (178)	Operating revenues	$ 59	$ 7,923
Total	**$ (62)**		**$ 59**	
2021				
Interest rate contracts	$ (58)	Interest Expense	$ —	$ 298
Commodity contracts	$ (142)	Operating revenues	$ (3)	$ 6,974
	$ (200)		**$ (3)**	
2020				
Commodity contracts	$ 1	Operating revenues	$ 6	$ 6,320

(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 $169 million of loss included in accumulated OCI at December 31, 2022 is expected to be reclassified into earnings within the next twelve months. We recorded immaterial amounts of net derivative losses related to discontinued cash flow hedges for the years ended December 31, 2022, 2021 and 2020.

(c) Corporate activities

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.

The net loss in accumulated OCI related to previously settled interest rate contracts is $38 million and $48 million as of December 31, 2022 and 2021, respectively. We amortized into income $9 million, $9 million and $8 million of the loss related to the settled interest rate contracts for the years ended December 31, 2022, 2021 and 2020, respectively. We will amortize approximately $9 million of the net loss on the interest rate contracts during 2023.

The effect of derivatives in cash flow hedging relationships on accumulated OCI for the years ended December 31, 2022, 2021 and 2020 consisted of:

Years Ended December 31,	(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)				
2022				
Interest rate contracts	$ —	Interest expense	$ 9	$ 303
2021				
Interest rate contracts	$ —	Interest expense	$ 9	$ 298
2020				
Interest rate contracts	$ (27)	Interest expense	$ 8	$ 316

(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 years ended December 31, 2022 and 2021 are as follows:

	Fair value of hedge	Location of (Gain) Recognized in Income Statement	Loss Recognized in Income Statement	Year to date total per Income Statement
(Millions)	As of December 31, 2022		Year Ended December 31, 2022	
Current liabilities	$ (29)	Interest Expense	$ 6	$ 303
Non-current liabilities	$ (86)			
	Cumulative effect on hedged debt			
Current debt	$ 29			
Non-current debt	$ 86			

	Fair value of hedge	Location of (Gain) Recognized in Income Statement	(Gain) Recognized in Income Statement	Year to date total per Income Statement
(Millions)	As of December 31, 2021		Year Ended December 31, 2021	
Current assets	$ —	Interest Expense	$ (3)	$ 298
Non-current liabilities	$ (19)			
	Cumulative effect on hedged debt			
Current debt	$ —			
Non-current debt	$ 19			

(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 December 31, 2022, UI would have had to post an aggregate of approximately $37 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. The amount of cash collateral under master netting arrangements that has not been offset against net derivative positions was $97 million and $67 million as of December 31, 2022 and 2021, respectively. Derivative instruments settlements and collateral payments are included throughout the "Changes in operating assets and liabilities" section of operating activities in the 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 December 31, 2022 is $13 million, for which we have posted collateral.

Note 13. Leases

We have operating leases for office buildings, facilities, vehicles and certain equipment. Our finance leases are primarily related to electric generation and certain buildings, vehicles and equipment. Certain of our lease agreements include rental payments adjusted periodically for inflation or are based on other periodic input measures. Our leases do not contain any material residual value guarantees or material restrictive covenants. Our leases have remaining lease terms of 1 year to 62 years, some of which may include options to extend the leases for up to 40 years, and some of which may include options to terminate. We consider extension or termination options in the lease term if it is reasonably certain we will exercise the option.

The components of lease cost for the years ended December 31, 2022, 2021 and 2020 were as follows:

For the Year Ended December 31,	2022	2021	2020
(Millions)			
Lease cost			
Finance lease cost			
Amortization of right-of-use assets	$ 12	$ 8	$ 17
Interest on lease liabilities	3	3	4
Total finance lease cost	15	11	21
Operating lease cost	20	14	16
Short-term lease cost	6	4	3
Variable lease cost	3	4	—
Total lease cost	$ 44	$ 33	$ 40

Balance sheet and other information as of December 31, 2022 and 2021 was as follows:

As of December 31,	2022	2021
(Millions, except lease term and discount rate)		
Operating Leases		
Operating lease right-of-use assets	$ 159	$ 148
Operating lease liabilities, current	13	12
Operating lease liabilities, long-term	161	149
Total operating lease liabilities	$ 174	$ 161
Finance Leases		
Other assets	$ 143	$ 156
Other current liabilities	7	4
Other non-current liabilities	80	91
Total finance lease liabilities	$ 87	$ 95
Weighted-average Remaining Lease Term (years)		
Finance leases	6.4	7.3
Operating leases	16.9	20.5
Weighted-average Discount Rate		
Finance leases	3.46 %	3.49 %
Operating leases	3.69 %	3.06 %

For the years ended December 31, 2022, 2021 and 2020 supplemental cash flow information related to leases was as follows:

For the Year Ended December 31,	2022	2021	2020
(Millions)			
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ 14	$ 16	$ 13
Operating cash flows from finance leases	$ 1	$ 3	$ 3
Financing cash flows from finance leases	$ 9	$ 6	$ 9
Right-of-use assets obtained in exchange for lease obligations:			
Finance leases	$ (1)	$ —	$ 46
Operating leases	$ 25	$ 10	$ 94

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

(Millions)	Finance Leases	Operating Leases
Year ending December 31,		
2023	$ 9	$ 16
2024	30	14
2025	8	14
2026	9	14
2027	10	16
Thereafter	33	183
Total lease payments	99	257
Less: imputed interest	(12)	(83)
Total	$ 87	174

Renewables has a sale-leaseback arrangement (as a seller-lessee) on a solar generation facility. The finance lease liability outstanding (including the current portion thereof) was $41 million and $45 million at December 31, 2022 and December 31, 2021, respectively. In 2013, Renewables sold the generation facility to a consortium of buyers (referred to as "Trusts") and simultaneously entered into an agreement with the Trusts for the right to use the facility for up to 15 years with an early buyout option in year 10. During 2022, Renewables elected not to exercise the early buyout option and prospectively adjusted the accounting for the lease, which contains a buyout option at fair value at the end of the lease term. The gain on the sale of the generation facility was deferred and is being amortized to depreciation expense over the 25-year life of the facility.

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

Note 14. Commitments and Contingent Liabilities

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 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 $28 million and $8 million, respectively, as of December 31, 2022, which has not changed since December 31, 2021, except for the accrual of carrying costs. If adopted as final by the FERC, the impact of the initial decision by the FERC administrative law judge would be an additional aggregate reserve for Complaints II and III of $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 CAPM for establishing the base return on equity. This resulted in a base return on equity of 9.88% as the midpoint of the zone of reasonableness. Various parties have requested rehearing on this decision, which was granted. On May 21, 2020, FERC issued a ruling, which, among other things, adjusted the methodology to determine the MISO transmission owners' ROE, resulting in an increase in ROE from 9.88% to 10.02% by utilizing the risk premium model, 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 FERC's orders and remanded the matter back to FERC. The D.C. Circuit Court held that FERC failed to offer a reasoned explanation for its decision to reintroduce the RPM after initially, and forcefully, rejecting it and that because FERC adopted that significant portion of its model in an arbitrary and capricious fashion, the new ROE produced by that model cannot stand. We cannot predict the potential impact the MISO transmission owners' ROE proceeding may have in establishing a precedent for the NETO's pending four Complaints.

On April 15, 2021, the FERC issued a supplemental Notice of Proposed Rulemaking (Supplemental NOPR) that proposes to eliminate the 50 basis-point ROE incentive for utilities who join Regional Transmission Organizations after three years of membership. The NETOs submitted initial comments in opposition to the Supplemental NOPR on June 25, 2021 and reply comments on July 26, 2021. If the elimination of the 50 basis-point ROE incentive adder becomes final, we estimate we would have an approximately $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 PPA entered into by Renewables, as seller, to the California Department of Water Resources, as purchaser, alleging that the terms and conditions of the PPA 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 PPAs unjust and unreasonable. However, the proposed ruling did conclude that the price of the PPAs 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, a buyer under a virtual PPA with a subsidiary of Renewables provided notice that the buyer 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. The buyer has requested an adjustment to the invoices that would increase the amount payable by approximately $29 million. Renewables has responded in writing stating that the invoice was properly calculated in accordance with the provisions of the PPA. The parties are scheduled to mediate this matter in March 2023 in order to reach a potential resolution. We cannot predict the outcome of this matter.

Power, Gas and Other Arrangements

Power and Gas Supply Arrangements – Networks

NYSEG and RG&E are the providers of last resort for customers. As a result, the companies buy physical energy and capacity from the NYISO. In accordance with the NYPSC's February 26, 2008 Order, NYSEG and RG&E are required to hedge on behalf of non-demand billed customers. The physical electric capacity purchases we make from parties other than the NYISO are to comply with the hedge requirement for electric capacity. The companies enter into financial swaps to comply with the hedge requirement for physical electric energy purchases. Other purchases, from some Independent Power Producers (IPPs) and the New York Power Authority, are from contracts entered into many years ago when the companies made purchases under contract as part of their supply portfolio to meet their load requirement. More recent IPP purchases are required to comply with the companies' Public Utility Regulatory Policies Act (PURPA) purchase obligation.

NYSEG, RG&E, SCG, CNG and BGC (collectively, the Regulated Gas Companies) satisfy their natural gas supply requirements through purchases from various producers and suppliers, withdrawals from natural gas storage, capacity contracts and winter peaking supplies and resources. The Regulated Gas Companies operate diverse portfolios of gas supply, firm transportation capacity, gas storage and peaking resources. Actual gas costs incurred by each of the Regulated Gas Companies are passed through to customers through state regulated purchased gas adjustment mechanisms, subject to regulatory review.

The Regulated Gas Companies purchase the majority of their natural gas supply at market prices under seasonal, monthly or mid-term supply contracts and the remainder is acquired on the spot market. The Regulated Gas Companies diversify their sources of supply by amount purchased and location and primarily acquire gas at various locations in the U.S. Gulf of Mexico region, in the Appalachia region and in Canada.

The Regulated Gas Companies acquire firm transportation capacity on interstate pipelines under long-term contracts and utilize that capacity to transport both natural gas supply purchased and natural gas withdrawn from storage to the local distribution system.

The Regulated Gas Companies acquire firm underground natural gas storage capacity using long-term contracts and fill the storage facilities with gas in the summer months for subsequent withdrawal in the winter months.

Winter peaking resources are primarily attached to the local distribution systems and are either owned or are contracted for by the Regulated Gas Companies, each of which is a Local Distribution Company. Each Regulated Gas Company owns or has rights to the natural gas stored in an LNG facility directly attached to its distribution system.

Other arrangements include contractual obligations for property, plant and equipment, material and services on order but not yet delivered at December 31, 2022.

Power, Gas and Other Arrangements – Renewables

Gas purchase commitments consist of firm transport capacity to fuel the Klamath Cogen and Peaking gas generators. Power purchase commitments include the following: (i) long-term firm transmission agreements with fixed monthly capacity payments that allow the delivery of electricity from wind and thermal generation sources to various customers (ii) a 95.6 MW (average) three-year purchase of hydro capacity and energy to provide balancing services to the NW wind assets that has monthly fixed payments (beginning in 2022 and expiring in 2024) and (iii) a five-year purchase of 52 MW (average) hydro capacity and energy to provide balancing services to the NW wind assets that has monthly fixed payments (beginning in 2019 and expiring in 2023). Power sales commitments include: (i) winter capacity sale of 150 MW through 2042, (ii) fixed price, fixed volume hydro energy sales through 2024, (iii) fixed price, fixed volume power sales off the Klamath Cogen facility, (iv) a seasonal tolling arrangement off the Klamath peaking facility with fixed capacity charges through 2024; (v) fixed price, fixed volume renewable energy credit sales off merchant wind facilities, (vi) sales of merchant wind farm capacity to various ISOs and (vii) sales of ancillary services (e.g., regulation and frequency response, generator imbalance, etc.) to third parties from Renewables' Balancing Authority.

In June 2020, Renewables entered into a Payment In Lieu of Taxes (PILOT) agreement related to two of its projects with Torrance County, New Mexico. The agreement requires PILOT payments to Torrance County through 2049. The total amount of PILOT payments related to the two projects in 2022 was $1 million.

Renewables also has easement contracts which are included in the table below.

Forward purchases and sales commitments under power, gas and other arrangements as of December 31, 2022 consisted of:

Year	Purchases	Sales
	(Millions)	
2023	$ 1,066	$ 321
2024	200	137
2025	112	43
2026	86	28
2027	66	22
Thereafter	993	61
Totals	**$ 2,523**	**$ 612**

Guarantee Commitments to Third Parties

As of December 31, 2022, we had approximately $707 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 22, 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 December 31, 2022, neither we nor our subsidiaries have any liabilities recorded for these instruments.

NECEC Commitments

On January 4, 2021, CMP transferred the 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.

