AVANGRID

2019 Annual Report

Dear Fellow Shareholders:

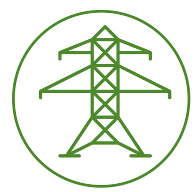
While 2019 was a challenging year, we made several important steps in line with our long-term strategy. I am optimistic as we look forward to a new year – and a new decade – knowing that we are well-positioned to continue our emergence as a leading clean energy company. We remained focused on delivering clean, reliable and affordable service to all our customers through our commitment to innovation, safety and long-term sustainable growth.

However, as I write this letter, as a global community, we face new significant challenges in 2020 due to the coronavirus pandemic. AVANGRID's top priority is to ensure the health and safety of our employees, suppliers and communities. We have been working closely with government officials, regulators, hospitals, emergency services and critical care centers to ensure continuity of service and we have also been helping customers address the financial impacts of the crisis by suspending service shut offs for non-payment and helping them manage their energy bills. The AVANGRID companies and Avangrid Foundation have also committed significant funds to support coronavirus response and recovery by helping vulnerable communities as they deal with the impact of the pandemic. We are mindful of the critical role we play in keeping the economy going, through continuity of energy supply, investments in infrastructure and job creation.

2019 IN REVIEW

In 2019, we continued to make progress executing our strategic plan, by investing $3 billion to modernize and upgrade the grid and increase our Renewables capacity.

AVANGRID's consolidated U.S. GAAP net income increased by approximately 18% year-over-year to $700 million, or $2.26 per share. Our 2019 non-U.S. GAAP consolidated adjusted net income, excluding mark-to-market and other one-time items , amounted to $673 million, or $2.17 per share. Year-end U.S. GAAP earnings reflected incremental rate increases at some of our regulated utilities, the sale of renewable assets, efficiencies and favorable mark to market and thermal and trading activities, which helped to partially offset the negative impacts of lower than expected wind resource, outage restoration and staging costs and lower than expected transmission revenues.



JAMES P. TORGERSON, CEO

Last year, Avangrid Renewables invested $1.4 billion and commissioned 831 MW of new wind projects, with another 700 MW of onshore wind expected to be operational in 2020.

In our Networks business, we achieved excellent safety results, reducing Avangrid employee lost time accidents by 11% compared to 2018. Networks investments amounted to $1.6 billion in 2019 and were the largest in the company's history. In 2019, we improved our response to storms in New York and New England, and we earned the Edison Electric Institute Emergency Response Award for Central Maine Power's (CMP) response to the October snow storm. We also were recognized among the Top Innovators of 2019 by Utilities Fortnightly magazine for our intelligent pipeline project at our gas companies. In 2019, we also made significant progress in negotiations for new rate cases at Central Maine Power, New York Electric & Gas (NYSEG) and Rochester Gas and Electric (RG&E), representing over half of our total rate base.

Last year, Avangrid Renewables invested $1.4 billion and commissioned 831 MW of new wind projects, with another 700 MW of onshore wind and 366 MW of wind repowering expected to be operational in 2020. The company also executed 480 MW of new Purchase Power Agreements (PPA), and closed several strategic transactions including the sale and transfer of a 50% stake in two renewables assets generating earnings gains for shareholders.

As part of our ongoing transformational journey as an organization, we successfully identified both near and long-term opportunities, including process, organizational, and technology initiatives to improve our performance and ensure that we are operating with best-in-class efficiency. Through these efforts, we achieved pre-tax savings of approximately $75 million in 2019, which helped to partially mitigate the negative impacts of lower than expected wind resource, outage restoration and staging costs and lower than expected transmission revenues. We will continue our efforts to optimize operational efficiency in 2020 and beyond.

AVANGRID continues to enjoy a strong financial position, which provides flexibility to fund our investment plan. During 2019, AVANGRID issued $2.1 billion of debt, including a $750 million Green Bond, and issued $133 million of tax equity.

INVESTING IN A CLEAN ENERGY FUTURE

AVANGRID is emerging as the leading clean energy company in New England with several major clean energy projects. These include the New England Clean Energy Connect (NECEC) project, which will deliver clean, reliable hydropower to New England, as well as our Vineyard Wind joint venture with Copenhagen Infrastructure Partners, which will construct the first large-scale offshore wind project in the United States.

In Maine, our $950 million NECEC transmission project, which will deliver 1,200 MW of renewable hydro-power to the New England grid, continued to advance through the permitting process. This includes approvals from the Maine Public Utilities Commission, the Massachusetts Department of Public Utilities and Maine Land Use Planning Commission, bringing us closer to our goal of making NECEC the region's largest new source of carbon emissions-free electricity. Once operational in 2022, the project will result in an annual reduction of 3.6 million metric tons of carbon dioxide emissions, equal to 700,000 fewer cars on the road.

Our 50/50 joint venture project with Copenhagen Infrastructure Partners, Vineyard Wind, is developing a 800 MW pioneer project in the nascent US offshore wind industry. In 2019 it faced some challenges as the Bureau of Ocean Energy Management (BOEM) delayed the issuance of its Environmental Impact Study and Record of Decision. BOEM recently announced a new permitting timeline with expected issuance of the Record of Decision in December 2020. Considering the revised schedule, we target a commissioning date no earlier than 2023. Throughout 2019, the project achieved other relevant permitting milestones, including the approval of contracts with the electric distribution companies by the Massachusetts Department of Public Utilities, as well as the approval from the Massachusetts Energy Facility Siting Board for the construction and operation of electric transmission facilities within the Commonwealth.

In late 2019, Park City Wind, our Vineyard Wind joint-venture to serve Connecticut, was selected by the Department of Energy and Environmental Protection to provide 804 MW of offshore wind, which is the equivalent of 14% of the state's electricity supply. The project will be located near Vineyard Wind's other planned offshore wind farm south of Martha's Vineyard, with an expected in-service date of 2025. The project will generate direct economic benefits of approximately $890M, including energy cost savings and workforce development initiatives with the potential to establish Bridgeport, Connecticut, as an offshore wind hub.

INNOVATING FOR OUR CUSTOMERS

As a leading clean energy company, AVANGRID debuted new core values in 2019 – Sustainable, Agile and Collaborative – and a new purpose: "Working together to deliver a more accessible clean energy model that promotes healthier, more sustainable communities every day." To fulfill that purpose, we are committed to investing in innovative and sustainable energy solutions for our customers.

AVANGRID is an innovative leader in the energy sector because we know innovation is key to a sustainable energy future and continued affordable, reliable service to our customers. In 2019, AVANGRID invested approximately $68 million in innovation projects that included generation-boosting software for onshore wind turbines, advanced data analytics for the electric distribution system, grid-scale battery storage installations, robotic process automation for customer service, and much more. AVANGRID is also establishing a new private fiber-optic network to help protect our assets. This is an industry leading practice in cybersecurity.

Demand for clean energy goes beyond powering our homes and businesses. We are building the power grid of the future, beginning with our Energy Smart Community where we pilot innovative projects in distribution automation, big-data analytics and battery storage that will enable the modern, clean energy experience that customers want. We are empowering customers to electrify their transportation by expanding incentives and deploying charging infrastructure. In 2019, the company announced plans to increase its own Electric Vehicle (EV) fleet by 75 percent. We are also planning a $34 million investment in the expansion of EV charging infrastructure across Maine and New York.

CREATING SUSTAINABLE VALUE

AVANGRID is playing a leading role in our country's clean energy transition, and as we grow, we are guided by the Sustainable Development Goals approved by the member countries of the United Nations as a framework for all countries and organizations. While we are focused on the goals targeting affordable and clean energy and climate action, our activities also directly contribute to other goals like life on land or industry, innovation and infrastructure, among others.

2020 is the third year AVANGRID earned a place on the Global Clean 200 list of the world's most sustainable publicly traded firms. We are also a constituent of the FTSE4Good Index Series and participate in the Carbon Disclosure Project, a global environmental disclosure system.

In Corporate Governance, we have been recognized in each of the past two years as one of the World's Most Ethical Companies by the Ethisphere Institute, received an award for Best Corporate Governance in the U.S. by World Finance Magazine, and were recognized as the North American utility with the best corporate governance by Ethical Boardroom Magazine in 2019.

We are committed to creating a more equitable, vibrant and sustainable future in communities across the United States. In 2019, the Avangrid Foundation invested more than $3 million in grants, scholarships and matching gift programs to more than 300 organizations. Our employees also serve and support our communities by donating their time and talents through numerous local volunteer efforts.

As one of the cleanest U.S. utilities and a leader in renewable energy, AVANGRID stands at the forefront of the nation's transformation to a clean energy economy. We have positioned ourselves as a pioneer in the U.S. offshore wind industry, are building the grid of the future, and developing clean and smart solutions for our customers. 2020 will mark AVANGRID's fifth year as a listed company. I know the momentum we've built will accelerate in 2020 and I look forward to what's ahead, even as we face the challenges ahead.

Finally, after a long and rewarding career, I have decided to retire effective June 23, 2020 the day after our annual meeting of shareholders. I am grateful to the Board of Directors for allowing me the honor of leading this great company during its first five years, and I want to thank all our dedicated employees for helping establish AVANGRID as a sustainable clean energy leader. Together, we have accomplished much, but our customers and communities rely on us to reach even greater heights. Under the next generation of leadership, I am confident that AVANGRID will be successful in delivering a cleaner and more accessible energy model for our customers and communities, every day.

Sincerely,

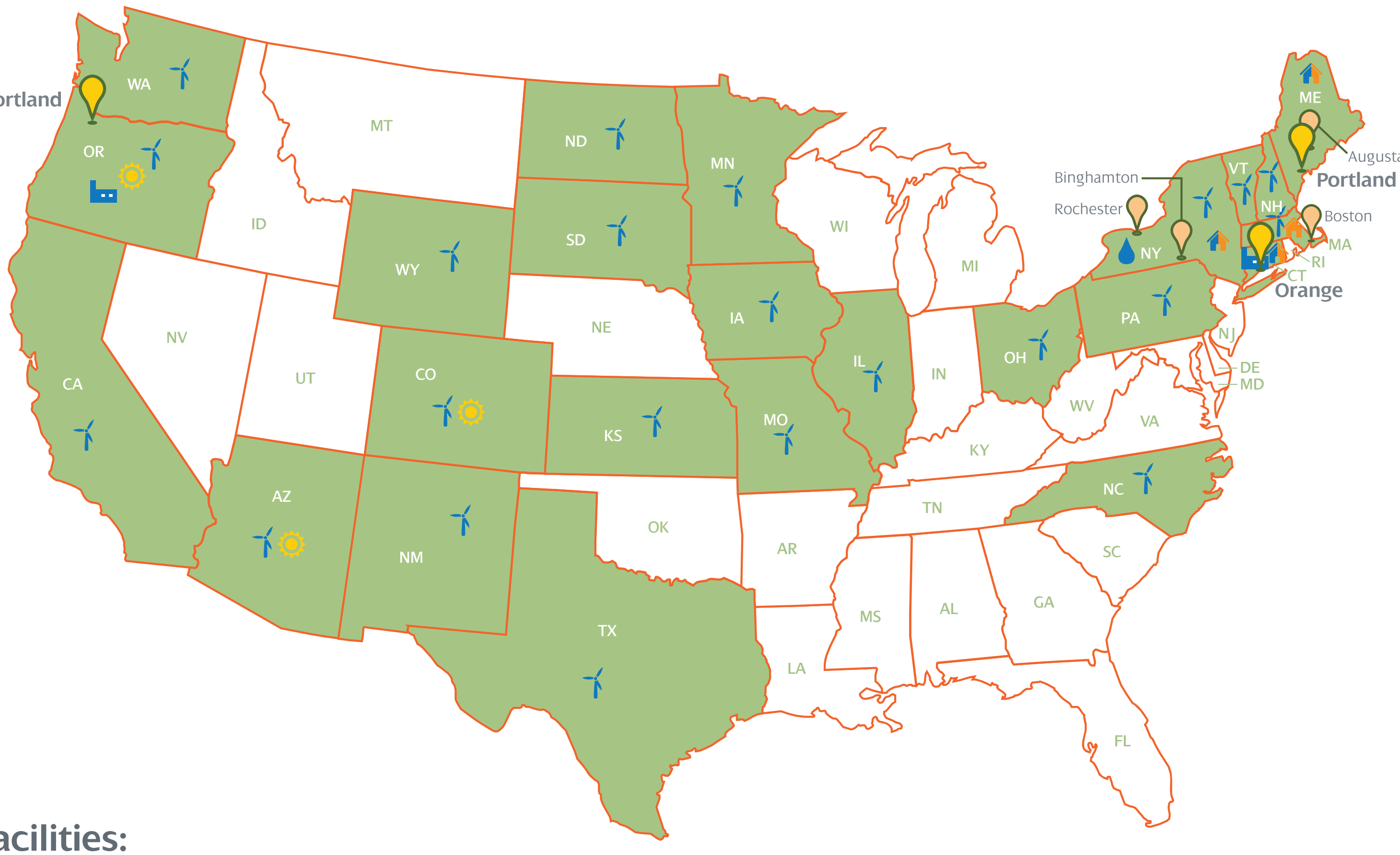
James P. Torgerson
Chief Executive Officer

1 Adjusted consolidated net income excludes restructuring charges, mark-to-market adjustments, accelerated depreciation from repowering of wind farms, impact of the Tax Act and adjustments for the non-core Gas storage business. For additional information, see "Non-GAAP Financial Measures" beginning on page 64 of our Annual Report on Form 10-K for the year ended December 31, 2019, included in this annual report.

AVANGRID

Utility of the Future

~ $34 billion in assets with operations in 24 states



Facilities:

- Corporate Offices
- Business Offices
- Wind Power — 7,259 MW
- Solar Power — 130 MW
- Thermal Generation — 840 MW
- Hydroelectric Generation — 118 MW
- Electric/Natural Gas Distribution Networks — 36,614 GWh; 206,663,000 DTh

NOTE: solid orange icon (MA) indicates natural gas distribution only.

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 affect local development, generate employment, and give back to the community.

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

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

Financial and Operational Highlights for 2019

8.4 GW Installed Capacity

$10.4B Rate Base

3.3M Customers

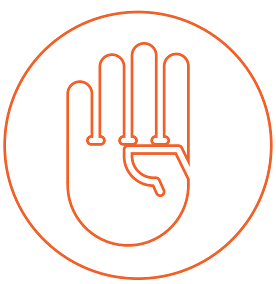
90% Emissions-free

17.7 GW Wind and Solar Pipeline

SELECTED FINANCIAL DATA *in millions, except per-share data*	
Revenues	$6,338
Operating income	$1,003
Net income	$700
Adjusted net income*	$673
Earnings per share	$2.26
Adjusted earnings per share*	$2.17
Dividends declared per share	$1.76
Dividend yield (year-end)	3.4%
Market cap (year-end)	$15,809
Total assets	$34,416
Equity	15,586
Non-current debt	$6,716
Investments	$2,981

SELECTED OPERATIONAL DATA	
Total customers	3,277,917
Electricity customers	2,261,180
Natural gas customers	1,016,737
Electricity delivered (GWh)	36,614
Natural gas delivered (DTh)	206,663,000
Electrical transmission & distribution lines (miles)	79,698
Gas distribution pipeline (miles)	23,018
Net electricity generation (GWh)	20,960
% emissions-free generation	83%
Installed capacity (MW)	8,360
% emissions-free capacity	90%
CO_2 emissions intensity (lbs CO_2/MWh)	162
Employees	6,597

Recognized Leader in Sustainability



AVANGRID has committed to ambitious targets to reduce CO_2 emissions from generation activities.

- 25% reduction in emissions intensity by the end of 2020 vs. 2015
- Carbon neutrality by the end of 2035

AVANGRID supports the U.N.'s 17 Sustainable Development Goals

MAIN FOCUS

7 AFFORDABLE AND CLEAN ENERGY

13 CLIMATE ACTION

DIRECT CONTRIBUTION

6 CLEAN WATER AND SANITATION

15 LIFE ON LAND

9 INDUSTRY, INNOVATION AND INFRASTRUCTURE

17 PARTNERSHIPS FOR THE GOALS

INDIRECT CONTRIBUTION

1 NO POVERTY

3 GOOD HEALTH AND WELL-BEING

5 GENDER EQUALITY

10 REDUCED INEQUALITIES

12 RESPONSIBLE CONSUMPTION AND PRODUCTION

16 PEACE, JUSTICE AND STRONG INSTITUTIONS

2 ZERO HUNGER

4 QUALITY EDUCATION

8 DECENT WORK AND ECONOMIC GROWTH

11 SUSTAINABLE CITIES AND COMMUNITIES

14 LIFE BELOW WATER

* Adjusted net income and adjusted EPS have been adjusted to reflect the effect of mark-to-market changes in the fair value of derivative instruments, restructuring charges primarily associated with reorganizing to better align our people resources with business demands and priorities as part of the Forward 2020+ program, impact from the Tax Act enacted by the U.S. federal government on December 22, 2017, and the impact of accelerated depreciation on the repowering of certain assets. For additional information, see "Non-GAAP Financial Measures" beginning on page 64 of our Annual Report on Form 10-K for the year ended December 31, 2019, including in this annual report.

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, 2019
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) 629-1200

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

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

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 Exchange 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 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 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 pursuant to Section 13(a) of the Exchange Act. ☐

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

The aggregate market value of the Avangrid, Inc.'s voting stock 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, 2019) was $2,836 million based on a closing sales price of $50.50 per share.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: 309,005,272 shares of common stock, par value $0.01, were outstanding as of February 28, 2020.

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 2020 Annual Meeting of the Shareholders are incorporated by reference into Part III to the extent described therein.

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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.

AGT	Algonquin Gas Transmission
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
Cayuga	Cayuga Operating Company, LLC
CENG	Constellation Energy Nuclear Group, LLC
CfDs	Contracts for Differences
CFTC	Commodity Futures Trading Commission
CLCPA	Climate Leadership and Community Protection Act
CL&P	The Connecticut Light and Power Company
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
DIMP	Distribution Integrity Management Program
DER	Distributed energy resources
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
DSP	Distributed System Platform
DTh	Dekatherm
EAM	Earnings adjustment mechanism
EDC	Massachusetts electric distribution companies
EDF	Environmental Defense Fund
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 III, LLC
Exchange Act	The Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FirstEnergy	FirstEnergy Corp.
FPA	Federal Power Act
Gas	Enstor Gas, LLC
GenConn	GenConn Energy LLC
GenConn Devon	GenConn's peaking generating plant in Devon, Connecticut
GenConn Middleton	GenConn's peaking generating plant in Middletown, Connecticut
Ginna	Ginna Nuclear Power Plant, LLC and the R.E. Ginna Nuclear Power Plant
Ginna Facility	R.E. Ginna Nuclear Power Plant
GNPP	Ginna Nuclear Power Plant, LLC.
HLBV	Hypothetical Liquidation at Book Value
HQUS	H.Q. Energy Services (U.S) Inc.
Iberdrola	Iberdrola, S.A., which owns 81.5% of the outstanding shares of Avangrid, Inc.
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
IRS	Internal Revenue Service
ISO	Independent system operator
ISO-NE	ISO New England, Inc.
Joint Proposal	The Joint Proposal, approved by the NYPSC on June 15, 2016, by NYSEG, RG&E and certain other signatory parties for a three-year rate plan for electric and gas service at NYSEG and RG&E commencing May 1, 2016.
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
MBTA	Migratory Bird Treaty Act
Merger Agreement	The Agreement and Plan of Merger, dated as of February 25, 2015, by and among Avangrid, Inc., Green Merger Sub, Inc. and UIL Holdings Corporation
Merger Sub	Green Merger Sub, Inc.
MEPCO	Maine Electric Power Corporation
MGP	Manufactured gas plants
MHI	Mitsubishi Heavy Industries
MNG	Maine Natural Gas Corporation
MPRP	Maine Power Reliability Program
MPUC	Maine Public Utilities 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
NOL	Net operating loss
Non-GAAP	Financial measures that are not prepared in accordance with U.S. GAAP, including adjusted net income and adjusted earnings per share
NYISO	New York Independent System Operator, Inc.
NYPA	New York Power Authority
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
OCC	Connecticut Office of Consumer Counsel
OCI	Other comprehensive income
OSHA	Occupational Safety and Health Act, as amended
OTTI	Other than temporary impairment
PA	Connecticut Public Act
PCB	Polychlorinated Biphenyls
PJM	PJM Interconnection, L.L.C.
PPA	Power purchase agreement
PTF	Pool Transmission Facilities
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
RFP	Request for Proposals
Renewables	Avangrid Renewables, LLC
REV	Reforming the Energy Vision
RG&E	Rochester Gas and Electric Corporation
ROE	Return on equity
ROU	Right-of-use
RPS	Renewable Portfolio Standards
RSSA	Reliability Support Services Agreement
RTO	Regional transmission organization
SCG	The Southern Connecticut Gas Company
Scottish Power	Scottish Power Ltd.
SEC	United States Securities and Exchange Commission
SOX	Sarbanes-Oxley Act
SPHI	Scottish Power Holdings, Inc.
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
WECC	Western Electricity Coordinating Council

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

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 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 future financial performance, anticipated liquidity and capital expenditures;
- actions or inactions of local, state or federal regulatory agencies;
- success in retaining or recruiting our officers, key employees or directors;
- changes in levels or timing of capital expenditures;
- adverse developments in general market, business, economic, labor, regulatory and political conditions;
- fluctuations in weather patterns;
- technological developments;
- the impact of any cyber breaches or other incidents, grid disturbances, acts of war or terrorism or natural disasters;
- the impact of any change to applicable laws and regulations affecting operations including those relating to the environment and climate change, taxes, price controls, regulatory approval and permitting;
- the implementation of changes in accounting standards; 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 is a leading sustainable energy company with approximately $34 billion in assets and operations in 24 states. AVANGRID has 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 8.0 gigawatts of electricity capacity, primarily through wind 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, and was named among the World’s Most Ethical companies in 2019 by the Ethisphere Institute. AVANGRID employs approximately 6,600 people. Iberdrola S.A., a corporation *(sociedad anónima)* organized under the laws of the Kingdom of Spain, a worldwide leader in the energy industry, directly owns 81.5% of outstanding shares of AVANGRID common stock. AVANGRID's primary business is ownership of its operating businesses, which 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 generation, transmission and distribution 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 public utility customers as of December 31, 2019. 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 had a combined wind, solar and thermal installed capacity of 8,001 megawatts, or MW, as of December 31, 2019, including Renewables’ share of joint projects, of which 7,259 MW was installed wind capacity. As of December 31, 2019, approximately 69% of the capacity was contracted, for an average period of 9.5 years, and 13% of installed capacity was hedged. Renewables is among the top three largest wind operators in the United States based on installed capacity as of December 31, 2019 and strives to lead the transformation of the U.S. energy industry to a sustainable, competitive, clean energy future. Renewables currently operates 61 wind farms in 21 states across the United States.

In December 2017, our management committed to a plan to sell the gas storage and trading businesses because they represented non-core businesses that are not aligned with our strategic objectives. At that time, we determined that the assets and liabilities associated with our gas trading and storage businesses met the criteria for classification as assets held for sale, but did not meet the criteria for classification as discontinued operations. On March 1, 2018, the Company closed a transaction to sell Enstor Energy Services, LLC, which operated AVANGRID’s gas trading business, to CCI U.S. Asset Holdings LLC, a subsidiary of Castleton Commodities International, LLC. On May 1, 2018, the Company closed a transaction to sell Enstor Gas, LLC, which operated AVANGRID's gas storage business, to Amphora Gas Storage USA, LLC. The agreement included, among other things, a transition services agreement that obligated ARHI to provide certain transition services for up to one year after the closing date.

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 under the name NGE Resources, Inc. and subsequently changed our name to Energy East Corporation. The stock of Energy East Corporation was publicly traded on the New York Stock Exchange, or NYSE. In 2007, Iberdrola acquired Scottish Power Ltd., or Scottish Power, including Scottish Power Holdings, Inc., or SPHI, the parent company of Scottish Power's U.S. subsidiaries. Through this acquisition, Iberdrola acquired PPM Energy, a subsidiary that operated SPHI's U.S. wind business, thermal generation operations and the gas storage and energy management businesses, and changed PPM Energy's name to Iberdrola Renewables. In 2008, Iberdrola acquired Energy East Corporation, and we changed our name to Iberdrola USA, Inc. in December 2009. In 2013, we completed an internal corporate reorganization to create a unified corporate presence for the Iberdrola brand in the United States, bringing all of its U.S. energy companies under one single holding company, Iberdrola USA, Inc. The internal reorganization, completed in November 2013, resulted in the concentration of our principal businesses in two major subsidiaries: Networks, which held all of our regulated utilities; and Renewables, which held our renewable and thermal generation businesses and gas storage and marketing businesses.

We were the corporate parent of The Southern Connecticut Gas Company, or SCG, Connecticut Natural Gas Corporation, or CNG, and The Berkshire Gas Company, or BGC, prior to UIL Holdings Corporation, or UIL, acquiring those companies in 2010.

On December 16, 2015, we completed the acquisition of UIL, pursuant to which UIL merged with and into our wholly-owned subsidiary, Green Merger Sub, Inc., or Merger Sub, with Merger Sub surviving as our wholly-owned subsidiary. The acquisition was effected pursuant to the Agreement and Plan of Merger, dated as of February 25, 2015, or the Merger Agreement, by and among us, Merger Sub and UIL. Following the completion of the acquisition, Merger Sub was renamed "UIL Holdings Corporation" and we were renamed 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. Effective as of April 30, 2016, UIL and its subsidiaries were transferred to a wholly-owned subsidiary of Networks.

Networks

Overview

Networks, a Maine corporation, holds our regulated utility businesses, including electric generation, 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;
- 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.

For the year ended December 31, 2019, Networks distributed approximately 36.6 million megawatt-hours, or MWh, of electricity. As of December 31, 2019, Networks provided electric service to its approximately 2.3 million customers in the states of New York, Maine and Connecticut. In total, the electric system of Networks' regulated utilities consisted of 8,703 miles of transmission lines, 70,995 miles of distribution lines and 819 substations as of December 31, 2019. Furthermore, for the year ended December 31, 2019, Networks delivered approximately 207 million dekatherms, or DTh, of natural gas, to approximately 1.0 million customers, providing service in the states of New York, Maine, Connecticut and Massachusetts.

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 statewide 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, 2019:

Utility	Rate Base(1) (in billions)	Electricity Customers	Electricity Delivered (in MWh)	Natural Gas Customers	Natural Gas Delivered (in DTh)
NYSEG	$ 2.9	902,593	15,525,000	268,806	57,511,000
RG&E	$ 2.0	383,592	7,072,000	317,661	61,120,000
CMP	$ 2.4	636,341	9,039,000	—	—
MNG	$ 0.1	—	—	4,974	1,254,000
UI	$ 1.8	338,654	4,978,000	—	—
SCG	$ 0.6	—	—	203,269	37,177,000
CNG	$ 0.5	—	—	181,527	39,157,000
BGC	$ 0.1	—	—	40,500	10,444,000

(1) "Rate base" means the net assets upon which a utility can receive a specified return, based on the 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, 2019.

During the last five years, Networks has invested nearly $6.4 billion in creating a 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

As of December 31, 2019, NYSEG served approximately 903,000 electricity customers and 269,000 natural gas customers across more than 40% of upstate New York's geographic area, while RG&E served approximately 384,000 electricity customers and 318,000 natural gas customers in a nine-county region centered around Rochester, in western New York.

In 2019, the nine hydroelectric plants owned by NYSEG and RG&E generated approximately 178 million kilowatt-hours, or kWh, of clean hydropower, which is enough energy to power approximately 25,000 homes across New York State, assuming an average electricity consumption of 600 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 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

As of December 31, 2019, CMP delivered electricity to more than 636,000 customers in an 11,000 square-mile service area in central and southern Maine. CMP completed a $1.4 billion investment plan in 2015 for the construction of upgrades to the bulk power transmission grid in Maine, the largest transmission investment in the history of Maine. This project included the construction of five new 345-kilovolt, or kV, substations and related facilities linked by approximately 440 miles of new transmission lines (referred to as the Maine Power Reliability Program, or MPRP).

CMP also 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.

As of December 31, 2019, MNG delivers natural gas to 4,974 customers in central and southern Maine. MNG continues to build out in 12 communities.

On February 14, 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, or RFP, to move forward as the alternative to the Northern Pass Transmission project which failed to win approval from the New Hampshire Site Evaluation Committee by March 27, 2018. On March 28, 2018, the DOER informed CMP that the conditional selection of Northern Pass Transmission project had been terminated, making the NECEC transmission project the lone winning bid in the RFP. 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 $950 million, would add 1,200 MW of transmission capacity to supply New England with power from reliable hydroelectric generation.

On June 13, 2018, CMP entered into transmission service agreements, or TSAs, with the Massachusetts electric distribution companies, or the 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 have executed certain PPAs with HQUS for sales of electricity and environmental attributes to the EDCs. The EDCs submitted the TSAs and PPAs to the DPU for approval on July 23, 2018, and CMP filed the TSAs for approval by the FERC on August 20, 2018. 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 power purchase agreements and the cost recovery by the EDCs of the TSA charges as required by the TSAs. This Order was subsequently appealed by NextEra Energy Resources, and CMP is coordinating its participation in the processing of the appeal with the MA EDCs; a judicial decision is expected by end of the second quarter of 2020. CMP also continues to negotiate with the EDCs the terms of assignment of the TSAs from CMP to NECEC Transmission LLC upon the project's transfer. On December 10, 2019, CMP submitted a petition to the FERC pursuant to Section 203 of the Federal Power Act, seeking the FERC's authorization to transfer the TSAs (FERC rate schedules) from CMP to NECEC Transmission LLC upon the project's transfer. The MPUC and FERC project's transfer proceedings are ongoing with a decision from the agencies expected at the end of the first quarter of 2020.

The NECEC project also requires certain permits, including environmental, from multiple state and federal agencies and a presidential permit from the U.S. Department of Energy, 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. These permitting activities are ongoing. CMP expects to obtain the applicable state and federal permits necessary to begin construction by the second quarter of 2020. See "Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*" in this Annual Report for further details.

Connecticut

As of December 31, 2019, UI served more than 339,000 residential, commercial and industrial customers in a service area of approximately 335 square miles in the southwestern part of Connecticut. The service area includes Bridgeport and New Haven and is home to a diverse array of business sectors including aerospace manufacturing, healthcare, biotech, financial services, precision manufacturing, retail and education. UI's retail electric revenues vary by season, with the highest revenues typically in the third quarter of the year reflecting seasonal rates, hotter weather and air conditioning use.

UI is also a party to a joint venture with Clearway Energy, Inc. (formerly NRG Yield, Inc.), which is an affiliate of Global Infrastructure Partners, or GIP, pursuant to which UI holds 50% of the membership interests in GCE Holding LLC, whose wholly-owned subsidiary, GenConn Energy LLC, or GenConn, operates peaking generation plants in Devon, Connecticut, or GenConn Devon, and Middletown, Connecticut, or GenConn Middletown. In September 2018, NRG Energy, Inc. sold its interests in NRG Yield, Inc. to GIP. The sale is not expected to have an impact on GenConn.

As of December 31, 2019, SCG and CNG provided local gas distribution services to approximately 385,000 customers in the greater Hartford-New Britain area, Greenwich and the southern Connecticut coast from Westport to Old Saybrook, including the cities of Bridgeport and New Haven.

Massachusetts

As of December 31, 2019, BGC provided local gas distribution services to approximately 41,000 customers in a service area in western Massachusetts, which includes the cities of Pittsfield, North Adams and Greenfield.

Rate Base

These rate base values were calculated using the best estimates as of December 31, 2019. The rate base of Networks' regulated utilities for the years indicated below were as follows:

Rate base	2017	2018	2019
		(in millions)	
NYSEG Electric	$ 1,872	$ 2,067	$ 2,250
NYSEG Gas	534	585	610
RG&E Electric	1,218	1,386	1,453
RG&E Gas	428	497	516
Subtotal New York	**4,052**	**4,535**	**4,829**
CMP Dist	854	903	933
CMP Trans	1,460	1,460	1,469
MNG	67	71	76
Subtotal Maine	**2,381**	**2,434**	**2,478**
UI Dist	1,007	1,035	1,112
UI Trans	570	592	672
SCG	536	550	587
CNG	449	479	538
Subtotal Connecticut	**2,562**	**2,656**	**2,909**
BGC	107	111	136
Total	**$ 9,103**	**$ 9,736**	**$ 10,352**

Earnings Sharing Mechanisms

Networks' regulated utilities' rate plans approved by State regulators often include earnings sharing mechanisms, or ESM, that are intended to encourage regulated utilities to operate efficiently. Pursuant to ESMs, if certain of the regulated utilities of Networks earn more than certain threshold amounts, they must share with customers a specified percentage of these earnings. Below is a history of ESMs over the past three years:

	2017	2018	2019
NYSEG Electric	50% / 50%: 9.65% - 10.15% 75% / 25%: 10.15% - 10.65% 90% / 10%: over 10.65%; Based on Actual Equity Ratio up to 50%	50% / 50%: 9.75% - 10.25% 75% / 25%: 10.25% - 10.75% 90% / 10%: over 10.75%; Based on Actual Equity Ratio up to 50%	50% / 50%: 9.75% - 10.25% 75% / 25%: 10.25% - 10.75% 90% / 10%: over 10.75%; Based on Actual Equity Ratio up to 50%
NYSEG Gas	Same as above	Same as above	Same as above
RG&E Electric	Same as above	Same as above	Same as above
RG&E Gas	Same as above	Same as above	Same as above
CMP Dist.	No ESM	No ESM	No ESM
CMP Trans.	No ESM	No ESM	No ESM
MNG	50% / 50% over 11.55%	50% / 50% over 11.55%	50% / 50% over 11.55%
UI	50% / 50% over 9.10%	50% / 50% over 9.10%	50% / 50% over 9.10%
SCG	No ESM	50% / 50% over 9.25%	50% / 50% over 9.25%
CNG	50% / 50% over 9.18%	50% / 50% over 9.18%	50% / 50% over 9.18%
BGC	No ESM	No ESM	No ESM

Renewables

The Renewables business, based in Portland, Oregon, is engaged primarily in the design, development, construction, management and operation of generation plants that produce electricity using renewable resources and, with more than 60 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 90% of Renewables' combined installed capacity as of December 31, 2019. For the year ended December 31, 2019, Renewables produced approximately 16,952,000 MWh of energy through wind power generation. Renewables had a pipeline of approximately 16,000 MW (approximately 11,000 MW - onshore and approximately 5,000 MW - offshore) of future renewable energy projects in various stages of development as of December 31, 2019.

Renewables' growing strategic business is offshore wind. Renewables has access to two lease areas off the coast of the eastern United States that it is developing through Vineyard Wind, LLC, a 50-50 partnership with Copenhagen Infrastructure Partners (CIP), a fund management company based in Denmark. In total, the lease areas have the potential to generate up to 5,000 MW of renewable energy. Renewables is currently developing two wind projects with CIP in one of the lease areas, which is 166,886 acres. The second lease area, acquired in 2018, is 132,370 acres and located over 16 nautical miles off the coast of Massachusetts.

One of the projects that Vineyard Wind, LLC is developing is the Vineyard Wind I project, which is a utility-scale offshore wind project in the United States. The 800 MW offshore wind project, located 15 miles off the coast of Massachusetts, will 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 second Vineyard Wind, LLC project is the Park City Wind project, an 804 MW project located in the same lease area as Vineyard Wind I, that will deliver clean, reliable energy to the residents of Connecticut through contracts with the electric distribution companies in Connecticut. Both projects are expected to be commissioned in through the mid-2020's, subject to permitting, contract negotiation and for Park City Wind, finalized purchase power agreements.

Typically, Renewables enters into long-term lease agreements with property owners who lease their land for renewable 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, in which Iberdrola had an 8.1% ownership interest until the whole ownership interest was sold in February 2020, and GE Wind, in the aggregate supplied turbines which accounted for 71% of Renewables' installed wind capacity as of December 31, 2019.

Renewables currently operates 61 wind farms in 21 states across the United States. To monetize the tax benefits resulting from production tax credits and accelerated tax depreciation available to qualifying wind energy projects, Renewables has entered into "tax equity" financing structures with third party investors for a portion of its wind farms. Renewables holds two operating wind 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 or, 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 earnings and benefits generated by the wind 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 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 in the United States, with 636 MW of combined capacity as of December 31, 2019. 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 four solar photovoltaic facilities with an installed capacity of 116 MW. The solar photovoltaic facilities produced over 262,000 MWh of renewable energy for the year ended December 31, 2019. Solar accounted for 1.5% of the total renewable energy generation from Renewables in these same periods.

Renewables is pursuing the continued development of a large pipeline of wind energy projects in various regions across the United States. Each site features a range of different atmospheric characteristics that ultimately drive the selection of turbine technology for the proposed project. As part of Renewables' wind resource assessment investigation, critical atmospheric parameters such as mean wind speed, extreme wind speed, turbulence intensity, and mean air density are characterized to represent long-term conditions, for over 20 years. The summary wind characteristics are then combined with a terrain, or orography, analysis to assess siting risks in order to mitigate any future operations and maintenance concerns that may arise due to improper turbine siting.

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. Renewables has deployed the following mix of turbines under this strategy. See "—Properties—Renewables" for more information regarding Renewables' turbine technology.

MFG	Model	Rating	Turbines	MW
Siemens-Gamesa	G83	2.0	60	120
Siemens-Gamesa	G87	2.0	650	1,300
Siemens-Gamesa	G90	2.0	236	472
Siemens-Gamesa	G97	2.0	109	218
Siemens-Gamesa	G114	2.0	282	581
Siemens-Gamesa	SWT2.3-93	2.3	44	101
GE	1.5s	1.5	133	200
GE	1.5sle	1.5	1,126	1,689
GE	2.3	2.3	83	184
GE	2.52	2.5	128	252
GE	2.5	2.5	9	23
MHI	MWT62/1.0	1.0	45	45
MHI	MWT92/2.4	2.4	167	401
MHI	MWT95/2.4	2.4	125	300
MHI	MWT102/2.4	2.4	1	2
Suzlon	S88	2.1	325	681
Vestas	NM48	0.7	3	2
Vestas	V47	0.7	34	22
Vestas	V82	1.7	98	161
Vestas	V126/3.45	3.45	14	48
Vestas	V136/3.6	3.6	109	392
Vestas	V136/3.8	3.8	17	65
Total			3,798	7,259

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 130 wind meteorological towers and 12 solar meteorological stations that are currently in operation. Additionally, a total of six light detecting and ranging and six sonic detecting and ranging remote sensing devices are deployed 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, which 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 another independent entity, the New York Independent System Operator, Inc., or NYISO. The FERC approves CMP's, UI's and New York TransCo's regulated electric utilities transmission revenue requirements. Wholesale electric transmission revenues are recovered through 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, or PTF, 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).

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 proposes to use this new methodology to resolve Complaints I, II, III, and IV filed by the New England state consumer advocates.

The new proposed ROE methodology set forth in the October 2018 Order considers more than just the two-step discounted cash flow, or DCF, analysis adopted in the FERC order on Complaint I vacated by the Court. The new proposed ROE methodology uses three financial analyses (i.e., DCF, the capital-asset pricing model, and the expected earnings analysis) to produce a range of returns to narrow the zone of reasonableness when assessing whether a complainant has met its initial burden of demonstrating that the utility's existing ROE is unjust and unreasonable. The new proposed ROE methodology establishes a range of just and reasonable ROEs of 9.60% to 10.99% and proposes a just and reasonable base ROE of 10.41% with a new ROE cap of 13.08%. Pursuant to the October 2018 Order, the NETOs filed briefs on the proposed methodology in all four Complaints on January 11, 2019 and replied to the initial briefs on March 8, 2019. On November 21, 2019, the FERC issued rulings on two complaints challenging the base return on equity for Midcontinent Independent System Operator, or MISO transmission owners. These rulings established a new zone of reasonableness based on equal weighting of the DCF and capital-asset pricing model for establishing the base return on equity. This resulted in a base return on equity of 9.88% as the midpoint of the zone of reasonableness. Various parties have requested rehearing on this decision. We cannot predict the outcome of this proceeding, and the potential impact it may have in establishing a precedent for our pending four Complaints.

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 $1.3 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 $1.3 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 and CFTC hold substantial enforcement authority, including the ability to assess civil penalties of up to $1.3 million per day per violation, to order disgorgement of profits and to recommend criminal penalties.

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. 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 is being 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.

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 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.

The following provides a summary of Networks regulated utilities' most recent rate cases:

- *New York*. On June 15, 2016, the NYPSC approved NYSEG's and RG&E's 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. For more information on rate case activity in New York, 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.

  The NYSEG and RG&E 2016 three-year rate plan ended in April 2019, and the existing customer rates at that time were continued, along with other rate plan provisions, pending new rates being established as a result of a new rate case. On May 20, 2019, the companies file rated cases in New York for new tariffs effective in the second quarter of 2020. The proposed rates facilitate the companies' transition to a cleaner energy future while allowing for important initiatives such as vegetation management, hardening/resiliency and emergency preparedness. The companies entered into ongoing settlement discussions with the staff and other parties in October 2019. On February 26, 2020, the companies filed notice with the NYPSC that an agreement in principle has been reached among the companies, the NYDPS staff and certain other parties to the matter. As a result, drafting of a joint proposal (settlement agreement) has commenced.

- *Maine*. On May 1, 2013, CMP filed a distribution service rate case in order to recover past and future investments and provide safe and adequate service. On August 25, 2014, MPUC approved a stipulation agreement that provided for a distribution rate increase of approximately $24.3 million, effective July 1, 2014, with an allowed ROE of 9.45% and an allowed equity ratio of 50%. The stipulation provided for the implementation of a revenue decoupling mechanism, or RDM, reserve accounting and sharing of incremental storm costs, a separate proceeding for recovery of a new billing system and no earnings sharing. On March 1, 2018, the MPUC issued a Notice of Investigation initiating a summary investigation into CMP's metering, billing and customer communications practices. Due to the highly technical nature of CMP's customer billing system, on March 22, 2018 the MPUC issued an Order Initiating Audit commencing a forensic audit of CMP’s customer billing system to identify any errors that have, or continue to result in billing inaccuracies. On July 10, 2018, the MPUC issued an Order Modifying Scope of Audit, which expanded the scope of the audit to include the customer communication practices that were originally identified in the Commission’s Notice of Investigation. On May 29, 2018, a ten-person complaint was filed with the MPUC against CMP, Networks and AVANGRID. The complaint requested that the MPUC open a rate case to determine if CMP is making excessive returns on investment and, therefore, whether CMP’s retail rates should be lower. The complaint also requested the MPUC deny certain costs associated with the October 2017 windstorm. On July 24, 2018, the MPUC issued an order dismissing the complaint and its associated request to deny the recovery of costs associated with the October 2017 windstorm. The order initiated an investigation into CMP’s rates and revenue requirement and directed CMP to make a filing consistent with the requirements for a general rate case no later than October 15, 2018. Consistent with the order in the ten-person complaint proceeding, on August 7, 2018, the MPUC issued a Notice of Investigation, opening the proceeding in which CMP would make its rate case filing and through which the MPUC will examine the rates and revenue requirements of CMP.

On October 15, 2018, CMP filed a general rate case as directed by the MPUC requesting a ROE of 10% and an equity ratio of 55%. CMP’s general rate case filing included a proposal to enhance the resiliency of the energy grid by expanding vegetation management and pursuing additional reliability measures such as pole replacements and addition of tree wire in selected areas. Such investments are designed to strengthen CMP’s power grid so it can better stand up to severe weather. CMP planned to use savings from the Tax Act to pay for the costs of resiliency programs, other investments in infrastructure and certain cost increases since 2014.

On December 20, 2018, the MPUC released the findings of the forensic audit of CMP’s customer billing system and customer communication practices. On January 14, 2019, the MPUC issued an Order and Notice of Investigation initiating an investigation of CMP’s metering and billing practices and initiating a separate investigation of the audit of CMP’s customer service and communication practices and incorporating such investigation into the general rate case. The Maine Office of Public Advocate, or OPA, for utility issues filed a motion to delay CMP's rate order decision to allow incorporation of the results of the separate metering and billing investigation. CMP did not oppose this motion.

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%, based on an allowed ROE of 9.25% and a 50% equity ratio. The rate increase is 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 will remain in effect until CMP has demonstrated satisfactory customer service performance on four specified service quality measures for a period of 18 consecutive months with measurement commencing on March 1, 2020. The order provides 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 retains the revenue decoupling mechanism implemented in 2014. The order denies CMP’s request to increase rates for higher costs associated with services provided by its affiliates and will instead initiate a management audit to assess the quality of these services as well as the impacts of the AVANGRID management structure on the quality of CMP’s customer service.

On March 5, 2015, MNG filed a rate case in order to further recover future investments and provide safe and adequate service. On May 3, 2016, all active parties to the case filed a stipulation that settled all matters at issue in the case and reflected a 10-year rate plan through April 30, 2026. The MPUC approved the stipulation on May 17, 2016, for new rates effective June 1, 2016. The settlement structure for non-Augusta customers includes a 34.6% delivery revenue increase over five years with an allowed 9.55% ROE and 50% 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 that 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. A disallowance for the initial 2012/2013 gross plant investment is not part of the approved stipulation.

- *Connecticut*. In December 2016, PURA approved distribution rate schedules for UI for three years with rate increases of $43 million, $13 million and $3 million in 2017, 2018 and 2019, respectively, based on an ROE of 9.10% and a 50% equity ratio. The new rate schedules 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 a requested storm reserve. Any dollars due to customers from the ESM continue to be first applied against any storm regulatory asset balance (if one exists at that time) or refunded to customers through a bill credit if such storm regulatory asset balance does not exist.

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

In December, 2018, PURA approved new tariffs for CNG effective January 1, 2019 for a three-year rate plan with rate increases of $9.9 million, $4.6 million and $5.2 million in 2019, 2020 and 2021, respectively. The new tariffs continued the RDM and DIMP mechanism, ESM and tariff increases based on an ROE of 9.30% and an equity ratio of 54% in 2019, 54.50% in 2020, and 55% in 2021.

