2017 Annual Report

AVANGRID

Dear Fellow Shareholders:

AVANGRID completed a remarkable second year. We executed on our growth strategy and delivered a total shareholder return of over 38% in 2017, adding $4.5 billion to shareholder value. We continued to grow our contracted renewables and regulated businesses, while delivering on our goal to complete a strategic review of our gas storage companies, ultimately resulting in the decision to exit those businesses. Importantly, our investments and operational initiatives continued to focus on our vision of a cleaner and more sustainable future by transforming to a digital utility with a commitment to ethical principles, transparency and leadership.

2017 in Review

We achieved consistent financial results in 2017 despite lower than expected wind production and one-time items that impacted our net income. Consolidated U.S. GAAP net income decreased by 40% year over year to $381 million, or $1.23 per share, primarily due to the strategic decision to sell the gas storage companies, although partially offset by the positive impact of federal tax reform. In the first quarter of 2018, we closed the transaction to sell our gas trading business and we reached an agreement to sell our gas storage assets, which is expected to be completed in the first half of 2018.

Our 2017 non-U.S. GAAP consolidated adjusted net income, excluding our gas storage businesses, mark-to-market and other one-time items,[1] improved 6% year over year to $682 million, or $2.20 per share. This improvement was driven by the implementation of new rate plans, the contribution of new wind capacity, and our continued focus on operational excellence and best practices. We continued to execute on the growth in our strategic plan as we invested $2.3 billion in 2017, an 18% increase over 2016. These investments in our Networks and Renewables businesses will enable a smarter and cleaner energy system for our customers.

In our Networks business, we invested $1.3 billion in projects such as the completion of our new Customer Smart Care Data System in Maine, and our Ginna Retirement and Auburn transmission projects in New York. We successfully negotiated a three-year rate settlement in Connecticut for Southern Connecticut Gas providing rate stability and predictability for our customers. This rate agreement, along with our three-year rate plans for all utilities in New York and electric distribution in Connecticut, and FERC-regulated transmission rates, provide rate certainty and visibility to 85% of our regulated asset base in the coming years. We continue to maintain our focus on the safe and reliable delivery of energy to all of our 3.2 million customers while continuously seeking opportunities to improve our quality of service. I am proud to say that all of our regulated companies saw their scores improve in the J.D. Power 2017 Electric Utility Industry Residential Satisfaction Study. Additionally, Central Maine Power and Rochester Gas & Electric, ranked in the top quartile in their respective classes.

In our Renewables business, we invested $955 million and completed the installation of 590 megawatts (MW) of generation during 2017, including four wind projects in California, Colorado, New Mexico and Vermont for a total of 534 MW and one solar project of 56 MW in Oregon. Additionally, we executed approximately 846 MW of new Power Purchase Agreements (PPAs) mainly with Fortune 100 Companies, including Google and a major footwear and apparel company. We started the construction of 411 MW, including one solar project in Oregon that will be operational this year and two wind projects in Oregon and Texas expected to be operational by the end of 2019. In addition, we made the necessary investments in 2017 to secure 80% of the full value of production tax credits for up to 1 gigawatt (GW) of new wind generation for projects completed by 2021. Finally, we have established an offshore business segment as a key part of our long-term growth strategy, one that differentiates us from other U.S. utilities and renewables companies, with two projects under development off the coasts of Massachusetts and North Carolina having a total potential capacity of 4GW. Regarding the project in Massachusetts, we acquired in 2017 a 50% stake in Vineyard Wind in partnership with Copenhagen Infrastructure Partners and submitted proposals in response to Requests for Proposals in Massachusetts and Connecticut to develop the nation's first large-scale offshore wind project. We expect other states to announce requests for proposals that include offshore wind, and see this as an excellent opportunity for us to help states reach renewable energy goals. Our expertise and that of our controlling shareholder, Iberdrola, provides us with a distinct advantage in this rapidly growing market.

Investing in a cleaner and smarter energy future

AVANGRID has strong growth prospects. On February 20, 2018 we reaffirmed our long term plan to grow earnings at 8–10% compound annual growth rate (CAGR) by 2020 over 2016 results, and extended this commitment to 2022, driving sustainable value creation for our shareholders. Also on February 20, 2018, we set our 2018 earnings per share guidance at $2.16 – $2.46 on a GAAP basis, and at $2.22 – $2.50 on an adjusted basis.[2]

From an industry perspective, the decarbonization and increased electrification of the economy will require more and smarter Networks and Renewables infrastructures. As the third largest wind operator in the country we are very well positioned to lead the transition towards a competitive and clean energy future with our pipeline of renewables projects. Our Networks business is building the electric grid of the future by investing in our transmission infrastructure to enable more renewables and developing smart customer solutions. We are enhancing our distribution system through automation and smart grid initiatives, such as Advanced Metering Infrastructure and our Smart Community project in New York, as we transform our business to meet the needs of our customers for both today and into the future.

We plan to invest $14.4 billion between 2017 and 2022, or $2.4 billion on average per year. This represents a 7% increase in annual investment compared to our previous plan. Approximately 75% of our investments have already been secured, either with regulatory approval or ongoing investment programs or with signed PPAs in Renewables. This gives us great confidence in our ability to achieve our long-term objectives. In Networks, we are actively making investments to improve and expand our infrastructure with a focus on automating and modernizing our grid. We expect our regulated asset base to reach $14.5 billion by 2022, increasing by 67% compared to 2016. In Renewables, our 8 GW pipeline of onshore wind and solar projects will allow us to grow our installed capacity by 45% to reach 8.6 GW by 2022.