Note 15. 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; four 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, six 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 $7 million related to seven of the twenty-four sites. We have paid remediation costs related to the remaining seventeen sites and do not expect to incur additional liabilities. Additionally, we have recorded an estimated liability of $9 million related to another twelve 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 December 31, 2022, our estimate for costs to remediate these sites ranges from $15 million to $22 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 and one site is included in Maine's Uncontrolled Sites Program. The remaining sites are not included in any registry list. 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 December 31, 2022, our estimate for all costs related to investigation and remediation of the fifty-three sites ranges from $160 million to $260 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 December 31, 2022, 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 December 31, 2022 and 2021, the liability associated with our MGP sites in Connecticut was $112 million and $113 million, respectively, 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 December 31, 2022 and 2021, our total recorded liability to investigate and perform remediation at all known inactive MGP sites discussed above and other sites was $289 million and $303 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 2138.

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 December 31, 2022, FirstEnergy's share of clean-up costs owed to NYSEG & RG&E is estimated at approximately $10 million and $7 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

In January 2012, Evergreen Power, LLC (Evergreen Power) and Asnat Realty LLC (Asnat), then owners of a former generation site on the Mill River in New Haven (English Station) that UI sold to Quinnipiac Energy in 2000, filed a lawsuit in federal district court in Connecticut related to environmental remediation at the English Station site. This proceeding was stayed in 2014 pending resolutions of other proceedings before the DEEP concerning the English Station site. In December 2016, the court administratively closed the file without prejudice to reopen upon the filing of a motion to reopen by any party. This claim was dismissed with prejudice in April 2022 in connection with the settlement agreement between the parties on the below-referenced state claim.

In December 2013, Evergreen Power and Asnat filed a subsequent lawsuit related to the English Station site. On April 16, 2018, the plaintiffs filed a revised complaint alleging fraud and unjust enrichment against UIL and UI and adding former UIL officers as named defendants alleging fraud. On February 21, 2019, the court granted our Motion to Strike with respect to all counts except for the count against UI for unjust enrichment. The counts stricken include all counts against the individual defendants as well as against UIL. The plaintiffs appealed the court's decision to strike, which decision the Appeals Court affirmed on May 4, 2021. The plaintiffs filed a petition to appeal to the Connecticut Supreme Court, which was denied, leaving only the claim against UI for unjust enrichment. In April 2022, UI entered into a settlement agreement with Evergreen Power and Asnat settling the remaining claim and the lawsuit was withdrawn.

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

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

As of December 31, 2022 and 2021, the amount reserved related to English Station was $19 million and $22 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.

Note 16. Income Taxes

In August 2022, the Inflation Reduction Act of 2022 ("IRA") was signed into law in the United States. The IRA created a new corporate alternative minimum tax ("CAMT") of 15% on adjusted financial statement income and an excise tax of 1% on the value of certain stock repurchases. 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 provisions of the IRA will be effective for periods beginning after December 31, 2022. Based on initial guidance, the Company currently expects to be subject to the CAMT starting in 2023 but does not expect it 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. Given the complexity and uncertainty around the applicability of the legislation to our specific facts and circumstances, we continue to analyze the IRA provisions while waiting on pending Department of Treasury regulatory guidance.

Since early 2020, and in response to regulatory orders received in most but not all of our operating jurisdictions, we began returning to customers both protected and unprotected excess accumulated deferred income tax (ADIT) from the 2017 Tax Act. Such amounts are subject to the terms of those orders while meeting the requirements of normalization for both ARAM and RSG methodologies.

Current and deferred taxes charged to expense for the years ended December 31, 2022, 2021 and 2020 consisted of:

Years Ended December 31,	**2022**	**2021**	**2020**
(Millions)			
Current			
Federal	$ —	$ 6	$ 3
State	2	4	9
Current taxes charged to expense	**2**	**10**	**12**
Deferred			
Federal	67	49	67
State	49	72	38
Deferred taxes charged to expense	**116**	**121**	**105**
Production tax credits	(97)	(109)	(87)
Investment tax credits	(1)	(1)	(1)
Total Income Tax Expense	**$ 20**	**$ 21**	**$ 29**

The differences between tax expense per the statements of income and tax expense at the 21% statutory federal tax rate for the years ended December 31, 2022, 2021 and 2020 consisted of:

Years Ended December 31,	2022	2021	2020
(Millions)			
Tax expense at federal statutory rate	$ 176	$ 140	$ 119
Depreciation and amortization not normalized	(20)	(19)	(13)
Investment tax credit amortization	(1)	(1)	(1)
Tax return related adjustments	2	—	1
Production tax credits	(97)	(109)	(87)
Tax equity financing arrangements	13	14	1
State tax expense, net of federal benefit	40	61	37
Excess ADIT amortization	(66)	(65)	(42)
Valuation allowance	(35)	21	12
Other, net	8	(21)	2
Total Income Tax Expense	**$ 20**	**$ 21**	**$ 29**

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

As of December 31,	2022	2021
(Millions)		
Deferred Income Tax Liabilities (Assets)		
Property related	$ 4,504	$ 4,257
Unfunded future income taxes	129	104
Federal and state tax credits	(942)	(844)
Federal and state NOL's	(1,086)	(998)
Joint ventures/partnerships	210	188
Nontaxable grant revenue	(270)	(292)
Pension and other post-retirement benefits	(11)	1
Tax Act - tax on regulatory remeasurement	(328)	(352)
Valuation allowance	87	110
Other	(80)	(158)
Deferred Income Tax Liabilities	**$ 2,213**	**$ 2,016**
Deferred tax assets	$ 2,717	$ 2,644
Deferred tax liabilities	4,930	4,660
Net Accumulated Deferred Income Tax Liabilities	**$ 2,213**	**$ 2,016**

As of December 31, 2022, we had gross federal tax net operating losses of $3.9 billion, federal PTCs and ITCs, federal R&D tax credits and other federal credits of $924 million, state tax effected net operating losses of $346 million in several jurisdictions and miscellaneous state tax credits of $147 million available to carry forward and reduce future income tax liabilities. The federal net operating losses begin to expire in 2028, while the federal tax credits begin to expire in 2023. The more significant state net operating losses begin to expire in 2024.

Valuation allowances are recorded to reduce deferred tax assets when it is more likely than not that all or a portion of a tax benefit will not be realized. The valuation allowance for deferred tax assets as of December 31, 2022 and 2021 was $87 million and $110 million, respectively. The $23 million change includes a $37 million decrease related to federal tax credit carryforwards, a $12 million increase related to state net operating losses and tax credit carryforwards and a $2 million increase related to federal net operating losses. The $87 million balance as of December 31, 2022 includes federal net operating loss and tax credit carryforward valuation allowance of $3 million and state net operating loss and state tax credit carryforward valuation allowance of $84 million.

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2022, 2021 and 2020 consisted of:

Years ended December 31,	2022	2021	2020
(Millions)			
Beginning Balance	$ 127	$ 127	$ 148
Increases for tax positions related to prior years	2	3	11
Increases for tax positions related to current year	2	—	—
Decreases for tax positions related to prior years	(4)	(3)	(32)
Ending Balance	**$ 127**	**$ 127**	**$ 127**

Unrecognized income tax benefits represent income tax positions taken on income tax returns but not yet recognized in the consolidated financial statements. The accounting guidance for uncertainty in income taxes provides that the financial effects of a tax position shall initially be recognized when it is more likely than not based on the technical merits the position will be sustained upon examination, assuming the position will be audited and the taxing authority has full knowledge of all relevant information.

Accruals for interest and penalties on tax reserves were immaterial for the years ended December 31, 2022, 2021 and 2020. If recognized, $107 million of the total gross unrecognized tax benefits would affect the effective tax rate.

It is estimated that no unrecognized tax benefits are anticipated to result in a net increase or decrease within 12 months of December 31, 2022.

AVANGRID and its subsidiaries, without ARHI, have been audited for the federal tax years 1998 through 2009. The results of these audits, net of reserves already provided, were immaterial. Tax years 2010 and forward are open for potential federal adjustments. All New York state returns, which were filed without ARHI, are closed through 2011 and Maine state returns are closed through 2015.

All federal tax returns filed by ARHI from the periods ended March 31, 2004, to December 31, 2009, are closed for adjustment. All New York combined state returns are closed for adjustment through 2011. Generally, the adjustment period for the individual states we filed in is at least as long as the federal period.

As of December 31, 2022, UIL is subject to audit of its federal tax return for years 2014 through its short period 2015. UIL's short period ending in 2015 is open and subject to Connecticut audit.

Note 17. Post-retirement and Similar Obligations

AVANGRID and its subsidiaries sponsor a number of retirement benefit plans. The plans include qualified defined benefit pension plans, supplemental non-qualified pension plans, defined contribution plans and other postretirement benefit plans for eligible employees and retirees. Eligibility and benefits vary depending on each plan's design. For example, certain benefits are based on years of service and final average compensation while others may use a cash balance formula that calculates benefits using a percentage of annual compensation.

Qualified Retirement Benefit Plans

As of December 31, 2022 and 2021, our obligations and funded status consisted of:

As of December 31,	Pension Benefits 2022	Pension Benefits 2021	Postretirement Benefits 2022	Postretirement Benefits 2021
(Millions)				
Change in benefit obligation				
Benefit Obligation as of January 1,	**$ 3,487**	**$ 3,819**	**$ 408**	**$ 452**
Service cost	27	40	2	3
Interest cost	111	87	10	10
Plan amendments	1	2	—	—
Actuarial loss (gain)	(716)	(184)	(103)	(23)
Curtailments/Settlements	(274)	(38)	—	—
Benefits paid	(184)	(239)	(33)	(34)
Benefit Obligation as of December 31,	**2,452**	**3,487**	**284**	**408**
Change in plan assets				
Fair Value of Plan Assets as of January 1,	**3,079**	**3,092**	**127**	**167**
Actual return on plan assets	(584)	237	(22)	15
Employer contributions	22	27	17	12
Settlements	(182)	(38)	—	—
Benefits paid	(184)	(239)	(33)	(67)
Fair Value of Plan Assets as of December 31,	**2,151**	**3,079**	**89**	**127**
Funded Status as of December 31,	**$ (301)**	**$ (408)**	**$ (195)**	**$ (281)**

During 2022, the pension and postretirement benefit obligations had actuarial gains of, respectively, $716 million and $103 million, primarily due to gains from discount rate increases of $644 million and $70 million, respectively. The pension benefit obligation had a reduction of $274 million from settlements ($182 million) and curtailments ($92 million). The settlements were lump-sum payments made within the pension plan guidelines at the discretion of the plan participants who opted to retire. The curtailments were driven by a Company decision to freeze pension benefit accruals and contribution credits for Networks non-union employees and transition their retirement benefits to a 401(k) plan.

During 2021, the pension benefit obligation had an actuarial gain of $184 million, primarily due to a $205 million gain from increases in discount rates. There were no significant gains or losses relating to the postretirement benefit obligations in 2021.

As of December 31, 2022 and 2021, funded status amounts recognized on our consolidated balance sheets consisted of:

As of December 31,	Pension Benefits 2022	Pension Benefits 2021	Postretirement Benefits 2022	Postretirement Benefits 2021
(Millions)				
Current liabilities	$ —	$ —	$ (5)	$ (5)
Non-current liabilities	(301)	(408)	(190)	(276)
Total	**$ (301)**	**$ (408)**	**$ (195)**	**$ (281)**

We have determined that Networks' regulated operating companies are allowed to defer as regulatory assets or regulatory liabilities items that would have otherwise been recorded in accumulated OCI pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans.