For more information on rate case activity in Connecticut, 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.

- *Massachusetts*. On January 18, 2019, the DPU approved a settlement agreement between BGC and the Massachusetts Attorney General's Office providing for new distribution rates for BGC. The settlement agreement provides for a $1.6 million distribution base rate increase effective February 1, 2019 (with a make-whole provision back to January 1, 2019), and an additional $0.7 million base distribution increase effective November 1, 2019, if certain investments are made by BGC. The distribution rate increase is based on a 9.70% ROE and 54% equity ratio. The settlement agreement provides for the implementation of an RDM and pension expense tracker and also provides that BGC will not file to change base distribution rates to become effective before November 1, 2021.

In addition, 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.

In April 2014, the NYPSC instituted its Reforming the Energy Vision, or REV, proceeding, the goals of which are to improve electric system efficiency and reliability, encourage renewable energy resources, support DER, and empower customer choice. Within REV and its related proceedings, the NYPSC is moving toward the establishment of a Distributed System Platform, or DSP, to manage and coordinate DER, and to provide customers with market data and tools to manage their energy use. The NYPSC has determined distribution utilities should be the DSP providers. The NYPSC also is examining how its regulatory practices should be modified to incent utility practices to promote REV objectives. The REV-related proceedings involve a two-phased schedule with an initial order relating to policy determinations for DSP and related matters issued in February 2015 and an initial order for regulatory design and regulatory matters issued in May 2016. All electric utilities were ordered to file an initial Distributed System Implementation Plan, or DSIP, by June 30, 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 December 2016 that was never acted upon. NYSEG and RG&E filed a new AMI request in their 2019 rate case filings.

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 earnings adjustment mechanism, or 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. In July 2018, NYSEG and RG&E submitted an updated DSIP plan consistent with guidance received from the NY Department of Public Service. 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. Phase Two of the Value of DER proceeding was established, and several working group sessions occurred between the latter half of 2017 and all of 2018, primarily addressing issues pertaining to compensation for DER and rate design. 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. The NYPSC also issued an order on value stack compensation for high-capacity-factor resources on December 12, 2019.

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.

Tax Cuts and Jobs Act

On December 22, 2017, the Tax Act was signed into law. The Tax Act significantly changed the federal taxation of business entities including, among other things, implementing a federal corporate tax rate decrease from 35% to 21% for tax years beginning after December 31, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates will result in amounts previously and currently collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates. The Networks utilities have adjusted rates to reflect the lower federal tax rates in effect, and our rate case filings in New York and Maine include proposals for the return of excess deferred taxes to customers. For more information on the Tax Act proceedings, 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.

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.

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

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 by-passable federally mandated congestion charges for all customers to recover the net costs of the PPAs.

On December 28, 2018, DEEP issued a directive to UI to negotiate and enter into PPAs with 12 projects, totaling approximately 12 million MWh, which were selected as a result of the Zero Carbon RFP issued by DEEP pursuant to PA 17-3, which provides that the net costs of the PPAs are recoverable through electric rates. One of the selected projects is the Millstone nuclear facility located in Waterford, Connecticut and owned by Dominion Energy, Inc. 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 remaining PPA has been executed and submitted for approval to PURA.

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 two thousand (2,000) MW in the aggregate. On December 5, 2019, DEEP announced that it had selected Vineyard Wind ("Vineyard"), an affiliate of UI, to provide 804 MW of offshore wind through the development of its Park City Wind Project. DEEP also ordered Eversource and UI to negotiate PPAs with Vineyard. Similar to the case with the zero carbon PPAs discussed above, the net costs of the PPAs are recoverable through electric rates.

Under Maine law 35-A M.R.S.A §§ 3210-C, 3210-D, 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 in Penobscot County, Maine. CMP's purchase obligations under the Rollins contract are approximately $7 million per year. Pursuant to a MPUC Order dated December 18, 2017, CMP entered into a 20-year agreement with Dirigo Solar, LLC on September 10, 2018, to purchase capacity and energy from multiple Dirigo solar facilities throughout CMP's service territory. CMP's purchase obligations under the Dirigo contract will increase as additional solar facilities are brought on line, eventually reaching a level of approximately $4 million per year. Pursuant to a MPUC Order dated November 6, 2019, CMP entered into a 20-year agreement with Maine Aqua Ventus I GP LLC on December 9, 2019, to purchase capacity and energy from an off-shore wind 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. In accordance with MPUC orders, CMP either sells the purchased energy from these facilities in the ISO New England markets or periodically auctions the purchased output to wholesale buyers in the New England regional market. Under applicable law, CMP is assured recovery of any differences between power purchase costs and achieved market revenues through a reconcilable component of its retail distribution rates. Although the MPUC has conducted multiple requests for proposals under M.R.S.A §3210-C and has tentatively accepted long-term proposals from other sellers, these selections have not yet resulted in additional currently effective contracts with CMP.

Environmental, Health and Safety

Permitting and Other Regulatory Requirements

Networks. Similar to Renewables, Networks' distribution utilities in New York, Maine, Connecticut and Massachusetts are subject to various 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 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.

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

Renewables. Renewables' projects are subject to a variety of state environmental review and permitting requirements. Many states where Renewables' projects are located, or may be located in the future, have laws that require state agencies to evaluate a broad array of environmental impacts before granting state permits. Generally, state agencies evaluate similar issues as federal agencies, including the project's impact on wildlife, historic 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 requirements 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 demonstrates 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 arising under federal law. For example, if a project is located near wetlands, a permit may be required from the U.S. Army Corps of Engineers, or 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. In addition, 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, even for incidental takings of migratory birds. 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 established by the U.S. Fish and Wildlife Service 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.

Global Climate Change and Greenhouse Gas Emission Issues

Global climate change and greenhouse gas emission 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 expect that any costs of these rules, regulations and requirements would be recovered from customers.

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.

On September 16, 2015, UI signed a partial consent order that was then issued by DEEP in August 2016 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.

Cyber Security

The Company promotes a strong culture of cyber security and safe use of the information and communications systems and other cyber assets in order to detect, prevent, defend and respond to cyber-attacks or cyber-incidents. The implementation of a robust cyber security program over the years includes the creation of a Cyber-Security Committee, the approval of new policies and procedures, training and awareness programs, tools, systems and dedicated teams.

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 states 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 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. Approximately 69% of Renewables' wind generating capacity is fully committed under PPAs as of December 31, 2019, with an average duration of 9.5 years. 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, demand 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.

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. Networks has experienced significant growth in alternative distribution sources of generation on its network over the past ten years, with approximately 90% of the growth coming from solar photovoltaic facilities.

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 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 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, 2019. 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—1983
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, 2019.

Utility	State	Substations	Transmission Lines (in miles)	Overhead Distribution Lines (in pole miles)	Underground Lines (in miles)	Total Distribution (in miles)	Electricity Customers
NYSEG	New York	429	4,548	32,223	2,911	35,134	902,593
RG&E	New York	155	1,095	5,940	2,935	8,875	383,592
CMP	Maine	207	2,921	21,803	1,545	23,348	636,341
UI	Connecticut	28	139	2,893	745	3,638	338,654

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, 2019:

Utility	State	Natural Gas Customers	Transmission Pipeline (in miles)	Distribution Pipeline (in miles)
NYSEG	New York	268,806	20	8,382
RG&E	New York	317,661	105	8,999
MNG	Maine	4,974	2	216
SCG	Connecticut	203,269	—	2,472
CNG	Connecticut	181,527	—	2,185
BGC	Massachusetts	40,500	—	764

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, 2019. 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	2003	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	2017	WECC
Colorado	Colorado Green	108 (GE, 1.5 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	17 (Vestas, 3.8 MW); 4 (Vestas, 3.5 MW)	78	2020	MRO
Iowa	Barton	80 (Gamesa, 2.0 MW)	160	2009	MRO
	Flying Cloud	29 (GE, 1.5 MW)	44	2004	MRO
	New Harvest	50 (Gamesa G87, 2.0W)	100	2012	MRO

Location	Wind Project	Turbines	Total Installed Capacity (MW)	Commercial Operation Date	North American Electric Reliability Corporation (NERC) Region
	Top of Iowa II	40 (Gamesa G87, 2.0 MW)	80	2008	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 MW)	101	2005	MRO
Missouri	Farmers City	73 (Gamesa G87, 2.0 MW)	146	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
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
North Carolina	Desert Wind	104 (Gamesa G114, 2.0 MW)	208	2016	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 S – 1.5 MW)	75	2005	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
Pennsylvania	Casselman	23 (GE, 1.5 MW)	35	2008	RFC
	Locust Ridge I	13 (Gamesa G87, 2.0)	26	2006	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); 8 (GE, 2.3 MW)	20	2019	MRO
Texas	Baffin	101 (Gamesa G97, 2.0 MW)	202	2015	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
	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

Location	Wind Project	Turbines	Total Installed Capacity (MW)	Commercial Operation Date	North American Electric Reliability Corporation (NERC) Region
	Big Horn II	25 (Gamesa, 2.0 MW)	50	2010	WECC
	Juniper Canyon	63 (Mitsubishi, 2.4 MW)	151	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, 2019. Unless otherwise noted, Renewables owns each such facility.

Facility	Location	Type of Facility	Installed Capacity (MW)	Commercial Operation Date
Poseidon Solar(1)	Pinal County, Arizona	Solar	10	2011
San Luis Valley Solar Ranch(2)	Alamosa County, Colorado	Solar	30	2012
Gala Solar	Deschutes County, Oregon	Solar	56	2017
Wy'East Solar	Sherman County, Oregon	Solar	10	2018
Klamath Cogeneration	Klamath Falls, Oregon	Thermal	536	2001
Klamath Peakers	Klamath Falls, Oregon	Thermal	100	2009

(1) Formerly Copper Crossing Solar Ranch. The name change occurred as part of our sale of a 50% interest in this project in 2019. See Note 22 to the financial statements in Part II, Item 8 of this form 10-K for more information on the sale. Capacity represents the 50% portion owned by Renewables.
(2) Operated pursuant to a sale-and-leaseback agreement.

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 and the release of critical operating information. In addition to physical security intrusions, a cyber breach could potentially lead to theft 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 an effort to reduce our vulnerability to cyber attacks, the AVANGRID board appointed a senior officer responsible for security (chief security officer) and we have established a dedicated corporate security office, responsible for improving and coordinating security and NERC compliance across the company. 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.

Employees

As of December 31, 2019, we had 6,597 employees excluding twelve international assignees. Of these 6,597 employees, 49.0% are represented by a union. The following table provides an overview of the number of employees at each business segment as of December 31, 2019:

Business Segment	Number of Employees (excluding International Assignees)	% of Union Workforce Subject to Collective Bargaining Agreement
Networks	5,375	60.2%
Renewables	871	—
Corporate	351	—
Total	6,597	49.0%

We have not experienced any work stoppages in the last five years and enjoy good relations with our labor unions. Virtually all of our employees work full-time.

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.

Item 1A. Risk Factors

Risks Relating to Our Regulatory Environment

Our businesses are subject to substantial regulation by federal, state and local regulatory agencies and our businesses, results of operations and prospects may be materially 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 our businesses 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, portions of which are more specifically identified in the following risk factors, regulates, among other things and to varying degrees, the industries in which our subsidiaries operate, our business segments, rates for our products and services, financings, capital structures, cost structures, construction, environmental obligations (including in respect of, among others, air emissions, water consumption, water discharge, protections for wildlife and humans, nuisance prohibitions and allowances, regulation of gas infrastructure operations and associated environmental and facility permitting), development and operation of electric generation facilities and electric and gas transmission and distribution facilities, natural gas transportation, processing and storage facilities, acquisition, disposal, depreciation and amortization of facilities and other assets, service reliability, hedging, derivatives transactions and commodities trading.

In our business planning and in the management of our subsidiaries' operations, we must address the effects of regulation on our businesses, including the significant and increasing compliance costs imposed on our operations as a result of such regulation, and any inability or failure to do so timely and adequately could have a material adverse effect on our businesses, results of operations, financial condition and cash flows. 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 our businesses. These decisions may require, for example, our businesses to cancel or delay planned development activities, to reduce or delay other planned capital expenditures or investments or otherwise incur costs that we may not be able to recover through rates, any of which could have a material adverse effect on the business, results of operations, financial condition and cash flows of our businesses. In addition, changes in the nature of the regulation of our business could have a material adverse effect on our business, results of operations, financial condition and cash flows. 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 changes, although any such changes, initiatives or interpretations may increase costs and competitive pressures on us, which could have a material adverse effect on our business, results of operations, financial condition and cash flows. There can be no assurance that we will be able to respond adequately or sufficiently quickly to such rules and developments, or to any other changes that reverse or restrict the competitive restructuring of the energy industry in those jurisdictions in which such restructuring has occurred. Any of these events could have a material adverse effect on our business, results of operations, financial condition and cash flows.

Our businesses are subject to the jurisdiction of various federal, state and local regulatory agencies including, but not limited to, the FERC, the CFTC, the DOE and the EPA. Further, Networks' regulated utilities in New York, Maine, Connecticut and Massachusetts 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, capacity and ancillary services, and for the transmission and distribution of these products, the costs charged to Networks' customers through tariffs including cost recovery clauses, the terms and conditions of Networks' services, procurement of electricity for Networks' customers, issuances of securities, the provision of services by affiliates and the allocation of those service costs, certain accounting matters, and certain aspects of the siting, construction and transmission and distribution systems. The FERC has the authority to impose penalties, which could be substantial, for violations of the FPA, the NGA, or related rules, including reliability and cyber security rules as described in further detail below. The Financial Accounting Standards Board, or FASB, or the SEC, may enact new accounting standards that could impact the way we are required to record revenue, expenses, assets and liabilities. 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 our businesses are permitted to earn on invested capital.

The regulatory process, which may be adversely affected by the political, regulatory and economic environment in New York, Maine, Connecticut and Massachusetts, as applicable, may limit our ability to increase earnings and does not provide any assurance as to 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 business, results of operation, financial condition and cash flows. Certain of these regulatory agencies also have the authority to audit the management and operations of our businesses in New York, Maine, Connecticut and Massachusetts and require or recommend operational changes. 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.

As previously described, we are subject to a variety of federal, state, local laws and regulations. The introduction of new laws or regulations or changes in existing laws or regulations, or the interpretation thereof, may alter the environment in which we do business and could increase the costs of doing business for us or restrict our actions and adversely affect our financial condition, operating results and cash flows.

Any failure to meet the reliability standards mandated by NERC could have a material adverse effect on our business, results of operation, financial condition and cash flows.

As a result of the EPAct 2005, owners, operators and users of bulk electric systems are subject to mandatory reliability standards developed by NERC and are subject to oversight by the FERC in the U.S. and governmental authorities in Canada. The standards are based on the functions that need to be performed to ensure that the bulk electric system operates reliably. Networks' and Renewables' businesses have been, and will continue to be, subject to routine audits and monitoring with respect to compliance with applicable NERC reliability standards, including standards approved by the FERC that could result in an increase in the number of assets (including cyber-security assets) designated as "BES Cyber Systems," which would subject such assets to NERC cyber-security standards. The implementation of the Balancing Authority registration for the Northwest Renewable assets in 2018 has brought increased NERC compliance requirements and additional compliance risks including increase in assets, budgets and experienced resources. This registration as a Balancing Authority also changes the NERC audit cycle from six years down to three years for Renewables. NERC and the FERC can be expected to continue to refine existing reliability standards as well as develop and adopt new reliability standards. Compliance with modified or new reliability standards may subject Networks' and/or Renewables' businesses to new requirements resulting in higher operating costs and/or increased capital expenditures. If Networks' and/or Renewables' businesses were found not to be in compliance with the mandatory reliability standards, it could be subject to penalties of up to $1.3 million per day per violation. Both the costs of regulatory compliance and the costs that may be imposed as a result of any actual or alleged compliance failures could have a material adverse effect on our business, results of operation, financial condition, reputation and prospects. AVANGRID will be subject to NERC audits for Renewables in February 2020 and for NYSEG in June 2020. Both audits will include operations and planning standards (including Balancing Authority standards for Renewables) and critical infrastructure protection standards.

The NYPSC has initiated a proceeding that may result in the alteration of the public utility model in New York State and could materially and adversely impact our business and operations in New York State.

In April 2014, the NYPSC commenced a proceeding titled REV, which is an initiative to reform New York State's energy industry and regulatory practices. REV has followed several simultaneous paths, including a formal Track 1 dealing with market design and platform technology and Track 2 dealing with regulatory reform. REV's objectives include the promotion of more efficient use of energy, increased utilization of renewable energy resources such as wind and solar in support of New York State's renewable energy goals and wider deployment of "distributed" energy resources, such as micro grids, on-site power supplies, and storage. Track 1 of the REV initiative involves the examination of the role that distribution utilities will have in the enablement of market-based deployment of DER to promote load management, system efficiency and peak load reductions. NYSEG and RG&E are participating in all aspects of the REV initiative with other New York utilities as well as providing their unique perspective.

Various other REV-related proceedings have also been initiated by the NYPSC, each of which is following its own schedule. These proceedings include the Clean Energy Fund, Demand Response Tariffs, Community Choice Aggregation, Large Scale Renewables and Community Distributed Generation.

Track 2 of the REV initiative is also underway, and through a NYPSC Staff Whitepaper review process, is examining potential changes in current regulatory, tariff, market design and incentive structures which could better align utility interests with achieving New York State and NYPSC 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 EAMs, platform service revenues, innovative rate designs and data utilization and security. NYSEG and RG&E continue to engage through a number of working groups that have been established to assist the implementation of the DSIP items and delivering the Value of DER/Net Metering changes.

We are not able to predict the outcome of the REV proceeding or its impact on our business, results of operations, financial condition and cash flows. While the end result of the REV process at the NYPSC remains unclear, it could alter the utility model in New York in a manner that could create material adverse impacts on our businesses and operations in New York.

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. As new investment in regional transmission infrastructure occurs in any one state, its cost is shared across New England in accordance with a FERC-approved formula found in the transmission tariff. Participating New England transmission owners' agreement to this regional cost allocation is set forth in the transmission operating agreement. This agreement can be modified with the approval of a majority of the transmission-owning utilities and approval by the FERC. In addition, other parties, such as state regulators, may seek certain changes to the regional cost allocation formula, which could have adverse effects on the rates Networks' distribution companies in New England charge their retail customers. The FERC has found that the New England rate protocols lacked transparency and have established a hearing and settlement procedures. We cannot predict the outcome of this proceeding.

The FERC has issued rules requiring all RTOs and transmission owning utilities to make compliance changes to their tariffs and contracts in order to further encourage the construction of transmission for generation, including renewable generation. This compliance will require RTOs (such as ISO-NE and NYISO) and the transmission owners in New England and New York to develop methodologies that allow for regional planning and cost allocation for transmission projects chosen in the regional plan that are designed to meet public policy goals such as reducing greenhouse gas emissions or encouraging renewable generation. Such compliance may also allow non-incumbent utilities and other entities to participate in the planning and construction of new projects in Networks' service areas and regionally.

Changes in RTO tariffs, transmission owners' agreements or legislative policy, or implementation of these new FERC planning rules, could adversely affect our transmission planning, results of operations, financial condition and cash flows.

We are subject to numerous environmental laws, regulations and other standards, including rules and regulations with respect to climate change, which could result in capital expenditures, increased operating costs and various liabilities, and could require us to cancel or delay planned projects or limit or eliminate certain operations.

Our businesses are 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 (including, but not limited to carbon dioxide), waste management, hazardous wastes (including the clean-up of former manufactured gas and electric generation facilities), marine, avian and other wildlife mortality and habitat protection, historical artifact preservation, natural resources and health and safety (including, but not limited to, electric and magnetic fields from power lines and substations, and ice throw, shadow flicker and noise related to wind turbines) 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 capital, operating and other 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. For example, new laws, regulations or treaties relating to climate change could mandate new or increased requirements to control or reduce the emission of greenhouse gases, such as carbon dioxide, taxes or fees on fossil fuels or emissions, cap and trade programs, emission limits and clean or renewable energy standards or mandates that require curtailment of operations for certain periods of time due to potential electromagnetic interference. 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, which could have an adverse effect on our operations, financial condition and cash flows.

Our 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 in New York, Maine, Connecticut and Massachusetts are subject to periodic review of their rates by the NYPSC, MPUC, PURA and DPU, respectively, and the retail rates charged to our regulated utilities' customers through base rates and cost recovery clauses are subject to the jurisdiction of the NYPSC, MPUC, PURA and DPU, as applicable. New rates may be proposed by Network's businesses, which are then subject to review, modification and final authorization and implementation by regulators. Alternatively, regulators may review the rates of Networks' regulated utilities on their own motion. Networks' regulated utilities' rate plans cover specified periods, but rates determined pursuant to a plan generally continue in effect until a new rate plan is approved by the state utility regulator. 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 (ROE). Actual costs may increase due to inflation 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 (including energy costs) that the regulators determine to have been imprudently incurred. Networks' regulated utilities defer for future recovery certain costs including major storm costs and environmental costs. In a number of proceedings in recent years, Networks' regulated subsidiaries have been denied recovery, 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 cash flows, results of operations and financial condition, and our ability to earn a return on investment and meet financial obligations, could be adversely affected.

Current electric and gas rate plans of Networks' regulated utilities include 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 remain part of the rate plan of Networks in future rate proceedings.

In addition, 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 by the FERC to receive for wholesale transmission service pursuant to the ISO-NE Open Access Transmission Tariff. Reductions to ROE adversely impact the revenues that Networks' regulated utilities receive from wholesale transmission customers and could have a material adverse effect on our business, results of operations, financial condition and cash flows.

Harming of protected species can result in curtailment of wind project operations and could have a material adverse effect on our business, results of operation, financial condition and cash flows.

The operation of energy projects and transmission of energy can adversely affect endangered, threatened or otherwise protected animal species under federal and state statutes, laws, rules and regulations. Wind projects involve a risk that protected flying species, such as birds and bats, will be harmed due to collision. Transmission and distribution lines are another source of potential avian collision as well as electrocution. Energy generation and transmission facilities can result in impacts to protected wildlife, including death caused by collision, electrocution and poisoning. Energy infrastructure occasionally affects endangered or protected species. Our businesses observe industry guidelines and government-recommended best practices to avoid, minimize and mitigate harm to protected species, but complete avoidance is not possible and subsequent penalties may result. Where appropriate, our businesses can apply for an "incidental take" permit for some protected species, which may be conditioned upon the institution of costly avoidance and remediation measures.

Violations of wildlife protection laws in certain jurisdictions may result in civil or criminal penalties, including violations of certain laws protecting migratory birds, endangered species and eagles. The ESA and analogous state laws restrict activities without a permit that may adversely affect endangered and threatened species or their habitat. The ESA also provides for private causes of action against a development project, an operating facility, or the agency that oversees the alleged violation of law. Complying with the state and federal laws protecting migratory birds, endangered species and eagles may require implementation of operating restrictions or a temporary, seasonal, or permanent ban on operations in affected areas, which can have a material adverse effect on the revenue of those projects. For example, there have been recent sightings of the protected California condor at Renewables' Manzana wind facility. Any incidental taking of a California condor could result in substantial financial, legal and reputational harm to us.

Renewables relies in part on governmental policies that support utility-scale renewable energy. Any reductions to, or the elimination of, governmental mandates and incentives that support utility-scale renewable energy or the imposition of additional taxes or other assessments on renewable energy, could result in a material adverse effect on our business, results of operations, financial condition and cash flows.

Renewables relies, in part, upon government policies that support utility-scale renewable energy projects and enhance the economic feasibility of developing and operating wind energy projects in regions in which Renewables operates or plans to develop and operate renewable energy facilities. The federal government and many state and local jurisdictions have policies or other mechanisms, such as tax incentives or renewable portfolio standards, or RPS, that support the sale of energy from utility-scale renewable energy facilities, such as wind -energy facilities. As a result of budgetary constraints, political factors or otherwise, federal, state and local governments from time to time may review their policies and other mechanisms that support renewable energy and consider 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 the development of new renewable energy projects, Renewables abandoning the development of new renewable energy projects, a loss of Renewables' investments in the projects and reduced project returns, any of which could have a material adverse effect on our business, results of operations, financial condition and cash flows.

Our businesses may face risks related to obtaining governmental approvals and permits in respect of project siting, financing, construction, operation and the negotiation of project development agreements which could delay a project and result in a material adverse effect on our business, results of operations, financial condition and cash flows.

Renewables owns, develops, constructs and/or operates electricity generation, including renewable and thermal generators, and associated transmission facilities. Networks develops, constructs, manages and operates transmission and distribution facilities to meet customer needs. As part of these operations, our businesses must periodically apply for licenses and permits from various local, state, federal and other regulatory authorities and abide by their respective conditions. In particular, with respect to Renewables, over the past years noise standards and siting criteria in the Northeast, where population density is higher compared to the Northwest, where Renewables also operates, have grown more restrictive. Federal and state siting legislation has increased its focus on potential conflicts with military installations. Offshore wind also incorporates a new and more complex permitting process and has higher development costs. If our businesses are unsuccessful in obtaining necessary licenses or permits on acceptable terms, there is a delay in obtaining or renewing necessary licenses or permits or regulatory authorities initiate any associated investigations or enforcement actions or impose related penalties or disallowances on us, they individually or in the aggregate could have a material adverse effect on our businesses, results of operations, financial condition and cash flows.

Our 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, results of operations, financial condition and cash flows.

Under the EPAct 2005 and the Dodd-Frank Act, our businesses are subject to enhanced FERC and CFTC statutory authority to monitor certain segments of the physical and financial energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of the electricity and gas markets. Under these laws, the FERC and CFTC have promulgated regulations that have increased compliance costs and imposed reporting requirements on our businesses. 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 a material 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 observe the market-related regulations and certain reporting and other requirements enforced by the FERC, the CFTC and the SEC. Additionally, to the extent that the 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. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations, financial condition and cash flows.

Renewables' ability to generate revenue from certain utility-scale wind energy power plants depends on having continuing interconnection arrangements, PPAs, or other market mechanisms and depends upon interconnecting utility and RTO rules, policies, procedures and FERC tariffs that do not present restrictions to current and future wind project operations.

The electric generation facilities owned by Renewables rely on interconnection and/or transmission agreements and transmission networks in order to sell the energy generated by such facility. If the interconnection and/or transmission agreement of an electric generating facility Renewables owns is terminated for any reason, Renewables may not be able to replace it with an interconnection or transmission arrangement on terms as favorable as the existing arrangement, or at all, or it may experience significant delays or costs in securing a replacement. If a transmission network to which one or more of Renewables' electric generating facilities is connected experiences outages or curtailments, the affected projects may lose revenue. These factors could materially affect Renewables' ability to forecast operations and negatively affect our business, results of operations, financial condition and cash flows. In addition, certain of Renewables' operating facilities' generation of electricity may be physically or economically curtailed, and off-takers or transmission or interconnection providers may be permitted to restrict wind project operations without paying full compensation to Renewables pursuant to PPAs or interconnection agreements or FERC tariff provisions or rules, policies or procedures of RTOs, which may reduce our revenues and impair our ability to capitalize fully on a particular facility's generating potential. Such curtailments or operational limitations could have a material adverse effect on our business, financial condition, results of operations and cash flows. 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 wind projects either not participate in the energy markets or bid and clear at negative prices which may require the wind 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 wind projects are required to pay money to operate in any given hour when prices are negative, then our financial results could be adversely affected.

New Tariffs imposed on imported goods may increase the capital expense in projects and have a negative impact on 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. Additional tariffs for wind towers are under consideration by the Federal Government. Trade disputes between the U.S. and other countries may result in additional tariffs or changes in existing ones. 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.

Risks Relating to Our Business and Operations

Disruptions, uncertainty or volatility in the credit and capital markets may negatively affect our liquidity and capital needs and our ability to meet our growth objectives and can also materially adversely affect our results of operations and financial condition.

A crisis affecting the banking system or the financial markets including severe volatility in stock and bond markets or the markets reliant on using the London Interbank Offer Rate, or LIBOR, as the basis for interest rate calculations could impact our financial operating conditions, our day-to-day activities, our liquidity and cash positions, the loss of significant investment opportunities, the value of our business and our financial condition. In addition, during periods of slow or little economic growth, energy conservation efforts often increase as well as the amount of uncollectible customer accounts often increase. These factors may also reduce earnings and cash flow.

Increases in interest rates or reductions in credit ratings could have an adverse impact on our cash flows, results of operations and financial condition.

Trends in the general level of interest rates and in the debt capital and credit markets could increase the cost of our borrowings and our ability to access the credit markets. We have floating rate exposure under our commercial paper program, our credit facilities and our term loan that closely tracks movements in LIBOR. LIBOR is the subject of recent national, international and other regulatory guidance and proposals for reform. These reforms and other pressures may cause LIBOR to be discontinued or to perform differently than in the past. The consequences of these developments cannot be entirely predicted, but could include fluctuations in interest rates or an increase in the cost of credit facility borrowings. The cost of new long-term debt can be affected by the level of U.S. treasury rates and conditions in the debt capital markets that affect credit spreads.

In addition, AVANGRID and certain of its subsidiaries have credit ratings which directly affect the cost of maintaining and borrowing under revolving credit facilities and which indirectly affect the cost of borrowing under our commercial paper program and the cost of new long-term debt raised in the debt capital markets. In addition, we intend to access the capital markets and issue securities from time to time, and a decrease in credit ratings or outlook could adversely affect our liquidity, increase borrowing costs and decrease demand for our debt or equity securities and increase the expense and difficulty of financing our operations and investments. Lower credit ratings could increase the cost of debt and equity capital and, depending on the rating and market conditions, preclude access to the debt and equity capital markets. Any of these events could have a materially adverse effect on our business, results of operations, financial condition and cash flows.

If Networks' electricity and natural gas transmission, transportation and distribution systems do not operate as expected, they could require unplanned expenditures, including the maintenance and refurbishment of Networks' facilities, which could adversely affect our business, results of operations, financial position and cash flows.

Networks' ability to operate its electricity and natural gas transmission, transportation and distribution systems is critical to the financial performance of our business. 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. These and other occurrences could reduce potential earnings and cash flows and increase the costs of repairs and replacement of assets. Losses incurred by Networks in respect of such occurrences may not be fully recoverable through insurance or customer rates. Further, certain of Networks' facilities require periodic upgrading and improvement.

In addition, unplanned outages typically increase Networks' operation and maintenance expenses. 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 replacement or spare parts could result in reduced profitability, harm to our reputation or regulatory penalties. For more information, see "*Risks Relating to Our Regulatory Environment*" above.

Our businesses' operations and power production may fall below expectations due to the impact of severe weather or other natural events, which could adversely affect our cash flows, results of operations and financial position.

Weather conditions directly influence the demand for electricity and natural gas and other fuels and affect the price of energy and energy-related commodities. Severe weather, such as ice and snow storms, hurricanes and other natural disasters, such as floods, fires and earthquakes, can be destructive and cause power outages, bodily injury and property damage or affect the availability of fuel and water, which may require additional costs or loss of revenues, for example, the costs incurred to restore service and repair damaged facilities, to obtain replacement power and to access available financing sources, may not be recoverable from customers and could adversely affect our cash flows, results of operations and financial position. Also, these events may impact reliability metrics subject to negative rate adjustments or penalties. Many of our facilities could be placed at greater risk of damage should changes in the global climate produce unusual variations in temperature and weather patterns, resulting in more intense, frequent and extreme weather events, abnormal levels of precipitation, wildfires and a change in sea level. A disruption or failure of electric generation, transmission or distribution systems or natural gas production, transmission, transportation, storage or distribution systems in the event of ice and snow storms, long periods of severe weather, hurricane, tornado or other severe weather event, or otherwise, could prevent us from operating our business in the normal course and could result in any of the adverse consequences described above. Because utility companies, including our regulated utilities, have large customer bases, they 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.

Furthermore, Renewables can incur damage to wind turbine equipment, either through natural events such as lightning strikes that damage blades or in-ground electrical systems used to collect electricity from turbines, 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. Many of the operating facilities of Networks are located either in, or close to, densely populated public places. A failure of, or damage to, these facilities, could result in bodily injury or death, property damage, the release of hazardous substances, extended service interruptions and loss of revenues. The cost of repairing damage to Networks' facilities and the potential disruption of their operations due to storms, natural disasters or other catastrophic events could be substantial. In respect of our businesses where cost recovery is available, recovery of costs to restore service and repair damaged facilities is or may be subject to regulatory approval, and any determination by the regulator not to permit timely and full recovery of the costs incurred could have a material adverse effect on our business, results of operations, financial condition and cash flows.

If wind conditions are unfavorable or below Renewables' production forecasts, or Renewables' wind turbines are not available for operation, Renewables projects' electricity generation and the revenue generated from its projects may be substantially below our expectations.

Changing wind patterns or lower than expected wind resource could cause reductions in electricity generation at Renewables' projects, which could affect the revenues produced by these wind generating facilities. Renewables' wind projects are sited, developed and operated to maximize wind performance. Prior to siting a wind facility, detailed studies are conducted to measure the wind resource in order to estimate future production. However, wind patterns or wind resource in the future might deviate from historical patterns and are difficult to predict. These events could negatively impact the results of operations of Renewables, which may vary 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 wind patterns or lower than expected wind resources could also degrade equipment or components and the interconnection and transmission facilities' lives or maintenance costs. Replacement and spare parts for wind turbines and key pieces of electrical equipment may be difficult or costly to acquire or may be unavailable. The loss of any suppliers or service providers or inability to find replacement suppliers or service providers or to purchase turbines at rates currently offered by Renewables' existing suppliers or a change in the terms of Renewables' supply or operations and maintenance agreements, such as increased prices for maintenance services or for spare parts, could have a material adverse effect on Renewables' ability to construct and maintain wind farms or the profitability of wind farm development and operation.

The revenues generated by Renewables' facilities depend upon Renewables' ability to maintain the working order of its wind turbines. A natural disaster, severe weather, accident, failure of major equipment, shortage of or inability to acquire critical replacement or spare parts, failure in the operation of any future transmission facilities that Renewables may acquire, including the failure of interconnection to available electricity transmission or distribution networks, could damage or require Renewables to shut down its turbines or related equipment and facilities, leading to decreases in electricity generation levels and revenues. Additionally, Renewables' operating projects generally do not hold spare substation main transformers in inventory. These transformers are designed specifically for each wind power project, and order lead times can be lengthy. If one of Renewables' projects had to replace any of its substation main transformers, it would be unable to sell all of its power until a replacement is installed.

If Renewables experiences a prolonged interruption at one of its operating projects due to natural events or operational problems and such events are not fully covered by insurance, Renewables' electricity generation levels could materially decrease, which could have a material adverse effect on its business, results of operation and financial condition and could adversely affect our cash flows, results of operations and financial position.

Cyber breaches, acts of war or terrorism, grid disturbances or security breaches involving the misappropriation of confidential and proprietary customer, employee, financial or system operating information could negatively impact our business.

Cyber breaches, acts of war or terrorism or grid disturbances resulting from internal or external sources could target our generation, transmission and distribution facilities or our information technology systems. In the regular course of business, we maintain sensitive customer, employee, financial and system operating information and are required by various federal and state laws to safeguard this information. Cyber or physical security intrusions could potentially lead to disabling damage to our generation, transmission and distribution facilities and to theft and the release of critical operating information or confidential customer or employee information, which could adversely affect our operations or adversely impact our reputation, and could result in significant costs, fines and litigation. We routinely experience attempts by external parties to penetrate and attack our networks and systems. Although such attempts have not resulted in any material breaches, disruptions or loss of business - critical information, our systems and procedures for preparing and protecting against such attacks and mitigating such risks may prove to be insufficient in the future and such attacks could have an adverse impact on our business and operations. 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. Additionally, the Company maintains a specific insurance program for cyber-risk in accordance with insurance market current offerings, which will need to be periodically reviewed due to the rapid evolution and broad range of cyber risks. While we maintain insurance coverage that is designed to address losses or claims that may arise in connection with cyber risks, such insurance coverage may be insufficient to cover all losses or claims that may arise from such risks. 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. In addition, we cannot ensure that a potential security breach may not occur or quantify the potential impact of such an event. Any such cyber breaches could result in a significant decrease in revenues, significant expense to repair system damage or security breaches, adverse impact on our reputation, regulatory penalties and liability claims, which could have a material adverse effect on our cash flows, results of operations and financial condition.

Risks including but not limited to any physical security breach involving unauthorized access, electricity or equipment theft and vandalism could adversely affect our business operations and adversely impact our reputation.

A physical attack on our transmission and distribution 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, which could adversely affect our operations or adversely impact our reputation, and could result in significant costs, fines and litigation. Additionally, certain of our power generation and transmission and distribution assets and equipment are at risk for theft and damage. Theft of, or damage to, components such as copper wire or solar panels can cause significant disruption to Networks' and Renewables' operations, respectively, and can lead to operating losses at those locations. Furthermore, Renewables can incur damage to wind turbine equipment through vandalism, such as gunshots into towers or other generating equipment. Such damage can cause disruption of operations for unspecified periods which may lead to operating losses at those locations.

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.

Renewables has exposure to commodity price movements through their "natural" long positions in electricity in addition to proprietary trading and hedging activities.

Networks and Renewables manage the exposure to risks of commodity price movements through internal risk management policies, enforcement of established risk limits and risk management procedures. These risk policies, risk limits and risk management procedures may not work as planned and cannot eliminate all risks associated with these activities. Even when these risk policies and procedures are followed, and decisions are made based on projections and estimates of future performance, results of operations may be diminished if the judgments and assumptions underlying those decisions prove to be incorrect. Our risk management tools and metrics associated with our hedging and trading procedures, such as daily value at risk, or VaR, stop loss limits and liquidity guidelines, are based on historical price movements. Due to the inherent uncertainty involved in price movements and potential deviation from historical pricing behavior, we are unable to assure that our risk management tools and metrics will be effective to protect against material adverse effects on our business, financial condition, results of operations and prospects. Factors, such as future prices and demand for power and other energy-related commodities, become more difficult to predict and the calculations become less reliable the further into the future estimates are made. As a result, we cannot fully predict the impact that some of our subsidiaries' commodity trading and hedging activities and risk management decisions may have on our business, results of operations, financial condition and cash flows.

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

We are pursuing broader development investment opportunities related to all segments of our business, particularly in respect of additional opportunities in electric transmission, renewable energy generation, interconnections to generating resources and other development investment opportunities. 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. Offshore wind brings significant development costs associated with single projects. Risks include regulatory approval processes, permitting, new legislation, economic events, environmental and community concerns, negative publicity, design and siting issues, difficulties in obtaining required rights of way, construction delays and cost overruns, including delays in equipment deliveries, particularly of wind turbines or transformers, severe weather, 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. 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. In addition, for Renewables' projects that are subject to PPAs, 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 production tax credits could result in losses that would be substantially greater than the amount of liquidated damages paid to Renewables. Any turbines associated with the approximately 700 MW of wind farms that Renewables plans to place in service during 2020 that do not reach commercial operation by December 31, 2020 are at risk of not qualifying for production tax credits, thereby reducing the economics of the project. Our ability to reach commercial operation in a timely manner is contingent on many variables including availability and timely delivery of materials and components, which rely in part on a global markets, which markets could be subject to political crises, public health crises or other catastrophic events that are outside of our control. For example, in December 2019, a strain of coronavirus was reported to have occurred in Wuhan, China. The outbreak of coronavirus has already resulted in supply chain and transportation disruptions worldwide and the extent to which the coronavirus may impact timelines of these projects is uncertain.

In May 2018, Vineyard Wind, LLC (AVANGRID has a 50% voting interest), or Vineyard Wind, was selected to build 800 MW of offshore wind in Massachusetts. The company still needs to obtain certain regulatory approvals before starting construction. A delay in obtaining all necessary permits may impact expected returns of this project or affect the final investment decision outcome. The Bureau of Ocean Energy Management, or BOEM, delayed the issuance of its Environmental Impact Study and Record of Decision for Vineyard Wind in order to perform a cumulative analysis of projects in the area. BOEM recently announced a new permitting timeline pursuant to which it is expected that BOEM will issue the Record of Decision in December 2020. The company is assessing the impacts of this timeline on the commencement of construction and commercial operation of Vineyard Wind.

In 2018, CMP was selected to construct a transmission line (NECEC) to provide renewable energy to Massachusetts. The company is going through a permitting process that includes federal, state and local permits that will need to be approved before the project starts construction. As is typical with large projects, we could experience delays, including in regulatory approvals, permitting and construction. Should any of these factors result in such delays or cancellations, our growth projections, financial position, results of operations and cash flows could be adversely affected or our future growth opportunities may not be realized as anticipated. In August 2019 a group of Maine voters submitted an application for Citizen's Initiative ("Referendum") to enact legislation to prevent the NECEC transmission project from proceeding. The proposed Citizen Initiative directs the MPUC to amend its May 3, 2019 order that granted the CPCN for the NECEC, one of the key State Permits. The Citizen Initiative's petition was issued for signature gathering on October 18, 2019. A petition requires signatures numbering not less than 10% of the total vote for Governor cast in the last election (63,067 signatures) by February 2020 to proceed to the ballot. The Citizen Initiative reported that it received over 75,000 signatures and these signatures are now being confirmed by the State Attorney's office. We are not able to predict the outcome of this initiative.

Advances in technology and rate design initiatives could impair or eliminate the competitive advantage of our business or could result in customer defection, which could have a material adverse effect on our growth, business, financial condition and results of operations.

The emergence of technology and initiatives designed to reduce greenhouse gas emissions or limit the effects of global warming and overall climate change has increased the development of new technologies for solar generation, energy efficiency and for investment in research and development 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, which could adversely affect our cash flows, results of operations and financial concerns. For example, net energy metering allows electricity customers who supply their own electricity from on-site generation to pay only for the net energy obtained from the utility. Further, the behind-the-meter storage systems and grid integration components such as inverters or electronics could result in electricity delivery customers abandoning the grid system or replacing part of grid services with self-supply or self-balancing, which could impact the return on current or future Networks' assets deployed and designed to serve projected load. Such emergence of alternative sources of energy supply can result in customers relying on the power grid for limited use, such as in the case of a deficit or an emergency, or completely abandoning the grid, which is known as customer defection. While currently the regulated utilities of Networks are subject to RDMs for distribution service, they are either legislatively or regulatory in nature and there is no assurance such mechanisms will always be available. The progressive reduction in the costs of distributed energy assets, as a result of technological improvements, large scale deployment in certain jurisdictions and constructive support regimes could result in customer defection (individually or integrated in micro-grids) when a net benefit analysis of investing in self-supply and storage of energy compared to energy provided by utility service appears attractive for certain customer classes. 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. Further, 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. Furthermore, the technologies used in the renewable energy sector change and evolve rapidly. Techniques for the production of electricity from renewable sources are constantly improving and becoming more complex. In order to maintain Renewables' competitiveness and expand its business, Renewables must adjust effectively to changes in technology. If Renewables fails to react effectively to current and future technological changes in the sector in a timely manner, Renewables' future business growth, results of operations and financial condition could be materially adversely affected.

Renewables' revenue may be reduced significantly upon expiration or early termination of PPAs if the market price of electricity decreases and Renewables is otherwise unable to negotiate favorable pricing terms.

Renewables' portfolio of PPAs is made up of PPAs that primarily have fixed or otherwise predetermined electricity prices for the life of the PPA. A decrease in the market price of electricity, including lower prices for traditional fossil fuels, could result in a decrease in revenues once a PPA has expired or upon a renewal of a PPA. Any decrease in the price payable to Renewables under new PPAs could have a material adverse effect on our business, results of operations, financial conditions and cash flows. For the majority of Renewables' wind energy generation projects, upon the expiration of a PPA, the project becomes a merchant project subject to market risks, unless Renewables can negotiate a renewal of the PPA. If Renewables is not able to replace an expiring or early terminated PPA with a contract on equivalent terms and conditions or otherwise obtain prices that permit operation of the related facility on a profitable basis, the affected site may temporarily or permanently cease operations and trigger an asset value impairment. The majority of the Renewables PPAs are fixed price contracts. An early termination of any may result in economic losses.

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 a material 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 businesses. 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.

Lower prices for other fuel sources may reduce the demand for wind and solar energy development, which could have a material adverse effect on Renewables' ability to grow its business.

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 energy, becomes less cost-competitive due to reduced government targets, increases in the cost of wind energy, new regulations, incentives that favor other forms of energy, cheaper alternatives or otherwise, demand for wind energy and other forms of renewable energy could decrease. Slow growth or a long-term reduction in the demand for renewable energy could have a material adverse effect on Renewables' ability to grow its business.

Volatility in the price of natural gas and home heating oil could adversely impact the demand for gas conversions and could have a material adverse effect on our regulated gas utilities' ability to grow their businesses.

Conversion from home heating oil to natural gas requires a significant investment by customers. If the price of natural gas does not remain sufficiently below the prices of home heating oil, current oil heating customers may elect not to convert to natural gas. Volatility in oil prices demonstrates the difficulty to predict future home heating costs. In addition, any new regulations imposed on natural gas, particularly on extraction of natural gas from shale formations, could lead to substantial increases in the price of natural gas. Reduced prices for heating oil or increases in in prices for natural gas may cause potential natural gas customers to forgo converting their heating systems to natural gas and as a result, could negatively impact the forecasted growth of the CNG, SCG and BGC businesses, and their cash flows, results of operations and financial condition.

Our subsidiaries do not own all of the land on which their projects are located and their use and enjoyment of real property rights for their projects may be adversely affected by the rights of lienholders and leaseholders that are superior to those of the grantors of those real property rights to our subsidiaries' projects, which could have a material adverse effect on their business, results of operations, financial condition and cash flows.