In addition, we have many other investment opportunities outside of this plan, especially in offshore wind and transmission solutions both in and outside of our service territories. In line with this, we are excited that the New England Clean Energy Connect (NECEC) transmission project was selected on March 28, 2018, to advance to negotiate a contract as the sole clean energy solution in the Massachusetts Section 83D RFP. This approximately $950 million investment includes a 1,200 MW high-voltage direct current transmission line linking the electrical grids in Québec and New England to deliver clean renewable hydro power from Canada to Massachusetts, with enough energy to power up to 1.5 million New England homes.

We also have a sector-leading financial position with our strong balance sheet and low leverage, which provides us flexibility to fund our investment plan. With the earnings growth projected in our long term outlook, we will look to increase our $1.728 per share dividend starting in 2018, consistent with our 65% to 75% payout ratio and subject to approval of our board of directors.

Driving the transformation towards the Digital Utility

We are executing on our Forward 2020+ Plan with the goal to attain best-in-class operational efficiency in the industry, creating sustainable value for our shareholders, customers and employees, thus being able to mitigate rate impacts of the investment plan. During 2017, we consolidated our corporate headquarters in Orange, Connecticut, and adopted a centralized shared services model. We are implementing hiring strategies to attract top talent and skills needed for the "utility of the future" and to help create a more agile organization. AVANGRID also launched an "Employee Ideas" program in 2017 and we received nearly 300 employee ideas with almost 50% accepted for implementation.

We are driving innovation and the deployment of new technology. During 2017 AVANGRID invested more than $50M in innovation activities, up 80% versus the previous year. Avangrid Networks operates an increasingly Intelligent Grid, with over 600 digitized substations remotely monitored and controlled, 1.2 million smart meters currently installed with 3.2 million smart meters expected by 2022. We are driving the digitization of customer services and interactions, and we are providing Smart Customer Solutions through the implementation of advanced customer care systems and grid analytics. We are also developing plans to support the adoption of electric vehicles and to integrate battery storage.

Renewables operates a National 24/7 Control Center with approximately 3,400 wind turbines, solar and gas generation facilities based on an advanced in-house operation and maintenance model, which includes the digital field worker. Our

Balancing Authority project for the Northwest region will manage a portfolio of 1,300 MW allowing us to enhance our customized renewable energy product offerings to the growing commercial and industrial business segment.

Delivering value in a sustainable manner

AVANGRID's corporate governance system is integral to our mission to create sustainable value for society, customers, and shareholders. We are committed to best practices in governance and a culture of ethics and transparency. In 2017 we adopted a majority voting standard in uncontested elections and refreshed the governance documents to increase clarity, consistency and alignment across AVANGRID and its subsidiaries. These governance enhancements reflect the Board's careful consideration of shareholder feedback we received. Our efforts did not go unnoticed. In 2017, AVANGRID was named the North America utility with the best corporate governance practices for the second consecutive year by the Ethical Board publication.

We believe the environment and the wellbeing of the communities we serve are a critical part of our corporate responsibility. AVANGRID and our employees donated almost $17 million in 2017 to charities and good causes to more than 750 organizations. Our employees also serve and support our communities by donating their time and talents through numerous local volunteer efforts.

We are committed to a sustainable and clean energy future, with almost 90% of our capacity mix already coming from renewable sources. In 2017, AVANGRID successfully issued $600 million in Green Bonds to support our clean energy initiatives. Also, as a result of our renewables investments, in 2017, our generation carbon emissions intensity was almost 9 times lower than the U.S. utility average, decreasing 8% year over year and 16% compared to the 2015 baseline. Our efforts have been recognized by the Carbon Disclosure Program. AVANGRID was one of only six U.S. utilities who received the top score of A-. We have also been named by Thompson Reuters as a 2017 Top 100 Global Energy Leader, and according to 2017 Newsweek Green Rankings, AVANGRID was one of the only seven companies in the world that earned more than 60% of their revenues from environmentally beneficial products and services, with AVANGRID being the only energy company among these seven.

AVANGRID places great value in protecting the electric grid that powers the homes and businesses of our customers. In November 2017, AVANGRID participated in GridEx IV, a biennial exercise designed to simulate a cyber and physical attack targeting the energy grid and other critical infrastructure across North America, hosted by the North American Electric Reliability Corporation. Representatives from all of our operating companies participated and we were able to exercise our Unified Incident Response Plan on a national level, which allows us to prepare for cyber incidents in the same way we do for storms or other threats.

AVANGRID is leading the transformation to a more competitive, smarter and cleaner energy future. We are building a more sustainable, reliable and secure energy infrastructure through our focus on the implementation of best practices and our multi-billion dollar investments in our core regulated and contracted businesses while maintaining our financial strength. The execution of our long-term strategy will drive earnings growth at an 8-10% compound annual growth rate (CAGR) and our commitment to increase our dividend starting this year. We are very confident in our long-term outlook and we expect to rank among the best-in-class companies in our industry, delivering sustainable long-term value to all our stakeholders, including shareholders, customers, and employees.

I also want to acknowledge the contributions Richard Nicholas, our Chief Financial Officer, who has announced his intention to retire in July. Rich was instrumental in ensuring the success of the merger of Iberdrola USA with UIL, which created AVANGRID. We all wish him well in retirement.