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

	Pension Benefits		Postretirement Benefits	
Years Ended December 31,	**2022**	**2021**	**2022**	**2021**
(Millions)				
Net loss (gain)	$ 181	$ 271	$ (91)	$ (18)
Prior service cost (credit)	$ 7	$ 10	$ (1)	$ (1)

Amounts recognized in OCI for ARHI for the years ended December 31, 2022 and 2021, consisted of:

	Pension Benefits		Postretirement Benefits	
Years Ended December 31,	**2022**	**2021**	**2022**	**2021**
(Millions)				
Net loss (gain)	$ 12	$ 16	$ (6)	$ (5)

As of December 31, 2022 and 2021, the projected benefit obligation (PBO) exceeded the fair value of pension plan assets for all qualified plans. The accumulated benefit obligation (ABO) exceeded the fair value of pension plan assets for all of our qualified plans, as of December 31, 2022, and for all but one plan, as of December 31, 2021. The aggregate PBO and ABO and the fair value of plan assets for our underfunded qualified plans consisted of:

	PBO in excess of plan assets	
As of December 31,	**2022**	**2021**
(Millions)		
Projected benefit obligation	$ 2,452	$ 3,487
Fair value of plan assets	$ 2,151	$ 3,079

	ABO in excess of plan assets	
As of December 31,	**2022**	**2021**
(Millions)		
Accumulated benefit obligation	$ 2,429	$ 1,790
Fair value of plan assets	$ 2,151	$ 1,536

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

Components of Networks' net periodic benefit cost and other changes in plan assets and benefit obligations recognized in income and regulatory assets and liabilities for the years ended December 31, 2022, 2021 and 2020 consisted of:

	Pension Benefits			Postretirement Benefits		
For the years ended December 31,	**2022**	**2021**	**2020**	**2022**	**2021**	**2020**
(Millions)						
Net Periodic Benefit Cost:						
Service cost	$ 26	$ 39	$ 46	$ 2	$ 3	$ 3
Interest cost	109	86	106	10	10	13
Expected return on plan assets	(162)	(199)	(198)	(6)	(7)	(8)
Amortization of prior service cost (benefit)	1	2	1	(1)	(5)	(9)
Amortization of net loss	49	115	124	(4)	2	2
Settlement charge	17	6		—	—	
Curtailment charge	(32)	—	—	—	—	—
Net Periodic Benefit Cost	**8**	**49**	**79**	**1**	**3**	**1**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities:						
Curtailments	(59)	—	(18)	—	—	—
Settlement charge	(17)	(6)	—	—	—	—
Net loss (gain)	33	(218)	46	(75)	(31)	11
Amortization of net loss	(49)	(115)	(124)	4	(2)	(2)
Current year prior service cost (credit)	1	2	7	—	1	—
Amortization of prior service (cost) benefit	(1)	(2)	(1)	1	5	9
Total Other Changes	**(92)**	**(339)**	**(90)**	**(70)**	**(27)**	**18**
Total Recognized	**$ (84)**	**$ (290)**	**$ (11)**	**$ (69)**	**$ (24)**	**$ 19**

Components of ARHI's net periodic benefit cost and other changes in plan assets and benefit obligations recognized in income and OCI for the years ended December 31, 2022, 2021 and 2020 consisted of:

	Pension Benefits			Postretirement Benefits		
For the years ended December 31,	**2022**	**2021**	**2020**	**2022**	**2021**	**2020**
(Millions)						
Net Periodic Benefit Cost:						
Service cost	$ 1	$ 1	$ 1	$ —	$ —	$ —
Interest cost	2	1	1	—	—	—
Expected return on plan assets	(2)	(2)	(2)	—	—	—
Amortization of net loss (gain)	1	2	2	(1)	(1)	(1)
Settlement/Curtailment charge	1	1	1	—	—	—
Net Periodic Benefit Cost	**3**	**3**	**3**	**(1)**	**(1)**	**(1)**
Other Changes in plan assets and benefit obligations recognized in OCI:						
Settlement charge	(1)	(1)	—	(1)	(1)	—
Net loss (gain)	(1)	(3)	1	(1)	1	—
Amortization of net (loss) gain	(1)	(2)	(2)	1	1	1
Amortization of prior service cost	—	—	—	—	—	—
Total Other Changes	**(3)**	**(6)**	**(1)**	**(1)**	**1**	**1**
Total Recognized	**$ —**	**$ (3)**	**$ 2**	**$ (2)**	**$ —**	**$ —**

The net periodic benefit cost for postretirement benefits represents the amount expensed for providing health care benefits to retirees and their eligible dependents. We include the service cost component in other operating expenses net of capitalized portion and include the components of net periodic benefit cost other than the service cost component in other expense.

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

	Pension Benefits		Postretirement Benefits	
As of December 31,	2022	2021	2022	2021
Discount rate	5.18 %	2.85 %	5.12 %	2.66 %
Rate of compensation increase	2.99 %	3.53 %	3.00 %	3.50 %
Interest crediting rate	2.87 %	2.87 %	N/A	N/A

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

The weighted-average assumptions used to determine our net periodic benefit cost for the years ended December 31, 2022, 2021 and 2020 consisted of:

	Pension Benefits			Postretirement Benefits		
Years Ended December 31,	2022	2021	2020	2022	2021	2020
Discount rate	2.85 %	2.34 %	3.01 %	2.66 %	2.19 %	2.99 %
Expected long-term return on plan assets	6.33 %	7.30 %	7.30 %	4.66 %	4.05 %	5.09 %
Rate of compensation increase	3.53 %	3.52 %	3.66 %	3.50 %	3.50 %	3.48 %

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations, and the effect of rebalancing of plan assets discussed below. Our analysis considered current capital market conditions and projected conditions. NYSEG, RG&E and UIL amortize unrecognized actuarial gains and losses over ten years from the time they are incurred as required by the NYPSC, PURA and DPU. Our other companies use the standard amortization methodology under which amounts in excess of ten-percent of the greater of the projected benefit obligation or market related value are amortized over the plan participants' average remaining service to retirement.

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

As of December 31,	2022	2021
Health care cost trend rate assumed for next year	5.00%/6.50%	5.00%/7.00%
Rate to which cost trend rate is assumed to decline (ultimate trend rate)	4.50%	4.50%
Year that the rate reaches the ultimate trend rate	2029 / 2025	2029 / 2025

Contributions

We make annual contributions in accordance with our funding policy of not less than the minimum amounts as required by applicable regulations. We expect to contribute $0 and $9 million, respectively, to our pension and other postretirement benefit plans during 2023.

Estimated Future Benefit Payments

Expected benefit payments as of December 31, 2022 consisted of:

(Millions)	Pension Benefits	Postretirement Benefits
2023	$ 233	$ 28
2024	$ 218	$ 27
2025	$ 215	$ 26
2026	$ 211	$ 25
2027	$ 206	$ 24
2028 - 2032	$ 938	$ 108

Non-Qualified Retirement Benefit Plans

We also sponsor various unfunded pension plans for certain current employees, former employees and former directors. The total liability for these plans, which is included in Other current and Other non-current liabilities on our consolidated balance sheets, was $44 million and $63 million at December 31, 2022 and 2021, respectively.

Plan Assets

Our pension plan assets are consolidated in one master trust. A consolidated master trust provides for a uniform investment manager lineup and an efficient, cost effective means of allocating income and expenses to each plan. Our primary investment objective is to have a diversified asset allocation policy that mitigates risk and volatility while meeting or exceeding our projected expected return to ensure that current and future benefit obligations are adequately funded. Further diversification and risk mitigation is achieved within each asset class by avoiding significant concentrations in certain markets, utilizing a combination or passive and active investment managers with unique skill and expertise, a systematic allocation to various asset classes and providing broad exposure to different segments of the equity, fixed income and alternative investment markets.

Networks and ARHI have established target asset allocation policies with allowable ranges for their pension plan assets within broad categories of asset classes made up of Return-Seeking investments and Liability-Hedging/Fixed Income investments. In 2020, a streamlined investment policy was implemented, which aligned target allocations to the estimated funded status of each specific plan. Return-Seeking assets range from 25%-60% and Liability-Hedging assets range from 40%-75%. Return-Seeking assets include investments in domestic, international and emerging equity, real estate, global asset allocation strategies and hedge funds. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

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

As of December 31, 2022		Fair Value Measurements		
(Millions)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 51	$ —	$ 51	$ —
U.S. government securities	252	252	—	—
Common stocks	57	57	—	—
Registered investment companies	104	104	—	—
Corporate bonds	708	—	708	—
Preferred stocks	1	1	—	—
Common collective trusts	472	—	472	—
Other, principally annuity, fixed income	33	—	33	—
	$ 1,678	$ 414	$ 1,264	$ —
Other investments measured at net asset value	473			
Total	**$ 2,151**			

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

As of December 31, 2021		Fair Value Measurements		
(Millions)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 69	$ 20	$ 49	$ —
U.S. government securities	298	298	—	—
Common stocks	138	138	—	—
Registered investment companies	276	276	—	—
Corporate bonds	837	—	837	—
Preferred stocks	1	1	—	—
Common collective trusts	862	—	862	—
Other, principally annuity, fixed income	51	—	51	—
	$ 2,532	$ 733	$ 1,799	$ —
Other investments measured at net asset value	547			
Total	**$ 3,079**			

Valuation Techniques

We value our pension plan assets as follows:

- Cash and cash equivalents – Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities – at the closing price reported in the active market in which the security is traded.
- Common stocks – at the closing price reported in the active market in which the individual investment is traded.
- Corporate bonds – based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks – at the closing price reported in the active market in which the individual investment is traded.
- Common collective trusts/Registered investment companies – Level 1: at the closing price reported in the active market in which the individual investment is traded. Level 2: the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- Other investments, principally annuity and fixed income – based on yields currently available on comparable securities of issuers with similar credit ratings.

- Other investments measured at net asset value (NAV) – fund shares offered to a limited group of investors and alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

Our postretirement plan assets are consolidated with one trustee in multiple voluntary employees' beneficiary association (VEBA) and 401(h) arrangements. The assets are invested in various asset classes to achieve sufficient diversification and mitigate risk. This is achieved for our VEBA assets by utilizing multiple institutional mutual and money market funds, which provide exposure to different segments of the securities markets. The 401(h) assets are invested alongside the Pension assets they are tied to and share the same asset allocation policy. Approximately 58% of the postretirement benefits plan assets are invested in VEBA and 401(h) arrangements that are not subject to income taxes with the remainder being invested in arrangements subject to income taxes.

In 2020, a streamlined investment policy was implemented for Networks and ARHI that aligned target allocations. Equities range from 49%-69% and Fixed Income assets range from 31-51%. Equity investments are diversified across U.S. and non-U.S. stocks, investment styles, and market capitalization ranges. Fixed Income investments are primarily invested in U.S. bonds and may also include some non-U.S. bonds. We primarily minimize the risk of large losses through diversification, but also through monitoring and managing other aspects of risk through quarterly investment portfolio reviews. Systematic rebalancing within target ranges increases the probability of increasing the projected expected return, while mitigating risk, should any asset categories drift outside their specified ranges.

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

As of December 31, 2022		**Fair Value Measurements**		
(Millions)	**Total**	**Level 1**	**Level 2**	**Level 3**
Asset Category				
Cash and cash equivalents	$ 2	$ —	$ 2	$ —
U.S. government securities	1	1	—	—
Registered investment companies	69	69	—	—
Corporate bonds	3	—	3	—
Common collective trusts	4	—	4	—
Other, principally annuity, fixed income	8	—	8	—
	$ 87	$ 70	$ 17	$ —
Other investments measured at net asset value	2			
Total	**$ 89**			

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

As of December 31, 2021		**Fair Value Measurements**		
(Millions)	**Total**	**Level 1**	**Level 2**	**Level 3**
Asset Category				
Cash and cash equivalents	$ 5	$ —	$ 5	$ —
U.S. government securities	1	1	—	—
Registered investment companies	101	101	—	—
Corporate bonds	3	—	3	—
Common collective trusts	5	—	5	—
Other, principally annuity, fixed income	9	—	9	—
	$ 125	$ 103	$ 22	$ —
Other investments measured at net asset value	2			
Total	**$ 127**			

Valuation Techniques

We value our postretirement plan assets as follows:

- Cash and cash equivalents – Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.

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

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

Defined contribution plans

We also have defined contribution plans, defined as 401(k)s, for all eligible AVANGRID employees. There are various match formulas depending on years of service, age and pension plan closure/freeze date. For the years ended December 31, 2022, 2021 and 2020, the annual contributions we made to these plans was $68 million, $58 million and $49 million, respectively.

Note 18. Equity

As of December 31, 2022 and 2021, we had 108,188 and 112,543 shares of common stock held in trust, respectively, and no convertible preferred shares outstanding. During the years ended December 31, 2022 and 2021, we issued 56,127 and 77,883,713 shares of common stock, respectively, and released 4,355 and 301,239 shares of common stock held in trust, respectively, each having a par value of $0.01. See Note 1 for information on our May 2021 equity issuance.

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. In 2022, there were no repurchases pursuant to the stock repurchase program. As of December 31, 2022, a total of 997,983 shares have been repurchased in the open market, all of which are included as AVANGRID treasury shares. As of December 31, 2022, the total cost of all repurchases, including commissions, was $47 million.

Accumulated OCI (Loss)

Accumulated OCI (Loss) for the years ended December 31, 2022, 2021 and 2020 consisted of:

Accumulated Other Comprehensive Income (Loss)	As of December 31, 2019	2020 Change	As of December 31, 2020	2021 Change	As of December 31, 2021	2022 Change	As of December 31, 2022
(Millions)							
Loss (gain) for defined benefit plans, net of income tax expense of $0 for 2020, $0 for 2021 and $3 for 2022	$ (12)	$ —	$ (12)	$ 2	$ (10)	$ 14	$ 4
Amortization of pension cost, net of income tax expense (benefit) of $3 for 2020, $(1) for 2021 and $1 for 2022	(7)	(13)	(20)	(8)	(28)	4	(24)
Unrealized (loss) gain from equity method investment, net of income tax (benefit) expense of $0 for 2020, $(3) for 2021 and $6 for 2022 (a)	$ —	$ —	$ —	$ (9)	$ (9)	$ 22	$ 13
Unrealized (loss) gain on derivatives qualifying as cash flow hedges:							
Unrealized loss during period on derivatives qualifying as cash flow hedges, net of income tax benefit of $(7) for 2020, $(44) for 2021 and $0 for 2022	(13)	(22)	(35)	(159)	(194)	(1)	(195)
Reclassification to net income of losses (gains) on cash flow hedges, net of income tax expense (benefit) of $2 for 2020, $(3) for 2021 and $19 for 2022 (b)	(63)	19	(44)	12	(32)	54	22
Loss on derivatives qualifying as cash flow hedges	(76)	(3)	(79)	(147)	(226)	53	(173)
Accumulated Other Comprehensive Loss	**$ (95)**	**$ (16)**	**$ (111)**	**$ (162)**	**$ (273)**	**$ 93**	**$ (180)**

(a) Foreign currency and interest rate contracts.