Our subsidiaries do not own all of the land on which their projects are located. For example, Renewables does not own all of the land on which its wind projects are located. Such projects generally are, and future projects may be, located on land occupied under long-term easements, leases and rights of way. The ownership interests in the land 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 the rights under such easements, leases or rights of way held by our operating subsidiaries may be subject to the rights of these third parties, and the rights of our operating subsidiaries to use the land 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. Any such loss or curtailment of the rights of our operating subsidiaries to use the land on which their projects are or will be located could have a material adverse effect on their business, results of operations, financial condition and cash flows.

We and our subsidiaries are subject to litigation or administrative proceedings, the outcome or settlement of which could adversely affect our business, results of operations, financial condition and cash flows.

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. These actions may include environmental claims, employment-related claims, class action suits and contractual disputes or claims for personal injury or property damage that occur in connection with services performed relating to the operation of our businesses, or actions by regulatory or tax authorities. Unfavorable outcomes or developments relating to these proceedings or future proceedings, such as judgments for monetary damages, injunctions or denial or revocation of permits, could have a material adverse effect on our business, financial condition, reputation and results of operations. In addition, settlement of claims could adversely affect our business, results of operations, financial condition and cash flows.

Storing, transporting and distributing natural gas involves inherent risks that could cause us to incur significant financial losses.

There are inherent hazards and operation risks in gas distribution activities, such as leaks, accidental 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, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. These activities may subject us to litigation and administrative proceedings that could result in substantial monetary judgments, fines or penalties. To the extent that the occurrence of any of these events is not fully covered by insurance or natural gas hedges, they could adversely affect our revenue, earnings and cash flow.

We are not able to insure against all potential risks and may become subject to higher insurance premiums, and our ability to obtain insurance and the terms of any available insurance coverage could be materially adversely affected by international, national, state or local events and company-specific events, as well as the financial condition of insurers.

Our businesses and activities are exposed to the risks inherent in the construction and operation of our respective assets, such as electrical power plants, wind power plants and other renewable energy projects and natural gas storage and distribution facilities, including breakdowns, manufacturing defects, natural disasters, terrorist attacks, cyber attacks and sabotage. Our subsidiaries are also exposed to third party liability risks and environmental risks. While our operating subsidiaries maintain insurance coverage, such insurance may not continue to be 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. For example, Renewables currently has 700 MW of installed capacity in California subject to known earthquake risks and approximately 1,100 MW of installed capacity on the Texas Gulf Coast subject to known hurricane and windstorm risks. Further, while insurance coverage applies to property damages and business interruptions, this coverage is limited as a result of severe insurance market restrictions and we are generally not fully insured against all significant losses. In addition, our subsidiaries' insurance policies are subject to annual review by their insurers. Our ability to obtain insurance and the terms of any available insurance coverage could be materially adversely affected by international, national, state or local events and company-specific events, as well as the financial condition of insurers. If insurance coverage is not available or obtainable on acceptable terms, we may be required to pay costs associated with adverse future events. If one of our operating subsidiaries were to incur a serious uninsured loss or a loss significantly exceeding the limits of their insurance policies, the results could have a material adverse effect on our business, results of operations, financial condition and cash flows.

Furthermore, Networks' gas distribution and transportation activities involve a variety of inherent hazards and operating risks, such as leaks, accidents, explosions, fires and mechanical problems and could result in serious injury to employees and non-employees, loss of human life, significant damage to property, environmental pollution and impairment of our subsidiaries' operations. In accordance with customary industry practice, our subsidiaries maintain insurance against some, but not all, of these risks and losses. The location of natural gas pipelines and other facilities near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages that could potentially result from these risks. The occurrence of any of these events not fully covered by insurance could adversely affect our business, results of operations, financial position and cash flows.

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 a material adverse effect on our business, results of operation, financial condition and cash flows.

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. The suppliers of our operating subsidiaries may fail to fulfill their warranty obligations or a particular defect may not be covered by a warranty. Even if a supplier fulfills its obligations, the warranty may not be sufficient to compensate the operating subsidiary for all of its losses. In addition, these warranties generally expire within two to five years after the date each equipment item is delivered or commissioned and are subject to liability limits. If installation is delayed, the operating subsidiaries may lose all or a portion of the benefit of a warranty. If Networks or Renewables seeks warranty protection and a supplier is unable or unwilling to perform its warranty obligations, whether as a result of its financial condition or otherwise, or if the term of the warranty has expired or a liability limit has been reached, there may be a reduction or loss of warranty protection for the affected equipment, which could have a material adverse effect on our business, results of operation, financial condition and cash flows.

A disruption in the wholesale energy markets or failure by an energy supplier could adversely affect our business and results of operation.

Almost all the electricity and gas that Networks sells to full-service customers is purchased through the wholesale energy markets or pursuant to contracts with energy suppliers. A disruption in the wholesale energy markets or a failure on the part of energy suppliers or operators of energy delivery systems that connect to Networks' energy facilities could adversely affect Networks' ability to meet its customers' energy needs and adversely affect our business and results of operation.

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

The rates that are permitted to be charged by our regulated natural gas utilities that allow for rate recovery generally allow such businesses to recover their cost of purchasing natural gas. In general, the various regulatory agencies allow our regulated utilities to recover the costs of natural gas purchased for customers on a dollar-for-dollar basis (in the absence of disallowances), without a profit component. Networks' regulated natural gas utilities periodically adjust customer rates for increases and decreases in the cost of gas purchased by such regulated utilities for sale to its 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.

Pension and post-retirement benefit plans could require significant future contributions to such plan that could adversely impact our business, results of operations, financial condition and cash flows.

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 the pension and post-retirement 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. Large funding requirements or significant increases in expenses could adversely impact our business, results of operations, financial condition and cash flows.

Our existing credit facilities contain, and agreements that we may enter into in the future may contain, covenants that could restrict our financial flexibility.

Our existing credit facilities, and the credit facilities of our subsidiaries, contain covenants imposing certain requirements on our business including covenants regarding the ratio of indebtedness to total capitalization. Furthermore, our subsidiaries periodically issue long-term debt, historically consisting of both secured and unsecured indebtedness. These third-party debt agreements also contain covenants, including covenants regarding the ratio of indebtedness to total capitalization. These requirements may limit our ability and the ability of our subsidiaries to take advantage of potential business opportunities as they arise and may adversely affect our conduct and our operating subsidiaries' current business, including restricting our ability to finance future operations and capital needs and limiting the subsidiaries' ability to engage in other business activities. Other covenants place or could place restrictions on our ability and the ability of our operating subsidiaries to, among other things, incur additional debt, create liens, and sell or transfer assets.

Agreements we and our operating subsidiaries enter into in the future may also have similar or more restrictive covenants, especially if the general credit market deteriorates. 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 of payment of the underlying obligations or may trigger acceleration of payment if not remedied within a specified period. Events of default under one agreement may trigger events of default under other agreements, although our regulated utilities are not subject to the risk of default of affiliates. Should payments become accelerated as the result of an event of default, the principal and interest on such borrowing would become due and payable immediately. If that should occur, we may not be able to make all of the required payments or borrow sufficient funds to refinance the accelerated debt obligations. Even if new financing is then available, it may not be on terms that are acceptable to us.

We 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 that is 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 us dividends. Prior to paying us dividends, the subsidiaries have financial obligations that must be satisfied, including among others, their operating expenses and obligations to creditors. Furthermore, 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.

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.

We and our subsidiaries may suffer the loss of key personnel or the inability to hire and retain qualified employees, which could result in a material adverse effect on our business, financial condition, results of operations and prospects.

The operations of our operating subsidiaries depend on the continued efforts of our employees and our subsidiaries' employees. Retaining key employees and maintaining the ability to attract new employees are important to our financial performance and for our subsidiaries' operations and financial performance. We cannot guarantee that any member of our management or of our subsidiaries' management will continue to serve in any capacity for any particular period of time. In addition, a significant portion of our and our subsidiaries' workforce, including many workers with specialized skills maintaining and servicing the electrical infrastructure, will be eligible to retire over the next five to ten years. Such highly skilled individuals cannot be quickly replaced due to the technically complex work they perform. If a significant amount of such workers retire and are not replaced, the subsequent loss in productivity and increased recruiting and training costs could result in a material adverse effect on our business, financial condition, results of operations and prospects.

We and our subsidiaries face the risk of strikes, work stoppages or an inability to negotiate future collective bargaining agreements on commercially reasonable terms which could have a material adverse effect on our business, results of operations, financial condition and cash flows.

A majority of the employees at Networks' facilities are subject to collective bargaining agreements with various unions. Additionally, unionization activities, including votes for union certification, could occur among non-union employees. 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 is uncertain, though risks are reduced by rigorous contingency planning. Strikes, work stoppages or an inability to negotiate future collective bargaining agreements on commercially reasonable terms could have a material adverse effect on our business, results of operations, financial condition and cash flows.

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

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 condition and results of operations.

The success of our business depends on achieving our strategic objectives, which may be through acquisitions, joint ventures, dispositions and restructurings.

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 actions, we may not achieve expected returns and other benefits as a result of various factors, including integration and collaboration challenges, such as personnel and technology. In addition, we may not achieve anticipated cost savings from restructuring actions. 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 to maximize the value of our business. 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. Alternatively, we may dispose of a business at a price or on terms that are less than we had anticipated. Failure to achieve our strategic objectives could have a material adverse effect on our business, results of operations, financial condition and cash flows.

Risks Relating to Ownership of Our Common Stock

The trading price and volume of our common stock may be volatile and the value of your investment could decline.

The trading price of and demand for shares of our common stock could fluctuate and will depend on a number of conditions, including:

- the risk factors described in this Annual Report on Form 10-K;
- general economic conditions in the U.S. and internationally, including changes in interest rates;
- changes in electricity and natural gas prices;
- actual, anticipated or unanticipated fluctuations in our quarterly and annual results and those of our competitors;
- our businesses, operations, results and prospects;
- future mergers and strategic alliances;
- market conditions in the energy industry;
- changes in law, government regulation, taxes, legal proceedings or other developments;
- shortfalls in our operating results from levels forecasted by securities analysts or by us;
- investor sentiment toward the stock of energy companies in general;
- announcements concerning us or our competitors;
- maintenance of acceptable credit ratings or credit quality;
- the likelihood, timing and amount of future equity issuances;
- the level of dividends and expectations for future dividend levels; and
- the general state of the securities markets.

These and other factors may impair the development or sustainability of a liquid market for shares of our common stock and the ability of investors to sell shares at an attractive price. These factors also could cause the market price and demand for shares of our common stock to fluctuate substantially, which may negatively affect the price and liquidity of shares of our common stock. These fluctuations could cause you to lose all or part of your investment in shares of our common stock. Many of these factors and conditions are beyond our control and may not be related to our operating performance.

If securities or industry analysts do not publish research or publish inaccurate or unfavorable research about us or our businesses, the price and trading volume of our common stock could decline.

The trading market for our common stock will, to some extent, depend on the research and reports that securities or industry analysts publish about us or our business. We do not have any control over these analysts. If one or more of the analysts who cover us should downgrade our shares or change their opinion of our business prospects or report inaccurate information, our share price would likely decline. If one or more of these analysts cease coverage of us or fail to publish reports on us regularly, demand for our common stock could decrease, which might cause our stock price and trading volume to decline.

Iberdrola exercises significant influence over us, 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 81.5% of outstanding shares of our common stock and will be able to exercise significant influence over our business 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, 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 is not required to have:

- a majority of its board of directors be independent directors;
- a compensation committee, or to have such committees be composed entirely of independent directors; and
- a nominating and corporate governance committee, or to have such committee composed entirely of independent directors.

In October 2016, our board determined that it was in the best interests of the company to establish a compensation, nominating and corporate governance committee. In light of our status as a controlled company, we currently rely on the NYSE exemptions with respect to board, compensation committee and nominating and corporate governance committee independence.

Because we are a controlled company, you will not have the same protections afforded to shareholders of companies that are subject to all of 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, restrictions in our debt agreements that limit our ability to pay dividends to shareholders 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.

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 under the Exchange Act, the Sarbanes-Oxley Act, or SOX, the Dodd-Frank Act, as well as rules adopted, and to be adopted, by the SEC and the NYSE. For example, beginning with the 2016 Annual Report on Form 10-K, Section 404 of SOX requires our management to 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 will continue to devote a substantial amount of time to these compliance activities. If we are not able to comply with the requirements of Section 404 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. Further, as a result of becoming a public company, we have incurred and will continue to incur higher legal, accounting and other expenses than we did as a private company, and these expenses may increase even more in the future.

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 is located in Portland, Oregon. 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, 2019:

Location	Type of Facility	Lease/Owned	Size (square feet)
Orange, Connecticut	Office	Owned	127,310
Augusta, Maine	Office	Leased	220,400
Portland, Maine	Office	Leased	15,194
Rochester, New York	Office	Owned	122,494
Portland, Oregon	Office	Leased	63,543

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 March 2, 2020 and a brief account of the business experience during the past five years of each executive officer are as follows:

Name	Age (1)	Title
James P. Torgerson	67	Chief Executive Officer
Douglas K. Stuver	56	Senior Vice President – Chief Financial Officer
Scott M. Tremble	40	Senior Vice President – Controller
Alejandro de Hoz García-Bellido	52	President and Chief Executive Officer of Renewables
David T. Flanagan	72	Executive Chairman of CMP
Peter T. Church	47	Senior Vice President – Human Resources & Corporate Administration
Ignacio Estella	50	Senior Vice President – Corporate Development
Robert D. Kump	58	Deputy Chief Executive Officer and President
Carl A. Taylor	55	President and Chief Executive Officer of NYSEG and RG&E
R. Scott Mahoney	54	Senior Vice President – General Counsel and Corporate Secretary
Anthony Marone	56	President and Chief Executive Officer of Networks

(1) Age as of December 31, 2019.

James P. Torgerson. Mr. Torgerson was appointed Chief Executive Officer of AVANGRID on December 16, 2015, upon consummation of the acquisition of UIL. Previously, Mr. Torgerson served as president and chief executive officer of UIL since 2006. Prior to 2006, Mr. Torgerson was president and chief executive officer of Midcontinent Independent System Operator, Inc. Mr. Torgerson serves as the chair of the board of directors of the American Gas Association and as a trustee of the Yale-New Haven Hospital, a Director of Yale New Haven Health System, board and executive committee member of the Edison Electric Institute (EEI). Mr. Torgerson co-chairs EEI's Board Committee for Reliability, Security and Business Continuity which includes responsibility related to cyber security for the EEI member utilities. Mr. Torgerson also is a member of the Electricity Sub-sector Coordinating Council (ESCC), that coordinates with the Federal Government (DOE, DHS, DOD, FBI and others) on physical and cyber security and natural disasters impacting the electric grid. Mr. Torgerson is the former chairman and director of the Connecticut Business and Industry Association and the former chairman of the Connecticut Institute for the 21st Century. Mr. Torgerson holds a bachelor's of business administration degree in accounting from Cleveland State University.

Douglas K. Stuver. Mr. Stuver was appointed Senior Vice President - Chief Financial Officer of AVANGRID on July 8, 2018, and is responsible for AVANGRID's investor relations corporate communications, risk management, treasury and purchasing divisions. Mr. Stuver joined AVANGRID in 2015 as Managing Director, Finance of Avangrid Renewables, LLC and served as Vice President – Controller of Avangrid Renewables, LLC from 2017 until 2018. Prior to joining the Company, he served as chief financial officer of the Company's prior affiliate, PacifiCorp, from 2008 to 2015. Mr. Stuver graduated magna cum laude with a B.A. from University of Pittsburgh and is a Certified Public Accountant (inactive status).

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.

Alejandro de Hoz García-Bellido. Mr. de Hoz García-Bellido was appointed President and Chief Executive Officer of Renewables on October 15, 2019. Mr. de Hoz García-Bellido previously served as Vice President of U.S. Offshore Wind of Renewables from November 3, 2017 until October 15, 2019. Prior to joining Renewables, Mr. de Hoz García-Bellido served as Offshore Business Performance director within the Iberdrola offshore business from 2013 until 2017, based both in London and Madrid, responsible for preparing Iberdrola's offshore pipeline for competitive auction processes both in the U.K. and Germany, as well as coordinating the teams to take awarded projects through the financial close. Prior to this, he held different positions within the Iberdrola group in developing the onshore wind business internationally, including the establishment in the French market and the development of the Mexican and Brazilian markets. Mr. de Hoz García-Bellido holds a degree in Physics from the University Complutense of Madrid and an MBA from ICAI-ICADE University of Madrid.

David T. Flanagan. Mr. Flanagan was appointed Executive Chairman of the Board of Directors of CMP effective February 18, 2020. Previously, Mr. Flanagan served as Chief Executive Officer of CMP from 1994 to 2000. Most recently, Mr. Flanagan served as the Interim President of the University of Southern Maine from 2014 until 2015. He also served as President and Chief

Executive Officer at Preservation Management Inc., a management company specializing in affordable housing, from 2010 to 2013 and as General Counsel for the United States Senate Homeland Security Committee for the Hurricane Katrina investigation from 2005 until 2006. Prior to joining Central Maine Power Company, he served as legal counsel to the Governor of the State of Maine from 1979 to 1984 and as a member of the Board of Trustees of the University of Maine System from 1986 to 1995. Mr. Flanagan holds a Bachelor's Degree from Harvard University and a J.D. from Boston College Law School.

Peter T. Church. Mr. Church was appointed Senior Vice President – Human Resources & Corporate Administration of AVANGRID on October 31, 2018, and is responsible for ensuring that human resources strategies and initiatives support AVANGRID's mission and objectives, overseeing all aspects of human resources management, practices and operations, and coordinates AVANGRID's other corporate administrative functions including health and safety, general services, and information technology and systems. Prior to joining AVANGRID, Mr. Church held a number of executive positions at UnitedHealth Group from 2012 to 2018 including serving as the Chief Talent Officer, Vice President, Human Capital - Commercial Markets, and Vice President, Talent Acquisition and Workforce Insights. Mr. Church earned both a Bachelor of Arts in Psychology as well as a Master of Arts in General/Experimental Psychology from the University of Hartford.

Ignacio Estella. Mr. Estella was appointed Senior Vice President – Corporate Development of AVANGRID on December 17, 2015, and is responsible for delivering non-organic growth opportunities for the Company beyond those of its present businesses. Previously, Mr. Estella served as corporate vice president of business origination of Iberdrola from May 2009 until November 2013 and vice president – corporate development of Iberdrola USA, Inc., from December 2013 to December 16, 2015. He served as gas markets development director of Iberdrola between February 2007 and April 2009. Mr. Estella holds a degree in law and business administration from the Universidad Pontificia Comillas and a Master of Public Administration, with concentration in industry analysis and strategic negotiation from Harvard University.

Robert D. Kump. Mr. Kump was appointed Deputy Chief Executive Officer and President of AVANGRID on June 5, 2019. Mr. Kump served as President and Chief Executive Officer of Networks from November 2010 until June 5, 2019 and as AVANGRID's Chief Corporate Officer from January 2014 to December 2016. Mr. Kump also served as a director of AVANGRID's subsidiaries CMP, NYSEG, and RG&E from 2009 until June 5, 2019, and as the Chief Executive Officer of Avangrid Service Company from October 2009 until June 5, 2019. Mr. Kump held various positions from February 1997 to October 2009 as AVANGRID's senior vice president and chief financial officer, vice president, controller and chief accounting officer, treasurer and secretary. Mr. Kump also previously held a number of positions at NYSEG from 1986 to 1997, including senior accountant-external financial reporting, director-investor relations, director-financial services, and treasurer. Mr. Kump earned a B.A. in accounting from Binghamton University and is a C.P.A. in New York.

Carl A. Taylor. Mr. Taylor was appointed President and Chief Executive Office of NYSEG and RG&E on June 30, 2017. Previously, Mr. Taylor served as Vice President of Customer Service of AVANGRID. Mr. Taylor started with NYSEG in 1987 as an electrical engineer in the generation planning area and progressed through positions of increasing seniority in the organization including president of NYSEG Solutions, Inc., a subsidiary of NYSEG. He earned a Bachelor of Electrical Engineering Degree from Rochester Institute of Technology and a Master's of Business Administration Degree from State University of New York at Binghamton.

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 previously 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.

Anthony Marone. Mr. Marone was appointed President and Chief Executive Officer of Networks on June 5, 2019. In this role, he has overall responsibility for Avangrid Networks' electric and natural gas operating companies in Connecticut and Massachusetts and functional responsibility for AVANGRID's regulatory and asset management and planning. Mr. Marone also serves as President – Connecticut and Massachusetts Operations of Networks, director of Avangrid Enterprises, Inc., Avangrid Networks, Inc., Avangrid Networks New York TransCo, LLC, Avangrid Service Company, Berkshire Energy Resources, The Berkshire Gas Company, Central Maine Power Company, CMP Group, Inc., Connecticut Energy Corporation, Connecticut Natural Gas Corporation, CTG Resources, Inc., Mainecom Services, New York State Electric & Gas Corporation, RGS Energy Group, Inc., Rochester Gas and Electric Corporation, The Southern Connecticut Gas Company, Thermal Energies, Inc., UIL Group, LLC, UIL Holdings Corporation, The Union Water-Power Company, United Capital Investment, Inc., The United Illuminating Company, United Resources, Inc., Xcelecom, Inc., and Xcel Services, Inc. Previously Mr. Marone served as senior vice president of customer and business services of UIL since May 14, 2013. Mr. Marone served as senior vice president – business services of UI and vice president of business services of UIL from November 16, 2010 to May 2013. Mr. Marone received his master's degree in engineering and business management from the University of New Haven and a bachelor's degree in mechanical engineering from the New York Institute of Technology.

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 28, 2020, there were 3,280 shareholders of record.

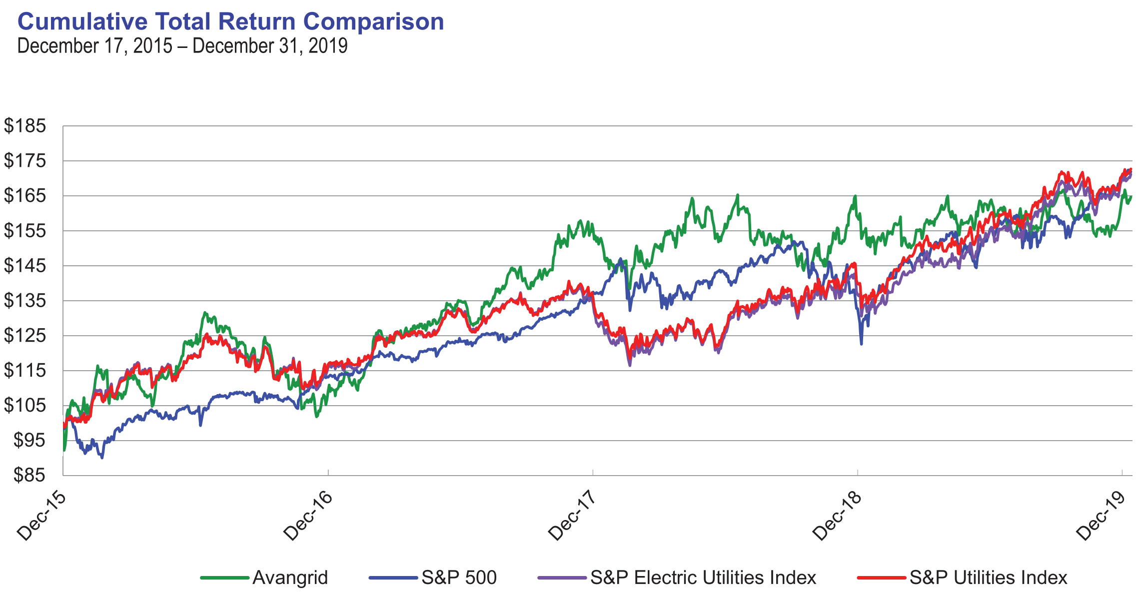
Dividends

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 17, 2015 through December 31, 2019.



	December 17, 2015		December 31, 2019	
AVANGRID	$	100.00	$	164.50
S&P 500	$	100.00	$	171.70
S&P Electric Utilities Index	$	100.00	$	170.89
S&P Utilities Index	$	100.00	$	172.56

The above information assumes that the value of the investment in shares of AVANGRID's common stock and each index was $100 on December 17, 2015, 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, 2019.

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. *Selected Financial Data*

The following selected consolidated financial data should be read in conjunction with the consolidated financial statements and the notes thereto in Item 8 of Part II, "Financial Statements and Supplementary Data," and the information contained in Item 7 of Part II, "Management's Discussion and Analysis of Financial Condition and Results of Operations." Historical results are not necessarily indicative of future results.

	Year Ended December 31, (millions, except per share data)				
Consolidated Statements of Income Data: *	**2019**	**2018**	**2017**	**2016**	**2015**
Operating Revenues	**$ 6,338**	**$ 6,478**	**$ 5,963**	**$ 6,018**	**$ 4,367**
Operating Income	1,003	1,127	505	1,194	599
Income Before Income Tax	**819**	**768**	**123**	**1,009**	**302**
Income tax expense (benefit)	143	170	(259)	377	29
Net Income	**676**	**598**	**382**	**632**	**273**
Net loss (income) attributable to noncontrolling interests	24	(3)	(1)	—	—
Net Income Attributable to Avangrid, Inc.	**$ 700**	**$ 595**	**$ 381**	**$ 632**	**$ 273**
Total Earnings Per Common Share, Basic and Diluted	$ 2.26	$ 1.92	$ 1.23	$ 2.04	$ 1.07
Weighted-average Number of Common Shares Outstanding:					
Basic	309,491,082	309,503,319	309,502,861	309,512,553	254,588,212
Diluted	309,514,910	309,712,628	309,661,883	309,817,322	254,605,111

Consolidated Balance Sheet Data:*					
As of December 31,	**2019**	**2018**	**2017**	**2016**	**2015**
(Millions)					
Total Property, Plant and Equipment	**$ 25,218**	**$ 23,459**	**$ 22,669**	**$ 21,548**	**$ 20,711**
Total Other Assets	**$ 3,828**	**$ 3,675**	**$ 3,589**	**$ 3,976**	**$ 3,795**
Total Assets	**$ 34,416**	**$ 32,167**	**$ 31,671**	**$ 31,309**	**$ 30,743**

As of December 31,	**2019**	**2018**	**2017**	**2016**	**2015**
(Millions)					
Liabilities					
Current portion of debt	$ 730	$ 394	$ 183	$ 349	$ 206
Non-current debt	$ 6,716	$ 5,368	$ 5,196	$ 4,510	$ 4,530
Total Liabilities	**$ 18,830**	**$ 16,764**	**$ 16,575**	**$ 16,101**	**$ 15,593**
Total Stockholder's Equity	**$ 15,237**	**$ 15,104**	**$ 15,077**	**$ 15,195**	**$ 15,137**
Total Equity	**$ 15,586**	**$ 15,403**	**$ 15,096**	**$ 15,208**	**$ 15,150**

*Selected financial data for UIL is included from December 16, 2015.

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."

AVANGRID is a leading sustainable energy company with approximately $34 billion in assets and operations in 24 states. AVANGRID has 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 8.0 gigawatts of electricity capacity, primarily through wind 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, and was named among the World's Most Ethical companies in 2019 by the Ethisphere Institute. AVANGRID employs approximately 6,600 people. Iberdrola S.A., a corporation *(sociedad anónima)* organized under the laws of the Kingdom of Spain, a worldwide leader in the energy industry, directly owns 81.5% of outstanding shares of AVANGRID common stock. AVANGRID's primary business is ownership of its operating businesses, which 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.

In December 2017, our management committed to a plan to sell the gas storage and trading businesses because they represented non-core businesses that are not aligned with our strategic objectives. At that time, we determined that the assets and liabilities associated with our gas trading and storage businesses met the criteria for classification as assets held for sale, but did not meet the criteria for classification as discontinued operations. On March 1, 2018, the Company closed a transaction to sell Enstor Energy Services, LLC, which operated AVANGRID's gas trading business, to CCI U.S. Asset Holdings LLC, a subsidiary of Castleton Commodities International, LLC. On May 1, 2018, the Company closed a transaction to sell Enstor Gas, LLC, which operated the AVANGRID's gas storage business, to Amphora Gas Storage USA, LLC. The agreement included, among other things, a transition services agreement that obligated ARHI to provide certain transition services for up to one year after the closing date.

On December 16, 2015, we completed our acquisition of UIL. 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. The acquisition was accounted for as a business combination. The results of operations of UIL since December 16, 2015, the acquisition date, have been included in the consolidated results of AVANGRID. Effective as of April 30, 2016, UIL and its subsidiaries were transferred to a wholly-owned subsidiary of Networks.

Through Networks, we own electric generation, transmission and distribution 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 public utility customers as of December 31, 2019.

Networks, a Maine corporation, holds our 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.

Through Renewables, we had a combined wind, solar and thermal installed capacity of 8,001 megawatts, or MW, as of December 31, 2019, including Renewables' share of joint projects, of which 7,259 MW was installed wind capacity. As of December 31, 2019, approximately 69% of the capacity was contracted, for an average period of 9.5 years, and 13% of installed capacity was hedged. Being among the top three largest wind operators in the United States based on installed capacity as of December 31, 2019, Renewables strives to lead the transformation of the U.S. energy industry to a sustainable, competitive, clean energy future. Renewables currently operates 61 wind farms in 21 states across the United States.

Summary of Results of Operations

Our operating revenues decreased by 2%, from $6,478 million for the year ended December 31, 2018, to $6,338 million for the year ended December 31, 2019.

Networks business revenues decreased mainly due to the pass-through of decreased purchased power and gas driven by lower commodity prices and volumes in the period. Renewables had an increase in revenues mainly due to an increase in thermal revenue and favorable mark to market, or MtM, changes on energy derivative transactions entered into for economic hedging purposes in the period, offset by unfavorable impacts from lower merchant pricing.

Net income attributable to AVANGRID increased by 18% from $595 million for the year ended December 31, 2018, to $700 million for the year ended December 31, 2019, primarily due to increased revenue and gain from the sale of assets in Renewables business in the period.

Adjusted net income (a non-GAAP financial measure) decreased by 2%, from $684 million for the year ended December 31, 2018 to $673 million for the year ended December 31, 2019. The decrease is primarily due to a $21 million decrease in Networks driven by increased non-deferrable outage restoration costs and an increase in personnel costs (net of capitalized staff costs) driven by headcount and overtime increases and a $28 million decrease in Corporate mainly driven by higher interest expense, offset by a $38 million increase in Renewables driven mainly by thermal revenue increase and a gain from the sale of assets and associated change in control during the period.

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

See "—*Results of Operations*" for further analysis of our operating results for the 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 major weather disturbances 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 2020, 70% of its standard service load for the second half of 2020 and 40% of its standard service load for the first half of 2021. Supplier of last resort service is procured on a quarterly basis and UI has a wholesale power supply agreement in place for the second quarter of 2020. However, from time to time there are no bidders in the procurement process for supplier of last resort service and in such cases UI manages the load directly.

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 utilizes regulatory deferrals to evaluate its financial condition and operating performance by reconciling differences between actual revenue received or cost incurred with the rate allowances provided under the tariffs set by the state utilities commissions and the FERC. Regulatory deferrals 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 portfolio standards, economic development programs, earnings sharing mechanism, low income programs, pension costs, other post-employment benefits costs, environmental remediation costs, major storm costs, distribution vegetation management costs (downward only), research and development, incremental maintenance initiatives (downward only), property taxes, Reforming the Energy Vision, or REV, initiatives, Nuclear Electric Insurance Limited credits, credit and debit card fees, 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. Additionally, the lower monthly minimum equity ratio requirement (a cushion of 300 basis points) provides flexibility to have short-term fluctuations that result in temporary shortfalls of the maximum equity ratio in any given month. The regulated utility subsidiaries are also prohibited by regulation from lending to unregulated affiliates.

Rates

In December 2016, PURA approved distribution rate schedules for UI for three years that became effective January 1, 2017, and which, among other things, provides for annual tariff increases and an ROE of 9.10% based on a 50% 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.

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

In December, 2018, PURA approved new tariffs for CNG effective January 1, 2019 for a three-year rate plan with rate increases of $9.9 million, $4.6 million and $5.2 million in 2019, 2020 and 2021, respectively. The new tariffs continued the RDM and DIMP mechanism, ESM and tariff increases based on an ROE of 9.30% and an equity ratio of 54% in 2019, 54.50% in 2020, and 55% in 2021.

On January 18, 2019, the DPU approved a settlement agreement between BGC and the Massachusetts Attorney General's Office providing for new distribution rates for BGC. The settlement agreement provides for a $1.6 million distribution base rate increase effective February 1, 2019 (with a make-whole provision back to January 1, 2019), and an additional $0.7 million base distribution increase effective November 1, 2019, if certain investments are made by BGC. The distribution rate increase is based on a 9.70% ROE and 54% equity ratio. The settlement agreement provides for the implementation of an RDM and pension expense tracker and also provides that BGC will not file to change base distribution rates to become effective before November 1, 2021.

On June 15, 2016, the NYPSC approved NYSEG's and RG&E's 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 proposal reflects many customer attributes including acceleration of the companies' natural gas leak prone main replacement programs and increased electric vegetation management to provide continued safe and reliable service. The delivery rate increase in the proposal can be summarized as follows:

	May 1, 2016		May 1, 2017		May 1, 2018	
	Rate Increase	Delivery Rate Increase	Rate Increase	Delivery Rate Increase	Rate Increase	Delivery Rate Increase
Utility	(Millions)	%	(Millions)	%	(Millions)	%
NYSEG Electric	$ 29.6	4.10%	$ 29.9	4.10%	$ 30.3	4.10%
NYSEG Gas	$ 13.1	7.30%	$ 13.9	7.30%	$ 14.8	7.30%
RG&E Electric	$ 3.0	0.70%	$ 21.6	5.00%	$ 25.9	5.70%
RG&E Gas	$ 8.8	5.20%	$ 7.7	4.40%	$ 9.5	5.20%

The allowed rate of return on common equity for NYSEG Electric, NYSEG Gas, RG&E Electric and RG&E Gas is 9.00%. The equity ratio for each company is 48%; however, the actual equity ratio of up to 50% is used for earnings sharing calculation purposes. The customer share of any earnings above allowed levels increases as ROE increases, with customers receiving 50%, 75% and 90% of earnings over 9.5%, 10.0% and 10.5% ROE, respectively, in the first rate year covering the period May 1, 2016 – April 30, 2017. The earnings sharing levels increased in rate year two (May 1, 2017 – April 30, 2018) to 9.65%, 10.15% and 10.65% ROE, respectively. The earnings sharing levels further increased in rate year three (May 1, 2018 – April 30, 2019) to 9.75%, 10.25% and 10.75% ROE, respectively. The Joint Proposal reflected the recovery of deferred NYSEG Electric storm costs of approximately $262 million, of which $123 million will be amortized over ten years and the remaining $139 million will be amortized over five years. The Joint Proposal also continued reserve accounting for qualifying major storms ($21.4 million annually for NYSEG Electric and $2.5 million annually for RG&E Electric). Incremental maintenance costs incurred to restore service in qualifying divisions are chargeable to the major storm reserve provided they meet certain thresholds.

The NYSEG and RG&E 2016 three-year rate plan ended in April 2019, and the existing customer rates at that time were continued, along with other rate plan provisions, pending new rates being established as a result of a new rate case. On May 20, 2019, NYSEG and RG&E filed rate cases with the New York State Department of Public Service (NYDPS) for new tariffs. The effective date of new tariffs, assuming an approximately 11-month suspension period, will be April 20, 2020. The proposed rates facilitate the companies' transition to a cleaner energy future while allowing for important initiatives such as vegetation management, hardening/resiliency and emergency preparedness. The companies are requesting delivery revenues to be based on a 9.50% ROE and 50% equity ratio. The below table provides a summary of the initial proposed delivery rate increases, delivery revenue percentages and total revenue percentages for all four businesses:

Utility	Requested Revenue Increase (Millions)		Delivery Revenue %	Total Revenue %
NYSEG Electric	$	156.7	20.4%	10.4%
NYSEG Gas	$	6.3	3.0%	1.4%
RG&E Electric	$	31.7	7.0%	4.1%
RG&E Gas	$	5.8	3.3%	1.4%

NYPSC staff and other parties filed responsive testimony on September 15, 2019. NYPSC staff is recommending an 8.2% ROE and 48% equity. NYPSC staff recommended the following rate increases/decreases: NYSEG electric a rate increase of $76.7 million, NYSEG Gas a rate decrease of $15.9 million, RG&E Electric a rate increase of $0.7 million and RG&E Gas a rate decrease of $22.5 million. NYPSC Staff is also recommending NYSEG credit the environmental reserve by $31.1 million due to the legal rulings in 2017 and 2018 that denied insurance claims against OneBeacon and Century Indemnity in an insurance lawsuit. The companies entered into settlement discussion with the staff and other parties in October 2019. On February 26, 2020, the companies filed notice with the NYPSC that an agreement in principle has been reached among the companies, the NYDPS staff and certain other parties to the matter. As a result, drafting of a joint proposal (settlement agreement) has commenced.

On August 25, 2014, the MPUC approved a stipulation agreement for a CMP rate change which provided for a distribution rate increase of approximately $24.3 million effective July 1, 2014 with an allowed ROE of 9.45% and an allowed equity ratio of 50%. The stipulation provided for the implementation of an RDM, reserve accounting and sharing of incremental storm costs, a separate proceeding for recovery of a new billing system and no earnings sharing.

On March 1, 2018, the MPUC issued a Notice of Investigation initiating a summary investigation into CMP's metering, billing, and customer communications practices. Due to the highly technical nature of CMP's customer billing system, on March 22, 2018 the MPUC issued an Order Initiating Audit commencing a forensic audit of CMP's customer billing system to identify any errors that have, or continue to result in billing inaccuracies. On July 10, 2018, the MPUC issued an Order Modifying Scope of Audit, which expanded the scope of the audit to include the customer communication practices that were originally identified in the Commission's Notice of Investigation.

On May 29, 2018, a ten-person complaint was filed with the MPUC against CMP, Networks and AVANGRID. The complaint requested that the MPUC open a rate case to determine if CMP is making excessive returns on investment and, therefore, whether CMP's retail rates should be lower. The complaint also requested the MPUC deny certain costs associated with the October 2017 windstorm. On July 24, 2018, the MPUC issued an order dismissing the complaint and its associated request to deny the recovery of costs associated with the October 2017 windstorm. The order initiated an investigation into CMP's rates and revenue requirement and directed CMP to make a filing consistent with the requirements for a general rate case no later than October 15, 2018.

On October 15, 2018, CMP filed a general rate case as directed by the MPUC requesting a ROE of 10% and an equity ratio of 55%. CMP's general rate case filing included a proposal to enhance the resiliency of the energy grid by expanding vegetation management and pursuing additional reliability measures such as pole replacements and addition of tree wire in selected areas. Such investments are designed to strengthen CMP's power grid so it can better stand up to severe weather. CMP planned to use savings from the Tax Act to pay for the costs of resiliency programs, other investments in infrastructure and certain cost increases since 2014. On December 20, 2018, the MPUC released the findings of the forensic audit of CMP's customer billing system and customer communication practices.

On January 14, 2019, the MPUC issued an Order and Notice of Investigation initiating an investigation of CMP's metering and billing practices and initiating a separate investigation of the audit of CMP's customer service and communication practices and incorporating such investigation into the general rate case. The Maine Office of Public Advocate, or OPA, for utility issues filed a motion to delay CMP's rate order decision to allow incorporation of the results of the separate metering and billing investigation. CMP did not oppose this motion.

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%, based on an allowed ROE of 9.25% and a 50% equity ratio. The rate increase is 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 will remain in effect until CMP has demonstrated satisfactory customer service performance on four specified service quality measures for a period of 18 consecutive months with measurement commencing on March 1, 2020. The order provides 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 retains the revenue decoupling mechanism implemented in 2014. The order denies CMP’s request to increase rates for higher costs associated with services provided by its affiliates and will instead initiate a management audit to assess the quality of these services as well as the impacts of the AVANGRID management structure on the quality of CMP’s customer service.

On March 5, 2015, MNG filed a rate case in order to further recover future investments and provide safe and adequate service. On May 3, 2016, all active parties to the case filed a stipulation which settled all matters at issue in the case and reflected a ten-year rate plan through April 30, 2026. The MPUC approved the stipulation on May 17, 2016, for new rates effective June 1, 2016. The settlement structure for non-Augusta customers includes a 34.6% delivery revenue increase over five years with an allowed 9.55% ROE and 50% 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. A disallowance for the initial 2012/2013 gross plant investment is not part of the approved stipulation.

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, or OCC, 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, 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 capital-asset pricing model for establishing the base return on equity. This resulted in a base return on equity of 9.88% as the midpoint of the zone of reasonableness. Various parties have requested rehearing on this decision. We cannot predict the outcome of this proceeding, and the potential impact it may have in establishing a precedent for our pending four Complaints.

Merger Settlement Agreement – Connecticut and Massachusetts

As part of the process of seeking and obtaining regulatory approval of the acquisition of UIL by AVANGRID in Connecticut and Massachusetts, AVANGRID and UIL reached settlement agreements with the OCC in Connecticut and with the Attorney General of the Commonwealth of Massachusetts and the Department of Energy Resources in Massachusetts, which settlement agreements included commitments of actions to be taken after the transaction closed.

Various commitments were made in Connecticut. Those commitments with continuing impacts are outlined below:

- Rate credits of $1.25 million/year for ten years (2018-2027) to CNG customers.
- Rate credits of $0.75 million/year for ten years (2018-2027) to SCG customers.
- Maintaining charitable contribution at historical contribution levels (between $500,000 and $800,000) for at least four years.

In connection with the acquisition proceeding, UI signed the partial consent order related to the investigation and remediation of the English Station site. To the extent that the investigation and remediation is less than $30 million, UI is required to remit to the State of Connecticut the difference between such costs and $30 million, to be applied to a public purpose as determined at the discretion of the Governor, the Attorney General 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.

Various commitments were made in Massachusetts, all of which have now been fulfilled.

New England Clean Energy Connect

On February 14, 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 utilities and the Massachusetts Department of Energy Resources, or DOER, in the Commonwealth of Massachusetts's 83D clean energy Request for Proposal, or RFP, to move forward as the alternative to the Northern Pass Transmission project which failed to win approval from the New Hampshire Site Evaluation Committee by March 27, 2018. On March 28, 2018, the DOER informed CMP that the conditional selection of Northern Pass Transmission project had been terminated, making the NECEC transmission project the lone winning bid in the RFP. 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 $950 million, would add 1,200 MW of transmission capacity to supply New England with power from reliable hydroelectric generation.

On June 13, 2018, CMP entered into transmission service agreements, or TSAs, with the purchasing Massachusetts electric distribution companies, or the 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 have executed certain PPAs with HQUS for sales of electricity and environmental attributes to the EDCs. The EDCs submitted the TSAs and PPAs to the DPU for approval on July 23, 2018, and CMP filed the TSAs for approval by the FERC on August 20, 2018. 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 power purchase agreements and the cost recovery by the EDCs of the TSA charges. This Order was subsequently appealed by NextEra Energy Resources, and CMP is coordinating its participation in the processing of the appeal with the MA EDCs; a judicial decision is expected by end of the second quarter of 2020. CMP also continues to negotiate with the EDCs the terms of assignment of the TSAs from CMP to NECEC Transmission LLC upon the project's transfer. On December 10, 2019, CMP submitted a petition to the FERC, seeking the FERC's authorization to transfer the TSAs (FERC rate schedules) from CMP to NECEC Transmission LLC upon the project's transfer. The MPUC and FERC project's transfer proceedings are ongoing with a decision from the agencies expected at the end of the first quarter of 2020.

The NECEC project requires a Certificate of Public Convenience and Necessity, or CPCN, from the MPUC in order to proceed to construction. CMP filed its petition for a certificate on September 27, 2017. On February 21, 2019, CMP, along with the Maine Office of the Public Advocate, the Governor's Energy Office, Industrial Energy Consumer Group, Conservation Law Foundation, Acadia Center, Western Mountains & Rivers Corporation, City of Lewiston, Maine State Chamber of Commerce and International Brotherhood of Electrical Workers, filed a settlement stipulation agreeing that the MPUC should grant a CPCN for the NECEC transmission project, subject to certain agreed-upon conditions. The settlement conditions provide for the transfer of the NECEC transmission project from CMP to NECEC Transmission LLC, a new subsidiary of Networks.; the funding by NECEC Transmission LLC, CMP and HQUS of certain funds to provide benefits to the State of Maine totaling approximately $250 million over the 40-year useful life of the NECEC transmission project; and other commitments. NECEC Transmission LLC is required to put in place and maintain a guaranty by AVANGRID or its successor in the amount of approximately $81 million to guarantee certain of the payment obligations of NECEC Transmission LLC under the settlement stipulation. The settlement stipulation also requires CMP, NECEC Transmission LLC and HQUS to enter into a support agreement reflecting, among other things, that HQUS will (i) pay NECEC Transmission LLC $3.5 million per year for 40 years beginning upon the commercial operation date of the NECEC transmission project, or the NECEC COD, which funds are to be used to fund a portion of NECEC Transmission LLC's share of the benefit commitments agreed in the settlement stipulation, (ii) contribute an additional $30 million over the first five years after the NECEC COD to fund HQUS's share of the benefit commitments, and (iii) the granting of a guaranty by Hydro-Québec or other appropriate credit support to guarantee HQUS's payment obligations under the support agreement.

On May 3, 2019, the NECEC Project received the CPCN from the MPUC. In August 2019, CMP and NECEC Transmission LLC commenced the required "follow-on" proceeding before the MPUC to obtain approval of the various affiliate transactions involved in the transfer of the NECEC from CMP to NECEC Transmission LLC. In accordance with the Stipulation approved by the Commission's CPCN Order, the transfer must occur before construction may commence. CMP anticipates closing on the transfer after receipt of the U.S. Army Corps of Engineers permit in the second quarter of 2020. The NECEC project also requires certain permits, including environmental, from multiple state and federal agencies and a presidential permit from the U.S. Department of Energy 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 (LUPC) deliberated and granted the LUPC Certification to NECEC. The Maine Department of Environmental Protection's decision is expected to follow within the next several weeks. Other permitting activities are ongoing. CMP expects to obtain the applicable state and federal permits by the end of the third quarter of 2020.