Finally, I want to thank all of our dedicated employees for their contributions in making AVANGRID a top tier energy company delivering high levels of customer satisfaction in a safe, efficient manner.

Sincerely,

James P. Torgerson
Chief Executive Officer

1 Adjusted consolidated net income excludes the Gas Storage businesses and certain losses related to their sale, and mark-to-market (MTM) earnings/losses, restructuring charges, an impairment of an investment, the impacts of tax reform and the sale of certain equity investments in 2016. For additional information, see “Non-GAAP Financial Measures” beginning on page 68 of our Annual Report on Form 10-K for the year ended December 31, 2017, included in this annual report.

2 Our adjusted earnings per share guidance excludes the gas storage business and mark-to-market (MTM) earnings/losses that cannot be estimated. For additional information, see “Non-GAAP Financial Measures” beginning on page 68 of our Annual Report on Form 10-K for the year ended December 31, 2017, included in this annual report.

AVANGRID, the utility of the future

~ $32 billion in assets with a presence in 27 states

Eight utilities in four states with ~ 3.2 million utility customers with a $9.1 billion rate base

3rd largest wind operator in the U.S with ~ 6.5 GW installed capacity (wind & solar)

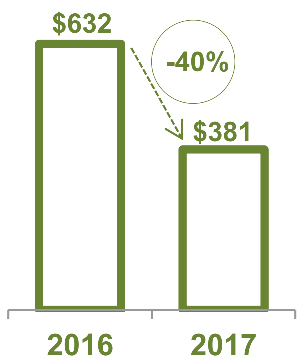
Financial and operational highlights for 2017

Selected financial data in millions, except per-share data (vs 2016)	
Revenues	$5,963 (-1%)
Operating income	$385 (-68%)
Net income	$381 (-40%)
Adjusted net income*	$682 (+6%)
Earnings per share	$1.23 (-40%)
Adjusted earnings per share*	$2.20 (+6%)
Dividends declared per share	$1.728
Dividend yield (year-end)	3.4%
Total shareholder return	39%
Market cap (year-end)	$15,630
Total assets	$31,671
Equity	$15,096
Non-current debt	$5,196
Investments	$2,262 (+18%)

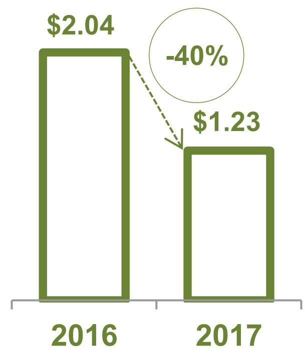
Selected operational data	
Total customers	3,229,812
Electricity customers	2,231,576
Natural gas customers	998,236
Electricity delivered (GWh)	36,591
Natural gas delivered (DTh)	175,477,000
Electrical transmission lines (miles)	8,657
Electrical distribution lines (miles)	70,934
Gas distribution pipeline (miles)	24,298
Net electricity generation (GWh)	18,104
% emissions-free generation	87%
Installed capacity (MW)	7,472
% emissions-free capacity	89%
CO_2 emissions intensity (lbs/MWh)	116.4
Employees	6,570

* Consolidated 2017 adjusted net income and adjusted EPS are non-GAAP financial measures. For additional information, see "Non-GAAP Financial Measures" beginning on page 68 of our Annual Report on Form 10-K for the year ended December 31, 2017.

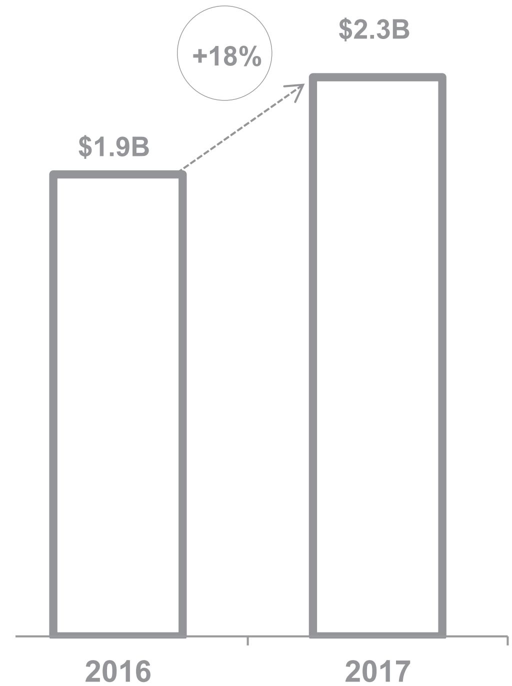
Net Income ($M)



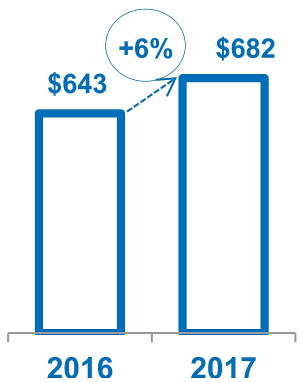
EPS



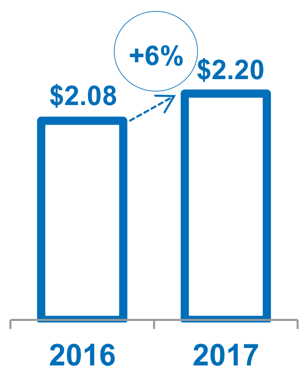
Capital Investments



Adjusted Net Income ($M)