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

Note 19. 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 years ended December 31, 2021 and 2020, while we did have securities that were dilutive, these securities did not result in a change in our earnings per share calculations for the years ended December 31, 2021 and 2020. The dilutive securities, which consist of performance and restricted units, did result in a change in our earnings per share calculation for the year ended December 31, 2022.

The calculations of basic and diluted earnings per share attributable to AVANGRID for the years ended December 31, 2022, 2021 and 2020, respectively, consisted of:

Years Ended December 31,	2022	2021	2020
(Millions, except for number of shares and per share data)			
Numerator:			
Net income attributable to AVANGRID	$ 881	$ 707	$ 581
Denominator:			
Weighted average number of shares outstanding - basic	386,727,246	358,086,621	309,494,939
Weighted average number of shares outstanding - diluted	387,215,785	358,578,608	309,559,387
Earnings per share attributable to AVANGRID			
Earnings Per Common Share, Basic	$ 2.28	$ 1.97	$ 1.88
Earnings Per Common Share, Diluted	$ 2.27	$ 1.97	$ 1.88

Note 20. Variable Interest Entities

We participate in certain partnership arrangements that qualify as 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 consolidated balance sheets valued based on an HLBV model. Earnings from the TEFs are recognized in net income attributable to noncontrolling interests in our 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. A further investment from our investor is expected shortly after the project's commercial operations in the estimated amount of $58 million, expected in 2023. Lund Hill is owned by Solis Solar Power I, LLC (Solis I).

In June 2022 we received an additional $109 million from a tax equity investor for the addition of Golden Hill wind farms under Aeolus Wind Power VIII, LLC (Aeolus VIII). Montague solar was contributed to Aeolus VIII at the same time, with a future investment from our investor in the estimated amount of $87 million expected after Montague solar project reaches commercial operations, expected in the second quarter of 2023.

As of December 31, 2022, the assets and liabilities of the VIEs totaled approximately $2,853 million and $424 million, respectively. As of December 31, 2021, the assets and liabilities of VIEs totaled approximately $2,039 million and $119 million, respectively. At both December 31, 2022 and 2021, 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 December 31, 2022, 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 22 - Equity Method Investments for information on our VIEs we do not consolidate.

Note 21. Grants, Government Incentives and Deferred Income

The changes in government grants recorded in deferred income as of December 31, 2022 and 2021 consisted of:

(Millions)	Government grants - Renewables	Other deferred income	Total
As of December 31, 2020	**$ 1,190**	**$ 14**	**$ 1,204**
Disposals	—	—	—
Recognized in income	(65)	(9)	(74)
As of December 31, 2021	**1,125**	**5**	**1,130**
Disposals	—	—	—
Recognized in income	(65)	(3)	(68)
As of December 31, 2022	**$ 1,060**	**$ 2**	**$ 1,062**

Within deferred income, we classify grants we received under Section 1603 of the American Recovery and Reinvestment Act of 2009, where the United States Department of Treasury (DOT) provides eligible parties the option of claiming grants for specified energy property in lieu of tax credits, which we claimed for the majority of our qualifying properties. Deferred income has been recorded for the grant amounts and is amortized as an offset against depreciation expense using the straight-line method over the estimated useful life of the associated property to which the grants apply. We recognize a net deferred tax asset for the book to tax basis differences related to the property for income tax purposes within the nontaxable grant revenue deferred income tax liabilities (see Note 16 – Income Taxes).

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

(Millions)	Government grants - Networks	Total
As of December 31, 2020	**$ 67**	**$ 67**
Disposals	—	—
Recognized in income	(4)	(4)
As of December 31, 2021	**63**	**63**
Disposals	—	—
Recognized in income	(4)	(4)
As of December 31, 2022	**$ 59**	**$ 59**

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

Note 22. Equity Method Investments

On December 16, 2020, Renewables sold a 85% ownership interest in a wind farm located in South Dakota (Tatanka) to WEC Infrastructure involving total consideration of $238 million, excluding closing costs, and recognized a gain of $12 million, net of tax. The pre-tax gain of $16 million is included in "Other income (expense)" in our consolidated statements of income. Our retained investment in Tatanka of $24 million was valued based on an enterprise value of $298 million and applying an effective percentage of economic benefits retained of 7.97%, which was derived from a DCF model similar to the model used for Goodwill as described in Note 7. The net gain includes $4 million related to the remeasurement of our retained investment in Tatanka. The transaction was accounted for as a sale of assets and resulted in a loss of control. The retained 15% ownership interest is accounted for as an equity method investment. As of both December 31, 2022, and 2021, the carrying value of our Tatanka investment was $23 million.

On December 13, 2019, Renewables transferred a 50% ownership interest in a wind farm and a solar project located in Arizona (Poseidon) to Axium involving total consideration of $112 million, excluding closing costs, and recognized a gain of $96 million, net of tax. The transaction was accounted for as the sale of a business and resulted in a loss of control. The retained 50% ownership interest is accounted for as an equity method investment. As of December 31, 2022 and 2021, the carrying value of our Poseidon investment was $87 million and $96 million, respectively.

In December 2018, Renewables sold 80% of our wholly owned subsidiary, Coyote Ridge Wind, LLC (Coyote Ridge), including substantially all of the related tax benefits, to WEC Infrastructure in exchange for $144 million of total proceeds with $84 million received in 2019 to complete the transaction. We account for the remaining 20% membership interest under the equity method of accounting. As of both December 31, 2022 and 2021, the carrying amount of our Coyote Ridge investment was $15 million.

Renewables has two 50-50 joint ventures with Horizon Wind Energy, LLC, which own and operate the Flat Rock Windpower LLC (Flat Rock I) and the Flat Rock Wind Power II LLC (Flat Rock II) wind farms located in upstate New York. Flat Rock I has a 231 MW capacity and Flat Rock II has a 91 MW capacity. We account for the Flat Rock joint ventures under the equity method of accounting. As of December 31, 2022 and 2021, the carrying amount of Flat Rock I was $90 million and $93 million, respectively, and Flat Rock II was $42 million and $44 million, respectively.

As of December 31, 2022, 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, 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.

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. As of December 31, 2022 and 2021, the carrying amount of Renewables' investments in Vineyard Wind, which was dissolved in 2022, and Vineyard Wind 1 was $9 million and $141 million, respectively.

Networks is a party to a 50-50 joint venture with Clearway Energy, Inc. in GenConn, which operates two peaking generation plants in Connecticut. The investment in GenConn is accounted for as an equity investment. As of December 31, 2022 and 2021, the carrying value of our GenConn investment was $94 million and $99 million, respectively.

Networks holds an approximate 20% ownership interest in New York TransCo. Through New York TransCo, Networks has formed a partnership with Central Hudson Gas and Electric Corporation, Consolidated Edison, Inc., National Grid, plc and Orange and Rockland Utilities, Inc. to develop a portfolio of interconnected transmission lines and substations to fulfill the objectives of the New York energy highway initiative, which is a proposal to install up to 3,200 MW of new electric generation and transmission capacity in order to deliver more power generated from upstate New York power plants to downstate New York. On April 8, 2019, New York Transco was selected as the developer for Segment B of the AC Transmission Public Policy Project by the NYISO. The selected project, New York Energy Solution (NYES), replaces nearly 80-year old transmission assets located in the upper to mid-Hudson Valley with streamlined, modernized technology, to enable surplus clean energy resources in upstate New York and help achieve the State's energy goals. The total project cost is $600 million plus interconnection costs. New York Transco is subject to regulatory approval of its rates, terms and conditions with the FERC. The investment in New York TransCo is accounted for as an equity investment. As of December 31, 2022 and 2021, the carrying value of our New York TransCo investment was $77 million and $49 million, respectively.

None of our joint ventures have any contingent liabilities or capital commitments, except for those disclosed above. Distributions received from equity method investments, excluding the return of capital as part of the Vineyard Wind 1 financial close disclosed above, amounted to $41 million, $21 million and $22 million for the years ended December 31, 2022, 2021 and 2020 respectively, which are reflected as either distributions of earnings or as returns of capital in the operating and investing sections of the consolidated statements of cash flows, respectively. In addition, during the years ended December 31, 2022, 2021 and 2020, we received $12 million, $11 million and $14 million of distributions in RECs from our equity method investments. As of December 31, 2022, there was $10 million of undistributed earnings from our equity method investments. Capitalized interest costs related to equity method investments were $0, $6 million and $8 million for the years ended December 31, 2022, 2021 and 2020, respectively.

Note 23. Other Financial Statement Items

Other income (expense)

Other income (expense) for the years ended December 31, 2022, 2021 and 2020 consisted of:

Years ended December 31,	2022	2021	2020
(Millions)			
Gain on sale of assets (a)	$ —	$ —	$ 20
Allowance for funds used during construction	63	88	56
Carrying costs on regulatory assets	16	17	28
Non-service component of net periodic benefit cost	(58)	(37)	(62)
Other	9	(8)	(24)
Total Other Income (Expense)	**$ 30**	**$ 60**	**$ 18**

(a) 2020 includes a $16 million gain from the Tatanka sale (see Note 22).

Accounts receivable and unbilled revenues, net

Accounts receivable and unbilled revenues, net as of December 31, 2022 and 2021 consisted of:

As of December 31,	2022	2021
(Millions)		
Trade receivables and unbilled revenues	$ 1,892	$ 1,420
Allowance for credit losses	(155)	(151)
Total Accounts receivable and unbilled revenues, net	**$ 1,737**	**$ 1,269**

The change in the allowance for credit losses as of December 31, 2022 and 2021 consisted of:

(Millions)	
As of December 31, 2019	**$ 69**
Current period provision	83
Write-off as uncollectible	(44)
As of December 31, 2020	**$ 108**
Current period provision	110
Write-off as uncollectible	(67)
As of December 31, 2021	**$ 151**
Current period provision	110
Write-off as uncollectible	(106)
As of December 31, 2022	**$ 155**

DPA receivable balances were $102 million and $108 million as of December 31, 2022 and 2021, respectively. As of December 31, 2022 and 2021, our allowance for credit losses for DPAs was $67 million and $68 million, respectively.

Prepayments and Other Current Assets

Prepayments and other current assets as of December 31, 2022 and 2021 consisted of:

As of December 31,	2022	2021
(Millions)		
Prepaid other taxes	$ 136	$ 95
Broker margin and collateral accounts	164	87
Other pledged deposits	12	4
Prepaid expenses	68	58
Other	6	1
Total	**$ 386**	**$ 245**

Other current liabilities

Other current liabilities as of December 31, 2022 and 2021 consisted of:

As of December 31,	2022	2021
(Millions)		
Advances received	$ 271	$ 204
Accrued salaries	153	127
Short-term environmental provisions	54	52
Collateral deposits received	68	58
Pension and other postretirement	5	5
Finance leases	7	4
Other	35	34
Total	**$ 593**	**$ 484**

Disposition

On May 13, 2021, Renewables sold 100% of its ownership interest in two solar projects located in Nevada to Primergy Hot Pot Holdings LLC for total consideration of $35 million and recognized a gain of $11 million, net of tax. The pre-tax gain of $15 million is recorded in "Operating revenues" in our consolidated statements of income. The total consideration includes variable consideration that Renewables could receive based on the achievement of certain regulatory and project development milestones. The transaction was accounted for as an asset sale.

Note 24. 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 restructuring charges, mark-to-market earnings from changes in the fair value of derivative instruments, accelerated depreciation derived from repowering of wind farms, costs incurred related to the PNMR Merger, a legal settlement, an offshore contract provision and costs incurred in connection with the COVID-19 pandemic.

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 consolidated financial statements. Refer to Note 4 - Revenue for more detailed information on revenue by segment.

Segment information as of and for the year ended December 31, 2022 consisted of:

For the Year Ended December 31, 2022	Networks	Renewables	Other(a)	AVANGRID Consolidated
(Millions)				
Revenue - external	$ 6,781	$ 1,141	$ 1	$ 7,923
Revenue - intersegment	1	—	(1)	—
Depreciation and amortization	660	424	1	1,085
Operating income	901	(36)	(13)	852
Earnings (losses) from equity method investments	11	251	—	262
Interest expense, net of capitalization	220	16	67	303
Income tax expense (benefit)	94	(114)	40	20
Capital expenditures	1,803	708	8	2,519
Adjusted net income	628	403	(130)	901
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.