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 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 by-passable federally mandated congestion charges for all customers to recover the net costs of the PPAs.

On December 28, 2018, DEEP issued a directive to UI to negotiate and enter into PPAs with twelve projects, totaling approximately 12 million MWh, which were selected as a result of the Zero Carbon RFP issued by DEEP pursuant to PA 17-3, which provides that the net costs of the PPAs are recoverable through electric rates. One of the selected projects is the Millstone nuclear facility located in Waterford, Connecticut and owned by Dominion Energy, Inc. DEEP's directive provides that UI should file these PPAs for PURA by March 31, 2019. UI has not yet entered into any of these PPAs. 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 remaining PPA has been executed and submitted for approval to PURA.

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. On December 5, 2019, DEEP announced that it had selected Vineyard Wind ("Vineyard"), an affiliate of UI, to provide 804 MW of offshore wind through the development of its Park City Wind Project. DEEP also ordered Eversource and UI to negotiate PPAs with Vineyard. 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 April 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, or DSP, 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. The NYPSC order on Track 1 affirmed that utilities would serve as the DSP and required utilities to file implementation plans before the end of 2015. Track 2 is 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. 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, or 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 and the companies renewed their EAM requests in their May 2019 rate case filings.

All electric utilities were ordered to file an initial Distributed System Implementation Plan, or DSIP, by June 30, 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 December 2016. 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 earnings adjustment mechanism 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. In July 2018, NYSEG and RG&E submitted an updated DSIP plan consistent with guidance received from the NY Department of Public Service. 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. The NYPSC also issued an order on value stack compensation for high-capacity-factor resources on December 12, 2019.

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

On May 18, 2018, NYSEG and RG&E filed a settlement joint proposal and investment joint proposal before the NYPSC to settle potential penalties and avoid litigation related to the March 2017 windstorm, pursuant to which, among other things, NYSEG and RG&E have agreed to make $4 million in investments designed to increase resiliency and improve emergency response in the areas impacted by the storm. The investments will not be reflected in rate base or operating expenses in establishing future delivery rates. On April 18, 2019, the NYPSC approved the joint proposals.

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 over 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 penalty of $10.5 million.

NYPSC directs Counsel to commence Judicial Enforcement Proceeding against NYSEG

On April 18, 2019, the NYPSC issued an Order Directing Counsel to the Commission to commence a special proceeding or an action in New York State Supreme Court to stop and prevent ongoing future violations by NYSEG of NYPSC regulations and orders. On December 24, 2019, the Commission filed a verified petition to commence the action against NYSEG. At the same time, NYSEG and the Commission settled the causes of action asserted in the verified petition and entered into a consent and stipulation and also submitted a joint motion to the court requesting that the court approve and enter a consent order and judgment reflecting the settlement. The consent order and judgment was issued by the court on January 24, 2020.

CMP Customer Billing System Investigation and Class Action

On March 1, 2018, the MPUC issued a Notice of Investigation initiating a summary investigation into CMP's metering, billing, and customer communications practices. Due to the highly technical nature of CMP's customer billing system, on March 22, 2018 the MPUC issued an Order Initiating Audit commencing a forensic audit of CMP's customer billing system to identify any errors that have, or continue to be resulting in billing inaccuracies. On July 10, 2018, the MPUC issued an Order Modifying Scope of Audit, which expanded the scope of the audit to include CMP's customer communication practices. On December 20, 2018, the MPUC released the findings of the forensic audit of CMP's customer billing system and customer communication practices. On January 14, 2019, the MPUC issued an Order and Notice of Investigation initiating an investigation of CMP's metering and billing practices. On September 3, 2019, the MPUC issued its Bench Analysis in the Metering and Billing Investigation and supported the findings of the independent audit. On September 7, the OPA issued testimony and findings from a separate audit firm which agreed with certain portions of the independent audit and also stated that continuing problems still persist in CMP's billing system. CMP provided rebuttal testimony on October 16, 2019, and hearings were held in November 2019. On January 30, 2020, the MPUC Commissioners deliberated and based on the verbal discussion, the Commissioners indicated that CMP's Metering and Billing system is accurately reporting data; there is no systemic root cause for high usage complaints and errors related to CMP's metering and billing system are localized and random, not systemic. The Commissioners were critical of CMP finding that CMP failed to implement proper testing of the SmartCare system prior to go-live; CMP's implementation of SmartCare was imprudent; CMP's SmartCare implementation experienced an unacceptable number of billing errors, delayed or estimated bills, bill presentment issues and unreasonable time required to address these issues; and the implementation issues were compounded by inadequate staffing, resulting in the inability of customers to contact a CMP representative. In its February 19, 2020 order in the CMP's distribution rate case proceeding discussed above the MPUC imposed a reduction of 100 basis points in ROE, as a management efficiency adjustment, to address concerns with CMP's customer service performance following the implementation of its new billing system in 2017. The management efficiency adjustment will remain in effect until CMP has demonstrated satisfactory customer service performance on four specified service quality measures for a period of 18 consecutive months with measurement commencing on March 1, 2020.

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 this claim under the common law of unjust enrichment, breach of contract and fraudulent and intentional misrepresentation and seeks damages, punitive damages, attorney fees and costs. On September 21, 2018, we filed a Motion to Dismiss all of the claims that was opposed by the plaintiffs. On November 14, 2018, the plaintiff filed a motion for a preliminary and permanent injunction enjoining CMP from sending putative class members disconnection notices and/or disconnecting their power until this litigation is resolved. On February 22, 2019, the Cumberland County Superior Court ordered that the proceedings be stayed until November 1, 2019 to allow resolution of the MPUC's formal investigation of CMP's billing practices and denied the plaintiff's motion for a temporary restraining order. On July 30, 2019, Douglas Herling, chief executive officer of CMP, and Iberdrola, S.A. were added as defendants and additional claims alleging violations of the Racketeer Influenced and Corrupt Organizations Act were added to the case. 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 30, 2020, the MPUC deliberated the metering, billing and customer communications investigation. The MPUC did find that with exception of certain localized and random errors, CMP's billing system is working as designed and there were no systemic errors in billing. The decision also included an administrative process to address unresolved customer complaints of high bills. The written order documenting these decisions will be issued by the MPUC. 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. We cannot predict the outcome of this class action lawsuit.

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 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 have instituted separate proceedings in New York, Maine, Connecticut, Massachusetts and the FERC, respectively, to review and address the implications of the Tax Act on the utilities.

In New York, the NYPSC staff issued a proposal on March 29, 2018, whereby the staff recommended that Tax Act benefits be returned to customers beginning October 1, 2018. On August 9, 2018, the NYPSC issued an Order requiring sur-credits effective October 1, 2018. The sur-credits for NYSEG and RG&E reflected the lower effective tax rate of 21%. For NYSEG Gas, RG&E Electric and RG&E Gas the NYPSC also required the sur-credit to include the return to customers of the January - September 2018 Tax Act savings over three years. The NYPSC allowed NYSEG Electric to continue to defer the January - September 2018 Tax Act savings as well as to continue to preserve the protected and unprotected Tax Act savings until the companies' next rate cases. In Connecticut, UI and SCG expect Tax Act savings to be deferred until they are reflected in tariffs in a future rate case, unless PURA determines otherwise. CNG and BGC included Tax Act savings in rate cases that were filed with PURA and the DPU, respectively, in the second quarter of 2018. In Maine, CMP adjusted rates beginning July 1, 2018 to pass back to customers the Tax Act savings after offsetting for recovery of deferred 2017 storm costs and in the general rate case filing with the MPUC is proposing to use savings arising out of the Tax Act to minimize rate increases while making its electric system more reliable. In its February 19, 2020 order in the CMP's distribution rate case proceeding discussed above, the MPUC approved CMP's distribution related accumulated deferred income tax balances associated with the Tax Act as well as the authorized amortization periods for the return of regulatory liabilities and the recovery regulatory assets. At the FERC, CMP transmission and UI transmission adjusted their tariffs in June 2018 to reflect the income statement value of Tax Act savings.

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 $154 million and $157 million, respectively, for this item at December 31, 2019 and December 31, 2018.

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 2020. 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. 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. 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 and CMP will begin collecting the Power Tax Regulatory asset beginning in July 2020 over 32.5 years.

Ginna Reliability Support Service Agreement

Ginna Nuclear Power Plant, LLC, or GNPP, which is a subsidiary of Constellation Energy Nuclear Group, LLC, or CENG, owns and operates the R.E. Ginna Nuclear Power Plant, or Ginna Facility, and together with GNPP, Ginna, a 581 MW single-unit pressurized water reactor located in Ontario, New York. In May 2014, the NYISO and then the NYPSC ruled that the Ginna Facility was required to maintain system reliability and ordered RG&E and GNPP to negotiate a Reliability Support Service Agreement, or RSSA.

On October 21, 2015, RG&E, GNPP, New York Department of Public Service, Utility Intervention Unit and Multiple Intervenors filed a joint proposal with the NYPSC for approval of the RSSA, as modified. On February 23, 2016, the NYPSC unanimously adopted the joint proposal, which provided for a term of the RSSA from April 1, 2015, through March 31, 2017 and RG&E monthly payments to Ginna in the amount of $15.4 million. In addition, RG&E was entitled to 70% of revenues from Ginna's sales into the NYISO energy and capacity markets, while Ginna was entitled to 30% of such revenues. The NYPSC also authorized RG&E to implement a rate surcharge effective January 1, 2016, to recover amounts paid to Ginna pursuant to the RSSA. The FERC issued an order authorizing the FERC settlement agreement in the Settlement Docket on March 1, 2016 at which point the rate surcharge went into effect. RG&E used deferred rate credit amounts (regulatory liabilities) to offset the full amount of the deferred collection amount (including carrying costs), plus credit amounts to offset all RSSA costs that exceed $2.3 million per month, not to exceed a total use of credits in the amount of $110 million, applicable through June 30, 2017. The available credits were insufficient to satisfy the final payment amount from RG&E to Ginna, and consistent with the agreement with the NYPSC, the RSSA surcharge continued past March 31, 2017, to recover up to $2.3 million per month until the final payment amount has been recovered by RG&E from customers which. RG&E has met all payment obligations associated with the RSSA and the surcharge is no longer in effect beginning August 1, 2019.

New York TransCo

Networks holds an approximate 20% ownership interest in New York TransCo, LLC. New York TransCo was established by the New York transmission utilities to develop, own, and operate electric transmission in New York.

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, 2019. 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

Under Maine law 35-A M.R.S.A §§ 3210-C, 3210-D, 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 in Penobscot County, Maine. CMP's purchase obligations under the Rollins contract are approximately $7 million per year. Pursuant to a MPUC Order dated December 18, 2017, CMP entered into a 20-year agreement with Dirigo Solar, LLC on September 10, 2018, to purchase capacity and energy from multiple Dirigo solar facilities throughout CMP's service territory. CMP's purchase obligations under the Dirigo contract will increase as additional solar facilities are brought on line, eventually reaching a level of approximately $4 million per year. Pursuant to a MPUC Order dated November 6, 2019, CMP entered into a 20-year agreement with Maine Aqua Ventus I GP LLC on December 9, 2019, to purchase capacity and energy from an off-shore wind 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. In accordance with MPUC orders, CMP either sells the purchased energy from these facilities in the ISO New England markets or periodically auctions the purchased output to wholesale buyers in the New England regional market. Under applicable law, CMP is assured recovery of any differences between power purchase costs and achieved market revenues through a reconcilable component of its retail distribution rates. Although the MPUC has conducted multiple requests for proposals under M.R.S.A §3210-C and has tentatively accepted long-term proposals from other sellers, these selections have not yet resulted in additional currently effective contracts with CMP.

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 Consolidated Appropriations Act, Public Law 114-113 entitles wind energy generating facilities to a production tax credit or investment tax credit in lieu of the production tax credit. Production tax credits began a phase-down in eligibility to 80% for facilities that commenced construction in 2017, 60% for facilities that commenced construction in 2018, and 40% for facilities that commenced construction in 2019. On December 20, 2019, the Setting Every Community up for Retirement Enhancement Act of 2019, or the Secure Act, was signed into law that extended the production tax credit and investment tax credit options for wind facilities to 60% of the full credit for facilities commencing construction in 2020, leaving in place the phased down credits for projects commencing in years prior to 2020.

Investment tax credits are 30% for solar projects that commenced construction in 2019 or prior, 26% for solar projects commencing construction in 2020, 22% for project commencing construction in 2021, and 10% for projects commencing construction in 2022 and thereafter. Solar projects must complete construction within four years or demonstrate continuous construction to qualify for the stated investment tax credits.

Additionally, the federal government and many states and local jurisdictions have policies or other mechanisms, such as tax incentives or RPS that support the sale of energy from utility-scale renewable energy facilities, such as wind and solar energy facilities. As a result of budgetary constraints, political factors or otherwise, U.S., state or local governments from time to time may review their policies and other mechanisms that support renewable energy and consider actions that would make them less conducive to the development and 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 the development of new renewable energy projects, Renewables abandoning the development of new renewable energy projects, a loss of Renewables' investments in the projects and reduced project returns, any of which could have a material adverse effect on Renewables' business, financial condition, results of operations and prospects.

Results of Operations

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

	Year Ended December 31, 2019			
	Total	Networks	Renewables	Other(1)
	(in millions)			
Operating Revenues	**$ 6,338**	**$ 5,164**	**$ 1,186**	**$ (12)**
Operating Expenses				
Purchased power, natural gas and fuel used	1,509	1,249	260	—
Operations and maintenance	2,301	1,928	392	(19)
Loss from assets held for sale	—	—	—	—
Depreciation and amortization	934	550	383	1
Taxes other than income taxes	591	544	56	(9)
Total Operating Expenses	**5,335**	**4,271**	**1,091**	**(27)**
Operating Income	**1,003**	**893**	**95**	**15**
Other Income (Expense)				
Other income (expense)	119	(17)	155	(19)
Earnings (losses) from equity method investments	3	11	(8)	—
Interest expense, net of capitalization	(306)	(269)	(10)	(27)
Income Before Income Tax	**819**	**618**	**232**	**(31)**
Income tax (benefit) expense	143	153	4	(14)
Net Income (Loss)	**676**	**465**	**228**	**(17)**
Net loss (income) attributable to noncontrolling interests	24	(2)	26	—
Net Income (loss) Attributable to Avangrid, Inc.	**$ 700**	**$ 463**	**$ 254**	**$ (17)**

	Year Ended December 31, 2018			
	Total	Networks	Renewables	Other(1)
	(in millions)			
Operating Revenues	**$ 6,478**	**$ 5,310**	**$ 1,139**	**$ 29**
Operating Expenses				
Purchased power, natural gas and fuel used	1,653	1,423	228	2
Operations and maintenance	2,248	1,880	366	2
Loss from assets held for sale	16	—	—	16
Depreciation and amortization	855	503	352	—
Taxes other than income taxes	579	529	57	(7)
Total Operating Expenses	**5,351**	**4,335**	**1,003**	**13**
Operating Income	**1,127**	**975**	**136**	**16**
Other Income (Expense)				
Other income (expense)	(66)	(79)	18	(5)
Earnings (losses) from equity method investments	10	13	(3)	—
Interest expense, net of capitalization	(303)	(260)	(33)	(10)
Income Before Income Tax	**768**	**649**	**118**	**1**
Income tax expense (benefit)	170	169	(31)	32
Net Income (Loss)	**598**	**480**	**149**	**(31)**
Net income attributable to noncontrolling interests	(3)	(2)	(1)	—
Net Income (loss) Attributable to Avangrid, Inc.	**$ 595**	**$ 478**	**$ 148**	**$ (31)**

	Year Ended December 31, 2017			
	Total	Networks	Renewables	Other(1)
	(in millions)			
Operating Revenues	**$ 5,963**	**$ 4,961**	**$ 1,047**	**$ (45)**
Operating Expenses				
Purchased power, natural gas and fuel used	1,338	1,153	225	(40)
Operations and maintenance	2,091	1,721	354	16
Loss from assets held for sale	642	—	—	642
Depreciation and amortization	824	474	325	25
Taxes other than income taxes	563	499	51	13
Total Operating Expenses	**5,458**	**3,847**	**955**	**656**
Operating Income (Loss)	**505**	**1,114**	**92**	**(701)**
Other Income (Expense)				
Other income (expense)	(62)	(72)	4	6
Earnings (losses) from equity method investments	(40)	15	(55)	—
Interest expense, net of capitalization	(280)	(244)	(28)	(8)
Income Before Income Tax	**123**	**813**	**13**	**(703)**
Income tax expense (benefit)	(259)	316	(320)	(255)
Net Income (Loss)	**382**	**497**	**333**	**(448)**
Net income attributable to noncontrolling interests	(1)	(1)	—	—
Net Income (loss) Attributable to Avangrid, Inc.	**$ 381**	**$ 496**	**$ 333**	**$ (448)**

(1)Other amounts represent Corporate, Gas and intersegment eliminations.

Comparison of Period to Period Results of Operations

Our operating revenues decreased by 2%, from $6,478 million for the year ended December 31, 2018, to $6,338 million for the year ended December 31, 2019.

Our purchased power, natural gas and fuel used decreased by 9%, from $1,653 million for the year ended December 31, 2018, to $1,509 million for the year ended December 31, 2019.

Our operations and maintenance increased by 2%, from $2,248 million for the year ended December 31, 2018, to $2,301 million for the year ended December 31, 2019.

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

Year Ended December 31, 2019 Compared to the Year Ended December 31, 2018

Networks

Operating revenues for the year ended December 31, 2019 decreased by $146 million, or 3%, from $5,310 million for the year ended December 31, 2018, to $5,164 million. Operating revenues changed due to the following items that have offsets within the income statement: decrease of $174 million in purchased power and purchased gas in the same period (offset in purchased power), $43 million decrease in recoverable pension expense (offset in other expenses), $11 million increase in property taxes (offset in taxes other than income taxes) and a $19 million increase in pass-through components, which are offset in operating expenses. Electricity and gas revenues increased by $48 million, primarily due to the impact of increased customer rates for the year ended December 31, 2019 compared to the same period of 2018. Electric and gas revenues decreased by $12 million due to higher earnings sharing during 2019 compared to the same period of 2018 and $5 million increase in other.

Purchased power, natural gas and fuel used for the year ended December 31, 2019 decreased by $174 million, or 12%, from $1,423 million for the year ended December 31, 2018, to $1,249 million. The decrease is primarily driven by a $164 million decrease in average commodity prices and an overall decrease in electricity and gas units procured due to a decline in degree days combined with a $10 million decrease in other power supply purchases in the period, offset within operating revenues.

Operations and maintenance during the year ended December 31, 2019 increased by $48 million, or 3%, from $1,880 million for the year ended December 31, 2018, to $1,928 million. Operations and maintenance expense changed due to a $19 million increase in pass through components (offset in revenue), $12 million increase in non-deferrable outage restoration costs, and an $18 million increase in personnel costs (net of capitalized staff costs) driven by headcount and overtime increases.

Renewables

Operating revenues for the year ended December 31, 2019 increased by $47 million, or 4% from $1,139 million for the year ended December 31, 2018, to $1,186 million. Operating revenues increased due to favorable MtM changes of $99 million on energy derivative transactions entered into for economic hedging purposes, an increase in wind production of $22 million from new capacity, an increase in thermal revenues of $28 million driven by higher average prices in the period and increased sales from Klamath (28% volume increase). These items were offset by an $68 million decrease due to prices decreasing 14% through a combination of lower merchant pricing, an adverse PPA mix, expired PPA contracts; a gain of $30 million from the sale of claims from a bankruptcy proceeding with a customer recorded in 2018; and a $4 million decrease in other revenues.

Purchased power, natural gas and fuel used for the year ended December 31, 2019 increased by $32 million, or 14%, from $228 million for the year ended December 31, 2018, to $260 million. The increase is primarily driven by an increase of $28 million and $6 million in power and thermal purchases, respectively, driven by the increase in volume and unit cost in the period, offset by favorable MtM changes on derivatives of $2 million due to market price changes in the current period.

Operations and maintenance for the year ended December 31, 2019 increased by $26 million, or 7%, from $366 million for the year ended December 31, 2018, to $392 million. The increase is primarily due to $37 million of increased costs resulting from headcount increases and higher maintenance costs, which are primarily attributed to growth and enhanced maintenance to increase availability. Additionally, operations and maintenance expense decreased by $11 million driven by an asset retirement obligation adjustment in 2019.

Depreciation, Amortization and Impairment

Depreciation, amortization and impairment expenses for the year ended December 31, 2019 increased by $63 million, or 7%, from $871 million for the year ended December 31, 2018, to $934 million. The increase is primarily due to increases of $47 million as a result of plant additions in Networks and Renewables in the period, increase of $31 million driven by accelerated depreciation from the repowering of wind farms in Renewables, offset by a loss of $16 million from remeasurement of assets held for sale driven by final purchase price negotiations and certain related working capital adjustments of Gas business recorded in 2018.

Other Income and (Expense) and Equity Earnings

Other income and (expense) and equity earnings for the year ended December 31, 2019 increased by $178 million, or 318%, from $(56) million for the year ended December 31, 2018, to $122 million, primarily due to a $30 million favorable change in allowance for funds used during construction, $43 million of favorable pension and other post-retirement expense in the period in Networks driven by lower actuarial loss amortization (offset in Networks revenue) and a $134 million gain from the sale of assets during the period in Renewables, offset by a decrease of $7 million in equity earnings, $11 million settlement penalty with the NYDPS in Networks and a decrease of $10 million driven by the write-off of certain development projects in Renewables in the current period.

Interest Expense, Net of Capitalization

Interest expense for the year ended December 31, 2019 increased by $3 million or 1% from $303 million for the year ended December 31, 2018, to $306 million. Networks had a $9 million increase in interest expense due to a higher average outstanding balance of debt in the period, partially offset by an $8 million decrease in carrying costs on regulatory deferrals. Corporate and Other added $26 million of interest expense from new debt issued in 2019. This is offset by an interest expense decrease in Renewables of $23 million due to lower average debt balances in the current period.

Income Tax Expense

The effective tax rate, inclusive of federal and state income tax, for the year ended December 31, 2019 was 17.5%, which is below the federal statutory tax rate of 21%, primarily due to the recognition of production tax credits associated with wind production and favorable discrete tax adjustments. The effective tax rate, inclusive of federal and state income tax, for the year ended December 31, 2018, was 22.1%, which is higher than the 21% statutory federal income tax rate, predominantly due to $20.7 million of tax expense recorded in connection with the disposal of the Gas business and discrete adjustments recorded during the period, offset by the recognition of production tax credits associated with wind production.

Year Ended December 31, 2018 Compared to the Year Ended December 31, 2017

Networks

Operating revenues for the year ended December 31, 2018 increased by $349 million, or 7%, from $4,961 million for the year ended December 31, 2017, to $5,310 million. Electricity and gas revenues increased by $82 million and $27 million, primarily due to the impact, respectively, of increased electric and gas customer rates in the year ended December 31, 2018 compared to the same period in 2017. Electricity and gas revenues for the year ended December 31, 2018 compared to the same period in 2017, increased by $87 million and $94 million due to increased commodity prices and higher volumes largely driven by an increase in degree days. Wholesale electricity and capacity revenues increased by $59 million for the year ended December 31, 2018 compared to the same period of 2017 due to an increase in average prices. Revenue related regulatory activities in the period increased primarily due to a $65 million increase in pass through components and $31 million increase in appliance revenue, both offset in operations and maintenance, and an increase of $13 million due to lower earnings sharing. These are primarily offset by an adjustment of $14 million to unfunded future income tax to reflect the change from a flow through to normalization method, which was recorded in 2017 as an increase to revenue with an offsetting and equal increase to income tax expense; a decrease of $78 million from deferrals of excess deferred income taxes due to changes in federal tax rates as a result of the Tax Act and $16 million in non-bypassable charges in the period.

Purchased power, natural gas and fuel used for the year ended December 31, 2018 increased by $270 million, or 23%, from $1,153 million for the year ended December 31, 2017, to $1,423 million. The increase is primarily driven by $175 million and $86 million increases in average commodity prices and overall increase in the units of electricity and gas, respectively, procured due to an increase in degree days combined with an $8 million increase in other power supply purchases.

Operations and maintenance during the year ended December 31, 2018 increased by $159 million, or 9%, from $1,721 million for the year ended December 31, 2017, to $1,880 million. The increase is primarily due to a $65 million increase in operations pass through costs and $31 million of costs related to appliance revenue, both offset in revenue, a $20 million increase due to non-deferrable outage restoration costs, a $13 million increase in uncollectible expenses and lower capitalized labor costs of $37 million in the period, offset by a $6 million decrease in personnel costs driven by lower termination settlements compared to the same period of 2017.

Renewables

Operating revenues for the year ended December 31, 2018 increased by $92 million, or 9% from $1,047 million for the year ended December 31, 2017, to $1,139 million. The increase in operating revenues was primarily due to an increase of $88 million with wind generation output increasing 1,730 GWh, an increase in thermal revenue of $12 million driven by higher prices, an increase of $25 million resulting from the sale of a claim from a bankruptcy proceeding with a customer, and an increase of $6 million resulting from the settlement of a lawsuit in the period, offset by an $8 million decrease driven by cancellation of First Energy PPAs combined with unfavorable mark-to-market, or MtM, changes of $32 million on energy derivative transactions entered into for economic hedging purposes.

Purchased power, natural gas and fuel used for the year ended December 31, 2018 increased by $3 million, or 1%, from $225 million for the year ended December 31, 2017, to $228 million. The increase is primarily driven by an increase of $25 million in power purchases and transmission costs due to the addition of new capacity, offset by MtM changes on derivatives of $22 million that were favorable due to market price changes in the current period.

Operations and maintenance for the year ended December 31, 2018 increased by $12 million or 3% from $354 million for the year ended December 31, 2017, to $366 million, which is primarily due to a $9 million increase in wind farm operations costs driven by new capacity with the remaining increase attributable to higher intercompany charges in 2018.

Depreciation, Amortization and Impairment

Depreciation, amortization and impairment expenses for the year ended December 31, 2018 decreased by $595 million or 41% from $1,466 million for the year ended December 31, 2017, to $871 million. The decrease is driven by lower loss from assets held for sale of $626 million recorded in connection with management's decision in 2017 to sell the gas trading and storage businesses. Net plant additions in Networks increased depreciation expense by $27 million in the period. Renewables added $34 million to depreciation expense due to a new operating capacity and $2 million of accelerated depreciation driven by repowering, offset by $9 million lower depreciation expense due to an increase in asset lives recorded in 2017 and $24 million of lower depreciation expense in Other driven by the cessation of depreciation of assets held for sale.

Other Income and (Expense) and Equity Earnings

Other income and (expense) and equity earnings for the year ended December 31, 2018 increased by $46 million, or 45%, from $(102) million for the year ended December 31, 2017, to $(56) million, primarily due to the impact of an other than temporary impairment, or OTTI, of $49 million on an equity method investment and a $3 million lower write-off of certain development projects in Renewables in 2017, a $10 million gain from the sale of our interest in Coyote Ridge in 2018, offset by an $8 million increase in non-service component of pension and other post-retirement cost and a decrease of $6 million in allowance for funds used during construction and other regulatory deferrals in Networks.

Interest Expense, Net of Capitalization

Interest expense for the year ended December 31, 2018 increased by $23 million or 8% from $280 million for the year ended December 31, 2017, to $303 million. Networks and Other added $13 million and $18 million of interest expense from new debt issued in 2018 and 2017. In addition, Renewables interest expense increased by $16 million due to an intercompany loan in the current period. This is offset by $24 million lower interest expense in Other driven by sale of the gas business in 2018.

Income Tax Expense

The effective tax rate, inclusive of federal and state income tax, for the year ended December 31, 2018 was 22.1%, which is higher than the 21% statutory federal income tax rate, predominantly due to $20.7 million of tax expense recorded in connection with the disposal of the Gas business and discrete adjustments recorded during the period, offset by the recognition of production tax credits associated with wind production. The effective tax rate, inclusive of federal and state income tax, for the year ended December 31, 2017, was (210.6)%, which is lower than the 35% statutory federal income tax rate applicable in 2017, predominately due to a $328 million tax benefit from measurement of deferred income tax balances as a result of the Tax Act. Additionally, a $14 million increase in income tax expense is due to unfunded future income tax to reflect the change from a flow through to normalization method, which was recorded as an increase to revenue, with an offsetting and equal increase to income tax expense during the year ended December 31, 2017. This increase was partially offset by other discrete tax adjustments and recognition of production tax credits associated with wind production during the same period.

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 as non-GAAP 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 used by AVANGRID to economically hedge market price fluctuations in related underlying physical transactions for the purchase and sale of electricity, loss from held for sale measurement, accelerated depreciation derived from repowering of wind farms, other than temporary impairment, or OTTI, impact of the Tax Act and adjustments for the non-core Gas storage business. 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.

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 adjusted net income (non-GAAP) by segment for the years ended December 31, 2019, 2018 and 2017, respectively:

	Year Ended December 31, 2019			
	Total	Networks	Renewables	Corporate *
		(in millions)		
Net Income Attributable to Avangrid, Inc.	**$ 700**	**$ 463**	**$ 254**	**$ (17)**
Adjustments:				
Mark-to-market adjustments - Renewables	(76)	—	(76)	—
Restructuring charges	6	3	1	3
Accelerated depreciation from repowering	33	—	33	—
Income tax impact of adjustments (1)	10	(1)	11	(1)
Adjusted Net Income (2)	**$ 673**	**$ 466**	**$ 223**	**$ (15)**

	Year Ended December 31, 2018				
	Total	Networks	Renewables	Corporate *	Gas Storage
			(in millions)		
Net Income (Loss) Attributable to Avangrid, Inc.	**$ 595**	**$ 478**	**$ 148**	**$ (12)**	**$ (19)**
Adjustments:					
Mark-to-market adjustments - Renewables	25	—	25	—	—
Restructuring charges	4	4	—	—	—
Loss from held for sale measurement	16	—	—	—	16
Impact of the Tax Act	46	5	16	25	—
Accelerated depreciation from repowering	3	—	3	—	—
Income tax impact of adjustments (1)	6	(1)	(7)	—	14
Gas Storage, net of tax	(11)	—	—	—	(11)
Adjusted Net Income (2)	**$ 684**	**$ 486**	**$ 185**	**$ 13**	**$ —**

	Year Ended December 31, 2017				
	Total	Networks	Renewables	Corporate *	Gas Storage
			(in millions)		
Net Income (Loss) Attributable to Avangrid, Inc.	**$ 381**	**$ 496**	**$ 333**	**$ 60**	**$ (508)**
Adjustments:					
Mark-to-market adjustments - Renewables	15	—	15	—	—
Restructuring charges	20	20	—	—	—
Loss from held for sale measurement	642	—	—	—	642
Impact of the Tax Act	(328)	(2)	(301)	(5)	(20)
Impairment of equity method investment	49	—	49	—	—
Income tax impact of adjustments (1)	(162)	(8)	24	—	(179)
Gas Storage, net of tax	64	—	—	—	64
Adjusted Net Income (2)	**$ 682**	**$ 507**	**$ 120**	**$ 55**	**$ —**

(1) Income tax impact of adjustments: $20 million from MtM adjustment, $(9) million from accelerated depreciation, $(2) million from restructuring charges, for the year ended December 31, 2019. $(6) million from MtM adjustment, $(1) million from accelerated depreciation, $(1) million from restructuring charges, $14 million from loss from held for sale measurement for the year ended December 31, 2018. Income tax impact of $(5) million from MtM adjustment, $(8) million from restructuring charges, $(13) million from OTTI on an equity method investment, $(179) million from loss from held for sale measurement and $43 million from adjustment to unitary income taxes as a result of expected future sale of Gas for the year ended December 31, 2017.

(2) Adjusted Net Income is a non-GAAP financial measure and is presented after excluding restructuring charges, OTTI on equity method investment, loss from held for sale measurement, impact of the Tax Act, accelerated depreciation derived from repowering of a wind farm, MtM activities in Renewables and Gas storage businesses.

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

Comparison of Period to Period Results of Operations

Year Ended December 31, 2019 Compared to the Year Ended December 31, 2018

Adjusted net income

Our adjusted net income decreased by $11 million, or 2%, from $684 million for the year ended December 31, 2018 to $673 million for the year ended December 31, 2019. The decrease is primarily due to a $21 million decrease in Networks driven by increased non-deferrable outage restoration costs and an increase in personnel costs (net of capitalized staff costs) driven by headcount and overtime increases and a $28 million decrease in Corporate mainly driven by higher interest expense, offset by a $38 million increase in Renewables driven mainly by thermal revenue increase and a gain from the sale of assets and associated change in control during the period.

Year Ended December 31, 2018 Compared to the Year Ended December 31, 2017

Adjusted net income

Our adjusted net income increased by $2 million, or less than 1%, from $682 million for the year ended December 31, 2017 to $684 million for the year ended December 31, 2018. The increase is primarily due to a $65 million increase in Renewables due to increased wind generation in the period, offset by a $21 million decrease in Networks driven by increased non-deferrable outage restoration costs and the associated impacts including lower capitalized labor in the period, $42 million decrease in Corporate mainly driven by lower interest income on intercompany loans due to the sale of the gas business in 2018 and higher income tax expense due to decreased unitary benefit driven by sale of gas business.

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, 2019, 2018 and 2017, respectively:

	Year Ended December 31,		
	2019	2018	2017
		(in millions)	
Networks	$ 463	$ 478	$ 496
Renewables	254	148	333
Corporate (1)	(17)	(12)	60
Gas Storage	—	(19)	(508)
Net Income	**$ 700**	**$ 595**	**$ 381**
Adjustments:			
Mark-to-market adjustments - Renewables (2)	(76)	25	15
Restructuring charges (3)	6	4	20
Loss from held for sale measurement (4)	—	16	642
Impact of the Tax Act (5)	—	46	(328)
Accelerated depreciation from repowering (6)	33	3	—
Impairment of equity method and other investment (7)	—	—	49
Income tax impact of adjustments	10	6	(162)
Gas Storage, net of tax	—	(11)	64
Adjusted Net Income (8)	**$ 673**	**$ 684**	**$ 682**

	Year Ended December 31,		
	2019	2018	2017
Networks	$ 1.50	$ 1.54	$ 1.60
Renewables	0.82	0.48	1.08
Corporate (1)	(0.06)	(0.04)	0.19
Gas Storage	—	(0.06)	(1.64)
Earnings Per Share	**$ 2.26**	**$ 1.92**	**$ 1.23**
Adjustments:			
Mark-to-market adjustments - Renewables (2)	(0.25)	0.08	0.05
Restructuring charges (3)	0.02	0.01	0.07
Loss from held for sale measurement (4)	—	0.05	2.08
Impact of the Tax Act (5)	—	0.15	(1.06)
Accelerated depreciation from repowering (6)	0.11	0.01	—
Impairment of equity method and other investment (7)	—	—	0.16
Income tax impact of adjustments	0.03	0.02	(0.52)
Gas Storage, net of tax	—	(0.04)	0.21
Adjusted Earnings Per Share (8)	**$ 2.17**	**$ 2.21**	**$ 2.20**

(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) 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.
(4) Represents loss from measurement of assets and liabilities held for sale in connection with the sale of the gas trading and storage businesses.
(5) Represents the impact from measurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017.
(6) Represents the amount of accelerated depreciation derived from the repowering of wind farms in Renewables.
(7) Includes OTTI on equity method investment recorded in 2017.
(8) Adjusted Net Income and Adjusted Earnings Per Share are non-GAAP financial measures and are presented after excluding restructuring charges, OTTI on equity method investment, loss from held for sale measurement, impact of the Tax Act, accelerated depreciation derived from the repowering wind farms, MtM activities in Renewables and Gas storage businesses.

Liquidity and Capital Resources

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

Liquidity Resources

At December 31, 2019, we had cash and cash equivalents of $178 million, as compared to $36 million at December 31, 2018. In addition to cash on hand, we have the capacity to borrow from third parties through a $2 billion commercial paper program, the $2.5 billion AVANGRID Credit Facility which backstops the commercial paper program and $500 million from an Iberdrola Group Credit Facility, both of which are described below.

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.

We manage our overall liquidity position as part of the group of companies controlled by Iberdrola, or the Iberdrola Group, and 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 December 31, 2019 and 2018, the balance was $150 million and zero, respectively. 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. We also have a bi-lateral demand note agreement with a Canadian affiliate of the Iberdrola Group under which we had notes payable balance outstanding of zero at both December 31, 2019 and December 31, 2018.

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, 2019 and February 28, 2020, there was $562 million and $859 million of commercial paper outstanding, respectively.

AVANGRID Credit Facility

AVANGRID and its subsidiaries, NYSEG, RG&E, CMP, UI, CNG, SCG and BGC have a revolving credit facility with a syndicate of banks, or the AVANGRID Credit Facility, that provides for maximum borrowings of up to $2.5 billion in the aggregate.

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. AVANGRID's maximum sublimit is $2 billion, NYSEG, RG&E, CMP and UI have maximum sublimits of $400 million, CNG and SCG have maximum sublimits of $150 million and BGC has a maximum sublimit of $40 million. Under the AVANGRID Credit Facility, each of the borrowers will pay an annual facility fee that is dependent on their credit rating. As of December 31, 2019, the facility fees range from 10.0 to 17.5 basis points. During 2019, we extended the maturity date for the AVANGRID Credit Facility by one year to June 29, 2024.

Since the facility is a backstop to the AVANGRID commercial paper program, the amounts available under the facility as of December 31, 2019 and February 28, 2020, were $1,938 million and $1,641 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 on the facility. As of both December 31, 2019 and February 28, 2020, there was no outstanding amount under this credit facility.

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 and long-term borrowings. 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.

On January 15, 2019, UI, CNG, SCG and BGC issued $195 million aggregate amount of notes/bonds with maturity dates ranging from 2029 to 2049 and fixed interest rates ranging from 4.07% to 4.52%.

On April 1, 2019, NYSEG issued $12 million of Indiana County Industrial Development Authority Pollution Control Revenue Bonds in a private placement maturing in 2024 with a fixed interest rate of 2.65%.

On May 16, 2019, AVANGRID issued $750 million of senior unsecured notes maturing in 2029 at a fixed interest rate of 3.80%.

On June 3, 2019, CMP issued $240 million aggregate principal amount of first mortgage bonds with maturity dates ranging from 2026 to 2034 and fixed interest rates ranging from 3.87% to 4.20%.

On August 27, 2019, RG&E issued $150 million aggregate principal amount of first mortgage bonds maturing in 2027 at a fixed interest rate of 3.10%.

On September 5, 2019, NYSEG issued $300 million aggregate principal amount of senior unsecured notes maturing in 2049 at a fixed interest rate of 3.30%.

On December 31, 2019, AVANGRID entered into a $500 million term loan credit agreement with two financial institutions. The agreement expires on June 30, 2021 and has a variable interest rate, which was 2.40% as of December 31, 2019.

At December 31, 2019, we had $5,153 million of debt (including the current portion thereof) outstanding in the Networks segment 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, 2019.

At December 31, 2019, we had a $50 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 production tax credits to the tax equity investor, along with a small percentage of cash generated by the projects, in exchange for an initial contribution. On June 28, 2019, Renewables closed on the sale of a tax equity interest in its Patriot wind project, which resulted in proceeds of $128 million.

At December 31, 2019, we had $2,293 million of long-term debt (including the current portion thereof) outstanding in corporate. Long-term debt in corporate consists mainly of $450 million of 4.625% notes due in 2020, $600 million of 3.150% notes due in 2024, $750 million of 3.80% notes due in 2029 issued in May 2019 and a $500 million term loan agreement entered into December 31, 2019.

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, 2019.

Capital Requirements

Funding Future Common Dividend Payments

We expect to fund any quarterly shareholder dividends primarily from the cash provided by operations of our businesses in the future. We have revolving credit facilities and a commercial paper program, as described above, to fund short-term liquidity needs and we believe that we will have access to the capital markets should additional, long-term growth capital be necessary.

Capital Expenditures

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

	2019	2018	2017
		(in millions)	
NYSEG	$ 574	$ 517	$ 364
RG&E	379	283	303
CMP	299	212	252
MNG	7	7	3
UI	192	153	176
SCG	83	57	53
CNG	60	55	70
BGC	19	17	18
Total	**$ 1,613**	**$ 1,301**	**$ 1,239**

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

	2019	2018	2017
		(in millions)	
Wind & solar	$ 1,281	$ 277	$ 902
Thermal	7	25	17
Corporate(1)	13	13	10
Total capital expenditures	**$ 1,301**	**$ 315**	**$ 929**

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

Networks increased its capital expenditures during the period from 2017 to 2019 to upgrade and expand electricity and natural gas transmission and distribution infrastructure. In 2019, NYSEG and RG&E continued their capital investments in a number of programs, including the grid automation project, distribution line project, FERC compliance programs, Rochester Area Reliability Project, or RARP, and Gas Distribution Mains and Leak Prone Main replacement project. In 2019, CMP's projects were mainly in developing its new customer relationship management and billing system and transmission investments in the Maine Electric Power Corporation, or MEPCO. UIL's projects were mainly driven by new customer connections, system and corrective reliability, system resiliency, infrastructure replacement and system operations.

Renewables also made capital investments during this three-year period. In 2019, there were capital expenditures of $1.2 billion on construction of Otter Creek, Karankawa, Montague, Tatanka Ridge and other wind and solar assets as well as the acquisition of Patriot Wind, $7 million in capital expenditures on the Klamath gas-fired cogeneration facility, or the Klamath Plant, $15 million on improvements to operating wind assets and $31 million in development costs.

In 2018, there were capital expenditures of $232 million on construction of Otter Creek, Karankawa, Montague, Wy'East Solar and other wind and solar assets, $25 million in capital expenditures on the Klamath Plant, $17 million on improvements to operating wind assets and $28 million in development costs.

In 2017, there were capital expenditures of $856 million on construction of El Cabo, Tule, Twin Buttes II, Deerfield and other wind assets, $17 million in capital expenditures on the Klamath Plant, $11 million on improvements to operating wind assets and $35 million in development costs.

Capital Improvement Projects

An important part of our business strategy involves capital improvement projects. Through Networks we plan to invest a total of approximately $9.58 billion from 2020 to 2024 to upgrade and expand electricity and natural gas transmission and distribution infrastructure. In the next 12 months, Networks plans to invest $529 million in Maine, including the NECEC, Spectrum Project, Fleet Services, Physical and Cyber Security, Line Inspection and Waterville-Winslow Reliability Project. In addition, CMP plans to continue developing its new customer relationship management and billing system and new transmission investments in MEPCO, 388 rebuild. MEPCO plans to invest $23 million in the next 12 months. NYSEG plans to invest $659 million in the next 12 months, including: NYSEG Grid Automation, AMI Project, NY WAN Expansion Project, BES Program - FERC Compliance, NYSEG Breaker Program, NYSEG Distribution Line Project, Phelps South Gas Replacement Project, Gas Distribution Mains and Leak Prone Main replacement. RG&E plans to invest $428 million in the next 12 months, including: RARP, BES Program - FERC Compliance, Station 23 115kV Substation, Telcom NY WAN Buildout, Gas Distribution Mains and Leak Prone Main replacement. UIL plans to invest $323 million in the next 12 months, including a number of programs and projects related to new customer connections, replacement of aging infrastructure, and improvement of system operations, reliability and resiliency. For gas operations, the most notable investments include cast iron/bare steel pipe replacement, infrastructure expansion and the connection of new customers.

Through Renewables we plan to invest at least a total of approximately $3.5 billion from 2020 to 2024 and add at least approximately 2,100 MW of generation capacity.

Renewables, through its joint venture in Vineyard Wind, was awarded a second Massachusetts offshore easement. During 2019, contributions of $106 million were made to a new offshore development project, which is accounted for as an equity method investment, to enter into the easement contract.

We expect to fund these capital improvement projects through a combination of retained earnings, 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 a revolving credit facility, 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, 2019, 2018 and 2017, respectively:

	Year Ended December 31,		
	2019	2018	2017
		(in millions)	
Cash Flows			
Net cash provided by operating activities	$ 1,593	$ 1,791	$ 1,763
Net cash used in investing activities	(2,713)	(1,564)	(2,341)
Net cash provided by (used in) from financing activities	1,261	(230)	528
Net decrease in cash, cash equivalents and restricted cash	**$ 141**	**$ (3)**	**$ (50)**

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, 2019 compared to the year ended December 31, 2018 decreased by $198 million, primarily attributable to higher operations and maintenance expenses and cash interest paid in the period.

The cash from operating activities for the year ended December 31, 2018 compared to the year ended December 31, 2017 increased by $28 million, primarily attributable to increased operating revenues in the period.

The cash from operating activities for the year ended December 31, 2017 compared to the year ended December 31, 2016 increased by $202 million, primarily attributable to increased operating revenues, excluding the impact of a non-cash adjustment of unfunded future income tax in 2016.

Investing Activities

Our investing activities have primarily focused on enhancing, automating and reinforcing the 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 and spending on gas generation assets.

In 2019, net cash used in investing activities was $2,713 million, which was comprised of $2,740 million of capital expenditures and $176 million of other investments and equity method investments, partially offset by $74 million of contributions in aid of construction and $126 million of proceeds from the sale of assets.

In 2018, net cash used in investing activities was $1,564 million, which was comprised of $1,787 million of capital expenditures, partially offset by $60 million of contributions in aid of construction, $4 million of cash distributions from equity method investments, and proceeds from sale of assets of $204 million primarily related to the sale of assets held for sale.

In 2017, net cash used in investing activities was $2,341 million, which was comprised of $2,416 million of capital expenditures, partially offset by $57 million of contributions in aid of construction, $4 million of cash distributions from equity method investments and proceeds of $12 million from the sale of assets.