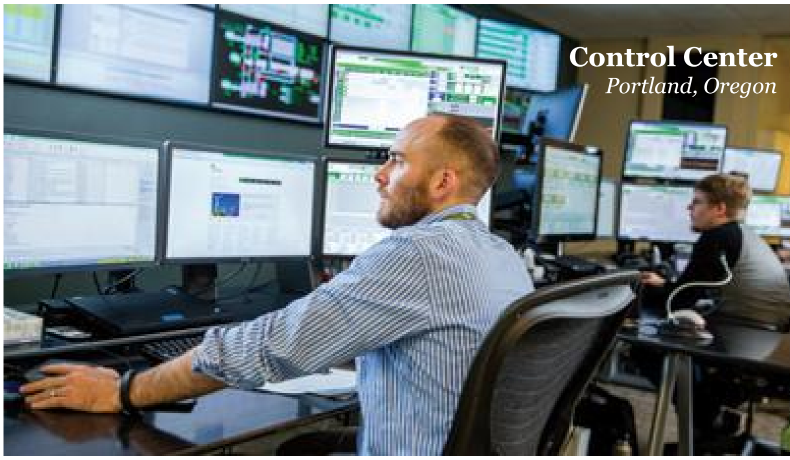
Adjusted EPS

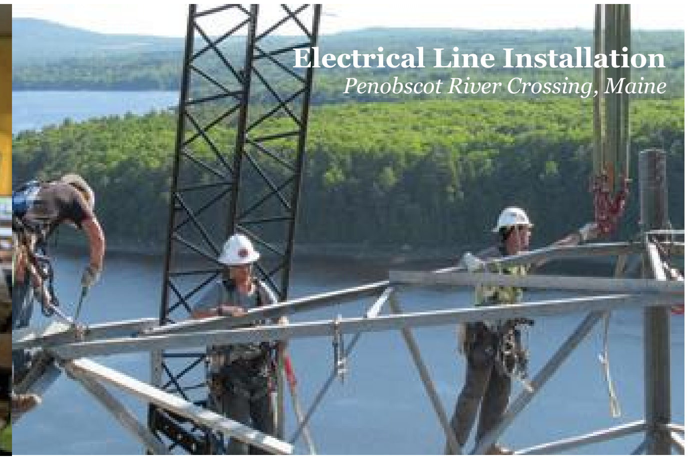


Facilities Net Capacity		Weight
Wind Farms	6,387 MW	(85%)
Hydro Power Plants	118 MW	(2%)
Solar Photovoltaic	106 MW	(1%)
Fuel Cells	13 MW	(0%)
Peaking Generators	212 MW	(3%)
Klamath Cogeneration[1]	636 MW	(9%)

Utilities	State	Electricity customers	Gas Customers
CNG	CT	--	176,836
SCG	CT	--	197,253
UI	CT	334,955	--
BGC	MA	--	40,136
CMP	ME	624,378	--
MNG	ME	--	4,617
NYSEG	NY	893,782	266,351
RG&E	NY	378,461	313,043

[1] Klamath cogeneration includes 100MW of peaking generator.


Control Center
Portland, Oregon


Electrical Line Installation
Penobscot River Crossing, Maine

Delivering energy in a sustainable manner and investing in a smarter and cleaner future

Building the grid of the future with transmission and smart customer solutions

Focused on clean energy with ~89% emission free capacity & renewable energy pipeline


Contracted renewables
150 MW Shiloh Wind Farm in Solano County, California

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, 2017

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, Inc.
(Exact name of registrant as specified in its charter)

New York **(State or other jurisdiction of incorporation or organization)**	**4911** **(Primary Standard Industrial Classification Code Number)**	**14-1798693** **(I.R.S. Employer Identification No.)**
180 Marsh Hill Road **Orange, Connecticut** **(Address of principal executive offices)**		**06477** **(Zip Code)**

Telephone: (207) 629-1200
(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock, $0.01 par value per share par value	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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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 and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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	☐ (Do not check if a smaller reporting company)	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, 2017) was $2,472 million based on a closing sales price of $44.15 per share.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: 309,086,480 shares of common stock, par value $0.01, were outstanding as of March 20, 2018.

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 2018 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.

Consent order refers to the partial consent order issued by DEEP in August 2016.

English station site refers to the former generation site on the Mill River in New Haven, Connecticut.

GenConn Devon refers to GenConn's peaking generating plant in Devon, Connecticut.

GenConn Middletown refers to GenConn's peaking generating plant in Middletown, Connecticut.

Ginna refers to the Ginna Nuclear Power Plant, LLC and the R.E. Ginna Nuclear Power Plant.

Iberdrola refers to Iberdrola, S.A., which owns 81.5% of the outstanding shares of Avangrid, Inc.

Iberdrola Group refers to the group of companies controlled by Iberdrola, S.A.

Installed capacity refers to the production capacity of a power plant or wind farm based either on its rated (nameplate) capacity or actual capacity.

Joint Proposal refers to the Joint Proposal, filed with the NYPSC on February 19, 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 refers to the Klamath gas-fired cogeneration facility located in the city of Klamath, Oregon.

Merger Agreement refers to 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.

NED pipeline refers to TGP's proposed Northeast Energy Direct project.