Segment information as of and for the year ended December 31, 2021 consisted of:

For the year ended December 31, 2021	Networks	Renewables	Other(a)	AVANGRID Consolidated
(Millions)				
Revenue - external	$ 5,753	$ 1,220	$ 1	$ 6,974
Revenue - intersegment	1	—	(1)	—
Depreciation and amortization	616	397	1	1,014
Operating income	876	26	(7)	895
Earnings (losses) from equity method investments	12	(5)	—	7
Interest expense, net of capitalization	217	1	80	298
Income tax expense (benefit)	98	(48)	(29)	21
Capital expenditures	2,294	680	2	2,976
Adjusted net income	661	170	(51)	780
As of December 31, 2021				
Property, plant and equipment	18,737	10,118	11	28,866
Equity method investments	148	412	—	560
Total assets	$ 26,126	$ 12,578	$ 800	$ 39,504

(a) Includes Corporate and intersegment eliminations.

Segment information for the year ended December 31, 2020 consisted of:

For the year ended December 31, 2020	Networks	Renewables	Other (a)	AVANGRID Consolidated
(Millions)				
Revenue - external	$ 5,187	$ 1,132	$ 1	$ 6,320
Revenue - intersegment	1	—	(1)	—
Depreciation and amortization	592	394	1	987
Operating income	877	(16)	8	869
Earnings (losses) from equity method investments	10	(13)	—	(3)
Interest expense, net of capitalization	234	7	75	316
Income tax expense (benefit)	120	(80)	(11)	29
Capital expenditures	1,838	943	—	2,781
Adjusted net income	$ 568	$ 115	$ (58)	$ 625

(a) Includes Corporate and intersegment eliminations.

Reconciliation of Adjusted Net Income to Net Income attributable to AVANGRID for the years ended December 31, 2022, 2021 and 2020 is as follows:

Years Ended December 31,	2022	2021	2020
(Millions)			
Adjusted Net Income Attributable to Avangrid, Inc.	**$ 901**	**$ 780**	**$ 625**
Adjustments:			
Mark-to-market adjustments - Renewables (1)	—	(53)	(5)
Offshore contract provision (2)	(24)	—	—
Restructuring charges (3)	—	—	(6)
Accelerated depreciation from repowering (4)	—	—	(9)
Impact of COVID-19 (5)	—	(34)	(29)
Merger costs (6)	(4)	(12)	(6)
Legal settlement - Gas storage (7)	—	—	(5)
Income tax impact of adjustments	7	26	16
Net Income Attributable to Avangrid, Inc.	**$ 881**	**$ 707**	**$ 581**

(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) Costs incurred in connection with an offshore contract provision.
(3) Restructuring and severance related charges relate to costs to implement an initiative to mitigate costs and achieve sustainable growth.
(4) Represents the amount of accelerated depreciation derived from repowering wind farms in Renewables.
(5) Represents costs incurred in connection with the COVID-19 pandemic, mainly related to bad debt provisions.
(6) Pre-merger costs incurred.
(7) Removal of the impact from Gas activity in the reconciliation to AVANGRID Net Income.

Note 25. 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 years ended December 31, 2022, 2021 and 2020, respectively, consisted of:

Years Ended December 31,	2022		2021		2020	
(Millions)	Sales To	Purchases From	Sales To	Purchases From	Sales To	Purchases From
Iberdrola, S.A.	$ 1	$ (46)	$ —	$ (52)	$ 1	$ (43)
Iberdrola Renovables Energia, S.L.	$ 1	$ (5)	$ —	$ (10)	$ —	$ (9)
Iberdrola Financiación, S.A.	$ —	$ (12)	$ —	$ (9)	$ —	$ (7)
Vineyard Wind	$ 7	$ —	$ 14	$ —	$ 9	$ —
Iberdrola Solutions	$ —	$ —	$ 7	$ (39)	$ 2	$ —
Other	$ 1	$ (3)	$ 2	$ (3)	$ —	$ —

In addition to the statements of income items above, we made purchases of turbines for wind farms from Siemens-Gamesa, in which Iberdrola had an 8.1% ownership interest until Iberdrola sold its interest in February 2020. After the sale, the turbine purchases are no longer considered related party transactions. The amounts capitalized for transactions while Siemens-Gamesa was considered a related party was $11 million for the year ended December 31, 2020.

Related party balances as of December 31, 2022 and 2021, respectively, consisted of:

As of December 31,	2022		2021	
(Millions)	Owed By	Owed To	Owed By	Owed To
Iberdrola, S.A.	$ 1	$ (29)	$ 3	$ (43)
Iberdrola Financiacion	$ —	$ (9)	$ —	$ (9)
Vineyard Wind	$ 3	$ (8)	$ 8	$ (8)
Iberdrola Solutions	$ —	$ (2)	$ —	$ (2)
Other	$ 4	$ (1)	$ —	$ (1)

Transactions with Iberdrola, our majority shareholder, relate predominantly to the provision and allocation of corporate services and management fees. 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. See Note 10 for a discussion of the Iberdrola Loan.

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 December 31, 2022 and 2021 was $0.

AVANGRID has a credit facility with Iberdrola Financiacion, S.A.U., a company of the Iberdrola Group. The facility has a limit of $500 million and matures on June 18, 2023. AVANGRID pays a facility fee of 10.5 basis points annually on the facility. As of both December 31, 2022 and 2021, there was no outstanding amount under this credit facility.

We have a bi-lateral demand note agreement with Iberdrola Solutions, LLC, which had notes payable balance of $2 million as of both December 31, 2022 and 2021. Renewables had financial forward power contracts with Iberdrola Solutions to hedge Renewables' merchant wind exposure in Texas that were settled in 2021.

See Note 22 - Equity Method Investments for more information on transactions with our equity method investees.

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.

Note 26. Stock-Based Compensation

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). As of December 31, 2022, the total number of shares authorized for stock-based compensation plans was 2,500,000.

Performance Stock Units

During 2016, 1,298,683 performance stock units (PSUs) were granted to certain officers and employees of AVANGRID. In 2017, 2018 and 2019, an additional 85,759, 75,350 and 3,881 PSUs, respectively, were granted to officers and employees of AVANGRID under the Plan with achievement measured based on certain performance and market-based metrics for the 2016 to 2019 time period.

The fair value of the PSUs on the grant date was $31.80 per share, which is expensed on a straight-line basis over the requisite service period of approximately seven years based on expected achievement. The fair value of the PSUs was determined using valuation techniques to forecast possible future stock prices, applying a weighted average historical stock price volatility of AVANGRID and industry companies, a risk-free rate of interest that is equal, as of the grant date, to the yield of the zero-coupon U.S. Treasury bill and a reduction for the respective dividend yield calculated based on the most recent quarterly dividend payment and the stock price as of the grant date.

In February 2020, a total number of 208,268 PSUs, before applicable taxes, were approved to be earned by participants based on achievement of certain performance metrics related to the 2016 through 2019 plan and are payable in three equal installments, net of applicable taxes. The remaining unvested PSUs were forfeited. In May 2020, 42,777 shares of common stock were issued to settle the first installment payment and 2,605 PSUs were forfeited from the originally approved total number of PSUs. In March 2021, 45,611 shares of common stock were issued to settle the second installment payment. The final payment will occur in 2022. In March 2022, 46,737 shares of common stock were issued to settle the third and final installment payment under this plan.

During 2021 and 2022, 1,336,787 PSUs and 215,235 PSUs, were granted to certain officers and employees of AVANGRID with achievement measured based on certain performance and market-based metrics for the 2021 to 2022 performance period. The PSUs will be payable in three equal installments, net of applicable taxes, in 2023, 2024 and 2025. The fair value of the PSUs on the grant date was $36.22 per share. The fair value of the PSUs was determined using valuation techniques to forecast possible future stock prices, applying a weighted average historical stock price volatility of AVANGRID and industry companies, a risk-free rate of interest that is equal, as of the grant date, to the yield of the zero-coupon U.S. Treasury bill and a reduction for the respective dividend yield calculated based on the most recently quarterly dividend payment and the stock price as of the grant date. The expense is recognized on a straight-line basis over the requisite service period of approximately four years based on expected achievement.

Restricted Stock Units

In June and October 2018, pursuant to the Avangrid, Inc. Omnibus Incentive Plan two restricted stock units (RSUs) awards of 60,000 and 8,000 RSUs, respectively, were granted to certain officers of AVANGRID. The RSUs vested in full in one installment in June and December 2020, respectively for each award. The fair value on the grant date was determined based on a price of $50.40 per share for the June 2018 awards and $47.59 per share for the October 2018 awards. In June 2020, 60,000 RSUs, plus dividend equivalents accrued through the vesting period, were settled for $3 million in cash. In March 2021, the October 2018 RSU grant was settled, net of applicable taxes, by issuing 5,953 shares of common stock.

In August 2020, 5,000 RSUs were granted to an officer of AVANGRID. The RSUs vest in three equal installments in 2021, 2022 and 2023, 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 $48.99 per share. In February 2021, the first installment of the RSU grant was settled by issuing 1,697 shares of common stock. In October 2021, this RSU grant was cancelled and the remaining unvested RSUs were forfeited.

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.

In June 2021, 17,500 RSUs were granted to an officer of AVANGRID with immediate vesting. The fair value on the grant date was determined based on a price of $53.59 per share. The RSU grant was settled, net of applicable taxes, by issuing 9,390 shares of common stock.

In January 2022, 17,500 RSUs were granted to an officer of AVANGRID with immediate vesting. The fair value on the grant date was determined based on a price of 48.16 per share. The RSU grant was settled, net of applicable taxes, by issuing 9,390 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 1st 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 March 2020, 167,060 Phantom Shares were granted to certain AVANGRID executives and employees. These awards will vest in three equal installments in 2020, 2021 and 2022 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 March 2022, $2 million was paid to settle the third and final installment under this plan.

In February 2022, 9,000 Phantom Shares were granted to certain AVANGRID executives and employees. These awards vest in three equal installments in 2022 - 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 August 2022, $0.1 million was paid to settle the first installment under this plan.

On February 16, 2023, 81,000 Phantom Shares were granted to certain AVANGRID executives and employees. These awards will 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.

As of December 31, 2022 and 2021, the total liability was $0 and $2 million, respectively, which is included in other current and non-current liabilities.

The total stock-based compensation expense, which is included in "Operations and maintenance" of our consolidated statements of income for the years ended December 31, 2022, 2021 and 2020 was $15 million, $18 million and $14 million, respectively. The total income tax benefits recognized for stock-based compensation arrangements for each of the years ended December 31, 2022, 2021 and 2020, were $4 million, $5 million and $4 million, respectively.

A summary of the status of the AVANGRID's nonvested PSUs and RSUs as of December 31, 2022, and changes during the fiscal year ended December 31, 2022, is presented below:

	Number of PSUs and RSUs	Weighted Average Grant Date Fair Value
Nonvested Balance – December 31, 2021	1,323,328	$ 36.05
Granted	258,168	$ 38.16
Forfeited	(412,776)	$ 36.21
Vested	(83,770)	$ 45.91
Nonvested Balance – December 31, 2022	1,084,951	$ 36.55

As of December 31, 2022, total unrecognized costs for non-vested PSUs, RSUs and Phantom Shares was $10 million. The weighted-average period over which the PSU, RSU and Phantom Shares costs will be recognized is approximately 2 years.

The weighted-average grant date fair value of PSUs and RSUs granted during the year was $38.16 per share for the year ended December 31, 2022.

Note 27. Subsequent events

On February 16, 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 April 3, 2023 to shareholders of record at the close of business on March 1, 2023.

Schedule I –Financial Statements of Parent

AVANGRID, INC. (PARENT)
CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF INCOME
FOR THE YEARS ENDED December 31, 2022, 2021 AND 2020

Years Ended December 31,	2022	2021	2020
(Millions)			
Operating Revenues	$ —	$ —	$ —
Operating Expenses			
Operating expense	11	19	10
Taxes other than income taxes	(1)	(11)	(11)
Total Operating Expenses	10	8	(1)
Operating (Loss) Income	(10)	(8)	1
Other Income			
Other income	49	22	35
Equity earnings of subsidiaries	999	756	641
Interest expense	(117)	(93)	(109)
Income Before Income Tax	921	677	568
Income tax expense (benefit)	40	(30)	(13)
Net Income	**$ 881**	**$ 707**	**$ 581**

See accompanying notes to Schedule I.

Schedule I –Financial Statements of Parent

AVANGRID, INC. (PARENT)
CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF COMPREHENSIVE INCOME
FOR THE YEARS ENDED December 31, 2022, 2021, AND 2020

Years Ended December 31,	**2022**	**2021**	**2020**
(Millions)			
Net Income	$ 881	$ 707	$ 581
Other comprehensive income (loss) of subsidiaries	93	(162)	(16)
Comprehensive Income	**$ 974**	**$ 545**	**$ 565**

See accompanying notes to Schedule I.