Financing Activities

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

In 2019, financing activities provided $1,261 million in cash reflecting primarily an issuance of non-current debt at Avangrid, Inc., and our regulated subsidiaries with the net proceeds of $2,137 million and tax equity financing contributions from non-controlling interests of $133 million, offset by a net decrease in non-current debt and current notes payable of $374 million, distributions to non-controlling interests of $63 million, payments on capital leases of $27 million and dividends of $545 million.

In 2018, financing activities used $230 million in cash reflecting primarily an issuance of non-current debt at NYSEG, RG&E, CMP and UI with the net proceeds of $597 million, tax equity financing contributions from non-controlling interests of $223 million, offset by a net decrease in non-current debt and current notes payable of $418 million, distributions to non-controlling interests of $76 million, payments on capital leases of $13 million and dividends of $537 million.

In 2017, financing activities provided $528 million in cash reflecting primarily an issuance of non-current debt at RG&E with the net proceeds of $294 million and notes at Avangrid, Inc. with net proceeds of $594 million, after price discount and issuance-related expenses, a net increase in non-current debt and current notes payable of $320 million, payments on the tax equity financing arrangements of $113 million, payments on capital lease of $33 million and dividends of $535 million.

Contractual Obligations

As of December 31, 2019, our contractual obligations (excluding any tax reserves) were as follows:

	Total	2020	2021	2022	2023	2024	Thereafter
				(in millions)			
Leases(1)	$ 293	$ 24	$ 20	$ 13	$ 57	$ 6	$ 173
Easements (2)	877	24	25	25	25	25	753
Projected future pension benefit plan contributions(3)	294	83	56	73	63	19	—
Long-term debt (including current maturities)(4)	7,446	730	801	363	439	612	4,501
Interest payments(5)	3,009	291	257	237	221	210	1,793
Material purchase commitments(6)	1,725	1,372	152	62	43	19	77
Total Contractual Obligations	**$ 13,644**	**$ 2,524**	**$ 1,311**	**$ 773**	**$ 848**	**$ 891**	**$ 7,297**

(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. The category now includes finance leases after the adoption of ASC 842 in 2019.

(2) Represents easement contracts which no longer qualify as leases under ASC 842 effective in 2019.

(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. The minimum required contributions for years after 2023 are not included as projections beyond 2023 are not available.

(4) Includes sinking fund obligations and obligations under capital leases. 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, 2019, 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, 2019.

(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, 2019.

Critical Accounting Policies and Estimates

The financial statements provided herein have been prepared in accordance with U.S. GAAP and include the accounts of AVANGRID and its consolidated subsidiaries. Significant accounting policies are described 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. In order to apply such regulatory accounting treatment and record regulatory assets and liabilities, certain criteria must be met. In determining whether the criteria are met 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 adjustments to its previous conclusions are necessary 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 these 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, assumptions are made 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 utilized to develop the discount rate for the AVANGRID plans is based upon the settlement of such liabilities as of December 31, 2019, utilizing a hypothetical portfolio of actual, high quality bonds, which 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 utilized 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.

We reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses for the regulated utilities of Networks as regulatory assets or liabilities as it is probable that such items will be recovered through the ratemaking process in future periods.

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 by the acquirer to former owners of the acquiree and the equity interests issued by the acquirer. Acquisition related costs are expensed as incurred. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the consideration transferred over the fair value of the identifiable net assets acquired is recorded as goodwill. 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.

In contrast to a business combination, we classify a transaction as an asset acquisition when substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or group of similar identifiable assets or otherwise does not meet the definition of a business.

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 will more likely than not reduce the fair value of the reporting unit below its carrying amount. A reporting unit is an operating segment or one level below an operating segment and is the level at which we test goodwill for impairment.

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

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

Our step one impairment testing, and step two if required, includes various assumptions, primarily the discount rate, which is based on an estimate of a market participant's marginal, weighted average cost of capital, and forecasted cash flows. We test the reasonableness of the conclusions of our step one impairment testing using a range of discount rates and a range of assumptions for long term cash flows.

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. 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 valuation model, or the DCF 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.

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 a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences. We defer the investment tax credits when earned and amortize them over the estimated lives of the related assets.

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 other comprehensive income, or 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.

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)" of the consolidated statements of income.

Uncertain tax positions have been classified as noncurrent unless expected to be paid within one year. In 2019, we netted our liability for uncertain tax positions against all same jurisdiction deferred tax assets, net operating losses and tax credit carryforwards. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the consolidated statements of income.

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 due to our inability to immediately monetize the tax credits.

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.

Off-Balance Sheet Arrangements

At December 31, 2019, we had approximately $3.5 billion 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, 2019, neither we nor our subsidiaries have any liabilities recorded for these instruments.

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 fixed price power risk, which is hedged with fixed price power trades. Its 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 99% probability level over a five-day holding period, indicating that it can be 99% confident that losses over five days would not exceed that value. The average VaR for 2019 was $20.6 million compared to a 2018 average of $18.7 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, including commercial paper of $562 million, was $8.0 billion at December 31, 2019, of which $1.1 billion had a floating interest rate; a change of 25 basis points in this interest rate would result in an interest expense fluctuation of approximately $3 million annually. The estimated fair value of our long-term debt at December 31, 2019 was $8.2 billion, in comparison to a book value of $7.4 billion.

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. In 2019 and 2018, AVANGRID entered into three forward interest rate swaps to hedge the issuance of the $750 million of fixed rate debt issued in 2019. The forward interest rate swaps were designated and qualified as cash flow hedges and were settled upon the forecasted debt issuance. The losses on the interest rate swap derivatives are reported as a component of accumulated OCI and are reclassified into earnings during the periods in which the related interest expense is incurred. Further information regarding the 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 were no interest rate derivative contracts outstanding at December 31, 2019.

Pension and Post-Retirement Plans

We provide pensions and other post-retirement benefits for a significant number of employees, former employees and retirees. In applying relevant accounting policies, we have made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, discount rates, health care cost trends and future compensation. The cost of pension and other post-retirement benefits in future periods will depend on actual returns on plan assets, assumptions for future periods, contributions and benefit experience. In 2019, we contributed $65 million to our pension plans. Our contribution to the pension plans in 2020 is expected to be approximately $83 million.

The discount rates used in accounting for pension and other benefit obligations in 2019 ranged from 2.93% to 4.09%. The expected rate of return on plan assets for qualified pension benefits in 2019 ranged from 5.50% to 7.40%. The following tables reflect the estimated sensitivity associated with a change in certain significant actuarial assumptions (each assumption change is presented mutually exclusive of other assumption changes):

		Impact on 2019 Pension Expense Increase (Decrease)	
	Change in Assumption	Pension Benefits	Post Retirement
		(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	$ (13)	$ (1)
Decrease in return on plan assets	50 basis points	$ 13	$ 1

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 uncollectable 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. We manage counterparty credit risk for our subsidiaries with energy management through established policies, including counterparty credit limits, and in some cases credit enhancements, such as cash prepayments, letters of credit, cash and other collateral and guarantees.

Some relevant considerations when assessing the credit risk exposure of the energy management operations are as follows:

- Operations are primarily concentrated in the energy industry.
- 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.
- Overall credit risk is managed through established credit policies by a Credit Risk Management group that is independent of the energy management function.
- Prospective and existing customers are reviewed for creditworthiness based upon established standards, with customers not meeting minimum standards providing various credit enhancements or secured payment terms, such as guarantees, letters of credit or the posting of margin cash collateral.
- Master netting agreements are used, where appropriate, to offset cash and non-cash gains and losses arising from derivative instruments with the same counterparty.

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, 2019, approximately 98% of our energy management counterparty credit risk exposure is associated with companies that have investment grade credit ratings.

Treasury Management (including Liquidity Risk)

We manage our overall liquidity position as part of the group of companies controlled by the Iberdrola Group, and are a party to a liquidity agreement with a financial institution, along with certain members of the Iberdrola Group. We optimize our liquidity within the United States 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 also have a bi-lateral demand note agreement with a Canadian affiliate of the Iberdrola Group. We have the capacity to borrow from third parties through a $2 billion commercial paper program, the $2.5 billion 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 unregulated affiliates 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 $50 million at December 31, 2019.

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 April 2019, Renewables recorded a net non-cash dividend of $309 million to Avangrid, Inc. to zero out account balances that had principally accumulated prior to January 2019.

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, 2019 and 2018, 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, 2019, and the related notes and financial statement schedule I (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, 2019 and 2018, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2019, 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, 2019, 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 March 2, 2020 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, 2019 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 for 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 primary procedures we performed to address this critical audit matter included the following. We tested 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 reporting unit's historical revenue forecasts to actual revenues. We compared the reporting unit's forecasted power production and forecasted market prices to historical power production and market prices. We also evaluated the forecasted market prices by comparing them to third-party published reports 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 the results of our independently developed discount rates 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 reflects the actions of regulators. These actions may result in the recognition of revenue and expenses in time periods that are different than non-rate-regulated enterprises. 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 primary procedures we performed to address this critical audit matter included the following. We tested 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.

Evaluation of tax equity financing arrangements

As discussed in Notes 3 and 20 to the consolidated financial statements, the Company participates in certain tax equity financing arrangements (TEFs) that qualify as variable interest entities (VIEs). For TEFs where the economic allocations of income are not based on pro rata ownership percentages, a balance sheet-oriented hypothetical liquidation at book value (HLBV) method is used to reflect the substantive profit sharing arrangement. Under the HLBV method, the amounts reported as noncontrolling interests and net income (loss) attributable to noncontrolling interests in the consolidated balance sheets and consolidated statements of income are based on the amounts the noncontrolling interest would hypothetically receive at each balance sheet date under the liquidation provisions of each partnership's ownership agreement assuming the net assets of the projects were liquidated at recorded amounts and distributed to the equity holders. Noncontrolling interests and net loss attributable to noncontrolling interests as of and for the year ended December 31, 2019 were $349 million and $24 million, respectively.

We identified the evaluation of tax equity financing arrangements as a critical audit matter. This was due to the nature and extent of audit effort required, which included specialized skills and knowledge to evaluate that the HLBV methodology used was consistent with the liquidation provisions of the underlying operating and partnership agreements, which can be based on income tax rules and regulations.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company's review of the HLBV model, including controls related to review of the setup and accounting of the partnership liquidation model in relation to the operating and partnership agreement provisions, as well as the applicable tax regulations. We involved tax professionals with specialized skills and knowledge, who assisted in:

- analyzing the tax status of the entities and the requirements of the operating and partnership agreement provisions, as well as the partnership tax regulations, and

- evaluating the Company's methodology for calculating the hypothetical liquidation amounts for a partnership in accordance with the operating and partnership agreement provisions, as well as the partnership tax regulations.

/s/ KPMG LLP

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

New York, New York
March 2, 2020

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, 2019, 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, 2019, 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, 2019 and 2018, 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, 2019, and the related notes and financial statement schedule I (collectively, the consolidated financial statements), and our report dated March 2, 2020 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
March 2, 2020

Avangrid, Inc. and Subsidiaries
Consolidated Statements of Income

Years Ended December 31,	2019	2018	2017
(Millions, except for number of shares and per share data)			
Operating Revenues	**$ 6,338**	**$ 6,478**	**$ 5,963**
Operating Expenses			
Purchased power, natural gas and fuel used	1,509	1,653	1,338
Operations and maintenance	2,301	2,248	2,091
Loss from assets held for sale	—	16	642
Depreciation and amortization	934	855	824
Taxes other than income taxes, net	591	579	563
Total Operating Expenses	**5,335**	**5,351**	**5,458**
Operating Income	**1,003**	**1,127**	**505**
Other Income and (Expense)			
Other income (expense)	119	(66)	(62)
Earnings (losses) from equity method investments	3	10	(40)
Interest expense, net of capitalization	(306)	(303)	(280)
Income Before Income Tax	**819**	**768**	**123**
Income tax expense (benefit)	143	170	(259)
Net Income	**676**	**598**	**382**
Net loss (income) attributable to noncontrolling interests	24	(3)	(1)
Net Income Attributable to Avangrid, Inc.	**$ 700**	**$ 595**	**$ 381**
Earnings Per Common Share, Basic:	**$ 2.26**	**$ 1.92**	**$ 1.23**
Earnings Per Common Share, Diluted:	**$ 2.26**	**$ 1.92**	**$ 1.23**
Weighted-average Number of Common Shares Outstanding:			
Basic	309,491,082	309,503,319	309,502,861
Diluted	309,514,910	309,712,628	309,661,883

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,	2019	2018	2017
(Millions)			
Net Income	**$ 676**	**$ 598**	**$ 382**
Other Comprehensive Income			
Gain on defined benefit plans, net of income taxes of $(0.3) and $1.1, respectively	1	3	—
Amortization of pension cost for nonqualified plans, net of income taxes of $(1.0), $0.3 and $0.2, respectively	(1)	1	1
Unrealized (loss) gain during the year on derivatives qualifying as cash flow hedges, net of income taxes of $(8.6), $(6.6) and $15.2, respectively	(22)	(21)	25
Reclassification to net income of losses (gains) on cash flow hedges, net of income taxes of $2.7, $(6.5) and $9.3, respectively	11	(8)	14
Other Comprehensive (Loss) Income	**(11)**	**(25)**	**40**
Comprehensive Income	665	573	422
Net loss (income) attributable to noncontrolling interests	24	(3)	(1)
Comprehensive Income Attributable to Avangrid, Inc.	**$ 689**	**$ 570**	**$ 421**

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

Avangrid, Inc. and Subsidiaries
Consolidated Balance Sheets

As of December 31,	2019	2018
(Millions)		
Assets		
Current Assets		
Cash and cash equivalents	$ 178	$ 36
Accounts receivable and unbilled revenues, net	1,082	1,142
Accounts receivable from affiliates	10	6
Derivative assets	11	16
Fuel and gas in storage	110	109
Materials and supplies	141	126
Prepayments and other current assets	199	229
Regulatory assets	294	299
Total Current Assets	**2,025**	**1,963**
Total Property, Plant and Equipment ($787 and $726 related to VIEs, respectively)	**25,218**	**23,459**
Operating lease right-of-use assets	70	—
Equity method investments	645	366
Other investments	63	58
Regulatory assets	2,567	2,640
Deferred income taxes regulatory	—	6
Other Assets		
Goodwill	3,119	3,127
Intangible assets	314	323
Derivative assets	84	63
Other	311	162
Total Other Assets	**3,828**	**3,675**
Total Assets	**$ 34,416**	**$ 32,167**

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

Avangrid, Inc. and Subsidiaries
Consolidated Balance Sheets

As of December 31,	2019	2018
(Millions, except share information)		
Liabilities		
Current Liabilities		
Current portion of debt	$ 730	$ 394
Notes payable	560	587
Interest accrued	72	62
Accounts payable and accrued liabilities	1,361	1,132
Accounts payable to affiliates	64	58
Dividends payable	136	136
Taxes accrued	56	59
Operating lease liabilities	12	—
Derivative liabilities	20	44
Other current liabilities	334	327
Regulatory liabilities	242	205
Total Current Liabilities	**3,587**	**3,004**
Regulatory liabilities	3,281	3,223
Other Non-current Liabilities		
Deferred income taxes	1,814	1,530
Deferred income	1,274	1,385
Pension and other postretirement	1,100	1,102
Operating lease liabilities	65	—
Derivative liabilities	85	97
Asset retirement obligations	190	217
Environmental remediation costs	338	339
Other	380	499
Total Other Non-current Liabilities	**5,246**	**5,169**
Non-current debt	6,716	5,368
Total Non-current Liabilities	**15,243**	**13,760**
Total Liabilities	**18,830**	**16,764**
Commitments and Contingencies	—	—
Equity		
Stockholders' Equity:		
Common stock, $.01 par value, 500,000,000 shares authorized, 309,752,140 shares issued; 309,005,272 shares outstanding	3	3
Additional paid-in capital	13,660	13,657
Treasury Stock	(12)	(12)
Retained earnings	1,681	1,528
Accumulated other comprehensive loss	(95)	(72)
Total Stockholders’ Equity	**15,237**	**15,104**
Noncontrolling interests	349	299
Total Equity	**15,586**	**15,403**
Total Liabilities and Equity	**$ 34,416**	**$ 32,167**

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

Consolidated Statements of Cash Flows
Avangrid, Inc. and Subsidiaries
Consolidated Statements of Cash Flows

Years Ended December 31,	2019	2018	2017
(Millions)			
Cash Flow from Operating Activities			
Net income	**$ 676**	**$ 598**	**$ 382**
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	934	855	824
Loss from assets held for sale	—	16	642
Accretion expenses	12	12	10
Regulatory assets/liabilities amortization and carrying cost	64	73	62
Pension cost	91	123	112
Earnings from equity method investments	(3)	(10)	40
Distribution of earnings from equity method investments	12	14	16
Unrealized (gains) losses on marked to market derivative contracts	(76)	22	17
Gain from divestment and disposal of property	(135)	(10)	(2)
Deferred taxes	138	151	(251)
Other non-cash items	(51)	(27)	(73)
Changes in operating assets and liabilities:			
Current assets	126	(117)	(89)
Noncurrent assets	(152)	(87)	218
Current liabilities	(5)	98	116
Noncurrent liabilities	(38)	80	(261)
Net Cash Provided by Operating Activities	**1,593**	**1,791**	**1,763**
Cash Flow from Investing Activities			
Capital expenditures	(2,740)	(1,787)	(2,416)
Contributions in aid of construction	74	60	57
Proceeds from sale of equity method and other investment	108	186	—
Proceeds from sale of property, plant and equipment	18	18	12
Payments to affiliates	(2)	—	—
Cash distribution from equity method investments	5	4	4
Other investments and equity method investments, net	(176)	(45)	2
Net Cash Used in Investing Activities	**(2,713)**	**(1,564)**	**(2,341)**
Cash Flow from Financing Activities			
Non-current debt issuances	2,137	597	888
Repayments of non-current debt	(346)	(217)	(305)
(Repayments) receipts of other short-term debt, net	(28)	(201)	625
Repayments of financing leases	(27)	(13)	(33)
Payments on tax equity financing arrangements	—	—	(113)
Repurchase of common stock	—	(4)	(3)
Issuance of common stock	—	(2)	(1)
Distributions to noncontrolling interests	(63)	(76)	—
Contributions from noncontrolling interests	133	223	5
Dividends paid	(545)	(537)	(535)
Net Cash Provided by (Used in) Financing Activities	**1,261**	**(230)**	**528**
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	**141**	**(3)**	**(50)**
Cash, Cash Equivalents and Restricted Cash, Beginning of Year	**43**	**46**	**96**
Cash, Cash Equivalents and Restricted Cash, End of Year	**$ 184**	**$ 43**	**$ 46**
Supplemental Cash Flow Information			
Cash paid for interest, net of amounts capitalized	$ 266	$ 224	$ 202
Cash paid (refunded) for income taxes	$ 2	$ (13)	$ 13

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, 2016	**308,993,149**	**$ 3**	**$ 13,653**	**$ (5)**	**$ 1,630**	**$ (86)**	**$ 15,195**	**$ 13**	**$ 15,208**
Net income	—	—	—	—	381	—	381	1	382
Other comprehensive income, net of tax of $24.7	—	—	—	—	—	40	40	—	40
Comprehensive income									422
Dividends declared, $1.728/share	—	—	—	—	(535)	—	(535)	—	(535)
Release of common stock held in trust	5,649	—	—	—	—	—	—	—	—
Issuance of common stock	70,493	—	(1)	—	—	—	(1)	—	(1)
Repurchase of common stock	(64,019)	—	—	(3)	—	—	(3)	—	(3)
Stock-based compensation	—	—	1	—		—	1		1
Transaction with noncontrolling interests	—	—	—	—	(1)	—	(1)	5	4
Balances, December 31, 2017	**309,005,272**	**3**	**13,653**	**(8)**	**1,475**	**(46)**	**15,077**	**19**	**15,096**
Adoption of accounting standards	—	—	—	—	(3)	(1)	(4)	140	136
Net income	—	—	—	—	595	—	595	3	598
Other comprehensive income, net of tax of $(11.7)	—	—	—	—	—	(25)	(25)	—	(25)
Comprehensive income									573
Dividends declared, $1.744/share	—	—	—	—	(540)	—	(540)	—	(540)
Issuance of common stock	81,208	—	1	—	(3)	—	(2)	—	(2)
Repurchase of common stock	(81,208)	—	—	(4)	—	—	(4)	—	(4)
Stock-based compensation	—	—	3	—	—	—	3	—	3
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(76)	(76)
Contributions from noncontrolling interests	—	—	—	—	4	—	4	213	217
Balances, December 31, 2018	**309,005,272**	**3**	**13,657**	**(12)**	**1,528**	**(72)**	**15,104**	**299**	**15,403**
Adoption of accounting standards	—	—	—	—	11	(12)	(1)	—	(1)
Net income	—	—	—	—	700	—	700	(24)	676
Other comprehensive income, net of tax of $(7.2)	—	—	—	—	—	(11)	(11)	—	(11)
Comprehensive income									665
Dividends declared, $1.76/share	—	—	—	—	(545)	—	(545)	—	(545)
Stock-based compensation	—	—	3	—	—	—	3	—	3
Distributions to noncontrolling interests	—	—	—	—	(4)	—	(4)	(59)	(63)
Contributions from noncontrolling interests	—	—	—	—	(9)	—	(9)	133	124
Balances, December 31, 2019	**309,005,272**	**$ 3**	**$ 13,660**	**$ (12)**	**$ 1,681**	**$ (95)**	**$ 15,237**	**$ 349**	**$ 15,586**

(*) 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., formerly Iberdrola USA, 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 81.5% of the outstanding common stock of AVANGRID. The remaining outstanding shares are publicly traded on the New York Stock Exchange and owned by various shareholders. AVANGRID was organized in 1997 as NGE Resources, Inc. under the laws of New York as the holding company for its principal operating utility companies.

In December 2017, management committed to a plan to sell the gas storage and trading businesses because they represented non-core businesses that were not aligned with our strategic objectives. On March 1, 2018, the Company closed a transaction to sell Enstor Energy Services, LLC, which operated AVANGRID's gas trading business, to CCI U.S. Asset Holdings LLC, a subsidiary of Castleton Commodities International, LLC (CCI). On May 1, 2018, the Company closed a transaction to sell Enstor Gas, LLC (Gas), which operated AVANGRID's gas storage business, to Amphora Gas Storage USA, LLC.

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

Regulatory assets and liabilities are amortized and the related expense or revenue is recognized in the consolidated statements of income consistent with the recovery or refund included in customer rates. We believe that 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

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 by the acquirer to former owners of the acquiree and the equity interests issued by the acquirer. Acquisition related costs are expensed as incurred. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the consideration transferred over the fair value of the identifiable net assets acquired is recorded as goodwill. 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.

In contrast to a business combination, we classify a transaction as an asset acquisition when substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or group of similar identifiable assets or otherwise does not meet the definition of a business.

(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 reported 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 the net assets of the projects were liquidated at recorded amounts determined in accordance with U.S. GAAP and distributed to the investors. The noncontrolling interest in our statements of income and comprehensive income is determined 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. The noncontrolling interest balances in the holdings are reported as a component of equity on our consolidated balance sheets.

(f) Equity method investments

We account for joint ventures 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 joint ventures as a reduction in the carrying amount of the investment and not as dividend income. We assess and record an impairment of our equity method investments in earnings for a decline in value that is determined to be other than temporary (OTTI).

(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 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 of first performing a qualitative assessment to determine whether a quantitative assessment is necessary (step zero). If we determine, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If we bypass step zero or perform the qualitative assessment, but determine that it is more likely than not that its fair value is less than its carrying amount, we perform a quantitative two step fair value based test. Step one compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, step two is performed. Step two requires an allocation of fair value to the individual assets and liabilities using business combination accounting guidance to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than its carrying amount, we record an impairment loss as a reduction to goodwill and a charge to operating expenses.

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

Property, plant and equipment are accounted for 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 an equal amount is added to the carrying amount of the asset.

Development and construction of our various facilities are carried out in stages. Project costs are expensed during early stage development activities. Once certain development milestones are achieved 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. Development projects in construction are reviewed periodically for any indications of impairment.

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

Wind turbine and related equipment costs, other project construction costs and interest costs related to the project are capitalized during the construction period through substantial completion. AROs are recorded at the date projects achieve commercial operation.

The cost of plant and equipment in use is depreciated 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)
	Combined cycle plants	35-75
	Hydroelectric power stations	45-90
Plant	Wind power stations	25-40
	Transport facilities	40-75
	Distribution facilities	5-82
Equipment	Conventional meters and measuring devices	7-41
	Computer software	4-25
Other	Buildings	30-82
	Operations offices	5-75

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. Consistent with FERC accounting requirements, Networks charges the original cost of utility plant retired or otherwise disposed to accumulated depreciation. The Networks composite rates for depreciation were 2.9% of average depreciable property for 2019 and 2.8% for 2018.

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 applying regulatory accounting, is a noncash item that represents the allowed cost of capital, including a return on equity (ROE), used to finance construction projects. The portion of AFUDC attributable to borrowed funds is recorded as a reduction of interest expense and the remainder is recorded 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 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 options 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. An impairment loss is required to be recognized if the carrying amount of the asset exceeds the undiscounted future net cash flows associated with that asset.

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

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

Changes in conditions or the occurrence of unforeseen events could require discontinuance of the hedge accounting or could affect the timing of the reclassification of gains or losses on cash flow hedges from OCI into earnings. 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. Book overdrafts representing outstanding checks in excess of funds on deposit are classified as “Accounts payable and accrued liabilities” on our consolidated balance sheets. Changes in book overdrafts are reported in the operating activities section of our consolidated statements of cash flows.

(o) Accounts receivable and unbilled revenue, net

We record accounts receivable at amounts billed to customers. Certain accounts receivable and payable 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 are settled on a net basis. Receivables and payables subject to such agreements are presented on our consolidated balance sheets on a net basis.

Accounts receivable include amounts due under Deferred Payment Arrangements (DPA). A DPA allows the account balance to be paid in installments over an extended period of time 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 thirty 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 are classified as short term.

The allowance for doubtful accounts is established by using both historical average loss percentages to project future losses, and a specific allowance is established for known credit issues or for specific items not considered in the historical average calculation. Amounts are written off when we believe that a receivable will not be recovered.

(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 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 as defined by the accounting guidance occur (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, the HLBV method allocates earnings to the noncontrolling interest, which considers the cash and tax benefits provided to the tax equity investors.

(q) Debentures, bonds and bank borrowings

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

(r) Inventory

Inventory comprises fuel and gas in storage and materials and supplies. This gas is recorded as inventory. Injections of inventory into storage are priced at the market purchase cost at the time of injection, and withdrawals of working gas from storage are priced at the weighted-average cost in storage. We continuously monitor the weighted-average cost of gas value to ensure it remains at the lower of cost and net realizable value. Inventories to support gas operations are reported on our consolidated balance sheets within “Fuel and gas in storage.”

We also have materials and supplies inventories that are used for construction of new facilities and repairs of existing facilities. These inventories are carried and withdrawn at the lower of cost and net realizable value and reported on 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 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, amounts receivable are recognized as an offset to expenses in our consolidated statements of income in the period in which the expenses are incurred.

(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. The liability is adjusted 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.

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. These are classified 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. Our environmental liabilities are recorded on an undiscounted basis. Our environmental liability accruals are expected to be paid through the year 2057.

(w) Post-employment and other employee benefits

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

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

We account for defined benefit pension or other postretirement plans, recognizing an asset or liability for the overfunded or underfunded plan status. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. Our utility operations reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in other comprehensive income, as management believes it is probable that such items will be recoverable through the ratemaking process. We use a December 31st measurement date for our benefits plans.

We amortize prior service costs for both the pension and other postretirement benefits plans on a straight-line basis over the average remaining service period of participants expected to receive benefits. 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 a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences. We defer the investment tax credits when earned and amortize them over the estimated lives of the related assets. We also recognize the income tax consequences of intra-entity transfers of assets other than inventory when the transfer occurs.

Deferred tax assets and liabilities are measured at the expected tax rate for the period in which the asset or liability will be realized or settled, based on legislation enacted as of the balance sheet date. 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. 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. In 2019, we netted our liability for uncertain tax positions against all same jurisdiction deferred tax assets, net operating losses and tax credit carryforwards. Our policy is to recognize interest and penalties on uncertain tax positions as a component of interest expense in the consolidated statements of income.

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) Leases

In February 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Codification (ASC) Topic 842, *Leases*, with subsequent amendments issued in 2018. The new lease guidance affects all companies and organizations that lease assets, and requires them to record on their balance sheet ROU assets and lease liabilities for the rights and obligations created by those leases. Under ASC 842, a lease is an arrangement that conveys the right to control the use of an identified asset for a period of time in exchange for consideration. The new guidance retains a distinction between finance leases and operating leases, while requiring companies to recognize both types of leases on their balance sheet. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the criteria for distinguishing between capital leases and operating leases in legacy U.S. GAAP - ASC 840. Lessor accounting remains substantially the same as ASC 840, but with some targeted improvements to align lessor accounting with the lessee accounting model and with the revised revenue recognition guidance under ASC 606. The new standard and amendments require new qualitative and quantitative disclosures for both lessees and lessors.

We adopted ASC 842 effective January 1, 2019, and elected the optional transition method under which we initially applied the standard on that date without adjusting amounts for prior periods, which we continue to present in accordance with ASC 840, including related disclosures. We recorded the cumulative effect of applying the new leases guidance as an adjustment to beginning retained earnings. In connection with our adoption, we:

- did not elect the package of three practical expedients available under the transition provisions which would have allowed us to not reassess: (i) whether expired or existing contracts were or contained leases, (ii) the lease classification for expired or existing leases, and (iii) whether previously capitalized initial direct costs for existing leases would qualify for capitalization under ASC 842.
- elected the land easement practical expedient and did not reassess land easements that did not meet the definition of a lease prior to adoption.
- used hindsight for determining the lease term and assessing the likelihood that a lease purchase option will be exercised in applying the new leases guidance.
- did not separate lease and associated non-lease components for transitioned leases, but instead are accounting for them together as a single lease component.

In March 2019, the FASB issued additional amendments to ASC 842 for minor codification improvements, which we early applied effective January 1, 2019, with no material effect to our consolidated results of operations, financial position and cash flows.

The cumulative effects of the changes to our consolidated balance sheet as of January 1, 2019, were as follows:

(Millions)	Balance at December 31, 2018	Adjustments Due to ASC 842	Balance at January 1, 2019
Assets			
Total Property, Plant and Equipment	$ 23,459	$ (147)	$ 23,312
Operating lease right-of-use assets	—	82	82
Other assets	162	146	308
Liabilities			
Current portion of debt	$ 394	$ (28)	$ 366
Operating lease liabilities, current	—	8	8
Other current liabilities	327	28	355
Operating lease liabilities, long-term	—	74	74
Other non-current liabilities	499	61	560
Non-current debt	5,368	(61)	5,307
Equity			
Retained earnings	$ 1,528	$ (1)	$ 1,527

Our adoption did not change the classification of lease-related expenses in our consolidated statements of income, and we do not expect significant changes to our pattern of expense recognition. Certain contracts previously classified as lessor leases, consisting mainly of Renewables' power purchase agreements, no longer meet the definition of a lease under ASC 842. As such, these contracts are accounted for under other U.S. GAAP, but there were no changes to our pattern of revenue recognition. As a result, our adoption will not materially affect our cash flows.

In comparison to our operating leases obligations disclosed as of December 31, 2018, certain land easement contracts that previously met the definition of a lease do not meet the ASC 842 definition of a lease, and therefore we excluded them from the transition adjustment. Our accounting for finance (formerly capital) leases is substantially unchanged. Refer to Note 13 for further details.

(b) Targeted improvements to accounting for hedging activities

In August 2017, the FASB issued targeted amendments with the objective to better align hedge accounting with an entity's risk management activities in the financial statements and to simplify the application of hedge accounting. The amendments address concerns of financial statement preparers over difficulties with applying hedge accounting and limitations for hedging both nonfinancial and financial risks and concerns of financial statement users over how hedging activities are reported in financial statements. The amended presentation and disclosure guidance is required only prospectively. Changes to the hedge accounting guidance to address those concerns: 1) expand hedge accounting for nonfinancial and financial risk components and amend measurement methodologies to more closely align hedge accounting with an entity's risk management activities; 2) eliminate the separate measurement and reporting of hedge ineffectiveness to reduce the complexity of preparing and understanding hedge results; 3) enhance disclosures and change the presentation of hedge results to align the effects of the hedging instrument and the hedged item in order to enhance transparency, comparability and understandability of hedge results; and 4) simplify the way assessments of hedge effectiveness may be performed to reduce the cost and complexity of applying hedge accounting. The amendments ease the administrative burden of hedge documentation requirements and assessing hedge effectiveness going forward. We adopted the hedge accounting amendments on January 1, 2019, and had no cumulative-effect adjustment to retained earnings because there were no amounts of ineffectiveness recorded for any existing hedges as of that date. Concurrently with the above targeted improvements, we adopted the additional amendments the FASB issued in October 2018 that permit use of the Overnight Index Swap rate based on the Secured Overnight Financing Rate as a U.S. benchmark interest rate for hedge accounting purposes. Use of that rate is in addition to the already eligible benchmark interest rates, which are: interest rates on direct Treasury obligations of the U.S. government, the London Interbank Offered Rate swap rate, the OIS Rate based on the Fed Funds Effective Rate and the Securities Industry and Financial Markets Association Municipal Swap Rate.

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

In February 2018, the FASB issued amendments to address a financial reporting issue that arose as a consequence of the Tax Cuts and Jobs Act of 2017 (the Tax Act) that the U.S. federal government enacted on December 22, 2017. Under previous guidance, an entity was required to include the adjustment of deferred taxes for the effect of a change in tax laws or rates in income from continuing operations, thus the associated tax effects of items within AOCI (referred to as stranded tax effects) did not reflect the appropriate tax rate. The amendments allow a reclassification from AOCI to retained earnings to eliminate the stranded tax effects resulting from the Tax Act. The amendments only relate to the reclassification of the income tax effects of the Tax Act, and do not affect the underlying guidance that requires the effect of a change in tax laws or rates to be included in income from continuing operations. We adopted the amendments effective January 1, 2019, and elected to reclassify the stranded tax effects of the Tax Act from AOCI to retained earnings at the beginning of the period of adoption. As a result, we reclassified approximately $12 million from AOCI to retained earnings within our consolidated statements of changes in equity.

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) Measurement of credit losses on financial instruments, amendments and updates

The FASB issued an accounting standards update in June 2016 that requires more timely recording of credit losses on loans and other financial instruments. The amendments affect entities that hold financial assets and net investment in leases that are not accounted for at fair value through net income (loans, debt securities, trade receivables, net investments in leases, off-balance-sheet credit exposures, etc.). They require an entity to present a financial asset (or group of financial assets) that is measured at amortized cost basis at the net amount expected to be collected. The allowance for credit losses is a valuation account that is deducted from the amortized cost basis of the financial asset(s) to present the net carrying value at the amount expected to be collected on the financial asset. The income statement reflects the measurement of credit losses for newly recognized financial assets, as well as the expected increases or decreases of expected credit losses that have taken place during the period. The measurement of expected credit losses is based on relevant information about past events, including historical experience, current conditions, and reasonable and supportable forecasts that affect the collectability of the reported amount. An entity must use judgment in determining the relevant information and estimation methods appropriate in its circumstances. The FASB subsequently issued various updates to this new guidance to clarify transition and scope requirements, make narrow-scope codification improvements and corrections and provide targeted transition relief. The new guidance, including the subsequent amendments, is effective for public entities that are SEC filers for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. Entities are to apply the amendments on a modified retrospective basis for most instruments. Early adoption is allowed.

Our implementation plan and steps included: evaluating financial assets within scope; documenting related technical accounting issues, policy considerations and financial reporting implications; and identifying changes to processes and controls to ensure all aspects of the new guidance were effectively addressed. Our adoption of the guidance on January 1, 2020, including our transition adjustment, will not materially affect our consolidated results of operations, financial position and cash flows.

(b) Simplifying the test for goodwill impairment

In January 2017, the FASB issued amendments to simplify the test for goodwill impairment, which are required for public entities and certain other entities that have goodwill reported in their financial statements. The amendments simplify the subsequent measurement of goodwill by eliminating Step 2 from the goodwill impairment test, which requires the valuation of assets acquired and liabilities assumed using business combination accounting guidance. Under the new guidance, an entity should perform its annual, or interim, goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; but the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. Also, an entity should consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable. Certain requirements are eliminated for any reporting unit with a zero or negative carrying amount; therefore the same impairment assessment applies to all reporting units. An entity still has the option to perform the qualitative assessment for a reporting unit to determine if the quantitative impairment test is necessary. The amendments are effective for public entities for annual and interim periods in fiscal years beginning after December 15, 2019, with the amendments applied on a prospective basis. Early adoption is allowed. Our adoption of the amendments on January 1, 2020, will not materially affect our results of operations, financial position, cash flows and disclosures.

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

In August 2018, the FASB issued amendments related to disclosure requirements for both fair value measurement and defined benefit plans. The amendments concerning fair value measurement remove, modify and add certain disclosure requirements in order to improve the overall usefulness of the disclosures and reduce unnecessary costs to companies to prepare the disclosures. The amendments to fair value measurement disclosures are effective for all entities for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted as specified. Certain amendments are to be applied prospectively, and all others are to be applied retrospectively. Our adoption of the amendments on January 1, 2020, will not materially affect our disclosures.

The amendments concerning disclosure requirements for defined benefit plans are narrow in scope and apply to all employers that sponsor defined benefit pension or other postretirement plans. They remove disclosures that are no longer considered cost beneficial, add certain new relevant disclosures and clarify specific requirements of disclosures concerning information for defined benefit pension plans. The amendments to defined benefit plan disclosures are effective for fiscal years ending after December 15, 2020. Early adoption is permitted and application is to be on a retrospective basis. Our adoption of the amendments on January 1, 2020, will not materially affect our disclosures.

(d) Targeted improvements to related party guidance for VIEs

In October 2018, the FASB issued amendments that affect reporting entities that are required to determine whether they should consolidate a legal entity under the consolidation guidance applicable to VIEs. The targeted improvements specifically applicable to public business entities clarify that indirect interests held through related parties in common control arrangements should be considered on a proportional basis for determining whether fees paid to decision makers and service providers are variable interests. The amendments are effective for public business entities for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted. Our adoption of the amendments on January 1, 2020, will not materially affect our consolidated results of operations, financial position, cash flows and disclosures.

(e) Clarifying guidance for certain collaborative arrangements with respect to revenue recognition

The FASB issued amendments in November 2018 to clarify the interaction between the guidance for certain collaborative arrangements and the guidance applicable to ASC 606. A collaborative arrangement is a contractual arrangement under which two or more parties actively participate in a joint operating activity and are exposed to significant risks and rewards that depend on the activity's commercial success. The targeted improvements clarify that certain transactions between collaborative arrangement participants are within the scope of ASC 606 and thus subject to all of its guidance. The amendments are effective for public business entities for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted, including adoption in any interim period for which financial statements have not been issued. Retrospective application to the date of initial application of ASC 606 is required. Our adoption of the amendments on January 1, 2020, will not materially affect our consolidated results of operations, financial position, cash flows and disclosures.

(f) Simplifying the accounting for income taxes

In December 2019, the FASB issued an accounting standards update that is intended to reduce complexity in accounting for income taxes. The amendments remove specific exceptions to the general principles in ASC 740, *Income Taxes*, eliminating the need for an entity to analyze whether the following apply in a given period: (1) exception to the incremental approach for intra-period tax allocation, (2) exceptions to accounting for basis differences when there are ownership changes in foreign investments and (3) exception in interim period income tax accounting for year-to-date losses that exceed anticipated losses. The amendments also improve financial statement preparers' application of income-tax related guidance and simplify U. S. GAAP for (1) franchise taxes that are partially based on income, (2) transactions with a government that result in a step up in the tax basis of goodwill, (3) separate financial statements of legal entities that are not subject to tax and (4) enacted changes in tax laws in interim periods. The amendments are effective for public business entities for fiscal years beginning after December 15, 2020, and interim periods within those fiscal years. Early adoption is permitted, including adoption in any interim period for which financial statements have not been issued, with adoption of all amendments in the same period. Application is on a retrospective and/or modified retrospective basis, or a prospective basis, depending on the amendment aspect. We expect our adoption will not materially affect our consolidated results of operations, financial position and cash flows.

Use of Estimates and Assumptions

The preparation of our consolidated financial statements in conformity with U.S. GAAP requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the reporting periods. Significant estimates and assumptions are used for, but not limited to: (1) allowance for doubtful accounts and unbilled revenues; (2) asset impairments, including goodwill; (3) 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. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our consolidated financial statements will change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside specialists to assist in our evaluations, as necessary. Actual results could differ from those estimates.

Union collective bargaining agreements

We have approximately 49.0% of the employees covered by a collective bargaining agreement. Agreements which will expire within the coming year apply to approximately 25.5% of our employees.

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 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. 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 Federal Energy Regulatory Commission (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 transmission service. We record revenue for all of those sales based upon the regulatory-approved tariff and the volume delivered or transmitted, which corresponds to the amount that we have a right to invoice. There are no material initial incremental costs of obtaining a contract in any of the arrangements. 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. Networks does not have any material significant payment terms because it receives payment at or shortly after the point of sale. For its New York utilities, Networks assesses its deferred payment arrangements at each balance sheet date for the existence of significant financing components, but has had no material adjustments as a result.

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, 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 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, derives its revenues primarily from providing natural gas storage services to customers, gas trading operations generally classified as derivative revenue in accordance with the applicable accounting standards, gas trading contracts not classified as derivatives, and other miscellaneous revenues including 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 2021 upon commercial operation. We also have a contract asset for costs incurred to cancel a PPA, which we will amortize over the 10-year contract period of the replacement PPA that will commence upon completion of the project. Contract assets totaled $12 million and $9 million at December 31, 2019 and December 31, 2018, respectively, 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 $10 million and $9 million at December 31, 2019 and December 31, 2018, respectively, and are presented in "Other current liabilities" on our consolidated balance sheets. We recognized $21 million and $13 million as revenue during the years ended December 31, 2019 and December 31, 2018, 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, 2019 and December 31, 2018 are as follows:

	Year Ended December 31, 2019			
	Networks	Renewables	Other (b)	Total
(Millions)				
Regulated operations – electricity	$ 3,485	$ —	$ —	$ 3,485
Regulated operations – natural gas	1,479	—	—	1,479
Nonregulated operations – wind	—	805	—	805
Nonregulated operations – solar	—	26	—	26
Nonregulated operations – thermal	—	29	—	29
Nonregulated operations – gas storage	—	—	—	—
Other(a)	91	62	(12)	141
Revenue from contracts with customers	**5,055**	**922**	**(12)**	**5,965**
Leasing revenue	6	—	—	6
Derivative revenue	—	244	—	244
Alternative revenue programs	75	—	—	75
Other revenue	28	20	—	48
Total operating revenues	**$ 5,164**	**$ 1,186**	**$ (12)**	**$ 6,338**

	Year Ended December 31, 2018			
	Networks	Renewables	Other (b)	Total
(Millions)				
Regulated operations – electricity	$ 3,641	$ —	$ —	$ 3,641
Regulated operations – natural gas	1,473	—	—	1,473
Nonregulated operations – wind	—	637	—	637
Nonregulated operations – solar	—	17	—	17
Nonregulated operations – thermal	—	47	—	47
Nonregulated operations – gas storage	—	—	10	10
Other(a)	58	(68)	9	(1)
Revenue from contracts with customers	**5,172**	**633**	**19**	**5,824**
Leasing revenue	38	346	—	384
Derivative revenue	—	124	10	134
Alternative revenue programs	80	—	—	80
Other revenue	20	36	—	56
Total operating revenues	**$ 5,310**	**$ 1,139**	**$ 29**	**$ 6,478**

(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, Gas and intersegment eliminations.

As of December 31, 2019 and December 31, 2018, accounts receivable balances related to contracts with customers were approximately $1,050 million and $1,118 million, respectively, including $345 million and $374 million of unbilled revenue, which are included in "Accounts receivable and unbilled revenues, net" on our consolidated balance sheets.

As of December 31, 2019, the aggregate amount of the transaction price allocated to performance obligations that are unsatisfied (or partially unsatisfied) were as follows:

As of December 31, 2019	2020	2021	2022	2023	2024	Thereafter	Total
(Millions)							
Revenue expected to be recognized on multiyear retail energy sales contracts in place	$ 1	$ 1	$ 1	$ 1	$ 1	$ —	$ 5
Revenue expected to be recognized on multiyear capacity and carbon-free energy sale contracts	35	27	19	11	8	25	126
Revenue expected to be recognized on multiyear renewable energy credit sale contracts	22	16	8	5	4	8	63
Total operating revenues	**$ 58**	**$ 44**	**$ 28**	**$ 17**	**$ 13**	**$ 33**	**$ 194**

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

The NYSEG and RG&E rate cases, the Maine distribution rate case 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.

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.

Each of Networks' eight utility companies must comply with regulatory procedures that differ in form but in all cases conform to the basic framework outlined above. 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).

CMP Distribution Rate Case

On May 1, 2013, CMP submitted its required distribution rate request with the MPUC. On July 3, 2014, after a fourteen-month review process, CMP filed a rate stipulation agreement on the majority of the financial matters with the MPUC. The stipulation agreement was approved by the MPUC on August 25, 2014. The stipulation agreement also noted that certain rate design matters would be litigated, which the MPUC ruled on October 14, 2014.

The rate stipulation agreement provided for an annual CMP distribution tariff increase of 10.7% or $24.3 million. The rate increase was based on a 9.45% ROE and 50% equity capital. CMP was authorized to implement a Rate Decoupling Mechanism (RDM) which reduces distribution revenue variations associated with energy efficiency and weather impacts on sales volumes. CMP also adjusted its storm costs recovery mechanism whereby it is allowed to collect in rates a storm allowance and to defer actual storm costs when such storm event costs exceed $3.5 million. CMP and customers share storm costs that exceed a certain balance on a fifty-fifty basis, with CMP's exposure limited to $3 million annually.