Non-GAAP refers to the financial measures that are not prepared in accordance with U.S. GAAP, including adjusted gross margin, adjusted EBITDA, adjusted net income and adjusted earnings per share.

AGT	Algonquin Gas Transmission
AMI	Automated Metering Infrastructure
AOCI	Accumulated other comprehensive income
ARHI	Avangrid Renewables Holdings, Inc.
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
CL&P	The Connecticut Light and Power Company
CMP	Central Maine Power Company
CNG	Connecticut Natural Gas Corporation
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
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
EAMs	Earnings adjustment mechanisms
EBITDA	Earnings before interest, taxes, depreciation and amortization
EDF	Environmental Defense Fund
EPA	Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
ERCOT	Electric Reliability Council of Texas
ESA	Endangered Species Act
ESC	Earnings 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
Ginna Facility	R.E. Ginna Nuclear Power Plant
GNPP	Ginna Nuclear Power Plant, LLC.
HLPSA	Hazardous Liquids Pipeline Safety Act of 1979

IRS	Internal Revenue Service
ISO	Independent system operator
ISO-NE	ISO New England, Inc.
Kinder Morgan	Kinder Morgan, Inc.
kV	Kilovolts
kWh	Kilowatt-hour
LDCs	Local distribution companies
LIBOR	London Interbank Offer Rate
LIPA	Long Island Power Authority
LNG	Liquefied natural gas
LNS	Local Network Service
MBTA	Migratory Bird Treaty Act
Mcf	One thousand cubic feet
Merger Sub	Green Merger Sub, Inc.
MEPCO	Maine Electric Power Corporation
MGP	Manufactured gas plants
MISO	Midcontinent Independent System Operator, Inc.
MHI	Mitsubishi Heavy Industries
MNG	Maine Natural Gas Corporation
MPRP	Maine Reliability Power 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
NEEWS	New England East West Solution
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.
NIPSCO	Northern Indiana Public Service Company
NGA	Natural Gas Act of 1938
NGPSA	Natural Gas Pipeline Safety Act of 1968
NOL	Net operating loss

NPNS	Normal purchases and normal sales
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 Tariiff
OCC	Connecticut Office of Consumer Counsel
OCI	Other comprehesive income
OSHA	Occupational Safety and Health Act, as amended
PCB	Polychlorinated Biphenyls
PHMSA	Pipeline and Hazardous Materials Safety Administration
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
RNS	Regional Network Service
RPS	Renewable Portfolio Standards
RSSA	Reliability Support Services Agreement
RTO	Regional transmission organizations
SCG	The Southern Connecticut Gas Company
Scottish Power	Scottish Power Ltd.
SEC	United States Securities and Exchange Commission
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

TGP	Tennessee Gas Pipeline Company LLC
TOTS	Transmission Owner Transmission Solutions
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, grid disturbances, acts of war or terrorism or natural disasters; and
- the impact of any change to applicable laws and regulations affecting operations, including those relating to environmental and climate change, taxes, price controls, regulatory approval and permitting; 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.

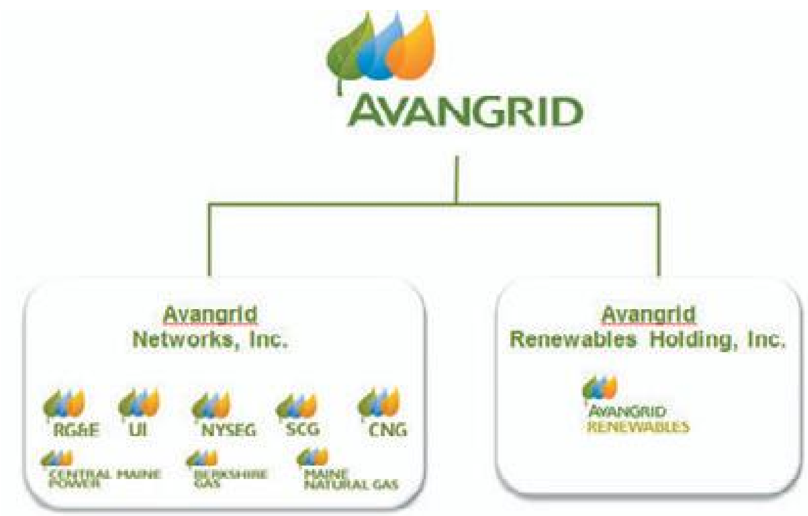
PART I

Item 1. *Business*

Overview

Avangrid, Inc., or AVANGRID, or the Company, formerly Iberdrola USA, Inc., is a New York corporation headquartered in Orange, Connecticut. AVANGRID is a diversified energy and utility company with approximately $32 billion in assets and operations in 27 states. The Company operates regulated utilities and electricity generation through two primary lines of business, Avangrid Networks and Avangrid Renewables. Avangrid Networks includes eight electric and natural gas utilities, serving 3.2 million customers in New York and New England. Avangrid Renewables operates 7.1 gigawatts of electricity capacity, primarily through wind power, with presence in 22 states across the United States. AVANGRID employs approximately 6,600 people. The company was formed by a merger between Iberdrola USA, Inc. and UIL Holdings Corporation, or UIL, in 2015. 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. Our primary business is ownership of our 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 2.2 million electric utility customers and delivering natural gas to approximately 1 million natural gas public utility customers as of December 31, 2017. 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 7,129 megawatts, or MW, as of December 31, 2017, including Renewables' share of joint projects, of which 6,387 MW was installed wind capacity. Approximately 72% of the capacity was contracted as of December 31, 2017, for an average period of 9.6 years. Being among the top three largest wind operators in the United States based on installed capacity as of December 31, 2017, Renewables strives to lead the transformation of the U.S. energy industry to a competitive, clean energy future. Renewables currently operates 58 wind farms in 21 states across the United States.