Schedule I –Financial Statements of Parent

AVANGRID, INC. (PARENT)
CONDENSED FINANCIAL INFORMATION OF PARENT
BALANCE SHEETS
AS OF December 31, 2022 AND 2021

As of December 31,	2022	2021
(Millions)		
Assets		
Current Assets		
Cash and cash equivalents	$ 28	$ 1,424
Accounts receivable from subsidiaries	190	128
Notes receivable from subsidiaries	1,440	1,475
Prepayments and other current assets	17	52
Total current assets	1,675	3,079
Investments in subsidiaries	20,588	18,500
Other assets		
Deferred income taxes	358	413
Other	3	3
Total other assets	361	416
Total Assets	**$ 22,624**	**$ 21,995**
Liabilities		
Current Liabilities		
Notes payable	396	—
Notes payable to subsidiaries	557	643
Accounts payable and accrued liabilities	7	3
Accounts payable to subsidiaries	3	9
Interest accrued	9	9
Interest accrued subsidiaries	9	1
Dividends payable	170	170
Other current liabilities	30	—
Total current liabilities	1,181	835
Derivative liabilities	86	19
Non-current debt	1,977	2,065
Total non-current liabilities	2,063	2,084
Total Liabilities	3,244	2,919
Equity		
Stockholders' Equity:		
Common stock	3	3
Additional paid-in capital	17,694	17,679
Treasury stock	(47)	(47)
Retained earnings	1,910	1,714
Accumulated other comprehensive loss	(180)	(273)
Total Equity	19,380	19,076
Total Liabilities and Equity	**$ 22,624**	**$ 21,995**

See accompanying notes to Schedule I.

AVANGRID, INC. (PARENT)
CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED December 31, 2022, 2021, AND 2020

Years Ended December 31,	2022	2021	2020
(Millions)			
Net Cash used in Operating Activities	**$ (742)**	**$ (397)**	**$ (142)**
Cash Flow from Investing Activities			
Notes receivable from subsidiaries	(14)	130	(73)
Investments in subsidiaries	(1,020)	(1,026)	(591)
Return of capital from investments in subsidiaries	664	1,122	419
Other investments	—	300	(300)
Net Cash (used in) provided by Investing Activities	**(370)**	**526**	**(545)**
Cash Flow from Financing Activities			
Receipts (repayments) of short-term notes payable from subsidiaries, net	1	(186)	(14)
Receipts (repayments) of short-term notes payable	397	(309)	(253)
Proceeds from non-current debt	—	—	744
(Repayments) proceeds from non-current debt with affiliate	—	(3,000)	3,000
Repayments of non-current debt	—	—	(950)
Repurchase of common stock	—	(33)	(2)
Issuance of common stock	(1)	3,998	(1)
Dividends paid	(681)	(613)	(545)
Net Cash (used in) provided by Financing Activities	**(284)**	**(143)**	**1,979**
Net (Decrease) Increase in Cash and Cash Equivalents	(1,396)	(14)	1,292
Cash and Cash Equivalents, Beginning of Year	1,424	1,438	146
Cash and Cash Equivalents, End of Year	**$ 28**	**$ 1,424**	**$ 1,438**
Supplemental Cash Flow Information			
Cash paid for interest	$ 86	$ 74	$ 111
Cash paid (refunded) payment for income taxes	$ (33)	$ (15)	$ 65

See accompanying notes to Schedule I.

Note 1. Basis of Presentation

Avangrid, Inc. (AVANGRID) is a holding company and we conduct substantially all of our business through our subsidiaries. Substantially all of our consolidated assets are held by our subsidiaries. Accordingly, our cash flow and ability to meet our obligations are largely dependent upon the earnings of our subsidiaries and the distribution or other payment of their earnings to us in the form of dividends, loans or advances or repayment of loans and advances from us. Our condensed financial statements and related footnotes have been prepared in accordance with regulatory statute 210.12-04 of Regulation S-X. Our condensed financial statements should be read in conjunction with the consolidated financial statements and notes thereto of AVANGRID and subsidiaries (AVANGRID Group).

AVANGRID indirectly or directly owns all of the ownership interests of our significant subsidiaries. AVANGRID relies on dividends or loans from our subsidiaries to fund dividends to our primary shareholder.

AVANGRID's significant accounting policies are consistent with those of the AVANGRID Group. For the purposes of these condensed financial statements, AVANGRID's wholly owned and majority owned subsidiaries are recorded based upon our proportionate share of the subsidiaries net assets.

AVANGRID files a consolidated federal income tax return that includes the taxable income or loss of all our subsidiaries. Each subsidiary company is treated as a member of the consolidated group and determines its current and deferred taxes separately and settles its current tax liability or benefit each year directly with AVANGRID pursuant to a tax sharing agreement between AVANGRID and our members.

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 was 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), 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, 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, 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. During the pendency of this appeal 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.

In addition, on January 3, 2022, Avangrid, PNMR and Merger Sub entered into an Amendment to the Merger Agreement (the 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 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 Amendment. As amended, the Merger agreement may be terminated by each of Avangrid and PNMR under certain circumstances, including if the Merger is not consummated by April 20, 2023 (subject to a three-month extension by Avangrid and PNMR by mutual consent if all of the conditions to the closing, other than the conditions related to obtaining regulatory approvals, have been satisfied or waived). 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. For example, AVANGRID and PNMR are preparing new filings under HSR. We cannot predict the outcome of these re-applications or requests for extensions of such approvals.

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 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 April 20, 2023, as amended (subject to a three-month extension by either party if all of the conditions to the closing, other than the conditions related to obtaining regulatory approvals, have been satisfied or waived). 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 (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 set 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 3-month LIBOR 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 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 81.5% ownership interest in AVANGRID.

Note 2. Common Stock

As of December 31, 2022, AVANGRID share capital consisted of 500,000,000 shares of common stock authorized, 387,734,757 shares issued and 386,628,586 shares outstanding, 81.6% of which are owned by Iberdrola, each having a par value of $0.01, for a total value of common stock of $3 million and additional paid in capital of $17,694 million. As of December 31, 2021, AVANGRID share capital consisted of 500,000,000 shares of common stock authorized, 387,678,630 shares issued and 386,568,104 shares outstanding, 81.6% of which were owned by Iberdrola, each having a par value of $ $0.01, for a total value of common stock capital of $3 million and additional paid in of $17,679 million. As of December 31, 2022 and 2021, we had 108,188 and 112,543 shares of common stock held in trust, respectively, and no convertible preferred shares outstanding. During the years ended December 31, 2022 and 2021, we issued 56,127 and 77,883,713 shares of common stock, respectively, and released 4,355 and 301,239 shares of common stock held in trust, respectively, each having a par value of $0.01.

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 target relative ownership percentage at 81.5%. The stock repurchase program may be suspended or discontinued at any time upon notice. In 2022, there were no repurchases pursuant to the stock repurchase program. As of December 31, 2022, a total of 997,983 shares have been repurchased in the open market, all of which are included as AVANGRID treasury shares. As of December 31, 2022, the total cost of all repurchases, including commissions, was $47 million.

On February 16, 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 April 3, 2023 to shareholders of record at the close of business on March 1, 2023.

Note 3. Long-Term Debt

In 2017, AVANGRID issued $600 million aggregate principal amount of its 3.15% notes maturing in 2024.

On May 16, 2019, AVANGRID issued $750 million aggregate principal amount of its 3.80% notes maturing in 2029. Proceeds of the offering were used to finance and/or refinance, in whole or in part, one or more eligible renewable energy generation facilities. Net proceeds of the offering after the price discount and issuance-related expenses were $743 million.

On April 9, 2020, AVANGRID issued $750 million aggregate principal amount of unsecured notes maturing in 2025 at a fixed interest rate of 3.20%. Net proceeds of the offering after the price discount and issuance-related expenses were $744 million.

On December 14, 2020, AVANGRID and Iberdrola entered into an intra-group loan agreement which provided AVANGRID with an unsecured subordinated loan in an aggregate principal amount of $3,000 million (the Iberdrola Loan). The Iberdrola Loan was repaid in 2021 with the proceeds of the common share issuance described in Note 1.

Note 4. Cash Dividends Paid by Subsidiaries

Cash dividends paid by subsidiary are as follows:

Years ended December 31,	2022	2021	2020
(millions)			
AVANGRID Networks	$ 645	$ 970	$ 419
AVANGRID Renewables	$ 19	$ 152	$ —

For the years ended December 31, 2022, 2021 and 2020, AVANGRID made capital contributions to Networks of $986 million, $1,011 million and $590 million, respectively.

During 2022 and 2021, AVANGRID recorded a net non-cash contribution and dividend of $473 million and $674 million, respectively, to and from its subsidiaries to zero out their account balances of notes receivable and payable.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.***

None.

Item 9A. ***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, or the Exchange Act), as of the end of the period covered by this Annual Report on Form 10-K. Based on such evaluation, our CEO and CFO have concluded that as of such date, our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by the Company in reports that it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms and (ii) accumulated and communicated to the Company's management, including its CEO and CFO, as appropriate to allow timely decisions regarding required disclosure.

Report of Management on Internal Control Over Financial Reporting

The management of AVANGRID is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. AVANGRID's internal control system over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles. AVANGRID's internal control over financial reporting includes those policies and procedures that:

1. pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company;

2. provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and

3. provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in condition, or that the degree of compliance with the policies or procedures may deteriorate.

AVANGRID's management assessed the effectiveness of AVANGRID's internal control over financial reporting as of December 31, 2022. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) ("COSO") in Internal Control-Integrated Framework. Based on this assessment, management determined that our internal control over financial reporting was effective as of December 31, 2022.

Our independent registered public accounting firm, KPMG LLP, has issued an audit report on the Company’s internal control over financial reporting, which appears in Part II, Item 8 of this Form 10-K.

Changes in Internal Control

There were no changes in our internal control over financial reporting identified in connection with the evaluation required by Rules 13a-15(d) and 15d-15(d) of the Exchange Act during the quarter ended December 31, 2022 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. *Other Information.*

None.

Item 9C. *Disclosure Regarding Foreign Jurisdictions that Prevent Inspections.*

Not applicable.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance.***

For information regarding our executive officers, see Part I of this Annual Report on Form 10-K. Additional information required by this item is incorporated by reference to our Proxy Statement for the 2023 Annual Meeting of Shareholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2022.

AVANGRID has a code of business conduct and ethics that applies to all employees including AVANGRID's principal executive officer, principal financial officer, principal accounting officer, directors, and other senior financial officers. The code is intended to provide guidance to employees, management, and the board to assure compliance with law and promote ethical behavior. Any amendment to the code, or any waivers of its requirements, will be disclosed if required on the company's website at www.avangrid.com.

Item 11. ***Executive Compensation.***

The information required by this item is incorporated by reference to our Proxy Statement for the 2023 Annual Meeting of Shareholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2022.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.***

The information required by this item is incorporated by reference to our Proxy Statement for the 2023 Annual Meeting of Shareholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2022.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence.***

The information required by this item is incorporated by reference to our Proxy Statement for the 2023 Annual Meeting of Shareholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2022.

Item 14. ***Principal Accountant Fees and Services.***

Our independent registered public accounting firm is KPMG LLP, New York, NY, Auditor Firm ID: 185

The information required by this item is incorporated by reference to our Proxy Statement for the 2023 Annual Meeting of Shareholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2022.

Part IV

Item 15. *Exhibits and Financial Statement Schedules.*

a) The following documents are made a part of this Annual Report on Form 10-K:

1. Financial Statements—Our consolidated financial statements are set forth under Part II, Item 8 "Financial Statements and Supplementary Data."

2. Financial Statement Schedules— Our financial statement schedules are set forth under Part II, Item 8 "Financial Statements and Supplementary Data."