CMP made a separate regulatory filing for a new customer billing system. In accordance with the stipulation agreement, a new billing system was needed and CMP made its filing on February 27, 2015 to request a separate rate recovery mechanism. On October 20, 2015, the MPUC issued an order approving a stipulation agreement authorizing CMP to proceed with the customer billing system investment. The approved stipulation allows CMP to recover the system costs effective July 1, 2017.

The rate stipulation does not have a predetermined rate term. CMP had the option to file for new distribution rates at its own discretion. The rate stipulation does not contain service quality targets or penalties. The rate stipulation also does not contain any earnings sharing requirements.

On May 29, 2018, a ten-person complaint was filed with the MPUC against CMP, Networks and AVANGRID. The complaint requested that the MPUC open a rate case to determine if CMP is making excessive returns on investment and, therefore, whether CMP's retail rates should be lower. The complaint also requested the MPUC deny certain costs associated with the October 2017 windstorm. On July 24, 2018, the MPUC issued an order dismissing the complaint and its associated request to deny the recovery of costs associated with the October 2017 windstorm. The order initiated an investigation into CMP's rates and revenue requirement and directed CMP to make a filing consistent with the requirements for a general rate case no later than October 15, 2018. Consistent with the order in the ten-person complaint proceeding, on August 7, 2018, the MPUC issued a Notice of Investigation, opening the proceeding in which CMP would make its rate case filing and through which the MPUC will examine the rates and revenue requirements of CMP.

On October 15, 2018, CMP filed a general rate case as directed by the MPUC requesting a ROE of 10% and an equity ratio of 55%. The company proposed to use savings arising out of changes in federal taxation pursuant to the Tax Act to keep its distribution prices stable while making its electric system more reliable. CMP's general rate case filing included a proposal to enhance the resiliency of the energy grid by expanding vegetation management and pursuing additional reliability measures such as pole replacements and addition of tree wire in selected areas. Such investments are designed to strengthen CMP's power grid so it can better stand up to severe weather. On December 20, 2018, the MPUC released the findings of the forensic audit of CMP's customer billing system and customer communication practices.

On January 14, 2019, the MPUC issued an Order and Notice of Investigation initiating an investigation of CMP's metering and billing practices and initiating a separate investigation of the audit of CMP's customer service and communication practices and incorporating such investigation into the general rate case. On February 22, 2019, the MPUC staff issued a Bench Analysis (BA) on all revenue requirement issues in this case, including customer service issues. The BA included, among other things, a proposal to reduce CMP's existing distribution rates by $2.0 - $3.6 million, inclusive of one-time items from July 2018, and implement a management efficiency adjustment as part of the rate setting process to reduce the MPUC staff recommended "unadjusted ROE of 9.35% by 75 to 100 basis points. On April 12, 2019, CMP filed rebuttal testimony to the Bench Analysis and intervenor testimony. On June 17, 2019, the MPUC Staff issued its Reply Bench Analysis in response to CMP's rebuttal testimony, which included a reduction of the "unadjusted" ROE recommendation to 8.75% based on current market conditions, maintained the proposed management efficiency adjustment of 75 to 100 basis points and proposed to maintain the current cap of $31.4 million on the shared service costs provided to CMP until a management audit on the cost effectiveness of such services is completed. The Maine Office of the Public Advocate (OPA) for utility issues filed a motion to delay CMP's rate order decision to allow incorporation of the results of the separate metering and billing investigation. CMP did not oppose this motion. In August 2019, the MPUC granted the OPA motion stating the outcome of the metering and billing investigation could aid the Commission in its final determination in the rate case. Regarding the other two tracks of the rate case (1) rate design and (2) the affiliate services market study; the MPUC decided those tracks can proceed and decisions on those issues can occur at the same time the Commission decides the revenue requirement issues. Finally, the MPUC decided not to address CMP's request to defer lost revenues with carrying costs or its request that the proposed service quality metrics and other tracking mechanisms be effective October 1, 2019. The MPUC decided to address those matters in its ultimate decision in the 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%, based on an allowed ROE of 9.25% and a 50% equity ratio. The rate increase is 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 will remain in effect until CMP Company has demonstrated satisfactory customer service performance on four specified service quality measures for a period of 18 consecutive months with measurement commencing on March 1, 2020. The order provides 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 retains the revenue decoupling mechanism implemented in 2014. The order denies CMP's request to increase rates for higher costs associated with services provided by its affiliates and will instead initiate a management audit to assess the quality of these services as well as the impacts of the AVANGRID management structure on the quality of CMP's customer service.

NYSEG and RG&E Rate Plans and Rate Case Filings

On June 15, 2016, the NYPSC approved NYSEG's and RG&E's 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 Joint Proposal reflects many customer benefits including: acceleration of the companies' natural gas leak prone main replacement programs and increased funding for electric vegetation management to provide continued safe and reliable service. The delivery rate increases in the Joint Proposal can be summarized as follows:

	May 1, 2016		May 1, 2017		May 1, 2018	
	Rate Increase	Delivery Rate Increase	Rate Increase	Delivery Rate Increase	Rate Increase	Delivery Rate Increase
Utility	(Millions)	%	(Millions)	%	(Millions)	%
NYSEG Electric	$ 29.6	4.10%	$ 29.9	4.10%	$ 30.3	4.10%
NYSEG Gas	$ 13.1	7.30%	$ 13.9	7.30%	$ 14.8	7.30%
RG&E Electric	$ 3.0	0.70%	$ 21.6	5.00%	$ 25.9	5.70%
RG&E Gas	$ 8.8	5.20%	$ 7.7	4.40%	$ 9.5	5.20%

The allowed rate of return on common equity for NYSEG Electric, NYSEG Gas, RG&E Electric and RG&E Gas is 9.00%. The equity ratio for each company is 48%; however, the equity ratio is set at the actual up to 50% for earnings sharing calculation purposes. The customer share of any earnings above allowed levels increases as the ROE increases, with customers receiving 50%, 75% and 90% of earnings over 9.5%, 10.0% and 10.5% ROE, respectively, in the first rate year covering the period May 1, 2016 – April 30, 2017. The earnings sharing levels increase in rate year two (May 1, 2017 – April 30, 2018) to 9.65%, 10.15% and 10.65% ROE, respectively. The earnings sharing levels further increase in rate year three (May 1, 2018 – April 30, 2019) to 9.75%, 10.25% and 10.75% ROE, respectively. The rate plans also include the implementation of a rate adjustment mechanism (RAM) designed to return or collect certain defined reconciled revenues and costs, new depreciation rates and continuation of the existing RDM for each business. The Joint Proposal reflects 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 ($21.4 million annually for NYSEG Electric and $2.5 million annually for RG&E Electric). Incremental maintenance costs incurred to restore service in qualifying divisions will be chargeable to the Major Storm Reserve provided they meet certain thresholds.

The Joint Proposal maintains 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 Joint Proposal also modifies 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 establishes threshold performance levels for designated aspects of customer service quality and continues and expands NYSEG's and RG&E's bill reduction and arrears forgiveness Low Income Programs with increased funding levels included in the proposal. The Joint Proposal provides 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 are included in the RAM to the extent cost recovery is not provided for elsewhere. Under the proposal, the RAM is 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 Joint Proposal provides 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 Joint Proposal also includes a downward-only Net Plant reconciliation. In addition, the Joint Proposal includes downward-only reconciliations for the costs of electric distribution and gas vegetation management, pipeline integrity and incremental maintenance. The Joint Proposal provides 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.

On May 20, 2019, NYSEG and RG&E filed rate cases with the New York State Department of Public Service (NYDPS) for new tariffs. The effective date of new tariffs, assuming an approximately 11-month suspension period, will be April 20, 2020. The proposed rates facilitate the companies' transition to a cleaner energy future while allowing for important initiatives such as vegetation management, hardening/resiliency and emergency preparedness. The companies are requesting delivery revenues to be based on a 9.50% ROE and 50% equity ratio. The below table provides a summary of the initial proposed delivery rate increases, delivery revenue percentages and total revenue percentages for all four businesses:

Utility	Requested Revenue Increase (Millions)		Delivery Revenue %	Total Revenue %
NYSEG Electric	$	156.7	20.4%	10.4%
NYSEG Gas	$	6.3	3.0%	1.4%
RG&E Electric	$	31.7	7.0%	4.1%
RG&E Gas	$	5.8	3.3%	1.4%

NYPSC staff and other parties filed responsive testimony on September 15, 2019. NYPSC staff is recommending an 8.2% ROE and 48% equity. NYPSC staff recommended the following rate increases/decreases: NYSEG electric a rate increase of $76.7 million, NYSEG Gas a rate decrease of $15.9 million, RG&E Electric a rate increase of $0.7 million and RG&E Gas a rate decrease of $22.5 million. NYPSC Staff is also recommending NYSEG credit the environmental reserve by $31.1 million due to the legal rulings in 2017 and 2018 that denied insurance claims against OneBeacon and Century Indemnity in an insurance lawsuit. The companies entered into settlement discussion with the staff and other parties in October 2019. On February 26, 2020, the companies filed notice with the NYPSC that an agreement in principle has been reached among the companies, the NYDPS staff and certain other parties to the matter. As a result, drafting of a joint proposal (settlement agreement) has commenced.

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 2020, 70% of its standard service load for the second half of 2020 and 40% of its standard service load for the first half of 2021. Supplier of last resort service is procured on a quarterly basis and UI has wholesale power supply agreement in place for the second quarter of 2020. However, from time to time there are no bidders in the procurement process for supplier of last resort service and, in such cases, UI manages the load directly.

In December 2016, the 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% equity ratio, continued UI's existing ESM pursuant to which UI and its customers share on a fifty-fifty 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.

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

In December, 2018, PURA approved new tariffs for CNG effective January 1, 2019 for a three-year rate plan with rate increases of $9.9 million, $4.6 million and $5.2 million in 2019, 2020 and 2021, respectively. The new tariffs continued the RDM and DIMP mechanism, ESM and tariff increases based on an ROE of 9.30%, and an equity ratio of 54% in 2019, 54.50% in 2020 and 55% in 2021.

On January 18, 2019, the DPU approved a settlement agreement between BGC and the Massachusetts Attorney General's Office providing for new distribution rates for BGC. The settlement agreement provides for a $1.6 million distribution base rate increase effective February 1, 2019 (with a make-whole provision back to January 1, 2019), and an additional $0.7 million base distribution increase effective November 1, 2019, if certain investments are made by BGC. The distribution rate increase is based on a 9.70% ROE and 54% equity ratio. The settlement agreement provides for the implementation of a RDM and pension expense tracker and also provides that BGC will not file to change base distribution to become effective before November 1, 2021.

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 (DSP) provider, and required the utilities to file an initial Distribution System Implementation Plan (DSIP) by June 30, 2016, followed by bi-annual updates. The companies filed the initial DSIP, which also included information regarding the potential deployment of Automated Metering Infrastructure (AMI) across its entire service territory. 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 has been included in the companies' May 20, 2019 rate filing.

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. A proposal for EAMs was included in the companies' May 20, 2019 rate filing.

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. In July 2018, NYSEG and RG&E submitted an updated DSIP plan consistent with guidance received from the NY Department of Public Service. 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. The NYPSC also issued an order on value stack compensation for high-capacity-factor Resources on December 12, 2019.

CMP Customer Billing System Investigation

On March 1, 2018, the MPUC issued a Notice of Investigation initiating a summary investigation into CMP's metering, billing and customer communications practices. Due to the highly technical nature of CMP's customer billing system, on March 22, 2018 the MPUC issued an Order Initiating Audit commencing a forensic audit of CMP's customer billing system to identify any errors that have, or continue to result in billing inaccuracies. On July 10, 2018, the MPUC issued an Order Modifying Scope of Audit, which expanded the scope of the audit to include CMP's customer communication practices. On December 20, 2018, the MPUC released the findings of the forensic audit of CMP's customer billing system and customer communication practices. On January

14, 2019, the MPUC issued an Order and Notice of Investigation initiating an investigation of CMP's metering and billing, practices and initiating a separate investigation of the audit of CMP's customer service and communication practices and incorporating such investigation into CMP's general rate case. On September 3, 2019, the MPUC issued its Bench Analysis in the Metering and Billing Investigation and supported the findings of the independent audit. On September 7, the OPA issued testimony and findings from a separate audit firm which agreed with certain portions of the independent audit and also stated that continuing problems still persist in CMP's billing system. CMP provided rebuttal testimony on October 16, 2019. On January 9, 2020 the hearing examiners issued their report whereby they recommended that the Commission find that the evidence in the record shows that there is no systemic problem within CMP's metering and billing systems that has caused erroneous high usage on customers' bills. Instead, the evidence-including the detailed forensic audit conducted by an independent third-party auditor-demonstrates that CMP's metering and billing systems have been, and continue to be, recording and transmitting customer usage data accurately, and, with the exception of discrete billing calculation and presentation issues, customers' billed amounts have been accurate. On January 30, 2020, the MPUC Commissioners deliberated and based on the verbal discussion, the Commissioners indicated that CMP's Metering and Billing system is accurately reporting data; there is no systemic root cause for high usage complaints and errors related to CMP's metering and billing system are localized and random, not systemic. The Commissioners were critical of CMP finding that CMP failed to implement proper testing of the SmartCare system prior to go-live; CMP's implementation of SmartCare was imprudent; CMP's SmartCare implementation experienced an unacceptable number of billing errors, delayed or estimated bills, bill presentment issues and unreasonable time required to address these issues; and the implementation issues were compounded by inadequate staffing, resulting in the inability of customers to contact a CMP representative. In its February 19, 2020 order in the CMP's distribution rate case proceeding discussed above the MPUC imposed a reduction of 100 basis points in ROE, as a management efficiency adjustment, to address concerns with CMP's customer service performance following the implementation of its new billing system in 2017. The management efficiency adjustment will remain in effect until CMP has demonstrated satisfactory customer service performance on four specified service quality measures for a period of 18 consecutive months with measurement commencing on March 1, 2020.

Tax Cuts and Jobs Act

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Tax Act) was signed into law. The Tax Act significantly changed the federal taxation of business entities including, among other things, implementing a federal corporate tax rate decrease from 35% to 21% for tax years beginning after December 31, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates will result in amounts previously and currently collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates. The NYPSC, MPUC, PURA, DPU and the FERC have instituted separate proceedings in New York, Maine, Connecticut, Massachusetts and the FERC, respectively, to review and address the implications of the Tax Act on the utilities.

In New York, the NYPSC staff issued a proposal on March 29, 2018, whereby the staff recommended that Tax Act benefits be returned to customers beginning October 1, 2018. Comments on this staff proposal were submitted by the Joint Utilities of New York with a separate Appendix by each respective major utility on June 27, 2018, including our New York utility companies. NYSEG and RG&E have stated that they believe Tax Act benefits should be utilized for utility programs for the benefit of customers, including for new projects such as AMI, other future resiliency investments and to recover deferred regulatory assets. On August 9, 2018, the NYPSC issued an Order requiring sur-credits effective October 1, 2018. The sur-credits for NYSEG and RG&E reflected the lower effective tax rate of 21%. For NYSEG Gas, RG&E Electric and RG&E Gas the NYPSC also required the sur-credit to include the return to customers of the January - September 2018 Tax Act savings over three years. The NYPSC allowed NYSEG Electric to continue to defer the January - September 2018 Tax Act savings as well as to continue to preserve the protected and unprotected Tax Act savings until the companies' next rate cases. In Connecticut, UI and SCG expect Tax Act savings to be deferred until they are reflected in tariffs in a future rate case, unless PURA determines otherwise. CNG and Berkshire included Tax Act savings in rate cases that were filed with PURA and the DPU, respectively, in the second quarter of 2018. In Maine, CMP adjusted rates beginning July 1, 2018 to pass back to customers the Tax Act savings after offsetting for recovery of deferred 2017 storm costs. In its February 19, 2020 order in the CMP's distribution rate case proceeding discussed above, the MPUC approved CMP's distribution related accumulated deferred income tax balances associated with the Tax Act as well as the authorized amortization periods for the return of regulatory liabilities and the recovery regulatory assets. At the FERC, CMP transmission and UI transmission adjusted their tariffs in June 2018 to reflect the income statement value of Tax Act savings.

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 $153 million and $157 million for this item at December 31, 2019 and 2018, respectively.

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 2020. 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. 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. 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 and CMP will begin collecting the Power Tax Regulatory asset beginning in July 2020 over 32.5 years.

Ginna Reliability Support Service Agreement

Ginna Nuclear Power Plant, LLC (GNPP), which is a subsidiary of Constellation Energy Nuclear Group, LLC (CENG), owns and operates the R.E. Ginna Nuclear Power Plant (Ginna Facility and together with GNPP, Ginna), a 581 MW single-unit pressurized water reactor located in Ontario, New York. In May 2014, the NYISO and then the NYPSC ruled that the Ginna Facility was required to maintain system reliability and ordered RG&E and GNPP to negotiate a Reliability Support Service Agreement (RSSA).

On October 21, 2015, RG&E, GNPP, New York Department of Public Service, Utility Intervention Unit and Multiple Intervenors filed a Joint Proposal with the NYPSC for approval of the RSSA, as modified. On February 23, 2016, the NYPSC unanimously adopted the joint proposal, which provided for a term of the RSSA from April 1, 2015 through March 31, 2017 and RG&E monthly payments to Ginna in the amount of $15.4 million. In addition, RG&E was entitled to 70% of revenues from Ginna's sales into the NYISO energy and capacity markets, while Ginna was entitled to 30% of such revenues. The NYPSC also authorized RG&E to implement a rate surcharge effective January 1, 2016, to recover amounts paid to Ginna pursuant to the RSSA. The FERC issued an order authorizing the FERC Settlement agreement in the Settlement Docket on March 1, 2016, at which point the rate surcharge went into effect. RG&E used deferred rate credit amounts (regulatory liabilities) to offset the full amount of the Deferred Collection Amount (including carrying costs), plus credit amounts to offset all RSSA costs that exceed $2.3 million per month, not to exceed a total use of credits in the amount of $110 million, applicable through June 30, 2017. The available credits were insufficient to satisfy the final payment amount from RG&E to Ginna, and consistent with the agreement with the NYPSC, the RSSA surcharge continues past March 31, 2017, to recover up to $2.3 million per month until the final payment has been recovered by RG&E from customers. RG&E has met all payment obligations associated with the RSSA and the surcharge is no longer in effect beginning August 1, 2019.

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 $5,090 million associated with the minimum equity requirements as of December 31, 2019.

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 is 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. 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 by-passable federally mandated congestion charges for all customers to recover the net costs of the PPAs.

On December 28, 2018, DEEP issued a directive to UI to negotiate and enter into PPAs with twelve projects, totaling approximately 12 million MWh, that were selected as a result of the Zero Carbon RFP issued by DEEP pursuant to PA 17-3, which provides that the net costs of the PPAs are recoverable through electric rates. One of the selected projects is the Millstone nuclear facility located in Waterford, Connecticut which is owned by Dominion Energy, Inc. UI completed negotiations and executed the PPA with the Millstone nuclear facility. UI filed the PPA with PURA on March 29, 2019, and PURA approved the PPA in September 2019. UI finalized negotiations and executed ten PPAs with ten of the remaining selected projects that were filed with PURA on May 31, 2019. At the direction of PURA, UI refiled Amended and Restated PPA's for nine of these projects in November 2019 and PURA approved those nine PPAs also in November 2019. The remaining PPA has been executed and submitted for approval to PURA. The twelfth selected project has declined to continue negotiations.

In August 2019, DEEP issued a RFP for up to 2,000 MW of offshore wind. On December 5, 2019, DEEP announced that it had selected Vineyard Wind, an affiliate of UI, to provide 804 MW of offshore wind through the development of its Park City Wind Project. DEEP also ordered Eversource and UI to negotiate PPAs with Vineyard. Similar to the case with the zero carbon PPAs discussed above, the net costs of the PPAs are recoverable through electric rates.

Under Maine law 35-A M.R.S.A §§ 3210-C, 3210-D, the MPUC is authorized to conduct periodic requests for proposals seeking long-term supplies of energy, capacity or Renewable Energy Certificates, or RECs, from qualifying resources. The MPUC is further authorized to order Maine transmission and distribution utilities to enter into contracts with sellers selected from the MPUC's competitive solicitation process. Pursuant to a MPUC Order dated October 8, 2009, CMP entered into a 20-year agreement with Evergreen Wind Power III, LLC, on March 31, 2010, to purchase capacity and energy from Evergreen's 60 Megawatt (MW) Rollins wind farm in Penobscot County, Maine. CMP's purchase obligations under the Rollins contract are approximately $7 million per year. Pursuant to a MPUC Order dated December 18, 2017, CMP entered into a 20-year agreement with Dirigo Solar, LLC on September 10, 2018, to purchase capacity and energy from multiple Dirigo solar facilities throughout CMP's service territory. CMP's purchase obligations under the Dirigo contract will increase as additional solar facilities are brought on line, eventually reaching a level of approximately $4 million per year. Pursuant to a MPUC Order dated November 6, 2019, CMP entered into a 20-year agreement with Maine Aqua Ventus I GP LLC on December 9, 2019, to purchase capacity and energy from an off-shore wind 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. In accordance with MPUC orders, CMP either sells the purchased energy from these facilities in the ISO New England markets or periodically auctions the purchased output to wholesale buyers in the New England regional market. Under applicable law, CMP is assured recovery of any differences between power purchase costs and achieved market revenues through a reconcilable component of its retail distribution rates. Although the MPUC has conducted multiple requests for proposals under M.R.S.A §3210-C and has tentatively accepted long-term proposals from other sellers, these selections have not yet resulted in additional currently effective contracts with CMP.

Equity Investment in Peaking Generation

UI is party to a 50-50 joint venture with Clearway Energy, Inc. in GenConn, which operates two peaking generation plants in Connecticut. The two peaking generation plants, GenConn Devon and GenConn Middletown, are both participating in the ISO-NE markets. PURA has approved revenue requirements for the period from January 1, 2020 through December 31, 2020 of $25 million and $29 million for GenConn Devon and GenConn Middletown, respectively.

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 the rate base or accruing carrying costs are the 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 $1,749 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, 2019 and 2018 consisted of:

As of December 31,	**2019**	**2018**
(Millions)		
Pension and other post-retirement benefits cost deferrals	$ 125	$ 141
Pension and other post-retirement benefits	1,061	1,138
Storm costs	272	346
Rate adjustment mechanism	79	18
Reliability support services	—	13
Revenue decoupling mechanism	19	7
Transmission revenue reconciliation mechanism	5	11
Contracts for differences	92	97
Hardship programs	29	26
Plant decommissioning	5	11
Deferred purchased gas	25	37
Deferred transmission expense	11	11
Environmental remediation costs	277	278
Debt premium	97	118
Unamortized losses on reacquired debt	29	23
Unfunded future income taxes	399	371
Federal tax depreciation normalization adjustment	153	157
Asset retirement obligation	17	18
Deferred meter replacement costs	27	29
Other	139	95
Total regulatory assets	**2,861**	**2,945**
Less: current portion	294	299
Total non-current regulatory assets	**$ 2,567**	**$ 2,646**

"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. The recovery of these amounts will be determined in future proceedings.

"Storm costs" for CMP, NYSEG and RG&E 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. As of December 31, 2019, deferred storm costs include $78 million and $37 million at NYSEG being recovered over ten and five year periods, respectively, from the June 2016 approval of the Joint Proposal by the NYPSC, and $96 million and $27 million at NYSEG and RG&E, respectively, not included in the Joint Proposal. The recovery of amounts not included in the Joint Proposal will occur through the RAM or determined as part of the current rate proceedings.

“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.

“Reliability support services” represents the difference between actual expenses for reliability support services and the amount provided for in rates.

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

“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.

“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 fifty 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 rates years covering 2011 forward. The recovery period in New York is from 27 to 39 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.

“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, 2019 and 2018 consisted of:

As of December 31, (Millions)	2019	2018
Energy efficiency portfolio standard	$ 72	$ 56
Gas supply charge and deferred natural gas cost	11	4
Pension and other post-retirement benefits cost deferrals	80	97
Carrying costs on deferred income tax bonus depreciation	49	72
Carrying costs on deferred income tax - Mixed Services 263(a)	15	20
2017 Tax Act	1,548	1,509
Revenue decoupling mechanism	17	19
Accrued removal obligations	1,173	1,153
Asset sale gain account	10	10
Economic development	27	28
Positive benefit adjustment	37	39
Theoretical reserve flow thru impact	14	19
Deferred property tax	17	25
Net plant reconciliation	23	19
Debt rate reconciliation	67	49
Rate refund – FERC ROE proceeding	32	29
Transmission congestion contracts	23	21
Merger-related rate credits	16	18
Accumulated deferred investment tax credits	13	14
Asset retirement obligation	14	13
Earnings sharing provisions	28	17
Middletown/Norwalk local transmission network service collections	18	19
Low income programs	33	38
Non-firm margin sharing credits	16	10
New York 2018 winter storm settlement	11	—
Other	159	130
Total regulatory liabilities	**3,523**	**3,428**
Less: current portion	242	205
Total non-current regulatory liabilities	**$ 3,281**	**$ 3,223**

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

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

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

"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 and DPU have instituted separate proceedings in New York, Maine, Connecticut and Massachusetts, respectively, to review and address the implications associated with the Tax Act on the utilities providing service in such states.

"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 gain on NYSEG’s 2001 sale of its interest in Nine Mile Point 2 nuclear generating station located in Oswego, New York. The net proceeds from the Nine Mile Point 2 nuclear generating station were placed in this account and will be used to benefit customers. The amortization period is five years and began in 2016.

“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. The amortization period is five years and began in 2016.

“Positive benefit adjustment” resulted from Iberdrola’s 2008 acquisition of AVANGRID (formerly Energy East Corporation). This is being used to moderate increases in rates. The amortization period is five years and began in 2016.

“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. The amortization period is five years and began in 2016.

“Merger-related rate credits” resulted from the acquisition of UIL. This is being used to moderate increases in rates. In the years ended December 31, 2019 and 2018, respectively, $2 million and $3 million of rate credits were applied against customer bills.

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

“Other” includes various items subject to reconciliation including excess generation service charge, rate change levelization and RAM.

Note 7. Goodwill and Intangible assets

Goodwill by reportable segment as of December 31, 2019 and 2018 consisted of:

As of December 31,	2019	2018
(Millions)		
Networks	$ 2,747	$ 2,747
Renewables	372	380
Total	**$ 3,119**	**$ 3,127**

During 2019, Renewables' goodwill was reduced by $8 million as a result of the sale of a 50% interest in the Poseidon projects described in Note 22. During 2018, 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. The goodwill for the Maine reporting unit resulted from the purchase of CMP by Energy East Corporation in 2000 and amounted to $325 million. Separately, the goodwill for the New York reporting unit resulted primarily from the purchase of RG&E by Energy East in 2002 and amounted to $654 million. The goodwill for the UIL reporting unit was generated from the acquisition of UIL on December 16, 2015, and amounts to $1,768 million.

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

Our step one impairment testing includes various assumptions, primarily the discount rate, which is based on an estimate of a market participant's marginal, weighted average cost of capital and forecasted cash flows. We test the reasonableness of the conclusions of our step one impairment testing using a range of discount rates and a range of assumptions for long term cash flows.

We had no impairment of goodwill in 2019 and 2018 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, 2019 and 2018:

As of December 31, 2019	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
(Millions)			
Wind development	$ 591	$ (289)	$ 302
Other	28	(16)	12
Total Intangible Assets	**$ 619**	**$ (305)**	**$ 314**

As of December 31, 2018	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
(Millions)			
Wind development	$ 588	$ (275)	$ 313
Other	25	(15)	10
Total Intangible Assets	**$ 613**	**$ (290)**	**$ 323**

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 for both the years ended December 31, 2019 and 2018 was $15 million, and for the year ended December 31, 2017, amortization expense was $22 million. 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, 2019, to be as follows:

Year ending December 31,	Amount
(Millions)	
2020	$ 15
2021	$ 14
2022	$ 13
2023	$ 12
2024	$ 12

Note 8. Property, Plant and Equipment

Property, plant and equipment as of December 31, 2019, consisted of:

As of December 31, 2019	Regulated	Nonregulated	Total
(Millions)			
Electric generation, distribution, transmission and other	$ 15,092	$ 12,360	$ 27,452
Natural gas transportation, distribution and other	4,387	13	4,400
Other common operating property	—	258	258
Total Property, Plant and Equipment in Service	**19,479**	**12,631**	**32,110**
Total accumulated depreciation	(4,969)	(4,090)	(9,059)
Total Net Property, Plant and Equipment in Service	**14,510**	**8,541**	**23,051**
Construction work in progress	1,269	898	2,167
Total Property, Plant and Equipment	**$ 15,779**	**$ 9,439**	**$ 25,218**

Property, plant and equipment as of December 31, 2018, consisted of:

As of December 31, 2018 (Millions)	Regulated	Nonregulated	Total
Electric generation, distribution, transmission and other	$ 14,242	$ 11,669	$ 25,911
Natural gas transportation, distribution and other	4,058	13	4,071
Other common operating property	—	226	226
Total Property, Plant and Equipment in Service (a)	**18,300**	**11,908**	**30,208**
Total accumulated depreciation (b)	(4,615)	(3,744)	(8,359)
Total Net Property, Plant and Equipment in Service	**13,685**	**8,164**	**21,849**
Construction work in progress	1,010	600	1,610
Total Property, Plant and Equipment	**$ 14,695**	**$ 8,764**	**$ 23,459**

(a) Includes capitalized leases of $226 million primarily related to electric generation, distribution, transmission and other. Finance leases (formerly known as capital leases) are no longer included in property plant and equipment after adoption of ASC 842 on January 1, 2019. See Note 3 for further information.
(b) Includes accumulated amortization of capitalized leases of $76 million.

Capitalized interest costs were $55 million, $26 million and $28 million for the years ended December 31, 2019, 2018 and 2017, respectively. Accrued liabilities for property, plant and equipment additions were $357 million, $154 million and $209 million as of December 31, 2019, 2018 and 2017, respectively.

We impaired or wrote off amounts of $11 million, $0 and $5 million for the years ended December 31, 2019, 2018 and 2017, respectively, resulting from reassessment of the economic feasibility of our various Renewables development projects under construction.

Depreciation expense for the years ended December 31, 2019, 2018 and 2017, amounted to $919 million, $840 million and $802 million, respectively.

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, 2019 and 2018 consisted of:

(Millions)	
As of December 31, 2017	**$ 196**
Liabilities settled during the year	(1)
Liabilities incurred during the year	5
Accretion expense	12
Revisions in estimated cash flows	5
As of December 31, 2018	**$ 217**
Liabilities settled during the year	(5)
Liabilities incurred during the year	6
Accretion expense	12
Revisions in estimated cash flows (a)	(40)
As of December 31, 2019	**$ 190**

(a) Represents a reduction 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. Restricted cash related to AROs was $2 million as of both December 31, 2019 and 2018. 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, 2019 and 2018 consisted of:

As of December 31,		2019		2018	
(Millions)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
First mortgage bonds - fixed (a)	2021-2049	$ 2,218	3.07%-8.00%	$ 2,055	3.07%-10.06%
Unsecured pollution control notes - fixed	2020-2029	538	2.00%-3.50%	526	2.00%-3.50%
Term loan - variable	2021	500	2.40%	—	
Other various non-current debt - fixed	2020-2049	4,228	2.80%-10.48%	3,127	2.80%-10.48%
Obligations under capital leases (b)		—		89	4.00%-4.44%
Unamortized debt issuance costs and discount		(38)		(35)	
Total Debt		**7,446**		**5,762**	
Less: debt due within one year, included in current liabilities		730		394	
Total Non-current Debt		**$ 6,716**		**$ 5,368**	

(a) The first mortgage bonds have pledged collateral of substantially all the respective utility's in service properties of approximately $6,876 million.

(b) Due to the adoption of ASC 842 in 2019 (see Notes 3 and 13 for more information), capital leases, now known as financing leases, are no longer reported as part of long-term debt.

On January 15, 2019, UI, CNG, SCG and BGC issued $195 million in aggregate amount of notes/bonds with maturity dates ranging from 2029 to 2049 and fixed interest rates ranging from 4.07% to 4.52%.

On April 1, 2019, NYSEG issued $12 million of Indiana County Industrial Development Authority Pollution Control Revenue Bonds in a private placement maturing in 2024 with a 2.65% fixed interest rate.

On May 16, 2019, we issued $750 million of senior unsecured notes maturing in 2029 at a fixed interest rate of 3.80%.

On June 3, 2019, CMP issued $240 million aggregate principal amount of first mortgage bonds with maturity dates ranging from 2026 to 2034 and fixed interest rates ranging from 3.87% to 4.20%.

On August 27, 2019, RG&E issued $150 million aggregate principal amount of first mortgage bonds maturing in 2027 at a fixed interest rate of 3.10%.

On September 5, 2019, NYSEG issued $300 million aggregate principal amount of senior unsecured notes maturing in 2049 at a fixed interest rate of 3.30%.

On December 31, 2019, we entered into a $500 million term loan credit agreement with two financial institutions. The agreement expires on June 30, 2021 and has a variable interest rate based on the London Interbank Offer Rate (LIBOR). The initial rate was set at 2.40% on December 31, 2019.

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

2020	2021	2022	2023	2024	Total
(Millions)					
$ 730	$ 801	$ 363	$ 439	$ 612	$ 2,945

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, 2019 and 2018.

Fair Value of Debt

The estimated fair value of debt amounted to $8,168 million and $5,952 million as of December 31, 2019 and 2018, 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.

Short-term Debt

Outstanding Notes Payable

AVANGRID had $560 million and $587 million of notes payable as of December 31, 2019 and 2018, respectively. As of December 31, 2019 and 2018, the balance consisted of $562 million and $589 million, respectively, of commercial paper, presented net of discounts on the balance sheet. AVANGRID has a commercial paper program with a limit of $2 billion which is backstopped by the AVANGRID credit facility described below.

AVANGRID Credit Facility

AVANGRID and its subsidiaries, NYSEG, RG&E, CMP, UI, CNG, SCG and BGC have a revolving credit facility with a syndicate of banks, or the AVANGRID Credit Facility, that provides for maximum borrowings of up to $2.5 billion in the aggregate.

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. AVANGRID's maximum sublimit is $2 billion, NYSEG, RG&E, CMP and UI have maximum sublimits of $400 million, CNG and SCG have maximum sublimits of $150 million and BGC has a maximum sublimit of $40 million. Under the AVANGRID Credit Facility, each of the borrowers will pay an annual facility fee that is dependent on their credit rating. As of December 31, 2019, the facility fees range from 10.0 to 17.5 basis points. During 2019, we extended the maturity date for the AVANGRID Credit Facility by one year to June 29, 2024.

Since the facility is a backstop to the AVANGRID commercial paper program, the amounts available under the facility as of December 31, 2019 and December 31, 2018 were $1,938 million and $1,911 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 on the facility. As of both December 31, 2019 and 2018, there was no outstanding amount under this credit facility.

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 for deferred compensation plans and a supplemental retirement benefit life insurance trust. The Rabbi Trusts primarily include equity securities and money market funds. 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. 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 New York Mercantile Exchange (NYMEX). Because we use prices quoted in an active market we include the fair value measurements in Level 1.
- NYSEG, RG&E and CMP 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 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 swap derivative instruments based on a model whose inputs are observable, such as the London Interbank Offered Rate (LIBOR) forward interest rate curves. We include the fair value measurement for these contracts in Level 2 (See Note 12 for further discussion of interest rate swaps).

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 their estimated fair values and are considered Level 1.

Restricted cash was $6 million and $7 million as of December 31, 2019 and 2018, respectively, which is included in “Other Assets” on our consolidated balance sheets.

The financial instruments measured at fair value as of December 31, 2019 and 2018 consisted of:

As of As of December 31, 2019	**Level 1**	**Level 2**	**Level 3**	**Netting**	**Total**
(Millions)					
Equity and other investments with readily determinable fair values	**$ 38**	**$ 13**	**$ —**	**$ —**	**$ 51**
Derivative assets					
Derivative financial instruments - power	$ 4	$ 23	$ 120	$ (54)	$ 93
Derivative financial instruments - gas	—	40	31	(71)	—
Contracts for differences	—	—	2	—	2
Total	**$ 4**	**$ 63**	**$ 153**	**$ (125)**	**$ 95**
Derivative liabilities					
Derivative financial instruments - power	$ (28)	$ (43)	$ (29)	$ 92	$ (8)
Derivative financial instruments - gas	(4)	(26)	(5)	33	(2)
Contracts for differences	—	—	(94)	—	(94)
Derivative financial instruments – Other	—	(1)	—	—	(1)
Total	**$ (32)**	**$ (70)**	**$ (128)**	**$ 125**	**$ (105)**

As of As of December 31, 2018	Level 1	Level 2	Level 3	Netting	Total
(Millions)					
Equity and other investments with readily determinable fair values	**$ 37**	**$ 10**	**$ —**	**$ —**	**$ 47**
Derivative assets					
Derivative financial instruments - power	$ 17	$ 23	$ 91	$ (59)	$ 72
Derivative financial instruments - gas	1	20	36	(55)	2
Contracts for differences	—	—	5	—	5
Total	**$ 18**	**$ 43**	**$ 132**	**$ (114)**	**$ 79**
Derivative liabilities					
Derivative financial instruments - power	$ (12)	$ (41)	$ (36)	$ 77	$ (12)
Derivative financial instruments - gas	(1)	(23)	(7)	22	(9)
Contracts for differences	—	—	(102)	—	(102)
Derivative financial instruments – Other	—	(16)	(2)	—	(18)
Total	**$ (13)**	**$ (80)**	**$ (147)**	**$ 99**	**$ (141)**

The reconciliation of changes in the fair value of financial instruments based on Level 3 inputs for the years ended December 31, 2019, 2018 and 2017 consisted of:

(Millions)	2019	2018	2017
Fair value as of January 1,	**$ (15)**	**$ 6**	**$ 31**
Gains for the year recognized in operating revenues	53	18	18
Losses for the year recognized in operating revenues	(2)	(9)	(1)
Total gains or losses for the period recognized in operating revenues	51	9	17
Gains recognized in OCI	2	—	2
Losses recognized in OCI	(3)	(5)	(1)
Total gains or losses recognized in OCI	(1)	(5)	1
Net change recognized in regulatory assets and liabilities	5	(5)	(17)
Purchases	(22)	(6)	(5)
Settlements	4	(10)	(17)
Transfers out of Level 3 (a)	3	(4)	(4)
Fair value as of December 31,	**$ 25**	**$ (15)**	**$ 6**
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	$ 51	$ 9	$ 17

(a) Transfers out of Level 3 were the result of increased observability of market data.

For assets and liabilities that are recognized in the consolidated financial statements at fair value on a recurring basis, we determine whether transfers have occurred between levels in the hierarchy by re-assessing categorization based on the lowest level of input that is significant to the fair value measurement as a whole at the end of each reporting period. There have been no transfers between Level 1 and Level 2 during the years reported.

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, 2019

Instruments	Instrument Description	Valuation Technique	Valuation Inputs	Index	Avg.	Max.	Min.
Fixed price power and gas swaps with delivery period > two years	Transactions with delivery periods exceeding two years	Transactions are valued against forward market prices on a discounted basis	Observable and extrapolated forward gas and power prices not all of which can be corroborated by market data for identical or similar products	NYMEX ($/MMBtu)	$ 2.90	$ 4.90	$ 2.07
				Indiana hub ($/MWh)	$ 30.54	$ 61.12	$ 19.10
				Mid C ($/MWh)	$ 24.75	$ 105.00	$ (0.50)
				Minn hub ($/MWh)	$ 25.10	$ 52.17	$ 12.51
				NoIL hub ($/MWh)	$ 27.36	$ 55.39	$ 15.50
				Ercot S hub ($/MWh)	$ 31.00	$ 248.39	$ 14.62

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 merchant wind positions. The power swaps are used to hedge merchant wind production in the West and Midwest.

We performed a sensitivity analysis around 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 merchant 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, 2019
Risk of non-performance	0.05% - 0.45%
Discount rate	1.69% - 1.83%
Forward pricing ($ per KW-month)	$3.80 - $7.03

Note 12. Derivative Instruments and Hedging

Our Networks, Renewables and Gas 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, 2019 and 2018, 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, 2019	Current Assets	Noncurrent Assets	Current Liabilities	Noncurrent Liabilities
(Millions)				
Not designated as hedging instruments				
Derivative assets	$ 1	$ 4	$ 1	$ 2
Derivative liabilities	(1)	(2)	(39)	(86)
	—	2	(38)	(84)
Designated as hedging instruments				
Derivative assets	—	—	—	—
Derivative liabilities	—	—	(1)	(1)
	—	—	(1)	(1)
Total derivatives before offset of cash collateral	—	2	(39)	(85)
Cash collateral receivable	—	—	27	1
Total derivatives as presented in the balance sheet	$ —	$ 2	$ (12)	$ (84)

As of December 31, 2018	Current Assets	Noncurrent Assets	Current Liabilities	Noncurrent Liabilities
(Millions)				
Not designated as hedging instruments				
Derivative assets	$ 18	$ 6	$ 10	$ 3
Derivative liabilities	(10)	(3)	(21)	(93)
	8	3	(11)	(90)
Designated as hedging instruments				
Derivative assets	—	—	—	—
Derivative liabilities	—	—	(2)	—
	—	—	(2)	—
Total derivatives before offset of cash collateral	8	3	(13)	(90)
Cash collateral receivable	—	—	—	—
Total derivatives as presented in the balance sheet	$ 8	$ 3	$ (13)	$ (90)

The net notional volumes of the outstanding derivative instruments associated with Networks' activities as of December 31, 2019 and 2018, respectively, consisted of:

As of December 31,	2019	2018
(Millions)		
Wholesale electricity purchase contracts (MWh)	5.1	4.9
Natural gas purchase contracts (Dth)	8.5	7.8
Fleet fuel purchase contracts (Gallons)	2.2	2.1

Derivatives not designated as hedging instruments

NYSEG and RG&E have an electric commodity charge that passes through rates costs for the market price of electricity. We use electricity contracts, both physical and financial, to manage fluctuations in electricity commodity prices in order to provide price stability to customers. We include the cost or benefit of those contracts in the amount expensed for electricity purchased when the related electricity is sold. We record changes in the fair value of electric hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities, in accordance with the 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 their 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, 2019 and 2018 and amounts reclassified from regulatory assets and liabilities into income for the years ended 2019, 2018 and 2017 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, 2019	**Electricity**	**Natural Gas**	**2019**	**Electricity**	**Natural Gas**
Regulatory assets	$ 24	$ 4	Purchased power, natural gas and fuel used	$ 25	$ 1
Regulatory liabilities	$ —	$ —			
December 31, 2018			**2018**		
Regulatory assets	$ —	$ —	Purchased power, natural gas and fuel used	$ (10)	$ (1)
Regulatory liabilities	$ 5	$ —			
			2017		
			Purchased power, natural gas and fuel used	$ 37	$ —

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, 2019, 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 $92 million, a gross derivative liability of $94 million ($92 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, 2018, UI has recorded a gross derivative asset of $5 million ($0 of which is related to UI's portion of the CfD signed by CL&P), a regulatory asset of $97 million, a gross derivative liability of $102 million ($96 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 or regulatory liabilities, for the years ended December 31, 2019, 2018 and 2017, respectively, were as follows:

	Years Ended December 31,		
	2019	**2018**	**2017**
(Millions)			
Derivative Assets	$ (3)	$ (6)	$ (8)
Derivative Liabilities	$ 8	$ 1	$ (9)

Derivatives designated as hedging instruments

The effect of derivatives in cash flow hedging relationships on OCI and income for the years ended December 31, 2019, 2018 and 2017, respectively, consisted of:

Year 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)				
2019				
Interest rate contracts	$ —	Interest expense	$ 6	$ 306
Commodity contracts	—	Purchased power, natural gas and fuel used	1	1,509
Foreign currency exchange contracts	(1)		—	
Total	**$ (1)**		**$ 7**	
2018				
Interest rate contracts	$ —	Interest expense	$ 8	$ 303
Commodity contracts	(1)	Purchased power, natural gas and fuel used	—	1,653
Total	**$ (1)**		**$ 8**	
2017				
Interest rate contracts	$ —	Interest expense	$ 8	$ 280
Commodity contracts	(1)	Purchased power, natural gas and fuel used	1	1,338
Total	**$ (1)**		**$ 9**	

(a) Changes in accumulated OCI are reported in 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 are designated and qualify as cash flow hedges and are expected to be settled upon the payment to vendors for capital expenditures. The gain or loss on the foreign exchange derivative is reported as a component of accumulated OCI and 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 $55 million and $61 million, as of December 31, 2019 and 2018, respectively. We recorded $6 million in net derivative losses related to discontinued cash flow hedges in each of the years ended December 31, 2019, 2018 and 2017. We will amortize approximately $4 million of discontinued cash flow hedges in 2020.

The unrealized loss of $1 million on hedge derivatives is reported in OCI because the forecasted transaction is considered to be probable as of December 31, 2019. We expect that immaterial amounts of those losses will be reclassified into earnings within the next twelve months. The maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted fleet fuel transactions is twelve months.

(b) Renewables and Gas activities

The below presented quantitative information includes derivative financial instruments associated with Gas activities, which were sold during 2018.