ARHI also holds a subsidiary, Enstor Gas, LLC, or Gas, which owns non-core natural gas storage and gas trading businesses (Gas) through Enstor Energy Services, LLC (gas trading) and Enstor Inc. (gas storage). Through Gas, as of December 31, 2017, we own approximately 67.5 billion cubic feet, or Bcf, of net working gas storage capacity. Gas operates 50.3 Bcf of contracted or managed natural gas storage capacity in North America through Enstor Energy Services, LLC, as of December 31, 2017.

In December 2017, our management committed to a plan to sell the gas storage and trading businesses because they represent non-core businesses that are not aligned with our strategic objectives. As a result, 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. The gas trading and storage businesses are being marketed for sale, and it is the Company's intention to complete the sales of these assets and liabilities within twelve months following their initial classification as held for sale. 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 February 16, 2018, the Company entered into a definitive agreement to sell Enstor Gas, LLC, which operates the AVANGRID's gas storage business, to Amphora Gas Storage USA, LLC. The agreement includes, among other things, a transition services agreement which obligates ARHI to provide certain transition services for up to one year after the closing date and includes a guarantee the Company will release certain obligations to Amphora Gas Storage USA, LLC. The transaction, which is subject to the satisfaction of customary closing conditions, is expected to be completed during the second quarter of 2018. Additional details on held for sale classification are provided in Note 25 to our consolidated financial statements contained in this Annual Report on Form 10-K.

Further information regarding the amount of revenues from external customers, including revenues by products and services, a measure of profit or loss and total assets for each segment for each of the last three fiscal years is provided in Note 22 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*" 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 the NYSE. In 2007, Iberdrola, S.A. acquired Scottish Power Ltd., or Scottish Power, including ScottishPower Holdings, Inc., or SPHI, the parent company of Scottish Power's U.S. subsidiaries. Through this acquisition, Iberdrola, S.A. 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, S.A. 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 holds all of our regulated utilities; and Renewables, which holds 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 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, S.A. 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 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, 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, 2017, Networks distributed approximately 36.6 million megawatt-hours, or MWh, of electricity. As of December 31, 2017, Networks provided electric service to its approximately 2.2 million customers in the states of New York, Maine and Connecticut. In total, the electric system of Networks' regulated utilities consisted of 8,657 miles of transmission lines, 70,934 miles of distribution lines and 822 substations as of December 31, 2017. Furthermore, for the year ended December 31, 2017, Networks delivered approximately 175 million dekatherms, or DTh, of natural gas, to approximately 1 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, 2017:

Utility	Rate Base(1) (in billions)	Electricity Customers	Electricity Delivered (in MWh)	Natural Gas Customers	Natural Gas Delivered (in DTh)
NYSEG	$ 2.4	893,782	15,374,000	266,351	41,283,000
RG&E	$ 1.6	378,461	7,016,000	313,043	51,465,000
CMP	$ 2.3	624,378	9,107,000	—	—
MNG	$ 0.1	—	—	4,617	1,358,000
UI	$ 1.6	334,955	5,094,000	—	—
SCG	$ 0.5	—	—	197,253	34,772,000
CNG	$ 0.5	—	—	176,836	36,736,000
BGC	$ 0.1	—	—	40,136	9,863,000

(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, 2017.

During the last five years, Networks has invested nearly $5.8 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, 2017, NYSEG served approximately 894,000 electricity customers and 266,000 natural gas customers across more than 40% of upstate New York's geographic area, while RG&E served approximately 378,000 electricity customers and 313,000 natural gas customers in a nine-county region centered around Rochester, in western New York.

In 2017, the nine hydroelectric plants owned by NYSEG and RG&E generated approximately 385 million kilowatt-hours, or kWh, of clean hydropower, which is enough energy to power 53,500 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, 2017, CMP delivered electricity to more than 624,000 customers in an 11,000 square-mile service area in central and southern Maine. CMP completed a $1.4 billion investment plan for the construction of upgrades to the bulk power transmission grid in Maine, the largest transmission investment in the history of Maine, which includes the construction of five new 345-kilovolt, or kV, substations and related facilities linked by approximately 440 miles of new transmission lines (refers to 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, 2017, MNG delivers natural gas to 4,617 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 proposed in a joint bid by CMP and Hydro-Québec, was selected by the Massachusetts electric utilities and the Massachusetts Department of Energy Resources in the Commonwealth of Massachusetts's 83D clean energy Request for Proposal, or RFP, to move forward as the alternative if the Northern Pass Transmission project fails to win approval from the New Hampshire Site Evaluation Committee by March 27, 2018. 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 megawatts of transmission capacity to supply New England with power from reliable hydroelectric generation.

Connecticut

As of December 31, 2017, UI served more than 335,000 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 NRG Yield Operating LLC, a subsidiary of NRG Yield, Inc., or NYLD, which is an affiliate of NRG Energy, Inc., or NRG, 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 February 2018, NRG announced that it has agreed to sell its ownership stake in NYLD. This sale is expected to close during the second half of 2018 and is not expected to have an impact on GenConn.