3. Exhibits—The following instruments and documents are included as exhibits to this report.

Exhibit Number	Exhibit Description
2.1	Agreement and Plan of Merger, dated as of February 25, 2015, by and among Avangrid, Inc. (formerly Iberdrola USA, Inc.), Green Merger Sub, Inc. and UIL Holdings Corporation (incorporated herein by reference to Annex A to the proxy statement/prospectus included as Exhibit 2.1 in our Registration Statement on Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
2.2	Agreement and Plan of Merger, dated as of October 20, 2020, by and among PNM Resources, I Inc., Avangrid, Inc. and NM Green Holdings, Inc. (incorporated herein by reference to Exhibit 2.1 to Form 8-K file with the Securities and Exchange Commission on October 21, 2020).
2.3	Amendment to Merger Agreement, dated as of January 3, 2022, by and among PNM Resources, Inc., Avangrid, Inc. and NM Green Holdings, Inc. (incorporated herein by reference to Exhibit 2.1 to Form 8-K file with the Securities and Exchange Commission on January 3, 2022).
3.1	Certificate of Incorporation of Avangrid, Inc. (incorporated herein by reference to Exhibit 3.2 to Form 8-K filed with the Securities and Exchange Commission on December 18, 2015).
3.2	Amended and Restated Bylaws of Avangrid, Inc. (incorporated herein by reference to Exhibit 3.1 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017 filed with the Securities and Exchange Commission on August 1, 2017).
4.1	Specimen Common Stock Certificate (incorporated herein by reference to Exhibit 4.1 to Form S-4/A filed with the Securities and Exchange Commission on October 21, 2015).
4.2	Senior Indenture, dated as of October 7, 2010, between UIL Holdings Corporation and The Bank of New York Mellon, as trustee (incorporated herein by reference to Exhibit 4.1 of UIL Holdings Corporation's Current Report on Form 8-K filed with the Securities and Exchange Commission on October 7, 2010).
4.3	First Supplemental Indenture, dated as of October 7, 2010, between UIL Holdings Corporation and The Bank of New York Mellon, as trustee (incorporated herein by reference to Exhibit 4.2 of UIL Holdings Corporation's Current Report on Form 8-K filed with the Securities and Exchange Commission on October 7, 2010).
4.4	Second Supplemental Indenture, dated as of December 16, 2015, among UIL Holdings Corporation, Green Merger Sub, Inc. and The Bank of New York Mellon, as trustee (incorporated herein by reference to Exhibit 4.2 to Form 8-K filed with the Securities and Exchange Commission on December 18, 2015).
4.5	Third Supplemental Indenture, dated as of December 19, 2016, among Avangrid, Inc., UIL Holdings Corporation and The Bank of New York Mellon, as trustee (incorporated herein by reference to Exhibit 4.5 of AVANGRID's Annual Report on Form 10-K for the fiscal year ended December 31, 2016 filed with the Securities and Exchange Commission on March 10, 2017).
4.6	Indenture, dated as of November 21, 2017, between the Company and The Bank of New York Mellon, as trustee (incorporated herein by reference to Exhibit 4.1 to Form 8-K filed with the Securities and Exchange Commission on November 21, 2017).

Exhibit Number	Exhibit Description
4.7	First Supplemental Indenture, dated November 21, 2017, between the Company and The Bank of New York Mellon, as trustee (incorporated herein by reference to Exhibit 4.2 to Form 8-K filed with the Securities and Exchange Commission on November 21, 2017).
4.8	Form of Global Note Representing the Notes (incorporated herein by reference to Exhibit 4.3 to Form 8-K filed with the Securities and Exchange Commission on November 21, 2017).
4.9	Second Supplemental Indenture, dated as of May 16, 2019, among Avangrid, Inc. and The Bank of New York Mellon, as trustee (incorporated herein by reference to Exhibit 4.2 to Form 8-K filed with the Securities and Exchange Commission on May 16, 2019).
4.10	Third Supplemental Indenture, dated April 9, 2020, between the Company and The Bank of New York Mellon, as trustee (incorporated herein by reference to Exhibit 4.2 to Form 8-K filed with the Securities and Exchange Commission on April 9, 2020).
4.11	Form of Global Note Representing the Notes (included in Third Supplemental Indenture, dated April 9, 2020, between the Company and The Bank of New York Mellon, as trustee and incorporated herein by reference to Exhibit 4.2 of AVANGRID’s Current Report on Form 8-K filed with the SEC on April 9, 2020).
4.12	Description of Avangrid, Inc.'s Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934 (incorporated herein by reference to Exhibit 4.9 of AVANGRID's Annual Report on Form 10-K for the fiscal year ended December 31, 2019 filed with the Securities and Exchange Commission on March 2, 2020).
4.13	Share Purchase Agreement, effective as of May 12, 2021, between Iberdrola, S.A. and Avangrid, Inc. (incorporated herein by reference to Exhibit 4.1 of AVANGRID’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2021 filed with the Securities and Exchange Commission on July 30, 2021).
4.14	Share Purchase Agreement, effective as of May 12, 2021, between Hyde Member LLC and Avangrid, Inc. (incorporated herein by reference to Exhibit 4.2 of AVANGRID’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2021 filed with the Securities and Exchange Commission on July 30, 2021).
10.1	Shareholder Agreement, dated as of December 16, 2015, by and between Avangrid, Inc. and Iberdrola, S.A. (incorporated herein by reference to Exhibit 4.1 to Form 8-K filed with the Securities and Exchange Commission on December 18, 2015).
10.2	Service Agreement, dated January 1, 2014, between Iberdrola USA, Inc. Management Corporation and Avangrid, Inc. (formerly Iberdrola USA, Inc.) (incorporated herein by reference to Exhibit 10.2 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.3	Employment Agreement dated October 1, 2010 among Robert Daniel Kump, Iberdrola USA Networks, Inc. (formerly Iberdrola USA, Inc.) and Iberdrola USA Management Corporation (incorporated herein by reference to Exhibit 10.23 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015). †
10.4	Service Contract dated January 16, 2014 between Robert Daniel Kump and Avangrid, Inc. (incorporated herein by reference to Exhibit 10.24 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015). †
10.5	Framework Agreement for the Provision of Corporate Services for Iberdrola and the Companies of its Group, and the Declaration of Acceptance, dated July 16, 2015 (incorporated herein by reference to Exhibit 10.28 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.6	Equipment Supply Agreement dated December 28, 2014 between Iberdrola Renewables, LLC and Gamesa Wind US, LLC (incorporated herein by reference to Exhibit 10.29 to Form S-4/A filed with the Securities and Exchange Commission on November 6, 2015).

Exhibit Number	Exhibit Description
10.7	Agreement and Release dated September 25, 2009 between Robert Daniel Kump and Iberdrola USA Management Corporation (formerly Energy East Management Corporation) (incorporated herein by reference to Exhibit 10.31 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015). †
10.8	Form of Indemnification Agreement between Avangrid, Inc. (formerly Iberdrola USA, Inc.) and its directors and officers (incorporated herein by reference to Exhibit 10.32 to Form S-4/A filed with the Securities and Exchange Commission on October 21, 2015).†
10.90	Commercial Paper/Certificates of Deposit Issuing and Paying Agent Agreement dated May 13, 2016 among Avangrid, Inc., as Issuer, and Bank of America, National Association, as Issuing and paying Agent (incorporated herein by reference to Exhibit 10.1 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016 filed with the Securities and Exchange Commission on August 4, 2016).
10.10	Form of Commercial Paper Dealer Agreement among Avangrid, Inc., as Issuer, and various Dealers (incorporated herein by reference to Exhibit 10.2 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016 filed with the Securities and Exchange Commission on August 4, 2016).
10.11	Substitution Agreement, dated as of December 19, 2016, between UIL Holdings Corporation and Avangrid, Inc. (incorporated herein by reference to Exhibit 10.45 of AVANGRID's Annual Report on Form 10-K for the fiscal year ended December 31, 2016 filed with the Securities and Exchange Commission on March 10, 2017).
10.12	Amended and Restated Avangrid, Inc. Omnibus Incentive Plan (incorporated herein by reference to Exhibit 10.1 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017 filed with the Securities and Exchange Commission on May 5, 2017).†
10.13	Customer Liquidity Agreement, dated December 1, 2017, between Avangrid, Inc., Bank of America, National Association, Iberdrola, S.A., Iberdrola Mexico, S.A. de C.V., and Scottish Power Ltd. (incorporated herein by reference to Exhibit 10.37 of AVANGRID's Annual Report on Form 10-K for the fiscal year ended December 31, 2017 filed with the Securities and Exchange Commission on March 26, 2018).
10.14	Underwriting Agreement, dated November 16, 2017, by and among the Avangrid, Inc., BBVA Securities Inc., BNP Paribas Securities Corp., Citigroup Global Markets Inc., and Wells Fargo Securities, LLC (incorporated herein by reference to Exhibit 1.1 to Form 8-K filed with the Securities and Exchange Commission on November 21, 2017).
10.15	Purchase Agreement, dated January 31, 2018, between Avangrid Renewables Holdings, Inc. and CCI U.S. Asset Holdings LLC (incorporated herein by reference to Exhibit 10.1 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended March 31, 2018 filed with the Securities and Exchange Commission on May 3, 2018).
10.16	Transmission Service Agreement, dated June 13, 2018, between Central Maine Power Company and NSTAR Electric Company (d/b/a Eversource) (incorporated herein by reference to Exhibit 10.2 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 filed with the Securities and Exchange Commission on August 2, 2018).
10.17	Transmission Service Agreement, dated June 13, 2018, among Central Maine Power Company, Massachusetts Electric Company (d/b/a National Grid), and Nantucket Electric Company (d/b/a National Grid) (incorporated herein by reference to Exhibit 10.3 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 filed with the Securities and Exchange Commission on August 2, 2018).
10.18	Transmission Service Agreement, dated June 13, 2018, between Central Maine Power Company and Fitchburg Gas & Electric Light Company (d/b/a Unitil) (incorporated herein by reference to Exhibit 10.4 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 filed with the Securities and Exchange Commission on August 2, 2018).

Exhibit Number	Exhibit Description
10.19	Transmission Service Agreement, dated June 13, 2018, between Central Maine Power Company and H.Q. Energy Services (U.S.) Inc. (incorporated herein by reference to Exhibit 10.5 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 filed with the Securities and Exchange Commission on August 2, 2018).
10.20	Transmission Service Agreement, dated June 13, 2018, between Central Maine Power Company and H.Q. Energy Services (U.S.) Inc. (incorporated herein by reference to Exhibit 10.6 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 filed with the Securities and Exchange Commission on August 2, 2018).
10.21	Transmission Service Agreement, dated June 13, 2018, between Central Maine Power Company and H.Q. Energy Services (U.S.) Inc. (incorporated herein by reference to Exhibit 10.7 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 filed with the Securities and Exchange Commission on August 2, 2018).
10.22	Transmission Service Agreement, dated June 13, 2018, between Central Maine Power Company and H.Q. Energy Services (U.S.) Inc. (incorporated herein by reference to Exhibit 10.8 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 filed with the Securities and Exchange Commission on August 2, 2018).
10.23	Employment Agreement, effective as of July 8, 2018, between Douglas K. Stuver and Avangrid Management Company, LLC (incorporated herein by reference to Exhibit 10.1 to AVANGRID's Current Report on Form 8-K filed with the SEC on July 20, 2018).†
10.24	First Amendment to Transmission Service Agreement dated October 9, 2018 by and between Central Maine Power Company and NSTAR Electric Company (d/b/a Eversource) (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed with the SEC on October 15, 2018).
10.25	First Amendment to Transmission Service Agreement dated October 9, 2018 by and among Central Maine Power Company, Massachusetts Electric Company (d/b/a National Grid) and Nantucket Electric Company (d/b/a National Grid) (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed with the SEC on October 15, 2018).
10.26	First Amendment to Transmission Service Agreement dated October 9, 2018 by and between Central Maine Power Company and Fitchburg Gas and Electric Light Company (d/b/a Unitil) (incorporated herein by reference to Exhibit 10.3 to Form 8-K filed with the SEC on October 15, 2018).
10.27	Amended and Restated Executive Variable Pay Plan (incorporated herein by reference to Exhibit 10.1 to Form 8-K file with the Securities and Exchange Commission on June 6, 2022).†
10.28	Underwriting Agreement, dated May 14, 2019, by and among the Avangrid, Inc., Credit Agricole Securities (USA) Inc, MUFG Securities Americas Inc., Citigroup Global Markets Inc., and Wells Fargo Securities, LLC (incorporated herein by reference to Exhibit 1.1 to Form 8-K filed with the Securities and Exchange Commission on May 16, 2019).
10.29	Term Loan Credit Agreement, dated December 31, 2019, among Avangrid, Inc., The Several Lenders, Mizuho Bank, LTD and The Bank of Nova Scotia (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed with the Securities and Exchange Commission on January 7, 2020).
10.30	Underwriting Agreement, dated April 7, 2020, by and among Avangrid, Inc. and BBVA Securities Inc., BNP Paribas Securities Corp., BofA Securities, Inc. and MUFG Securities Americas Inc., as representatives of the several Underwriters named therein (incorporated herein by reference to Exhibit 1.1 to Form 8-K filed with the Securities and Exchange Commission on April 9, 2020).
10.31	Employment Agreement, dated June 11, 2020, by and between Avangrid Management Company, LLC and Dennis V. Arriola (incorporated herein by reference to Exhibit 10.1 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2020 filed with the Securities and Exchange Commission on July 31, 2020).†