We sell fixed-price gas and power forwards to hedge our merchant wind assets from declining commodity prices for our Renewables business. We also purchase fixed-price gas and basis swaps and sell fixed-price power in the forward market to hedge the spark spread or heat rate of our merchant thermal assets. We also enter into tolling arrangements to sell the output of our 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, 2019 and 2018, respectively, consisted of:

As of December 31,	2019	2018
(MWh/Dth in Millions)		
Wholesale electricity purchase contracts	4	5
Wholesale electricity sales contracts	9	6
Natural gas and other fuel purchase contracts	29	29
Financial power contracts	10	11
Basis swaps - purchases	42	42
Basis swaps - sales	1	4

The fair values of derivative contracts associated with Renewables' activities as of December 31, 2019 and 2018, respectively, consisted of:

As of December 31,	2019	2018
(Millions)		
Wholesale electricity purchase contracts	$ 10	$ 11
Wholesale electricity sales contracts	4	(12)
Natural gas and other fuel purchase contracts	(2)	(2)
Financial power contracts	73	55
Basis swaps - purchases	—	(6)
Total	**$ 85**	**$ 46**

The tables below present Renewables' derivative positions as of December 31, 2019 and 2018, 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, 2019	Current Assets	Noncurrent Assets	Current Liabilities	Noncurrent Liabilities
(Millions)				
Not designated as hedging instruments				
Derivative assets	$ 23	$ 110	$ 42	$ 13
Derivative liabilities	(1)	(7)	(48)	(18)
	22	103	(6)	(5)
Designated as hedging instruments				
Derivative assets	—	18	5	4
Derivative liabilities	—	(9)	(13)	(6)
	—	9	(8)	(2)
Total derivatives before offset of cash collateral	22	112	(14)	(7)
Cash collateral (payable) receivable	(11)	(30)	7	6
Total derivatives as presented in the balance sheet	$ 11	$ 82	$ (7)	$ (1)

As of December 31, 2018	Current Assets	Noncurrent Assets	Current Liabilities	Noncurrent Liabilities
(Millions)				
Not designated as hedging instruments				
Derivative assets	$ 19	$ 96	$ 29	$ 17
Derivative liabilities	(5)	(3)	(48)	(35)
	14	93	(19)	(18)
Designated as hedging instruments				
Derivative assets	2	1	2	4
Derivative liabilities	—	—	(7)	(10)
	2	1	(5)	(6)
Total derivatives before offset of cash collateral	16	94	(24)	(24)
Cash collateral (payable) receivable	(8)	(34)	9	17
Total derivatives as presented in the balance sheet	$ 8	$ 60	$ (15)	$ (7)

Derivatives not designated as hedging instruments

The effects of trading and non-trading derivatives associated with Renewables' activities for the year ended December 31, 2019, consisted of:

	Year Ended December 31, 2019		
	Trading	Non-trading	Total amount per income statement
(Millions)			
Operating Revenues			
Wholesale electricity purchase contracts	$ (1)	$ —	
Wholesale electricity sales contracts	3	40	
Financial power contracts	(3)	23	
Financial and natural gas contracts	(1)	1	
Total (loss) gain included in operating revenues	$ (2)	$ 64	$ 1,338
Purchased power, natural gas and fuel used			
Wholesale electricity purchase contracts	$ —	$ —	
Wholesale electricity sales contracts	—	—	
Financial power contracts	—	(1)	
Financial and natural gas contracts	—	15	
Total gain included in purchased power, natural gas and fuel used	$ —	$ 14	$ 1,509
Total (Loss) Gain	$ (2)	$ 78	

During September 2019, Renewables liquidated a portion of one of its wholesale electricity sales contracts and recorded a gain of $43 million for the year ended December 31, 2019.

The effects of trading and non-trading derivatives associated with Renewables' and Gas' activities for the years ended December 31, 2018 and 2017, consisted of:

Years Ended December 31,	2018		2017	
(Millions)	Trading	Non-trading	Trading	Non-trading
Wholesale electricity purchase contracts	$ 4	$ 11	$ (3)	$ 1
Wholesale electricity sales contracts	(2)	(15)	4	(3)
Financial power contracts	—	(19)	(1)	(5)
Financial and natural gas contracts	4	—	(8)	—
Natural gas and other fuel purchase contracts	—	—	—	(8)
Total Gain (Loss)	$ 6	$ (23)	$ (8)	$ (15)

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, 2019, 2018 and 2017 consisted of:

Year Ended December 31,	(Loss) Gain Recognized in OCI on Derivatives (a)	Location of Gain Reclassified from Accumulated OCI into Income	Loss (Gain) Reclassified from Accumulated OCI into Income	Total amount per Income Statement
(Millions)				
2019				
Commodity contracts	$ (5)	Operating revenues	$ 3	$ 6,338
2018				
Commodity contracts	$ (11)	Operating revenues	$ (22)	$ 6,478
2017				
Commodity contracts	$ 41	Operating revenues	$ 14	$ 5,963

(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 $6 million of loss included in accumulated OCI at December 31, 2019 is expected to be reclassified into earnings within the next 12 months. We recorded immaterial amounts of net derivative losses related to discontinued cash flow hedges for the years ended December 31, 2019, 2018 and 2017.

(c) Interest rate swaps

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. In May 2019, we settled interest rate swaps designated as cash flow hedges related to the issuance of the $750 million in debt described in Note 10. The net loss in accumulated OCI related to these interest rate swaps is $38 million as of December 31, 2019. We amortized into income $2 million of the loss related to the settled interest rate swaps for the year ended December 31, 2019. We will amortize into income approximately $4 million of the net loss on the interest rate swaps during 2020.

The table below presents our interest rate swap derivative positions as of December 31, 2019 and 2018, respectively, including the location of the net derivative positions on our consolidated balance sheets:

As of December 31, 2019	Current Liabilities
(Millions)	
Designated as hedging instruments	
Derivative liabilities	$ —
As of December 31, 2018	
(Millions)	
Designated as hedging instruments	
Derivative liabilities	$ (16)

The effect of derivatives in cash flow hedging relationships on accumulated OCI for the years ended December 31, 2019 and 2018, respectively, 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)				
2019				
Interest rate contracts	$ (24)	Interest expense	$ 2	$ 306
2018				
Interest rate contracts	$ (16)	Interest expense	$ —	$ 303

(a) Changes in OCI are reported on a pre-tax basis. The amount in accumulated OCI is being reclassified into earnings over the underlying debt maturity period which ends in 2029.

On January 31, 2020, AVANGRID entered into two forward interest rate swaps, with a total notional amount of $600 million, to hedge the issuance of forecasted fixed rate debt in the first quarter of 2020. The forward interest rate swaps are designated and qualify as cash flow hedges, have mandatory termination dates of March 31, 2020, and are expected to be settled upon the forecasted debt issuance. The gains or losses on the interest rate swap derivatives will be reported as a component of accumulated OCI and reclassified into earnings in the period or periods during which the related interest expense of the forecasted debt is incurred.

(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 rating on senior debt were to fall below investment grade. If such an event had occurred as of December 31, 2019, UI would have had to post an aggregate of approximately $18 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 $21 million and $26 million as of December 31, 2019 and 2018, 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, 2019 is $28 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 64 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 year ended December 31, 2019 were as follows:

For the Year Ended December 31,	2019
(Millions)	
Lease cost	
Finance lease cost	
Amortization of right-of-use assets	$ 12
Interest on lease liabilities	3
Total finance lease cost	15
Operating lease cost	18
Short-term lease cost	5
Variable lease cost	2
Total lease cost	$ 40

Balance sheet and other information for the year ended December 31, 2019 was as follows:

As of December 31,	2019
(Millions, except lease term and discount rate)	
Operating Leases	
Operating lease right-of-use assets	$ 70
Operating lease liabilities, current	12
Operating lease liabilities, long-term	65
Total operating lease liabilities	$ 77
Finance Leases	
Other assets	$ 133
Other current liabilities	9
Other non-current liabilities	54
Total finance lease liabilities	$ 63
Weighted-average Remaining Lease Term (years)	
Finance leases	7.59
Operating leases	12.98
Weighted-average Discount Rate	
Finance leases	5.35%
Operating leases	3.62%

For the year ended December 31, 2019, supplemental cash flow information related to leases was as follows:

For the Year Ended December 31,	2019
(Millions)	
Cash paid for amounts included in the measurement of lease liabilities:	
Operating cash flows from operating leases	$ 13
Operating cash flows from finance leases	$ 3
Financing cash flows from finance leases	$ 27
Right-of-use assets obtained in exchange for lease obligations:	
Finance leases	$ 1
Operating leases	$ 3

As of December 31, 2019, maturities of lease liabilities were as follows:

(Millions)	Finance Leases	Operating Leases
Year ending December 31,		
2020	$ 10	$ 14
2021	7	13
2022	3	10
2023	50	7
2024	—	6
Thereafter	2	51
Total lease payments	72	101
Less: imputed interest	(9)	(24)
Total	$ 63	$ 77

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 $50 million and $52 million at December 31, 2019 and December 31, 2018, 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. 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. We used the incremental borrowing rate on January 1, 2019, for operating leases that commenced prior to that date.

Comparative 2018 and 2017 Leases Disclosures

The following are the 2018 annual lease disclosures, presented in accordance with ASC 840.

Operating lease expense relating to operational facilities, office building leases and vehicle and equipment leases was $59 million, $72 million and $71 million for the years ended December 31, 2018, 2017 and 2016, respectively. Amounts related to contingent payments predominantly linked to electricity generation at the respective facilities were $11 million, $19 million and $22 million for the years ended December 31, 2018, 2017 and 2016, respectively. Leases for most of the land on which wind farm facilities are located have various renewal and termination clauses.

On January 16, 2014, as required by the NYPSC, NYSEG renewed a Reliability Support Services Agreement (RSS Agreement) with Cayuga Operating Company, LLC (Cayuga) for Cayuga to provide reliability support services to maintain necessary system reliability through June 2017. Cayuga owns and operates the Cayuga Generating Facility (Facility), a coal-fired generating station that includes two generating units. Cayuga operates and maintains the RSS units and manages and complies with scheduling deadlines and requirements for maintaining the Facility and the RSS units as eligible energy and capacity providers and complies with dispatch instructions. NYSEG paid Cayuga a monthly fixed price and also paid for capital expenditures for specified capital projects. NYSEG was entitled to a share of any capacity and energy revenues earned by Cayuga. We accounted for this arrangement as an operating lease. The net expense incurred under this operating lease was $18 million for the year ended December 31, 2017, and $38 million for the year ended December 31, 2016.

On October 21, 2015, RG&E, GNPP and multiple intervenors filed a joint proposal with the regulator for approval of the modified RSS Agreement for the continued operation of the Ginna Facility. On February 23, 2016, the NYPSC unanimously adopted the joint proposal, which provided for a term of the RSSA from April 1, 2015, through March 31, 2017 and RG&E monthly payments to GNPP in the amount of $15 million. RG&E was entitled to 70% of revenues from GNPP's sales into the energy and capacity markets, while GNPP was entitled to 30% of such revenues. We accounted for this arrangement as an operating lease. The net expense incurred under this operating lease was $6 million for the year ended December 31, 2017, and $115 million for the year ended December 31, 2016.

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

Year	Operating Leases	Capital Leases	Total
		(Millions)	
2019	$ 31	$ 30	$ 61
2020	39	10	49
2021	38	7	45
2022	35	2	37
2023	33	50	83
Thereafter	735	2	737
Total	**$ 911**	**$ 101**	**$ 1,012**

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 likely and can be reasonably estimated. We do not provide for accrual of legal costs expected to be incurred in connection with a loss contingency.

Transmission - ROE Complaint – CMP and UI

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

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

CMP and UI reserved for refunds for Complaints I, II and III consistent with the FERC's March 3, 2015 decision in Complaint I. Refunds were provided to customers for Complaint I. The CMP and UI total reserve associated with Complaints II and III is $25 million and $7 million, respectively, as of December 31, 2019, which has not changed since December 31, 2018, 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). The FERC proposes to use this new methodology to resolve Complaints I, II, III and IV filed by the New England state consumer advocates.

The new proposed ROE methodology set forth in the October 2018 Order considers more than just the two-step discounted cash flow (DCF) analysis adopted in the FERC order on Complaint I vacated by the Court. The new proposed ROE methodology uses three financial analyses (i.e., DCF, the capital-asset pricing model and the expected earnings analysis) to produce a range of returns to narrow the zone of reasonableness when assessing whether a complainant has met its initial burden of demonstrating that the utility's existing ROE is unjust and unreasonable. The new proposed ROE methodology establishes a range of just and reasonable ROEs of 9.60% to 10.99% and proposes a just and reasonable base ROE of 10.41% with a new ROE cap of 13.08%. Pursuant to the October 2018 Order, the NETOs filed initial briefs on the proposed methodology in all four Complaints on January 11, 2019 and replied to the initial briefs on March 8, 2019. On November 21, 2019, the FERC issued rulings on two complaints challenging the base return on equity for Midcontinent Independent System Operator, or MISO transmission owners. These rulings established a new zone of reasonableness based on equal weighting of the DCF and capital-asset pricing model for establishing the base return on equity. This resulted in a base return on equity of 9.88% as the midpoint of the zone of reasonableness. Various parties have requested rehearing on this decision. We cannot predict the outcome of this proceeding, and the potential impact it may have in establishing a precedent for our pending four Complaints.

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. There is no specific timetable for the FERC's ruling. 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. We cannot predict the outcome of this proceeding.

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 New York State Department of Public Service (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 (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 directs 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. The Commission granted the companies a series of extensions to respond to the portion of the Order to Show Cause with respect to why the Commission should not pursue a penalty action. 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 penalty of $10.5 million.

NYPSC directs Counsel to commence Judicial Enforcement Proceeding against NYSEG

On April 18, 2019, the NYPSC issued an Order Directing Counsel to the Commission to commence a special proceeding or an action in New York State Supreme Court to stop and prevent ongoing future violations by NYSEG of NYPSC regulations and orders. On December 24, 2019, the Commission filed a verified petition to commence the action against NYSEG. At the same time, NYSEG and the Commission settled the causes of action asserted in the verified petition and entered into a consent and stipulation and also submitted a joint motion to the court requesting that the court approve and enter a consent order and judgment reflecting the settlement. The consent order and judgment was issued by the court on January 24, 2020.

Class Actions Regarding LDC Gas Transportation Service on Algonquin Gas Transmission

Breiding et al. v. Eversource and Avangrid - Class Action. On November 16, 2017, a class action lawsuit was filed in the U.S. District Court for the District of Massachusetts on behalf of customers in New England against the Company and Eversource alleging that certain of their respective subsidiaries that take gas transportation service over the Algonquin Gas Transmission (AGT), which for AVANGRID would be its indirect subsidiaries SCG and CNG, engaged in pipeline capacity scheduling practices on AGT that resulted in artificially increased electricity prices in New England. These allegations were based on the conclusions of a whitepaper issued by the Environmental Defense Fund (EDF), an environmental advocacy organization, on October 10, 2017, purporting to analyze the relationship between the New England electricity market and the New England local gas distribution companies. The plaintiffs assert claims under federal antitrust law, state antitrust, unfair competition and consumer protection laws, and under the common law of unjust enrichment. They seek damages, disgorgement, restitution, injunctive relief and attorney fees and costs. On February 27, 2018, the FERC released the results of a FERC staff inquiry into the pipeline capacity scheduling practices on the AGT. The inquiry arose out of the allegations made by the EDF in its whitepaper. The FERC announced that, based on an extensive review of public and non-public data, it had determined that the EDF study was flawed and led to incorrect conclusions. FERC also stated that the staff inquiry revealed no evidence of anticompetitive withholding of natural gas pipeline capacity on the AGT and that it would take no further action on the matter. On April 27, 2018, the Company filed a Motion to Dismiss all of the claims based on federal preemption and lack of any evidence of antitrust behavior, citing, among other reasons, the results of the FERC staff inquiry conclusion. The plaintiffs filed opposition to the motion to dismiss on May 25, 2018. On September 11, 2018, the District Court granted the Company's Motion and dismissed all claims. On January 29, 2019, the plaintiffs filed a brief in support of appeal and on April 26, 2019, the Company and Eversource filed a joint brief in opposition. On May 17, 2019, the plaintiffs filed a reply to the opposition. On September 18, 2019, the First Circuit Court of Appeals affirmed the district court's dismissal of the plaintiff's claims. The plaintiffs filed a motion seeking en banc review on October 16, 2019. On November 15, 2019, the First Circuit Court of Appeals denied the motion.

PNE Energy Supply LLC v. Eversource Energy and Avangrid, Inc. - Class Action. On August 10, 2018, PNE Energy Supply LLC, a competitive energy supplier located in New England that purchases electricity in the day-ahead and real time wholesale electric market, filed a civil antitrust action, on behalf of itself and those similarly situated, against the Company and Eversource alleging that their respective gas subsidiaries illegally manipulated the supply of pipeline capacity in the "secondary capacity market" in order to artificially inflate New England natural gas and electricity prices. These allegations were also based on the conclusions of the whitepaper issued by EDF. The plaintiff claims to represent entities who purchased electricity directly in the wholesale electricity market that it claims was targeted by the alleged anticompetitive conduct of Eversource and the Company. On September 28, 2018, the Company filed a Motion to Dismiss all of the claims based on federal preemption and lack of any evidence of antitrust behavior, citing, among other reasons, the results of the FERC staff inquiry and the dismissal of the related case, *"Breiding et al. v. Eversource and Avangrid,"* by the same court in September. The plaintiffs filed opposition to the motion to dismiss on October 26, 2018 and the Company filed a reply on November 15, 2018. The district court heard oral arguments on the motion to dismiss on January 18, 2019. On April 26, 2019, the Company filed a brief in support of its motion to dismiss, and on June 7, 2019, the district court granted the Company's Motion to Dismiss and dismissed all claims. On July 3, 2019, the plaintiffs filed notice of appeal in the U.S. Court of Appeals for the First Circuit and, on October 18, 2019, filed a brief in support of appeal. We cannot predict the outcome of this class action lawsuit.

Yankee Nuclear Spent Fuel Disposal Claim

CMP has an ownership interest in Maine Yankee Atomic Power Company, Connecticut Yankee Atomic Power Company and Yankee Atomic Electric Company (the Yankee Companies), three New England single-unit decommissioned nuclear reactor sites, and UI has an ownership interest in Connecticut Yankee Atomic Power Company. Pursuant to the statute of limitations, the Yankee Companies file a lawsuit periodically to recover damages from the Department of Energy (DOE) for breach of the Nuclear Spent Fuel Disposal Contract to remove spent nuclear fuel and greater than class C waste as required by contract.

On May 22, 2017, the Yankee Companies filed a next case in the Federal Court of Claims (Court), seeking damages for the period from January 1, 2013 through December 31, 2016. The Court issued its decision on the trial on February 21, 2019, awarding the Yankee Companies a combined $103 million (Connecticut Yankee $41 million, Maine Yankee $34 million and Yankee Atomic $28 million) and on April 23, 2019, the award became final. The damage awards are returned to customers either through customer refunds or by reducing future costs. Refunds or reductions in costs are reflected in the Yankee Companies billings to shareholders, including CMP and UI. CMP and UI received their proportionate share of the awards, based on percentage of ownership, totaling $8 million which will be returned to customers.

Gas Storage Indemnification Claims

On May 1, 2018, ARHI closed a transaction to sell our gas storage business to Amphora Gas Storage USA, LLC. On October 30, 2019, ARHI received notice of a claim for indemnification from Amphora Gas Storage USA, LLC under the purchase agreement with respect to such sale in the amount of approximately $20 million related to, among other things, certain alleged violations of occupational, health and safety requirements, the condition and sufficiency of assets and a third party intellectual property infringement claim. Pursuant to the terms of the purchase agreement, the aggregate amount for which ARHI may be responsible to indemnify Amphora Gas Storage USA, LLC for all claims arising under the purchase agreement, other than those related to certain fundamental representations, tax matters and claims involving fraud, shall not exceed 15% of the purchase price, or approximately $10 million. 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 NYPA 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, 2019.

Power, Gas and Other Arrangements – Renewables

Gas purchase commitments consist of firm transport capacity to fuel the Cogen and Peaking gas generators. Power purchase commitments include the following: (i) a 55 MW Biomass PPA for 12 years (two years remaining) with a guaranteed output of 34.4 MW flat and a schedule of fixed price rates depending on season and time of day, (ii) 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 and (iii) 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 2019 and expiring in 2021) and (iv) 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) a 55 MW Biomass off-take agreement for 12 years (two years remaining) with guaranteed annual production of 34.4 MW flat with a schedule of fixed price rates depending on season and time of day, (ii) a retail renewable power sales agreement for 12 MW (average) expiring in 2026, (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 sales of ancillary services (e.g., regulation and frequency response, generator imbalance, etc.) to third parties from Renewables' Balancing Authority.

Renewables has easement contracts which are no longer considered leases under ASC 842 (see Note 3 for further details). These easement contracts still represent contractual obligations and are now included in the table below.

Forward purchases and sales commitments under power, gas and other arrangements as of December 31, 2019 consisted of:

Year	Purchases	Sales
	(Millions)	
2020	$ 1,396	$ 192
2021	177	138
2022	87	72
2023	68	52
2024	44	39
Thereafter	830	87
Totals	**$ 2,602**	**$ 580**

Guarantee Commitments to Third Parties

As of December 31, 2019, we had approximately $474 million of standby letters of credit, surety bonds, guarantees and indemnifications outstanding. 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, 2019, neither we nor our subsidiaries have any liabilities recorded for these instruments.

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-five waste sites, which do not include sites where gas was manufactured in the past. Seventeen of the twenty-five sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites; six sites are included in Maine's Uncontrolled Sites 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, seven of the twenty-five 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 $5 million related to ten of the twenty-five sites. We have paid remediation costs related to the remaining fifteen sites and do not expect to incur additional liabilities. Additionally, we have recorded an estimated liability of $8 million related to another eleven 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. Our estimate for costs to remediate these sites ranges from $12 million to $21 million as of December 31, 2019. 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). Eight sites are included in the New York State Registry; three sites are included in the New York State Department of Environmental Conservation Multi-Site Order on Consent; three sites are part of Maine's Voluntary Response Action Program with two such sites part of 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.

Our estimate for all costs related to investigation and remediation of the fifty-three sites ranges from $164 million to $430 million as of December 31, 2019. 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; no liability was recorded related to these sites as of December 31, 2019 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, 2019 and 2018, the liability associated with our MGP sites in Connecticut, 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, was $97 million and $99 million, respectively.

Our total recorded liability to investigate and perform remediation at all known inactive MGP sites discussed above and other sites was $349 million and $366 million as of December 31, 2019 and 2018, 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 2057.

FirstEnergy

NYSEG sued FirstEnergy under the Comprehensive Environmental Response, Compensation, and Liability Act to recover environmental cleanup costs at sixteen former MGP sites, which are included in the discussion above. In July 2011, the District Court issued a decision and order in NYSEG's favor, requiring FirstEnergy to pay NYSEG approximately $60 million for past and future clean-up costs at the sixteen sites in dispute. On September 9, 2011, FirstEnergy paid NYSEG $30 million, representing their share of past costs of $27 million and pre-judgment interest of $3 million.

FirstEnergy appealed the decision to the Second Circuit Court of Appeals. On September 11, 2014, the Second Circuit Court of Appeals affirmed the District Court's decision in NYSEG's favor, but modified the decision for nine sites, reducing NYSEG's damages for incurred costs from $27 million to $22 million, excluding interest, and reducing FirstEnergy's allocable share of future costs at these sites. NYSEG refunded FirstEnergy the excess $5 million in November 2014.

FirstEnergy remains liable for a substantial share of clean up expenses at nine MGP sites. Based on current projections, FirstEnergy's share is estimated at approximately $21 million. This amount is being treated as a contingent asset and has not been recorded as either a receivable or a decrease to the environmental provision. Any recovery will be flowed through to NYSEG customers.

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 (the English Station site) that UI sold to Quinnipiac Energy in 2000, filed a lawsuit in federal district court in Connecticut related to environmental remediation at the English Station site. This proceeding was stayed in 2014 pending resolutions of other proceedings before the DEEP concerning the English Station site. In December 2016, the court administratively closed the file without prejudice to reopen upon the filing of a motion to reopen by any party.

In December 2013, Evergreen Power and Asnat filed a subsequent lawsuit related to the English Station site. On April 16, 2018, the plaintiffs filed a revised complaint alleging fraud and unjust enrichment against UIL and UI and adding former UIL officers as named defendants alleging fraud. On February 21, 2019, the court granted our Motion to Strike with respect to all counts except for the count against UI for unjust enrichment. The counts stricken include all counts against the individual defendants as well as against UIL. The plaintiffs have appealed the court's decision to strike. We cannot predict the outcome of this matter.

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

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

As of December 31, 2019 and 2018, the amount reserved for this matter was $16 million and $20 million, respectively. We cannot predict the outcome of this matter**.**

Note 16. Income Taxes

Upon enactment of the Tax Act, the Company remeasured its existing deferred income tax balances as of December 31, 2017 to reflect the decrease in the corporate income tax rate from 35% to 21%, which resulted in a material decrease to its net deferred income tax liability balances based on reasonable estimates that could be determined at that time. The Company's non-regulatory businesses recorded a corresponding net increase or decrease to income tax expense, while the utility operations recorded corresponding regulatory liabilities or assets to the extent that such amounts are probable of settlement or recovery through customer rates. The amount and timing of potential settlements of the established net regulatory liabilities are determined by the regulated utilities' respective rate regulators and IRS Normalization rules. As of December 31, 2018, the Company has completed the measurement and accounting of certain effects of the Tax Act which have been reflected in the consolidated financial statements.

Current and deferred taxes charged to expense (benefit) for the years ended December 31, 2019, 2018 and 2017 consisted of:

Years Ended December 31,	**2019**	**2018**	**2017**
(Millions)			
Current			
Federal	$ 11	$ 17	$ (20)
State	(6)	2	12
Current taxes charged to expense (benefit)	**5**	**19**	**(8)**
Deferred			
Federal	152	233	(124)
State	44	(12)	(73)
Deferred taxes charged to expense (benefit)	**196**	**221**	**(197)**
Production tax credits	(57)	(68)	(53)
Investment tax credits	(1)	(2)	(1)
Total Income Tax Expense (Benefit)	**$ 143**	**$ 170**	**$ (259)**

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, 2019 and 2018 and 35% statutory federal tax rate for the year ended December 31, 2017 consisted of:

Years Ended December 31, (Millions)	2019	2018	2017
Tax expense at federal statutory rate	$ 172	$ 161	$ 43
Depreciation and amortization not normalized	(23)	(5)	9
Investment tax credit amortization	(1)	(2)	(1)
Tax return related adjustments	(2)	(6)	7
Production tax credits	(57)	(68)	(53)
Tax equity financing arrangements	8	—	(10)
Federal tax rate impact on held for sale classification	—	21	82
State tax expense (benefit), net of federal benefit	30	(8)	(40)
Tax Act - remeasurement	—	46	(328)
Other, net	16	31	32
Total Income Tax Expense (Benefit)	**$ 143**	**$ 170**	**$ (259)**

Deferred tax assets and liabilities as of December 31, 2019 and 2018 consisted of:

As of December 31, (Millions)	2019	2018
Deferred Income Tax Liabilities (Assets)		
Property related	$ 4,007	$ 3,787
Unfunded future income taxes	101	107
Federal and state tax credits	(632)	(691)
Federal and state NOL’s	(989)	(993)
Joint ventures/partnerships	136	132
Nontaxable grant revenue	(335)	(354)
Pension and other post-retirement benefits	43	8
Tax Act - tax on regulatory remeasurement	(409)	(393)
Valuation allowance	33	23
Other	(141)	(102)
Deferred Income Tax Liabilities	**1,814**	**1,524**
Classified as regulatory assets	—	(6)
Total Deferred Income Tax Liabilities	**$ 1,814**	**$ 1,530**
Deferred tax assets	$ 2,506	$ 2,533
Deferred tax liabilities	4,320	4,057
Net Accumulated Deferred Income Tax Liabilities	**$ 1,814**	**$ 1,524**

As of December 31, 2019, we had gross federal tax net operating losses of $3.6 billion, federal renewable energy and investment tax credits, federal R&D tax credits and other federal credits of $600 million, state tax effected net operating losses of $289 million in several jurisdictions and miscellaneous state tax credits of $142 million available to carry forward and reduce future income tax liabilities. We recognized a valuation allowance of $33 million. 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 2021.

Valuation allowances are recorded to reduce deferred tax assets when it is more likely than not that all or a portion of a tax benefit will not be realized. The valuation allowance for deferred tax assets as of December 31, 2019 and 2018 was $33 million and $23 million, respectively. Valuation allowances have been established on various federal tax credits, state net operating losses and state tax credit carryforwards. The Company has recorded a federal valuation allowance on its federal tax credit carryforwards of $4 million and has recorded a state valuation allowance on its state net operating losses and state tax credit carryforwards of $29 million. The $10 million increase in valuation allowance from 2018 to 2019 includes an increase of $4 million for additional valuation allowance on Federal tax credit carryforwards and an increase of $6 million on state net operating losses and state tax credits.

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2019, 2018 and 2017 consisted of:

Years ended December 31,	2019	2018	2017
(Millions)			
Beginning Balance	$ 153	$ 45	$ 40
Increases for tax positions related to prior years	14	111	23
Increases for tax positions related to current year	16	—	—
Decreases for tax positions related to prior years	(18)	(3)	(16)
Reduction for tax position related to settlements with taxing authorities	(17)	—	(2)
Ending Balance	**$ 148**	**$ 153**	**$ 45**

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, 2019, 2018 and 2017. If recognized, $98 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 twelve months of December 31, 2019.

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, 2019, UIL is subject to audit of its federal tax return for years 2014 through its short period 2015. UIL income tax years 2011 through its short period in 2015 are open and subject to Connecticut and Massachusetts audit.

Note 17. Post-retirement and Similar Obligations

Networks has funded noncontributory defined benefit pension plans that cover eligible Networks employees and retirees. The plans provide defined benefits based on years of service and final average salary for employees hired before 2002. Most employees hired in 2002, or later based upon the plan, are covered under a cash balance plan or formula where their benefit accumulates based on a percentage of annual salary and credited interest. During 2013, Networks announced that they would discontinue, effective December 31, 2013, the cash balance accruals for all non-union employees covered under the cash balance plans or formula. At the same time, the plans were closed to newly-hired non-union employees. The plans had been closed to newly-hired union employees in prior years. CMP's unionized employees covered under a cash balance plan ceased to receive accruals as of December 31, 2014. NYSEG's unionized employees covered under the cash balance plans ceased to receive accruals as of December 31, 2015. Their earned balances will continue to accrue interest but will no longer be increased by a flat dollar amount or percentage of pay, as defined by the plan. Instead, they will receive a contribution to their account under their respective company's defined contribution plan. There was no change to the defined benefit plans for employees covered under the plans that provide defined benefits based on years of service and final average salary. Employees not participating in a defined benefit plan are eligible to receive an enhanced or core 401(k) Company matching contribution, depending on whether they are union or non-union employees, respectively.

Networks has other postretirement health care benefit plans that cover eligible employees and retirees. The plans were closed to newly-hired non-union employees at the end of 2010. The plans had been closed to union employees in prior years. The pre-Medicare-eligible healthcare plans are contributory and participants' contributions are adjusted annually. Networks average contribution to these plans is limited at a level determined in prior periods. Except for a small group of "grandfathered" retirees, all Medicare eligible retirees that choose to participate are provided with a subsidy through a Health Reimbursement Account (HRA) to purchase coverage on the individual market.

With the acquisition of UIL, Networks also includes pension and other postretirement plans of UIL operating utility companies. The UI pension plans cover about one half of employees of UIL. The plan was closed to newly-hired employees in 2005. UI also has a non-qualified supplemental pension plan for certain employees.

The Regulated Gas Companies in Connecticut and Massachusetts have multiple qualified pension plans covering eligible union and management employees and retirees. The union plans are all closed to new hires, and the non-union plans were closed as of December 31, 2017. These entities also have non-qualified supplemental pension plans for certain employees and retirees. The qualified pension plans are traditional defined benefit plans or cash balance plans for those hired on or after specified dates. In some cases, neither of these plans is offered to new employees and have been replaced with enhanced 401(k) plans for those hired on or after specified dates. Employees not participating in a defined benefit plan are eligible to receive an enhanced or core 401(k) Company matching contribution.

In addition to providing pension benefits, UI also provides other postretirement benefits, consisting principally of health care and life insurance benefits, for retired employees and their dependents. The plans were closed to newly-hired non-union employees at the end of April 2005 and to newly-hired union employees at the end of March 2005. The healthcare plans are contributory and participants' contributions are adjusted annually. For Medicare eligible non-union retirees, UI provides a subsidy through an HRA for retirees to purchase coverage on the individual market. Medicare eligible union retirees have the option of receiving a subsidy through an HRA or paying contributions and participating in company-sponsored retiree health plans.

SCG and CNG also have plans providing other postretirement benefits for eligible employees and retirees. The SCG plans were closed to newly-hired non-union employees at the end of 1995, the SCG plans were closed to newly-hired union employees by the end of March 2010 and to newly-hired CNG union employees by end of March 2011. These benefits consist primarily of health care, prescription drug and life insurance benefits for retired employees and their dependents. For Medicare eligible non-union retirees, SCG and CNG provide a subsidy through an HRA for retirees to purchase coverage on the individual market. Medicare eligible union retirees have the option of receiving a subsidy through an HRA or paying contributions and participating in company-sponsored retiree health plans.

ARHI has a funded defined benefit pension plan for eligible employees hired prior to January 1, 2008. The benefit is based on the participant's age, service and five years average pay at the time of the freeze date of April 30, 2011. ARHI has other postretirement health care benefit plans covering eligible retirees and employees hired prior to January 1, 2008. Health and life insurance rates are based on age and service points at the time of retirement. Effective July 1, 2019, all Medicare eligible ARHI retirees that choose to participate are provided with a subsidy through a Health Reimbursement Account (HRA) to purchase coverage on the individual market.

Obligations and funded status of Networks and ARHI as of December 31, 2019 and 2018 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2019**	**2018**	**2019**	**2018**
(Millions)				
Change in benefit obligation				
Benefit obligation as of January 1,	**$ 3,374**	**$ 3,593**	**$ 425**	**$ 491**
Service cost	41	44	3	4
Interest cost	130	128	16	19
Plan participants' contributions	—	—	—	9
Plan Amendments	(2)	—	—	(3)
Actuarial loss (gain)	347	(159)	26	(55)
Benefits paid	(221)	(237)	(31)	(41)
Reclassified from held for sale	—	5	—	1
Benefit Obligation as of December 31,	**3,669**	**3,374**	**439**	**425**
Change in plan assets				
Fair value of plan assets as of January 1,	**2,544**	**2,865**	**148**	**165**
Actual return (loss) on plan assets	460	(135)	22	(5)
Employer contributions	65	48	16	20
Plan participants' contributions	—	—	—	9
Benefits paid	(221)	(237)	(31)	(41)
Reclassified from held for sale	—	3	—	—
Fair Value of Plan Assets as of December 31,	**2,848**	**2,544**	**155**	**148**
Funded Status as of December 31,	**$ (821)**	**$ (830)**	**$ (284)**	**$ (277)**

Amounts recognized as of December 31, 2019 and 2018 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2019**	**2018**	**2019**	**2018**
(Millions)				
Current liabilities	$ —	$ —	$ (5)	$ (5)
Non-current liabilities	(821)	(830)	(279)	(272)
Total	**$ (821)**	**$ (830)**	**$ (284)**	**$ (277)**

Amounts recognized in OCI for ARHI for the years ended December 31, 2019, 2018 and 2017, consisted of:

	Pension Benefits			Postretirement Benefits		
Years Ended December 31,	**2019**	**2018**	**2017**	**2019**	**2018**	**2017**
(Millions)						
Net loss (gain)	$ 23	$ 24	$ 25	$ (8)	$ (7)	$ (4)

We have determined that all 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 regulatory assets or regulatory liabilities for Networks for the years ended December 31, 2019, 2018 and 2017 consisted of:

	Pension Benefits			Postretirement Benefits		
Years Ended December 31,	**2019**	**2018**	**2017**	**2019**	**2018**	**2017**
(Millions)						
Net loss (gain)	$ 706	$ 762	$ 737	$ 13	$ (8)	$ 35
Prior service cost (credit)	$ 4	$ 4	$ 6	$ (21)	$ (25)	$ (31)

Our accumulated benefit obligation (ABO) for all defined benefit pension plans of Networks and ARHI was $3,451 million and $3,174 million as of December 31, 2019 and 2018, respectively. CMP's and NYSEG's postretirement benefits were partially funded as of December 31, 2019 and 2018.

The projected benefit obligation (PBO) and the ABO exceeded the fair value of pension plan assets for all plans of Networks and ARHI as of December 31, 2019 and 2018.

The aggregate PBO and ABO and the fair value of plan assets for underfunded plans of Networks and ARHI as of December 31, 2019 and 2018 consisted of:

	PBO in excess of plan assets	
As of December 31,	**2019**	**2018**
(Millions)		
Projected benefit obligation	$ 3,669	$ 3,374
Fair value of plan assets	$ 2,848	$ 2,544

	ABO in excess of plan assets	
As of December 31,	**2019**	**2018**
(Millions)		
Accumulated benefit obligation	$ 3,451	$ 3,174
Fair value of plan assets	$ 2,848	$ 2,544

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, 2019, 2018 and 2017 consisted of:

(Millions)	Pension Benefits			Postretirement Benefits		
For the years ended December 31,	**2019**	**2018**	**2017**	**2019**	**2018**	**2017**
Net Periodic Benefit Cost:						
Service cost	$ 41	$ 44	$ 42	$ 3	$ 4	$ 5
Interest cost	128	126	137	16	18	21
Expected return on plan assets	(190)	(199)	(195)	(7)	(8)	(8)
Amortization of prior service (benefit) cost	(1)	1	2	(10)	(9)	(9)
Amortization of net loss	113	149	126	1	6	5
Net Periodic Benefit Cost	**91**	**121**	**112**	**3**	**11**	**14**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities:						
Net loss (gain)	80	175	3	13	(37)	(5)
Amortization of net loss	(113)	(149)	(126)	(1)	(6)	(5)
Current year prior service cost	(2)	—	—	—	(3)	—
Amortization of prior service benefit (cost)	1	(1)	(2)	10	9	9
Total Other Changes	**(34)**	**25**	**(125)**	**22**	**(37)**	**(1)**
Total Recognized	**$ 57**	**$ 146**	**$ (13)**	**$ 25**	**$ (26)**	**$ 13**

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, 2019, 2018 and 2017 consisted of:

(Millions)	Pension Benefits			Postretirement Benefits		
For the years ended December 31,	2019	2018	2017	2019	2018	2017
Net Periodic Benefit Cost:						
Service cost	$ 1	$ —	$ —	$ —	$ —	$ —
Interest cost	2	2	2	—	1	1
Expected return on plan assets	(2)	(2)	(2)	—	—	—
Amortization of net loss (gain)	1	1	1	(1)	—	—
Settlement charge	—	1	—	—	—	—
Net Periodic Benefit Cost	**2**	**2**	**1**	**(1)**	**1**	**1**
Other Changes in plan assets and benefit obligations recognized in OCI:						
Net loss (gain)	—	1	2	—	(3)	(1)
Amortization of net (loss) gain	(1)	(1)	(1)	1	—	—
Amortization of prior service cost	—	—	—	(2)	—	—
Total Other Changes	**(1)**	**—**	**1**	**(1)**	**(3)**	**(1)**
Total Recognized	**$ 1**	**$ 2**	**$ 2**	**$ (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.

Amounts expected to be amortized from regulatory assets or liabilities into net periodic benefit cost for the year ending December 31, 2020 consist of:

(Millions)	Pension Benefits	Postretirement Benefits
Estimated net loss	$ 123	$ 2
Estimated prior service cost (benefit)	$ 1	$ (9)

Amounts expected to be amortized from OCI into net periodic benefit cost for the year ending December 31, 2020 consist of:

(Millions)	Pension Benefits	Postretirement Benefits
Estimated net loss (gain)	$ 2	$ (1)

We expect that no pension benefit or postretirement benefit plan assets will be returned to us during the year ending December 31, 2020.

The weighted-average assumptions used to determine benefit obligations for Networks and ARHI as of December 31, 2019 and 2018 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	2019	2018	2019	2018
Discount rate - Networks	2.93% / 3.19%	3.93% / 4.09%	2.93% / 3.19%	3.93% / 4.09%
Discount rate - ARHI	3.10%	4.09%	3.10%	4.09%
Rate of compensation increase - Networks	3.00% - 6.50%	3.50% - 4.20%	—	—

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 net periodic benefit cost for Networks and ARHI for the years ended December 31, 2019, 2018 and 2017 consisted of:

	Pension Benefits			Postretirement Benefits		
Years Ended December 31,	**2019**	**2018**	**2017**	**2019**	**2018**	**2017**
Discount rate - Networks	3.93% / 4.09%	3.63% / 3.80%	4.12% / 4.24%	3.93% / 4.09%	3.63% / 3.80%	4.12% / 4.24%
Discount rate - ARHI	4.09%	3.80%	3.81%	4.09%	3.80%	3.81%
Expected long-term return on plan assets - Networks	7.00% / 7.40%	7.00% / 7.40%	7.00% / 7.50%	4.90% - 7.00%	6.13%	6.13%
Expected long-term return on plan assets - ARHI	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%
Expected long-term return on plan assets - nontaxable trust - Networks	—	—	—	6.40%	6.40%	6.50%
Expected long-term return on plan assets - taxable trust - Networks	—	—	—	4.20%	4.20%	4.25%
Rate of compensation increase - Networks	3.50%-4.20%	3.50% - 4.20%	3.50% - 4.20%	—	—	—

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, 2019 and 2018 consisted of:

As of December 31,	**2019**	**2018**
Health care cost trend rate assumed for next year - Networks	7.00%/7.75%	7.50%/8.50%
Health care cost trend rate assumed for next year - ARHI	6.75% / 7.50%	7.00%/7.75%
Rate to which cost trend rate is assumed to decline (ultimate trend rate) - Networks	4.50%	4.50%
Rate to which cost trend rate is assumed to decline (ultimate trend rate) - ARHI	4.50%	4.50%
Year that the rate reaches the ultimate trend rate - Networks	2029 / 2027	2030 / 2028
Year that the rate reaches the ultimate trend rate - ARHI	2029 / 2027	2029 / 2027

The effects of a one-percent change in the assumed health care cost trend rates would have the following effects:

	1% Increase	**1% Decrease**
(Millions)		
Effect on total of service and interest cost	$ 1	$ —
Effect on postretirement benefit obligation	$ 12	$ (11)

Contributions

We make annual contributions in accordance with our funding policy of not less than the minimum amounts as required by applicable regulations. Networks expects to contribute $82 million to the pension benefit plans during 2020.

Estimated Future Benefit Payments

Expected benefit payments and Medicare Prescription Drug, Improvement and Modernization Act of 2003 subsidy receipts reflecting expected future service for Networks and ARHI as of December 31, 2019 consisted of:

(Millions)	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
2020	$ 209	$ 32	$ 1
2021	$ 210	$ 32	$ 1
2022	$ 216	$ 31	$ —
2023	$ 217	$ 30	$ —
2024	$ 219	$ 29	$ —
2025 - 2028	$ 1,097	$ 134	$ 2

Non-Qualified Pension Plans

Networks and ARHI 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 $56 million and $54 million at December 31, 2019 and 2018, respectively.

Plan Assets

Our pension benefits plan assets for Networks and ARHI were consolidated from three legacy master trusts to one new master trust in 2019. A consolidated trust provides for a uniform investment manager lineup and an efficient, cost effective means of allocating expenses and investment performance to each plan. Our primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our risk tolerance. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. Our primary means for achieving capital preservation is through diversification of the trusts' investments while avoiding significant concentrations of risk in any one area of the securities markets. Further diversification is achieved within each asset group through utilizing multiple asset managers and systematic allocation to various asset classes and providing broad exposure to different segments of the equity, fixed income and alternative investment markets.

The asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. Networks and ARHI have established target asset allocation policies within allowable ranges for their pension benefits plan assets within broad categories of asset classes made up of Return-Seeking investments and Liability-Hedging investments. Networks currently has target allocations ranging from 35%-70% for Return-Seeking assets and 34%-65% for Liability-Hedging assets. ARHI currently has a target allocation of 60% for Return-Seeking assets and 40% for Liability-Hedging assets. Return-Seeking assets also include investments in real estate, global asset allocation strategies and hedge funds. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of pension benefits plan assets, by asset category, as of December 31, 2019, consisted of:

As of December 31, 2019		Fair Value Measurements		
(Millions)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 42	$ —	$ 42	$ —
U.S. government securities	87	87	—	—
Registered investment companies	464	464	—	—
Corporate bonds	458	—	458	—
Preferred stocks	1	1	—	—
Common collective trusts	572	—	572	—
Other, principally annuity, fixed income	84	—	84	—
	$ 1,708	**$ 552**	**$ 1,156**	**$ —**
Other investments measured at net asset value	1,140			
Total	**$ 2,848**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2018 (a), consisted of:

As of December 31, 2018		Fair Value Measurements		
(Millions)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 52	$ —	$ 52	$ —
U.S. government securities	15	15	—	—
Registered investment companies	424	421	3	—
Corporate bonds	413	—	413	—
Preferred stocks	3	—	3	—
Common collective trusts	634	—	634	—
Other, principally annuity, fixed income	71	—	71	—
	$ 1,612	**$ 436**	**$ 1,176**	**$ —**
Other investments measured at net asset value	932			
Total	**$ 2,544**			

(a) Certain amounts have been reclassified within this table to conform to the 2019 presentation.

Valuation Techniques

We value our pension benefits plan assets as follows:

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

Our postretirement benefits plan assets are held with trustees in multiple voluntary employees' beneficiary association (VEBA) and 401(h) arrangements and are invested among and within various asset classes to achieve sufficient diversification in accordance with our risk tolerance. This is achieved for our postretirement benefits plan assets through the utilization of multiple institutional mutual and money market funds, providing exposure to different segments of the fixed income, equity and short-term cash markets. Approximately 37% 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.