As of December 31, 2017, SCG and CNG provided local gas distribution services to approximately 374,000 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, 2017, BGC provided local gas distribution services to approximately 40,000 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, 2017. The rate base of Networks' regulated utilities for the years indicated below were as follows:

Rate base	2015	2016	2017
		(in millions)	
NYSEG Electric	$ 1,825	$ 1,828	$ 1,872
NYSEG Gas	531	490	534
RG&E Electric	1,175	1,061	1,218
RG&E Gas	446	407	428
Subtotal New York	3,977	3,786	4,052
CMP Dist	781	790	854
CMP Trans	1,472	1,447	1,460
MNG	60	69	67
Subtotal Maine	2,313	2,306	2,381
UI Dist	942	972	1,007
UI Trans	508	544	570
SCG	477	510	536
CNG	396	429	449
Subtotal Connecticut	2,323	2,456	2,562
BGC	91	91	107
Total	$ 8,704	$ 8,638	$ 9,103

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:

	2015	2016	2017
NYSEG Electric	50% / 50%: 10.90% - 11.65% 85% / 15%: over 11.65%; Based on Actual Equity Ratio up to 50%	50% / 50%: 9.50% - 10.00% 75% / 25%: 10.00% - 10.50% 90% / 10%: over 10.50%; Based on Actual Equity Ratio up to 50% *	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%
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	No ESM	No ESM	50% / 50% over 11.55%
UI	50% / 50% over 9.15%	50% / 50% over 9.15%	50% / 50% over 9.10%
SCG	No ESM	No ESM	No ESM **
CNG	50% / 50% over 9.18%	50% / 50% over 9.18%	50% / 50% over 9.18%
BGC	No ESM	No ESM	No ESM

*No ESM from January through April 2016.

** ESM is effective from January 1, 2018.

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, 2017. For the year ended December 31, 2017, Renewables produced approximately 14,488,000 MWh of energy through wind power generation. Renewables had a pipeline of approximately 12,000 MW (approximately 8,000 MW - onshore and approximately 4,000 MW - offshore) of future renewable energy projects in various stages of development as of December 31, 2017.

Typically, Renewables enters into long-term lease agreements with property owners who lease their land for renewable 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 has an 8.1% ownership, and GE Wind, in the aggregate supplied turbines which accounted for 73% of Renewables' installed wind capacity as of December 31, 2017.

Renewables currently operates 58 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 9 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, enter into fixed and contingent notes for their membership interests in the financing structures. In return, the investors receive substantially all of the cash flows and tax 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, 2017. 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 three solar photovoltaic facilities with an installed capacity of 106 MW. The solar photovoltaic facilities produced over 164,000 MWh of renewable energy for the year ended December 31, 2017. Solar accounted for 1.1% 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 Gamesa, GE, Vestas, Siemens, 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
Gamesa	G83	2.0	60	120
Gamesa	G87	2.0	651	1,302
Gamesa	G90	2.0	237	474
Gamesa	G97	2.0	109	218
Gamesa	G114	2.0	282	581
GE	1.5s	1.5	133	200
GE	1.5sle	1.5	1,072	1,608
GE	2.3	2.3	57	131
MHI	MWT62/1.0	1.0	45	45
MHI	MWT92/2.4	2.4	168	403
MHI	MWT95/2.4	2.4	125	300
MHI	MWT102/2.4	2.4	1	2
NEG	NM48	0.7	3	2
Siemens	SWT2.3-93	2.3	44	101
Suzlon	S88	2.1	341	716
Vestas	V47	0.7	34	22
Vestas	V82	1.7	97	160
Total			3,459	6,385

The Renewables meteorology team supports the commercial development of wind energy projects in Renewables' pipeline by performing a wide variety of detailed investigations to characterize the expected wind energy production from a proposed wind farm in its pre-construction phase of development. These investigations include measuring the wind resource with several well-equipped meteorological masts, utilizing state of the art laser-based and acoustic-based remote sensing equipment, computational fluid dynamics modeling software, and energy modeling software packages that characterize wake losses from any upwind turbines that may be present. The Renewables fleet of measurement masts consists of over 170 towers that are currently in operation. Additionally, a total of 6 light detecting and ranging, and 5 sonic detecting and ranging, remote sensing devices are deployed at sites across the United States. 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 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 play in the pursuit of this goal.

Gas

The Gas business, based in Houston, Texas, operates a natural gas storage and natural gas trading business through its wholly-owned direct subsidiaries, Enstor, Inc., an Oregon corporation (natural gas storage) and Enstor Energy Services, LLC, a Delaware limited liability company (natural gas trading). Gas owns and operates four natural gas storage facilities, with a total storage capacity of 88.5 Bcf and a net working gas storage capacity of 67.5 Bcf. Enstor Operating Company, LLC, a Texas limited liability company and wholly-owned direct subsidiary of Enstor, Inc., manages all four natural gas storage facilities. The demand for natural gas storage is dependent upon the seasonal differences in the weather. Since market prices and temporal price spreads for natural gas reflect the demand for these products and their availability at a given time, the overall operating results of Gas' business may fluctuate substantially on a seasonal basis. Severe weather, such as ice and snow storms, hurricanes and other natural disasters may cause outages, bodily injury or property damage, which may require Gas to incur additional costs, such as operation and maintenance expenses, which may not be recoverable from customers. See "—Properties—Gas" for more information regarding Gas' natural gas storage facilities. Enstor Energy Services, LLC also contracts and manages natural gas storage and pipeline capacity throughout the United States and parts of Canada. Gas operates 53.0 Bcf of contracted or managed natural gas storage capacity in North America through Enstor Energy Services, LLC, as of December 31, 2017.