Exhibit Number	Exhibit Description
10.32	Revolving Credit Agreement, dated June 29, 2020, among Avangrid, Inc., the several lenders from time to time parties thereto, Mizuho Bank, Ltd., as administrative agent, and The Bank of Nova Scotia and Banco Bilbao Vizcaya Argentaria, S.A. New York Branch, as co-syndication agents (incorporated herein by reference to Exhibit 10.2 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2020 filed with the Securities and Exchange Commission on July 31, 2020).
10.33	Amendment No. 2 to the Revolving Credit Agreement, dated June 29, 2020, 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 banks and other financial institutions or entities from time to time parties thereto, JPMorgan Chase Bank, N.A., as administrative agent, and Bank of America, N.A., as syndication agent, MUFG Bank, Ltd. and Santander Bank, N.A., as co-documentation agents, and Banco Bilbao Vizcaya Argentaria, S.A. New York Branch, as sustainability agent (incorporated herein by reference to Exhibit 10.3 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2020 filed with the Securities and Exchange Commission on July 31, 2020),
10.34	Second Amendment to Transmission Service Agreement and Consent to Assignment dated June 25, 2020 by and between Central Maine Power Company and NSTAR Electric Company (d/b/a Eversource) (incorporated herein by reference to Exhibit 10.4 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2020 filed with the Securities and Exchange Commission on July 31, 2020).
10.35	Second Amendment to Transmission Service Agreement and Consent to Assignment dated June 25, 2020 by and among Central Maine Power Company, Massachusetts Electric Company (d/b/a National Grid), and Nantucket Electric Company (d/b/a National Grid) incorporated herein by reference to Exhibit 10.5 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2020 filed with the Securities and Exchange Commission on July 31, 2020).
10.36	Second Amendment to Transmission Service Agreement and Consent to Assignment dated June 25, 2020 by and between Central Maine Power Company and Fitchburg Gas and Electric Light Company (d/b/a Unitil) (incorporated herein by reference to Exhibit 10.6 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2020 filed with the Securities and Exchange Commission on July 31, 2020).
10.37	Second Amendment to Transmission Service Agreement and Consent to Assignment dated June 25, 2020 by and between Central Maine Power Company and H.Q. Energy Services (U.S.) Inc. (incorporated herein by reference to Exhibit 10.7 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2020 filed with the Securities and Exchange Commission on July 31, 2020).
10.38	Second Amendment to Transmission Service Agreement and Consent to Assignment dated June 25, 2020 by and between Central Maine Power Company and H.Q. Energy Services (U.S.) Inc. (incorporated herein by reference to Exhibit 10.8 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2020 filed with the Securities and Exchange Commission on July 31, 2020).
10.39	Second Amendment to Transmission Service Agreement and Consent to Assignment dated June 25, 2020 by and between Central Maine Power Company and H.Q. Energy Services (U.S.) Inc. (incorporated herein by reference to Exhibit 10.9 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2020 filed with the Securities and Exchange Commission on July 31, 2020).
10.40	Second Amendment to Transmission Service Agreement and Consent to Assignment dated June 25, 2020 by and between Central Maine Power Company and H.Q. Energy Services (U.S.) Inc. (incorporated herein by reference to Exhibit 10.10 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2020 filed with the Securities and Exchange Commission on July 31, 2020).
10.41	Intra-Group Loan Agreement, dated December 14, 2020, between Avangrid, Inc. and Iberdrola, S.A. (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed with the Securities and Exchange Commission on December 18, 2020).
10.42	Employment Agreement, dated March 15, 2021, between Avangrid Management Company, LLC. and Catherine S. Stempien.†*

Exhibit Number	Exhibit Description
10.43	Side Letter Agreement, dated April 15, 2021, between Avangrid, Inc. and Iberdrola, S.A. (incorporated herein by reference to Exhibit 10.1 to AVANGRID's Current Report on Form 8-K filed with the Securities and Exchange Commission on April 16, 2021).
10.44	Employment Agreement, dated June 13, 2021, between Avangrid Management Company, LLC. and R Scott Mahoney (incorporated herein by reference to Exhibit 10.1 to AVANGRID's Current Report on Form 8-K filed with the Securities and Exchange Commission on July 16, 2021).†
10.45	Restructuring Agreement, dated September 15, 2021, among CI-II Park Holding LLC, CI III Park Holding LLC, CI IV Master DEVCO LLC, Avangrid Renewables, LLC and Vineyard Wind LLC. (incorporated herein by reference to Exhibit 10.1 to AVANGRID's Current Report on Form 8-K filed with the Securities and Exchange Commission on September 21, 2021).
10.46	Revolving Credit Agreement, dated as of November 23, 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 AVANGRID's Current Report on Form 8-K filed with the Securities and Exchange Commission on November 24, 2021).
10.47	Form of Phantom Award Agreement (incorporated herein by reference to Exhibit 10.1 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended March 31, 2022 filed with the Securities and Exchange Commission on April 29, 2022).†
10.48	Employment Agreement, dated June 1, 2022, between Avangrid Management Company, LLC and Pedro Azagra Blázquez (incorporated herein by reference to Exhibit 10.1 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2022 filed with the Securities and Exchange Commission on July 27, 2022).†
10.49	Employment Agreement, dated June 29, 2022, between Avangrid Management Company, LLC and Patricia Cosgel (incorporated herein by reference to Exhibit 10.2 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2022 filed with the Securities and Exchange Commission on July 27, 2022).†
10.50	Separation Agreement and Release, dated September 8, 2022, between Avangrid Management Company, LLC and Dennis V. Arriola (incorporated herein by reference to Exhibit 10.1 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended September 30, 2022 filed with the Securities and Exchange Commission on October 26, 2022).†
10.51	Form of Restricted Stock Unit Award Agreement.†*
21.1	Significant subsidiaries of the Registrant.*
23.1	Consent of KPMG LLP, independent registered public accounting firm of Avangrid, Inc.*
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.*

Exhibit Number	Exhibit Description
32	Chief Executive Officer and Chief Financial Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*
101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH	Inline XBRL Taxonomy Extension Schema Document.*
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document.*
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document.*
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document.*
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document.*
104	The cover page from the Company's Annual Report on Form 10-K for the year ended December 31, 2022, formatted as Inline XBRL and contained in Exhibit 101.

* Filed herewith.

† Compensatory plan or agreement.

The foregoing list of exhibits does not include instruments defining the rights of the holders of certain long-term debt of Avangrid, Inc. and its subsidiaries where the total amount of securities authorized to be issued under the instrument does not exceed ten percent (10%) of the total assets of Avangrid, Inc. and its subsidiaries on a consolidated basis; and Avangrid, Inc. hereby agrees to furnish a copy of each such instrument to the SEC on request.

Item 16. ***Form 10-K Summary.***

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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: February 22, 2023

By: /s/ Pedro Azagra Blázquez

Pedro Azagra Blázquez

Director and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Pedro Azagra Blázquez Pedro Azagra Blázquez	Director and Chief Executive Officer (Principal Executive Officer)	February 22, 2023
/s/ Patricia C. Cosgel Patricia C. Cosgel	Chief Financial Officer (Principal Financial Officer)	February 22, 2023
/s/ Scott M. Tremble Scott M. Tremble	Controller (Principal Accounting Officer)	February 22, 2023
/s/ Ignacio S. Galán Ignacio S. Galán	Chairman of the Board	February 22, 2023
/s/ John E. Baldacci John E. Baldacci	Director	February 22, 2023
/s/ Daniel Alcain López Daniel Alcain López	Director	February 22, 2023
/s/ Robert Duffy Robert Duffy	Director	February 22, 2023
/s/ Teresa Herbert Teresa Herbert	Director	February 22, 2023
/s/ Patricia Jacobs Patricia Jacobs	Director	February 22, 2023
/s/ John L. Lahey John L. Lahey	Director	February 22, 2023
/s/ Santiago Martinez Garrido Santiago Martinez Garrido	Director	February 22, 2023
/s/ José Sáinz Armada José Sáinz Armada	Director	February 22, 2023
/s/ Alan D. Solomont Alan D. Solomont	Director	February 22, 2023
/s/ Camille Joseph Varlack Camille Joseph Varlack	Director	February 22, 2023
/s/ Agustin Delgado Martin Agustin Delgado Martin	Director	February 22, 2023
/s/ María Fátima Báñez García María Fátima Báñez García	Director	February 22, 2023

EXHIBIT 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the registration statements (No. 333-212616 and No. 333-208571) on Form S-8 of our reports dated February 22, 2023, with respect to the consolidated financial statements (and financial statement schedule I) of Avangrid, Inc. and the effectiveness of internal control over financial reporting.

/s/ KPMG LLP

New York, New York
February 22, 2023

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. 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 report on Form 10-K 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.
February 22, 2023

/s/ Patricia C. Cosgel

Patricia C. Cosgel
Senior Vice President - Chief Financial Officer
Avangrid, Inc.
February 22, 2023

EXHIBIT 31.2

CERTIFICATION

I, Patricia C. Cosgel, certify that:

1. I have reviewed this annual report on Form 10-K 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: February 22, 2023

/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 annual report on Form 10-K 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: February 22, 2023	/s/ Pedro Azagra Blázquez
	Pedro Azagra Blázquez
	Director and Chief Executive Officer

EXHIBIT 21.1

LIST OF SUBSIDIARIES OF Avangrid, Inc.

Name of Subsidiary	State or Jurisdiction of Incorporation Or Organization
Avangrid Networks, Inc.(1)*	Maine
New York State Electric & Gas Corporation(2)	New York
Rochester Gas and Electric Corporation(2)	New York
Central Maine Power Company(2)	Maine
Maine Natural Gas Corporation(2)	Maine
UIL Holdings Corporation(2)	Connecticut
The United Illuminating Company(4)	Connecticut
The Southern Connecticut Gas Company(4)	Connecticut
Connecticut Natural Gas Corporation(4)	Connecticut
The Berkshire Gas Company(4)	Massachusetts
Avangrid Renewables Holdings, Inc.(1)*	Delaware
Avangrid Renewables, LLC(3)	Oregon

(1) Subsidiary of Avangrid, Inc.
(2) Subsidiary of Avangrid Networks, Inc.
(3) Subsidiary of Avangrid Renewables Holdings, Inc.
(4) Subsidiary of UIL Holdings Corporation

* Holding Company

Appendix

2015 Pro Forma Net Income Reconciliation

YEARS ENDED DECEMBER 31	2015[4]
Net Income Attributable to Avangrid, Inc.	**$273**
Adjustments:	
Net income representing a full year of UIL[4]	133
Merger costs[3]	122
Income tax impact of adjustments	(51)
Net Income Pro Forma[5]	**$477**
Merger costs[3]	
Mark-to-market earnings – Renewables[1]	(25)
Impact of COVID-19[2]	-
Income tax impact of adjustments	6
Adjusted Net Income	**$458**
Net (loss) income attributable to noncontrolling interests	-
Income tax expense (benefit)	122
Depreciation and amortization	862
Interest expense, net of capitalization	364
Other (income) expense	(79)
(Earnings) losses from equity method investments	(14)
Adjusted EBITDA	**$1,713**
Retained PTCs/ITCs	102
PTCs allocated to tax equity investors	56
Adjusted EBITDA with Tax Credits	**$1,871**

[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 as result of COVID 19 impact.

[3] Pre-merger costs incurred.

[4] Represents full year UIL 2015 after merger adjustments

[5] Represents unaudited pro forma information reflecting the combined results of operations as if the UIL acquisition had been completed on January 1, 2014.

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AVANGRID | A Member of The IBERDROLA Group

Additional Information

Executive Office

Avangrid, Inc.
180 Marsh Hill Road
Orange, CT 06477
207.629.1190
avangrid.com

Common Stock

The common stock of Avangrid, Inc. is listed on the New York Stock Exchange and trades under the ticker symbol "AGR."

Financial Information

Comprehensive financial and other information about Avangrid, Inc. can be obtained by visiting the Investor Relations section of our website at **avangrid.com**. Available information includes historical share information, dividend history, past and present financial statements, recent company presentations, and filings with the U.S. Securities and Exchange Commission. This information – including the Avangrid, Inc. Forms 10-K, 10-Q, 8-K and other published corporate literature – is also available without charge upon written request to:

R. Scott Mahoney
Senior Vice President – General Counsel
& Corporate Secretary
Avangrid, Inc.
180 Marsh Hill Road
Orange, CT 06477

Avangrid, Inc. uses its website as a channel of distribution for material company information. Important information, including news releases, financial and operational information, earnings and analyst presentations, and information about upcoming presentations and events is routinely posted and accessible on the Investors Relations section of our website at **avangrid.com**.

In addition, our website allows investors and other interested persons to sign up to automatically receive email alerts when the company posts news releases, SEC filings and certain other information on our website.

Shareholder Inquiries

Shareholder inquiries can be directed to Investor Relations via email at **investors@avangrid.com** or by writing to:
Investor Relations
Avangrid, Inc.
180 Marsh Hill Road
Orange, CT 06477

Transfer Agent and Registrar

Shareholders with inquiries regarding address corrections, dividend payments, lost certificates or changes in registered ownership should contact the Avangrid, Inc. stock transfer agent:

Broadridge Corporate Issuer Solutions, Inc.
Brentwood, NY 11717
P.O. Box 1342
1.877.681.8024
shareholder@broadridge.com

2022 Sustainability Report

Copies of the company's 2022 Sustainability Report can be obtained on by visiting our website at **avangrid.com** or by emailing Investor Relations at **investors@avangrid.com**.

References to websites are inactive textual references only and the contents of our website are not incorporated by reference into this 2022 Annual Report for any purpose.

AVANGRID

A Member of
The **IBERDROLA** Group