Networks has established a target asset allocation policy within allowable ranges for postretirement benefits plan assets of 45%-65% for equity securities, 25%-45% for fixed income and 5%-25% for all other investment types. ARHI's asset allocation policy has a target allocation of 45% in equity securities, 50% in fixed income and 5% for cash and cash equivalents investments. Equity investments are diversified across U.S. and non-U.S. stocks, investment styles, and market capitalization ranges. Fixed income investments are primarily invested in U.S. bonds and may also include some non-U.S. bonds. Other asset classes, including alternative investments, are used to enhance long-term returns while improving portfolio diversification. We primarily minimize the risk of large losses through diversification but also through monitoring and managing other aspects of risk through quarterly investment portfolio reviews. Systematic rebalancing within target ranges increases the probability that the annualized return on investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of other postretirement benefits plan assets, by asset category, as of December 31, 2019 consisted of:

As of December 31, 2019		Fair Value Measurements		
(Millions)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 31	$ —	$ 31	$ —
Common stocks	16	16	—	—
Registered investment companies	98	98	—	—
Corporate bonds	2	—	2	—
Other, principally annuity, fixed income	8	—	8	—
Total	**$ 155**	**$ 114**	**$ 41**	**$ —**

The fair values of other postretirement benefits plan assets, by asset category, as of December 31, 2018 (a) consisted of:

As of December 31, 2018		Fair Value Measurements		
(Millions)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 9	$ 5	$ 4	$ —
Common stocks	15	15	—	—
Registered investment companies	115	115	—	—
Corporate bonds	2	—	2	—
Other, principally annuity, fixed income	7	—	7	—
Total	**$ 148**	**$ 135**	**$ 13**	**$ —**

(a) Certain amounts have been reclassified within this table to conform to the 2019 presentation.

Valuation Techniques

We value our postretirement benefits plan assets as follows:

- Cash and cash equivalents – Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- 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.
- Other investments, principally annuity and fixed income – based on yields currently available on comparable securities of issuers with similar credit ratings.

Pension and postretirement benefit plan equity securities did not include any Iberdrola common stock as of both December 31, 2019 and 2018.

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. The annual contributions made through these plans for AVANGRID amounted to $40 million, $37 million and $36 million for 2019, 2018 and 2017 respectively.

Note 18. Equity

As of December 31, 2019, our share capital consisted of 500,000,000 shares of common stock authorized, 309,752,140 shares issued and 309,005,272 shares outstanding, 81.5% 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 $13,660 million. As of December 31, 2018, our share capital consisted of 500,000,000 shares of common stock authorized, 309,752,140 shares issued and 309,005,272 shares outstanding, 81.5% 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 capital of $13,657 million. We had 485,810 shares of common stock held in trust and no convertible preferred shares outstanding as of both December 31, 2019 and December 31, 2018. During the year ended December 31, 2019, we issued no shares of common stock and released no shares of common stock held in trust each having a par value of $0.01.

During the year ended December 31, 2018, we issued 81,208 shares of common stock and released no shares of common stock held in trust, 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 the relative ownership percentage of Iberdrola at 81.5%. The stock repurchase program may be suspended or discontinued at any time upon notice. Out of a total of 261,058 treasury shares of common stock of AVANGRID as of December 31, 2019, 115,831 shares were repurchased during 2016, 64,019 shares were repurchased in May 2017 and 81,208 shares were repurchased in May 2018, all in the open market. The total cost of repurchases, including commissions, was $12 million as of December 31, 2019.

Accumulated OCI (Loss)

Accumulated OCI (Loss) for the years ended December 31, 2019, 2018 and 2017 consisted of:

Accumulated Other Comprehensive Income (Loss)	As of December 31, 2016	2017 Change	As of December 31, 2017	Adoption of new accounting standard	2018 Change	As of December 31, 2018	Adoption of new accounting standard	2019 Change	As of December 31, 2019
(Millions)									
Change in revaluation of defined benefit plans, net of income tax expense (benefit) of $1.1 for 2018 and $(0.3) for 2019	$ (14)	$ —	$ (14)	$ —	$ 3	$ (11)	$ (2)	$ 1	$ (12)
Loss (gain) for nonqualified pension plans, net of income tax expense (benefit) of $0.2 for 2017, $0.3 for 2018 and $(1.0) for 2019	(7)	1	(6)	(1)	1	(6)	—	(1)	(7)
Unrealized (loss) gain on derivatives qualifying as cash flow hedges:									
Unrealized gain (loss) during period on derivatives qualifying as cash flow hedges, net of income tax expense (benefit) of $15.2 for 2017, $(6.6) for 2018 and $(8.6) for 2019	5	25	30	—	(21)	9	—	(22)	(13)
Reclassification to net income of losses (gains) on cash flow hedges, net of income tax expense (benefit) of $9.3 for 2017, $(6.5) for 2018 and $2.7 for 2019 (a)	(70)	14	(56)	—	(8)	(64)	(10)	11	(63)
Gain (loss) on derivatives qualifying as cash flow hedges	(65)	39	(26)	—	(29)	(55)	(10)	(11)	(76)
Accumulated Other Comprehensive (Loss) Income	**$ (86)**	**$ 40**	**$ (46)**	**$ (1)**	**$ (25)**	**$ (72)**	**$ (12)**	**$ (11)**	**$ (95)**

(a) Reclassification is reflected in the operating expenses line item in the 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. In 2019, 2018 and 2017, while we did have securities that were dilutive, these securities did not result in a change to our earnings per share calculations for the years ended December 31, 2019, 2018 and 2017.

The calculations of basic and diluted earnings per share attributable to AVANGRID for the years ended December 31, 2019, 2018 and 2017, consisted of:

Years Ended December 31,	2019	2018	2017
(Millions, except for number of shares and per share data)			
Numerator:			
Net income attributable to AVANGRID	$ 700	$ 595	$ 381
Denominator:			
Weighted average number of shares outstanding - basic	309,491,082	309,503,319	309,502,861
Weighted average number of shares outstanding - diluted	309,514,910	309,712,628	309,661,883
Earnings per share attributable to AVANGRID			
Earnings Per Common Share, Basic	$ 2.26	$ 1.92	$ 1.23
Earnings Per Common Share, Diluted	$ 2.26	$ 1.92	$ 1.23

Note 20. Variable Interest Entities

We participate in certain partnership arrangements that qualify as VIEs. These arrangements 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 June 28, 2019, we acquired Patriot Wind Farm LLC and associated entities (Patriot) which have constructed a 226 MW wind farm in Nueces County, Texas for a total purchase price of $317 million. The wind farm constitutes substantially all of the value of the consideration paid to the seller; therefore, the purchase was accounted for as an asset acquisition. We allocated the purchase price to property, plant and equipment of $344 million, derivative liabilities of $26 million and other liabilities of $1 million. In conjunction with the purchase, we entered into a TEF with a third-party investor at a sale price of $128 million.

The assets and liabilities of the VIEs totaled approximately $806 million and $29 million, respectively, at December 31, 2019. As of December 31, 2018 the assets and liabilities of VIEs totaled approximately $876 million and $50 million, respectively. At both December 31, 2019 and 2018, the assets and liabilities of the VIEs consisted primarily of property, plant and equipment and equity method investments. At December 31, 2019 and 2018, equity method investments of VIEs were approximately $0 and $101 million, respectively.

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.

On September 30, 2019, Renewables contributed $50 million to Aeolus Wind Power II LLC (Aeolus), including $31 million to third party investors, to accelerate the third-party investors recovering their investment and achieving their cumulative after-tax return. On December 13 2019, we repurchased the remaining 4.4% of Aeolus we did not control from the third-party investors. The difference between the amount paid of $14 million and the noncontrolling interest balance of $10 million was recorded as an adjustment to equity because there was no change in control as a result of the transaction. After the transaction, Aeolus is no longer considered a VIE. At December 31, 2019, we consider El Cabo Wind, LLC (El Cabo) and Patriot to be VIEs.

Our El Cabo and Patriot 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.

In February 2020, tax equity financing agreements were executed for a portfolio of three newly-constructed wind farms and one repowering of an existing wind farm. The portfolio company, named Aeolus Wind Power VII LLC, will be comprised of Karankawa Wind, LLC, Montague Wind Power Facility, LLC, Otter Creek Wind Farm LLC, and Mountain View Power Partners III, LLC (collectively "Aeolus VII"), and will total 681 MW of wind power. We received $237 million from two tax equity investors on March 2, 2020, which represents their investment in the first two of these wind farms that have reached commercial operations. The third facility will be transacted once it reaches commercial operations later in 2020.

Note 21. Grants, Government Incentives and Deferred Income

The changes in deferred income as of December 31, 2019 and 2018 consisted of:

(Millions)	Government grants	Other deferred income	Total
As of December 31, 2017	**$ 1,427**	**$ 19**	**$ 1,446**
Additions	9	—	9
Recognized in income	(69)	(1)	(70)
As of December 31, 2018	**1,367**	**18**	**1,385**
Disposals	(3)	—	(3)
Derecognition due to sale (a)	(38)	—	(38)
Recognized in income	(68)	(2)	(70)
As of December 31, 2019	**$ 1,258**	**$ 16**	**$ 1,274**

(a) Grants no longer controlled by us due to the 2019 sale of a 50% interest in the Poseidon projects. See Note 22 for further information.

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).

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 DOT. We believe we are in compliance with each grant's terms and conditions as of December 31, 2019 and 2018.

Note 22. Equity Method Investments

On December 13, 2019, Renewables transferred a 50% ownership in a wind farm and a solar project located in Arizona (Poseidon) to an unaffiliated third party involving total consideration of $112 million, excluding closing costs, and recognized a gain of $96 million, net of tax. The pre-tax gain of $134 million is included in "Other income (expense)" in our consolidated statements of income. The net gain includes $50 million related to the remeasurement of our retained investment in Poseidon which was valued based on the consideration received in the transaction. The transaction was accounted for as the sale of a business and resulted in a loss of control. The retained 50% ownership is accounted for as an equity method investment. As of December 31, 2019, the carrying value of Poseidon was $111 million.

In August 2018, we acquired the remaining 50% ownership of a joint venture, which owns and operates a 162 MW wind farm located in Southeast Colorado (Colorado Wind Ventures LLC), which commenced operations in January 2004. The wind farm, being a single asset, constituted substantially all of the fair value of the gross assets acquired and, therefore, the transaction was considered an asset acquisition. We accounted for this venture under the equity method of accounting through the date of the asset acquisition. During the year ended December 31, 2017, we recorded an OTTI of $49 million on this investment. The fair value for OTTI calculation purposes was determined using Level 3 inputs and was estimated based on a discounted cash flows valuation technique utilizing the net amount of estimated future cash inflows and outflows related to the respective PPA.

In December 2018, we 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 recorded a gain of $4 million and $10 million from this transaction in "Other expense" in our consolidated statements of income for the years ended December 31, 2019 and 2018, respectively. We account for the remaining 20% membership interest under the equity method of accounting. The carrying amount of our investment was $14 million and $5 million as of December 31, 2019 and 2018.

We have two 50-50 joint ventures with Horizon Wind Energy, LLC, which own and operate the Flat Rock Windpower LLC and the Flat Rock Wind Power II LLC wind farms located in upstate New York. Flat Rock Wind Power LLC, which commenced operations in January 2006, has a 231 MW capacity. Flat Rock Wind Power II LLC commenced operations in September 2007 and has a 91 MW capacity. We account for the Flat Rock joint ventures under the equity method of accounting. The carrying amount of these investments was $105 million and $114 million for Flat Rock Wind Power LLC, and $49 million and $53 million for Flat Rock Wind Power II LLC, as of December 31, 2019 and 2018, respectively.

We hold a 50% voting interest in Vineyard Wind, LLC (Vineyard Wind), a joint venture with Copenhagen Infrastructure Partners. Vineyard Wind acquired an easement from the U.S. Bureau of Ocean Energy Management containing rights to develop offshore wind generation in a 260-square mile area located southeast of Martha's Vineyard. The area subject to easement has the capacity for siting up to approximately 3,000 MW. In May 2018, Vineyard Wind was selected by the Massachusetts Electric Distribution Companies (EDCs) to construct and operate Vineyard Wind's proposed 800 MW wind farm and electricity transmission project pursuant to the Massachusetts Green Communities Act Section 83C RFP for offshore wind energy projects. During 2019, contributions were made to a new offshore development project of $106 million to enter into the easement contract. In December 2019, DEEP selected Vineyard Wind to provide 804 MW of offshore wind through the development of its Park City Wind Project.

As of December 31, 2019, Renewables has contributed $120 million to Vineyard Wind under the provisions of the LLC agreement. In January 2020, Renewables contributed an additional $13 million to Vineyard Wind. We expect to provide additional capital contributions. There was $5 million and $0 receivable from Vineyard Wind as of December 31, 2019 and 2018, respectively. Renewables, through its joint venture in Vineyard Wind, was awarded a second Massachusetts offshore easement. We account for this venture under the equity method of accounting. The carrying amount of this investment was $227 million and $52 million as of December 31, 2019 and 2018, respectively.

Through UI, we are 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 being accounted for as an equity investment, the carrying value of which was $113 million and $119 million as of December 31, 2019 and 2018, 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. NYSEG's contribution as 20% co-owner is $120 million. As of December 31, 2019 and 2018, the amount receivable from New York TransCo was $0 and $1 million, respectively. The investment in New York TransCo is being accounted for as an equity investment, the carrying value of which was $26 million and $23 million, as of December 31, 2019 and 2018, respectively. New York Transco is subject to regulatory approval of its rates, terms, and conditions with the FERC.

None of our joint ventures have any contingent liabilities or capital commitments. Distributions received from equity method investments amounted to $17 million, $18 million and $20 million for the years ended December 31, 2019, 2018 and 2017 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, 2019 and 2018, we received $9 million and $8 million of distributions in RECs from our equity method investments. As of December 31, 2019, there was an immaterial amount of undistributed earnings from our equity method investments. Capitalized interest costs related to equity method investments were $7 million and $0 for the years ended December 31, 2019 and 2018, respectively.

Note 23. Other Financial Statements Items

Loss from assets held for sale

In connection with the 2018 sale of our gas trading and storage businesses, we recorded a loss from held for sale measurement of $16 million and $642 million, respectively, for the years ended December 31, 2018 and 2017, which is included in "Loss from assets held for sale" in our consolidated statements of income.

Other income (expense)

Other income (expense) for the years ended December 31, 2019, 2018 and 2017 consisted of:

Years ended December 31,	2019	2018	2017
(Millions)			
Gain on sale of assets (a)	$ 148	$ 10	$ —
Allowance for funds used during construction	46	30	36
Carrying costs on regulatory assets	21	21	11
Non-service component of net periodic benefit cost	(79)	(128)	(120)
Other	(17)	1	11
Total Other Income (Expense)	**$ 119**	**$ (66)**	**$ (62)**

(a) 2019 includes a $134 million gain from the sale of 50% of our interest in the Poseidon projects, and 2018 includes a $10 million gain from the sale of our interest in Coyote Ridge (see Note 22).

Accounts Receivable

Accounts receivable as of December 31, 2019 and 2018 consisted of:

As of December 31,	2019	2018
(Millions)		
Trade receivables	$ 1,151	$ 1,204
Allowance for bad debts	(69)	(62)
Total Accounts Receivable	**$ 1,082**	**$ 1,142**

The allowance for bad debts relates entirely to gas and electricity consumers and comprises an amount that has been reserved following historical averages of loss percentages.

The change in the allowance for bad debts as of December 31, 2019 and 2018 consisted of:

(Millions)	
As of December 31, 2016	**$ 64**
Current period provision	69
Write-off as uncollectible	(69)
As of December 31, 2017	**$ 64**
Current period provision	74
Write-off as uncollectible	(76)
As of December 31, 2018	**$ 62**
Current period provision	92
Write-off as uncollectible	(85)
As of December 31, 2019	**$ 69**

DPA receivable balances were $65 million and $62 million as of December 31, 2019 and 2018, respectively.

Prepayments and Other Current Assets

Prepayments and other current assets as of December 31, 2019 and 2018 consisted of:

As of December 31,	2019	2018
(Millions)		
Prepaid other taxes	$ 123	$ 137
Broker margin and collateral accounts	33	37
Other pledged deposits	3	6
Prepaid expenses	34	43
Other	6	6
Total	**$ 199**	**$ 229**

Other current liabilities

Other current liabilities as of December 31, 2019 and 2018 consisted of:

As of December 31, (Millions)	2019	2018
Advances received	$ 140	$ 129
Accrued salaries	89	81
Short-term environmental provisions	40	60
Collateral deposits received	44	42
Pension and other postretirement	5	5
Finance leases	9	—
Other	7	10
Total	**$ 334**	**$ 327**

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 eight 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, loss from held for sale measurement, accelerated depreciation derived from repowering of wind farms, OTTI on equity method investment, impact of the Tax Act and adjustments for the non-core Gas storage business.

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, 2019 consisted of:

For the year ended December 31, 2019 (Millions)	Networks	Renewables	Other(a)	AVANGRID Consolidated
Revenue - external	$ 5,150	$ 1,186	$ 2	$ 6,338
Revenue - intersegment	14	—	(14)	—
Depreciation and amortization	550	383	1	934
Operating income	893	95	15	1,003
Earnings (losses) from equity method investments	11	(8)	—	3
Interest expense, net of capitalization	269	10	27	306
Income tax expense (benefit)	153	4	(14)	143
Capital expenditures	1,612	1,125	3	2,740
Adjusted net income	466	223	(15)	673
As of December 31, 2019				
Property, plant and equipment	15,840	9,368	10	25,218
Equity method investments	139	506	—	645
Total assets	$ 23,250	$ 13,163	$ (1,997)	$ 34,416

(a) Includes Corporate and intersegment eliminations.

Segment information as of and for the year ended December 31, 2018 consisted of:

For the year ended December 31, 2018 (Millions)	Networks	Renewables	Other(a)	AVANGRID Consolidated
Revenue - external	$ 5,304	$ 1,137	$ 37	$ 6,478
Revenue - intersegment	6	2	(8)	—
Loss from assets held for sale	—	—	16	16
Depreciation and amortization	503	352	—	855
Operating income	975	136	16	1,127
Earnings (losses) from equity method investments	13	(3)	—	10
Interest expense, net of capitalization	260	33	10	303
Income tax expense (benefit)	169	(31)	32	170
Capital expenditures	1,377	410	—	1,787
Adjusted net income	486	185	13	684
As of December 31, 2018				
Property, plant and equipment	14,754	8,697	8	23,459
Equity method investments	142	224	—	366
Total assets	$ 22,239	$ 10,703	$ (775)	$ 32,167

(a) Includes Corporate, Gas and intersegment eliminations.

Segment information for the year ended December 31, 2017 consisted of:

For the year ended December 31, 2017 (Millions)	Networks	Renewables	Other (a)	AVANGRID Consolidated
Revenue - external	$ 4,950	$ 1,038	$ (25)	$ 5,963
Revenue - intersegment	11	9	(20)	—
Loss from assets held for sale	—	—	642	642
Depreciation and amortization	474	325	25	824
Operating income (loss)	1,114	92	(701)	505
Earnings (losses) from equity method investments	15	(55)	—	(40)
Interest expense, net of capitalization	244	28	8	280
Income tax expense (benefit)	316	(320)	(255)	(259)
Capital expenditures	1,305	1,097	14	2,416
Adjusted net income	$ 507	$ 120	$ 55	$ 682

(a) Includes Corporate, Gas and intersegment eliminations.

Reconciliation of Adjusted Net Income to Net Income attributable to AVANGRID for the years ended December 31, 2019, 2018 and 2017 is as follows:

Years Ended December 31,	2019	2018	2017
(Millions)			
Adjusted Net Income Attributable to Avangrid, Inc.	**$ 673**	**$ 684**	**$ 682**
Adjustments:			
Impairment of equity method and other investment (1)	—	—	(49)
Restructuring charges (2)	(6)	(4)	(20)
Mark-to-market adjustments - Renewables (3)	76	(25)	(15)
Loss from held for sale measurement (4)	—	(16)	(642)
Impact of the Tax Act (5)	—	(46)	328
Accelerated depreciation from repowering (6)	(33)	(3)	—
Income tax impact of adjustments	(10)	(6)	162
Gas Storage, net of tax (7)	—	11	(64)
Net Income Attributable to Avangrid, Inc.	**$ 700**	**$ 595**	**$ 381**

(1) Represents OTTI on equity method investment recorded in 2017.
(2) Restructuring and severance related charges relate to costs resulted 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 (See Note 27 - Restructuring and Severance Related Expenses – for further details).
(3) Mark-to-market earnings relates to earnings impacts from changes in the fair value of Renewables' derivative instruments associated with electricity and natural gas.
(4) Represents loss from measurement of assets and liabilities held for sale in connection with the committed plan to sell the gas trading and storage businesses.
(5) Represents the impact from measurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017.
(6) Represents the amount of accelerated depreciation derived from repowering wind farms in Renewables.
(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, 2019, 2018 and 2017, respectively, consisted of:

Years Ended December 31,	2019		2018		2017	
(Millions)	Sales To	Purchases From	Sales To	Purchases From	Sales To	Purchases From
Iberdrola Canada Energy Services, Ltd	$ —	$ —	$ —	$ (5)	$ —	$ (33)
Iberdrola Renovables Energia, S.L.	$ —	$ (9)	$ —	$ (14)	$ —	$ (9)
Iberdrola, S.A.	$ 1	$ (42)	$ 1	$ (38)	$ 1	$ (36)
Iberdrola Financiación, S.A.	$ —	$ (3)	$ —	$ (3)	$ —	$ (2)
Iberdrola Energia Monterrey, S.A. de C.V.	$ —	$ —	$ 3	$ —	$ 46	$ —
Vineyard Wind	$ 13	$ —	$ 3	$ —	$ —	$ —
Other	$ 2	$ (3)	$ 2	$ (5)	$ 1	$ (1)

In addition to the statements of income items above, we made purchases of turbines for wind farms from Siemens-Gamesa, in which Iberdrola has an 8.1% ownership. The amounts capitalized for these transactions were $18 million and $6 million for the years ended December 31, 2019 and 2018, respectively. In February 2020, Iberdrola sold its entire ownership share in Siemens-Gamesa; therefore, future transactions will not be considered related party.

Related party balances as of December 31, 2019 and 2018, respectively, consisted of:

As of December 31,	2019		2018	
(Millions)	Owed By	Owed To	Owed By	Owed To
Siemens-Gamesa	$ —	$ (18)	$ —	$ (14)
Iberdrola, S.A.	$ 1	$ (42)	$ 1	$ (40)
Iberdrola Renovables Energía, S.L.	$ —	$ —	$ 4	$ —
Vineyard Wind	$ 5	$ —	$ —	$ —
Other	$ 4	$ (4)	$ 1	$ (4)

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.

Transactions with Iberdrola Canada Energy Services (ICES) predominantly relate to the purchase of gas for ARHI's gas-fired cogeneration facility in Klamath, Oregon. There are no notes payable amounts owed to ICES as of both December 31, 2019 and December 31, 2018.

Transactions with Iberdrola Energia Monterrey predominantly relate to the sale of gas by Enstor Gas for the power generation plant in Monterrey, Mexico.

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.

Refer to Note 22 - Equity Method Investments for information on transactions with our equity method investees.

AVANGRID manages its overall 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 December 31, 2019 and 2018 was $150 million and $0, respectively.

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, 2019 and 2018, there were no amounts outstanding under this credit facility.

Note 26. Stock-Based Compensation

Under the Avangrid, Inc. Omnibus Incentive Plan, 1,298,683 performance stock units (PSUs) were granted to certain officers and employees of AVANGRID in July 2016. 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 this plan. The PSUs will vest upon achievement of certain performance and market-based metrics related to the 2016 through 2019 plan and will be payable in three equal installments in 2020, 2021 and 2022. As of December 31, 2019, the total number of shares authorized for stock-based compensation plans was 2,500,000.

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 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 vest in full in one installment in June and December 2020, respectively for each award, provided that the award holders remain continuously employed with AVANGRID through such dates. The fair value on the grant date was determined based on a price of $50.40 and $47.59 per share, respectively, for June and October 2018 awards.

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, 2019, 2018 and 2017 was $3 million, $2 million and $1 million, respectively. The total income tax benefit recognized for stock-based compensation arrangements for each of the years ended December 31, 2019, 2018 and 2017, was $1 million.

A summary of the status of the AVANGRID's nonvested PSUs and RSUs as of December 31, 2019, and changes during the fiscal year ended December 31, 2019, is presented below:

	Number of PSUs	Weighted Average Grant Date Fair Value
Nonvested Balance – December 31, 2018	1,268,722	$ 32.80
Granted	6,284	$ 38.78
Forfeited	(726)	$ 31.80
Nonvested Balance – December 31, 2019	1,274,280	$ 32.83

As of December 31, 2019, total unrecognized costs for non-vested PSUs and RSUs were $3 million. The weighted-average period over which the PSU and RSUs costs will be recognized is approximately 2 years.

The weighted-average grant date fair value of PSUs and RSUs granted during the year was $38.78 per share for the year ended December 31, 2019.

Note 27. Restructuring and Severance Related Expenses

In 2017, we announced initial targeted voluntary workforce reductions predominantly within the Networks segment. Those actions primarily include: reducing our workforce through voluntary programs in various areas to better align our people resources with business demands and priorities; reorganizing our human resources function to substantially consolidate in Connecticut, as well as related costs to vacate a lease and relocate employees; and reducing our information technology (IT) workforce to make increasing use of external services for operations, support, and development of systems. In 2019, we also announced changes across the Company aimed to mitigate costs and deliver sustainable growth, including among others, outsourcing and insourcing of certain areas of the Company and technology initiatives that help improve efficiency and reduce costs. For the years ended December 31, 2019, 2018 and 2017, those decisions and transactions resulted in restructuring charges of $4 million, $3 million and $15 million, respectively, for severance expenses and $4 million for lease termination expenses in 2017, which are included in "Operations and maintenance" in the consolidated statements of income and approximately $1 million of accelerated amortization of leasehold improvements, which are included in "Depreciation and amortization" in the consolidated statements of income for the year ended December 31, 2017. The remaining costs for severance agreements are being accrued ratably over the remaining service periods, which span intermittent periods through December 2019. For the year ended December 31, 2019, the severance and lease restructuring charges reserves, which are recorded in "Other current liabilities" and "Other liabilities", consisted of:

For the Year Ended December 31,	2019
	(Millions)
Beginning Balance	$ 4
Restructuring and severance related expenses	4
Payments	(3)
Ending Balance	$ 5

Note 28. Quarterly financial data (unaudited)

Selected quarterly financial data for 2019 and 2018 are set forth below:

(Millions, except per share data)	1st Quarter		2nd Quarter		3rd Quarter		4th Quarter	
2019								
Operating revenues	$	1,842	$	1,400	$	1,487	$	1,609
Operating Income	$	341	$	207	$	239	$	216
Net Income	$	216	$	105	$	139	$	216
Net Income attributable to Avangrid, Inc.	$	217	$	110	$	150	$	223
Earnings Per Common Share, Basic and Diluted: (1)	$	0.70	$	0.36	$	0.48	$	0.72
2018								
Operating revenues	$	1,865	$	1,402	$	1,546	$	1,665
Operating Income	$	403	$	222	$	253	$	249
Net Income	$	238	$	110	$	134	$	116
Net Income attributable to Avangrid, Inc.	$	244	$	107	$	125	$	119
Earnings Per Common Share, Basic and Diluted: (1)	$	0.79		0.35/0.34	$	0.40	$	0.38

(1) Based on 309.5 million weighted average number of shares outstanding each quarter in both 2019 and 2018 for basic and diluted earnings per share.

The third and fourth quarters of 2019 include, respectively, a gain of $43 million ($32 million after income tax) from liquidation of a portion of wholesale electricity sales contracts and a gain of $134 million ($96 million after income tax) from the sale of 50% of our interest in the Poseidon projects.

The first and second quarters of 2018 include a loss of $5 million and $10 million, respectively, associated with measurement of held for sale assets of gas trading and storage business, $14 million and $17 million after income taxes. Additionally, the second and fourth quarters of 2018 include the impacts of $7 million and $39 million, respectively, from the measurement of deferred income tax balances as a result of the Tax Act enacted on December 22, 2017 by the U.S. federal government.

Note 29. Subsequent events

On February 19, 2020 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 1, 2020 to shareholders of record at the close of business on March 6, 2020.

Schedule I –Financial Statements of Parent

AVANGRID, INC. (PARENT)
CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF INCOME
FOR THE YEARS ENDED December 31, 2019, 2018 AND 2017
(Millions)

Years Ended December 31,	2019	2018	2017
Operating Revenues	$ —	$ —	$ —
Operating Expenses			
Operating expense	3	3	3
Taxes other than income taxes	(12)	(11)	5
Total Operating Expenses	(9)	(8)	8
Operating Income (Loss)	9	8	(8)
Other Income			
Other income	59	48	58
Equity earnings of subsidiaries	711	604	312
Interest expense	(93)	(56)	(29)
Income Before Income Tax	686	604	333
Income tax (benefit) expense	(14)	9	(48)
Net Income	**$ 700**	**$ 595**	**$ 381**

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, 2019, 2018, AND 2017
(Millions)

Years Ended December 31,	**2019**	**2018**	**2017**
Net Income	$ 700	$ 595	$ 381
Other comprehensive (loss) income of subsidiaries	(11)	(25)	40
Comprehensive Income	**$ 689**	**$ 570**	**$ 421**

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, 2019 AND 2018
(Millions)

As of December 31,	2019	2018
Assets		
Current Assets		
Cash and cash equivalents	$ 146	$ —
Accounts receivable from subsidiaries	22	306
Notes receivable from subsidiaries	2,529	666
Prepayments and other current assets	—	21
Total current assets	2,697	993
Investments in subsidiaries	16,859	16,067
Other assets		
Deferred income taxes	374	312
Other	3	1
Total other assets	377	313
Total Assets	**$ 19,933**	**$ 17,373**
Liabilities		
Current Liabilities		
Current portion of debt	$ 456	$ 8
Notes payable	561	588
Notes payable to subsidiaries	1,674	456
Accounts payable and accrued liabilities	2	10
Accounts payable to subsidiaries	7	9
Interest accrued	10	7
Interest accrued subsidiaries	18	6
Dividends payable	136	136
Taxes accrued	24	—
Total current liabilities	2,888	1,220
Non-current debt	1,808	1,049
Total Liabilities	4,696	2,269
Equity		
Stockholders' Equity:		
Common stock	3	3
Additional paid-in capital	13,660	13,657
Treasury Stock	(12)	(12)
Retained earnings	1,681	1,528
Accumulated other comprehensive loss	(95)	(72)
Total Equity	15,237	15,104
Total Liabilities and Equity	**$ 19,933**	**$ 17,373**

See accompanying notes to Schedule I.

AVANGRID, INC. (PARENT)
CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED December 31, 2019, 2018, AND 2017
(Millions)

Years Ended December 31,	2019	2018	2017
Net Cash used in Operating Activities	**$ (1,299)**	**$ (323)**	**$ (1)**
Cash Flow from Investing Activities			
Notes receivable from subsidiaries	633	462	(532)
Investments in subsidiaries	(399)	(48)	—
Return of capital from investments in subsidiaries	433	116	308
Net Cash (used in) provided by Investing Activities	667	530	(224)
Cash Flow from Financing Activities			
Receipts (repayments) of short-term notes payable from subsidiaries, net	107	246	(246)
(Repayments) receipts of short-term notes payable	(27)	82	357
Proceeds of non-current debt	1,243	—	594
Repurchase of common stock	—	(4)	(3)
Issuance of common stock	—	(2)	(1)
Dividends paid	(545)	(537)	(535)
Net Cash provided by (used in) Financing Activities	778	(215)	166
Net Increase (Decrease) in Cash and Cash Equivalents	146	(8)	(59)
Cash and Cash Equivalents, Beginning of Year	—	8	67
Cash and Cash Equivalents, End of Year	$ 146	$ —	$ 8
Supplemental Cash Flow Information			
Cash paid for interest	$ 85	$ 55	$ 52
Cash paid (refunded) payment for income taxes	$ 43	$ 55	$ (8)

See accompanying notes to Schedule I.

Note 1. Basis of Presentation

Avangrid, Inc. (AVANGRID), formerly Iberdrola USA, Inc., is a holding company and conducts substantially all of its business through its subsidiaries. Substantially all of its consolidated assets are held by such subsidiaries. Accordingly, its cash flow and its ability to meet its obligations are largely dependent upon the earnings of these subsidiaries and the distribution of other payment of such earnings to in the form of dividends, loans or advances or repayment of loans and advances from it. These condensed financial statements and related footnotes have been prepared in accordance with regulatory statute 210.12-04 of Regulation S-X. These 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 its significant subsidiaries. AVANGRID relies on dividends or loans from its subsidiaries to fund dividends to its 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 its proportionate share of the subsidiaries net assets.

AVANGRID will file a consolidated federal income tax return that includes the taxable income or loss of all its subsidiaries for the 2019 tax period. 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 its members.

Note 2. Common Stock

As of December 31, 2019, AVANGRID share capital consisted of 500,000,000 shares of common stock authorized, 309,752,140 shares issued and 309,005,272 shares outstanding, 81.5% 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 $13,660 million. As of December 31, 2018, AVANGRID share capital consisted of 500,000,000 shares of common stock authorized, 309,752,140 shares issued and 309,005,272 shares outstanding, 81.5% 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 $13,657 million. AVANGRID had 485,810 shares of common stock held in trust and no convertible preferred shares outstanding as of both December 31, 2019 and 2018. During the year ended December 31, 2019, AVANGRID issued no shares of common stock and released no shares of common stock held in trust. During the year ended December 31, 2018, AVANGRID issued 81,208 shares of common stock and released 0 shares of common stock held in trust each having a par value of $0.01.

AVANGRID has 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 the relative ownership percentage of Iberdrola at 81.5%. The stock repurchase program may be suspended or discontinued at any time upon notice. Out of 261,058 treasury shares of common stock of AVANGRID as of December 31, 2019, 115,831 shares were repurchased during 2018, 64,019 shares were repurchased in May 2017 and 81,208 shares were repurchased in May 2018, all in the open market. The total cost of repurchase, including commissions, was $12 million as of December 31, 2019.

On February 19, 2020 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 1, 2020 to shareholders of record at the close of business on March 6, 2020.

Note 3. Debt

Supplemental Indenture

On December 19, 2016, AVANGRID, its subsidiary, UIL, and The Bank of New York Mellon, entered into a supplemental indenture, pursuant to which AVANGRID assumed from UIL all the obligations under the indenture dated as of October 7, 2010 between UIL and The Bank of New York Mellon and all obligations relating to $450 million in aggregate principal amount of 4.625% notes due 2020 issued by UIL in 2010 prior to the merger. For the purpose of the supplemental indenture, a capital contribution of $483 million was made by AVANGRID to UIL in December 2016.

On November 21, 2017, AVANGRID issued $600 million aggregate principal amount of its 3.150% notes maturing in 2024. Proceeds of the offering were used to reduce short-term debt incurred to fund capital expenditures associated with development of renewable energy generation facilities. Net proceeds of the offering after the price discount and issuance-related expenses were $594 million.

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 December 31, 2019, we entered into a $500 million term loan credit agreement with two financial institutions. The agreement expires on June 30, 2021 and has a floating interest rate which was 2.40% as of December 31, 2019.

Note 4. Cash Dividends Paid by Subsidiaries

Cash dividends paid by subsidiary are as follows:

Years ended December 31,	2019	2018	2017
(millions)			
AVANGRID Networks	$ 433	$ 116	$ 308

In 2019, AVANGRID made capital contributions of $108 million and $50 million, respectively, to its subsidiaries, UI and NYSEG. In 2018, AVANGRID made a capital contribution of $50 million to its subsidiary, UI. During 2019 and 2018, AVANGRID recorded a net non-cash contribution and dividend of $219 million and $1,515 million, respectively, to and from its subsidiaries to zero out their account balances of notes receivables and payables.

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:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company;

(ii) 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

(iii) 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, 2019. 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, 2019.

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, 2019 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. ***Other Information.***

None.

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 2020 Annual Meeting of Shareholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2019.

Item 11. ***Executive Compensation.***

The information required by this item is incorporated by reference to our Proxy Statement for the 2020 Annual Meeting of Shareholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2019.

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 2020 Annual Meeting of Shareholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2019.

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 2020 Annual Meeting of Shareholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2019.

Item 14. ***Principal Accountant Fees and Services.***

The information required by this item is incorporated by reference to our Proxy Statement for the 2020 Annual Meeting of Shareholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2019.

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).
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).
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 filed with the SEC for the fiscal year ended December 31, 2016).
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).
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	Description of Avangrid, Inc.'s Securities Registered Pursuant to Section 12 of the Securities. Exchange Act of 1934.*

Exhibit Number	Exhibit Description
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	Accession Agreement, dated September 16, 2011, between Iberdrola Renewables Holdings, Inc. and Bank Mendes Gans N.V. (incorporated herein by reference to Exhibit 10.14 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.4	Guarantee and Support Agreement, dated April 3, 2008, between Iberdrola, S.A. and ScottishPower Holdings, Inc. (incorporated herein by reference to Exhibit 10.15 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.5	Amendment No. 1 to Guarantee and Support Agreement, dated May 27, 2010, between Iberdrola, S.A. and Iberdrola Renewables Holdings, Inc. (formerly known as ScottishPower Holdings, Inc.) (incorporated herein by reference to Exhibit 10.16 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.6	English Translation of Regulations for the "2014-2016 Strategic Bonus" for Senior Officers and Officers of Iberdrola, S.A. and Its Group of Companies (incorporated herein by reference to Exhibit 10.19 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015).†
10.7	Provisions to be Applied to U.S. Participants in Relation to the Regulations for the "2014-2016 Strategic Bonus" for Senior Officers and Officers of Iberdrola, S.A. and Its Group of Companies (incorporated herein by reference to Exhibit 10.20 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015). †
10.8	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). †
10.9	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). †
10.10	Employment Agreement dated March 1, 2008 between R. Scott Mahoney and Iberdrola USA Management Corporation (formerly Energy East Management Corporation) (incorporated herein by reference to Exhibit 10.27 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015).†
10.11	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).
10.12	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).
10.13	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). †

Exhibit Number	Exhibit Description
10.14	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).†
10.15	UIL Holdings Corporation 2008 Stock and Incentive Compensation Plan as Amended and Restated May 14, 2013 (incorporated herein by reference to Exhibit 99.1 to Form S-8 filed with the Securities and Exchange Commission on December 16, 2015).†
10.16	UIL Holdings Corporation Deferred Compensation Plan Grandfathered Benefits Provisions, dated August 4, 2008 (incorporated herein by reference to Exhibit 99.2 to Form S-8 filed with the Securities and Exchange Commission on December 16, 2015).†
10.17	UIL Holdings Corporation Deferred Compensation Plan Non-Grandfathered Benefits Provisions, as amended and restated effective dated January 1, 2013 (incorporated herein by reference to Exhibit 99.3 to Form S-8 filed with the Securities and Exchange Commission on December 16, 2015).†
10.18	Amended and Restated UIL Holdings Corporation Change In Control Severance Plan II, dated August 4, 2008 (incorporated herein by reference to Exhibit 10.28a of UIL Holdings Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).†
10.19	Employment Agreement, dated as of January 1, 2016, among Avangrid, Inc., Avangrid Service Company and James P. Torgerson (incorporated herein by reference to Exhibit 10.1 to AVANGRID's Current Report on Form 8-K filed with the SEC on April 22, 2016).†
10.20	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).
10.21	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).
10.22	Form of Performance Stock Unit Grant Agreement (incorporated herein by reference to Exhibit 10.1 to AVANGRID's Current Report on Form 8-K filed with the SEC on July 19, 2016).†
10.23	Avangrid, Inc. Omnibus Incentive Plan (incorporated herein by reference to Form S-8 filed with the SEC on July 21, 2016).†
10.24	Uncommitted Line of Credit for Standby Letters of Credit Agreement, dated as of December 2, 2016, between Avangrid, Inc. and Crédit Agricole Corporate (incorporated herein by reference to Exhibit 10.44 of AVANGRID's Annual Report on Form 10-K filed with the SEC for the fiscal year ended December 31, 2016).
10.25	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 filed with the SEC for the fiscal year ended December 31, 2016).
10.26	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).†
10.27	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.
10.28	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).

Exhibit Number	Exhibit Description
10.29	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).
10.30	Purchase Agreement, dated February 16, 2018, between Avangrid Renewables Holdings, Inc. and Amphora Gas Storage USA, LLC (incorporated herein by reference to Exhibit 10.2 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended March 31, 2018).
10.31	Restricted Stock Unit Grant Notice and Agreement dated June 7, 2018, between Avangrid, Inc. and James P. Torgerson (incorporated herein by reference to Exhibit 10.1 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018).†
10.32	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).
10.33	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).
10.34	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).
10.35	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).
10.36	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).
10.37	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).
10.38	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).
10.39	Revolving Credit Agreement, dated as of June 29, 2018, 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, JPMorgan Chase Bank, N.A., as Administrative Agent, MUFG Bank, LTD. and Santander Bank, N.A., as Co-Documentation Agents, Bank of America, N.A., as Syndication Agent, Banco Bilbao Vizcaya Argentaria, S.A. New York Branch, as Sustainability Agent, and JPMorgan Chase Bank, N.A., Merrill Lynch, Pierce, Fenner & Smith Incorporated, , MUFG Bank, LTD., Santander Bank, N.A., and BBVA Securities, 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 SEC on June 29, 2018).
10.40	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).†
10.41	Employment Agreement, effective September 27, 2018, between Peter Church and Avangrid Management Company, LLC (incorporated herein by reference to Exhibit 10.44 of AVANGRID's Annual Report on Form 10-K for the year ended December 31, 2018).†

Exhibit Number	Exhibit Description
10.42	Restricted Stock Unit Grant Notice and Agreement dated October 29, 2018, between Avangrid, Inc. and Peter Church (incorporated herein by reference to Exhibit 10.45 of AVANGRID's Annual Report on Form 10-K for the year ended December 31, 2018).†
10.43	Executive Variable Pay Plan (incorporated by reference to Exhibit 10.1 to AVANGRID's Current Report on Form 8-K filed with the SEC on February 21, 2018).†
10.44	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).
10.45	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).
10.46	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).
10.47	Amended and Restated Executive Variable Pay Plan (incorporated by reference to Exhibit 10.1 to AVANGRID's Current Report on Form 8-K filed with the SEC on February 20, 2019).†
10.48	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).
10.49	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).
10.50	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).
10.51	Employment Agreement, dated March 30, 2004 between Anthony Marone III and The United Illuminating Company.†*
10.52	First Amendment to Employment Agreement, dated as of November 18, 2004, between Anthony Marone III and The United Illuminating Company.†*
10.53	Second Amendment to Employment Agreement, dated as of August 4, 2008, between Anthony Marone III and The United Illuminating Company.†*
10.54	Letter Agreement, dated September 20, 2016, between Anthony Marone III and Avangrid, Inc.†*
10.55	Employment Agreement, dated May 18, 2017, between Laura Beane and Avangrid Renewables, LLC.†*
10.56	Letter Agreement, dated September 30, 2019, between Laura Beane and Avangrid, Inc.†*
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.*

Exhibit Number	Exhibit Description
31.2	Chief Financial Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
32	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, 2019, formatted as Inline XBRL and contained in Exhibit 101.

* Filed herewith.

† Compensatory plan or agreement.

— Confidential treatment has been requested for portions of this document. The omitted portions of this document have been submitted separately to the Securities and Exchange Commission.

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: March 2, 2020

By: /s/ James P. Torgerson

James P. Torgerson

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/ James P. Torgerson James P. Torgerson	Director and Chief Executive Officer (Principal Executive Officer)	March 2, 2020
/s/ Douglas K. Stuver Douglas K. Stuver	Chief Financial Officer (Principal Financial Officer)	March 2, 2020
/s/ Scott M. Tremble Scott M. Tremble	Controller (Principal Accounting Officer)	March 2, 2020
/s/ Ignacio Sánchez Galán Ignacio Sánchez Galán	Chairman of the Board	March 2, 2020
/s/ John E. Baldacci John E. Baldacci	Director	March 2, 2020
/s/ Pedro Azagra Blázquez Pedro Azagra Blázquez	Director	March 2, 2020
/s/ Robert Duffy Robert Duffy	Director	March 2, 2020
/s/ Teresa Herbert Teresa Herbert	Director	March 2, 2020
/s/ Patricia Jacobs Patricia Jacobs	Director	March 2, 2020
/s/ John L. Lahey John L. Lahey	Director	March 2, 2020
/s/ Santiago Martinez Garrido Santiago Martinez Garrido	Director	March 2, 2020
/s/ Sonsoles Rubio Reinoso Sonsoles Rubio Reinoso	Director	March 2, 2020
/s/ José Sáinz Armada José Sáinz Armada	Director	March 2, 2020
/s/ Alan D. Solomont Alan D. Solomont	Director	March 2, 2020
/s/ Elizabeth Timm Elizabeth Timm	Director	March 2, 2020

EXHIBIT 31.1

CERTIFICATION

I, James P. Torgerson, 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: March 2, 2020

/s/ James P. Torgerson

James P. Torgerson
Director and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Douglas K. Stuver, 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: March 2, 2020

/s/ Douglas K. Stuver

Douglas K. Stuver
Chief Financial Officer

EXHIBIT 32

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

Pursuant to 18 U.S.C. 1350, the undersigned, James P. Torgerson and Douglas K. Stuver, 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/ James P. Torgerson

James P. Torgerson
Director and Chief Executive Officer
Avangrid, Inc.
March 2, 2020

/s/ Douglas K. Stuver

Douglas K. Stuver
Chief Financial Officer
Avangrid, Inc.
March 2, 2020

Additional Information

EXECUTIVE OFFICE

Avangrid, Inc.
180 Marsh Hill Road
Orange, CT 06477
207.629.1200 | 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
877.681.8024
shareholder@broadridge.com

2019 SUSTAINABILITY REPORT

Copies of the company's 2019 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 2019 Annual Report for any purpose.

AVANGRID