The gas trading and storage businesses are being marketed for sale, and it is the Company's intention to complete the sales of these assets and liabilities within twelve months following their initial classification as held for sale. 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 February 16, 2018, the Company entered into a definitive agreement to sell Enstor Gas, LLC, which operates the AVANGRID's gas storage business, to Amphora Gas Storage USA, LLC. The agreement includes, among other things, a transition services agreement which obligates ARHI to provide certain transition services for up to one year after the closing date and includes a guarantee the Company will release certain obligations to Amphora Gas Storage USA, LLC. The transaction, which is subject to the satisfaction of customary closing conditions, is expected to be completed during the second quarter of 2018. Additional details on held for sale classification are provided in Note 25 to our consolidated financial statements contained in this Annual Report on Form 10-K.

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, Renewables' competitive generation and Gas' natural gas storage and energy trading 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; FERC also oversees the rates, terms and conditions of 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, UI and New York TransCo 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 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).

In 2014, the FERC determined that the base ROE in Complaint I should be set at 10.57% for the first complaint refund period and that a utility's total or maximum ROE should not exceed 11.74%. The FERC issued an order consolidating the second and third complaints and establishing hearing procedures. The administrative law judge issued an initial decision in the second and third complaints on March 22, 2016. The initial decision determined that: (1) for the 15 month refund period in the second complaint, the base ROE should be 9.59% and the ROE Cap (base ROE plus incentive ROEs) should be 10.42% and (2) for the 15 month refund period in the third complaint and prospectively, the base ROE should be 10.90% and that the ROE Cap should be 12.19%. The initial decision in the second and third complaints is the administrative law judge's recommendation to the FERC Commissioners. The FERC is expected to make its final decision in 2018.

On March 3, 2015, the FERC issued an Order on Rehearing in the first complaint denying all rehearing requests from the complainants and the NETOs. In June 2015 the NETOs and complainants both filed an appeal in the U.S. Court of Appeals for the District of Columbia of the FERC's final order. On April 14, 2017, the Court of Appeals, or the Court, vacated FERC's decision on Complaint I and remanded it to FERC. The Court held that FERC, as directed by statute, did not determine first that the existing ROE was unjust and unreasonable before determining a new base ROE. The Court ruled that FERC should have first determined that the then existing 11.14% base ROE was unjust and unreasonable before selecting the 10.57% as the new base ROE. The Court also found that FERC did not provide reasoned judgment as to why 10.57%, the point ROE at the midpoint of the upper end of the zone of reasonableness, is a just and reasonable ROE. Instead, FERC had only explained in its order that the midpoint of 9.39% was not just and reasonable and a higher base ROE was warranted. On June 5, 2017, the NETOs made a filing with FERC seeking to reinstate transmission rates to the status quo ante (effect of the Court vacating order is to return the parties to the rates in effect prior to FERC Final decision in Complaint I) as of June 8, 2017, the date the Court decision became effective. In that filing, the NETOs stated that they would not begin billing at the higher rates until 60 days after FERC has a quorum of commissioners. On October 6, 2017, FERC issued an order rejecting the NETOs request to collect transmission revenue requirements at the higher ROE of 11.14%, pending FERC order on remand. In reaching this decision, FERC stated that it has broad remedial authority to make whatever ROE it eventually determines to be just and reasonable effective for the Complaint I refund period and prospectively from October 2014, the effective date of the Complaint I Order. Therefore the NETOs will not be harmed financially by not immediately returning to their pre-Complaint I ROE. We anticipate FERC to address the Court decision during 2018. Complaint IV is proceeding through litigation with an initial decision expected from the administrative law judge by March 31, 2018.

On December 28, 2015, the FERC issued an order instituting section 206 proceedings and establishing hearing and settlement judge procedures. Pursuant to section 206 of the FPA, the FERC instituted proceedings because it found that ISO-NE Transmission, Markets, and Services Tariff is unjust, unreasonable, and unduly discriminatory or preferential. The FERC stated that ISO-NE's Tariff lacks adequate transparency and challenge procedures with regard to the formula rates for ISO-NE Participating Transmission Owners, including UI, MEPCO and CMP. The FERC also found that the current Regional Network Service, or RNS and Local Network Service, or LNS, formula rates appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful as the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates. A settlement judge has been appointed and settlement discussions are underway. We are unable to predict the outcome of this proceeding at this time.

On October 5, 2017, the NETOs filed a Motion for Dismissal of Pancaked Return on Equity Complaints in light of the decision by the Court in April 2017 that became effective on June 8, 2017. The NETOs assert that all four complaints should be dismissed because the complainants have not shown that the existing ROE of 11.14% is unjust and unreasonable as the Court decision requires. In addition, the NETOs assert that Complaints II, III and IV should also be dismissed because the Court decision implicitly found that FERC's acceptance of Pancaked FPA Section 206 complaints was statutorily improper as Congress intended that the 15-month refund period under Section 206 applies whenever FERC does not complete its review of a complaint within the 15-month period. In the event FERC chooses not to dismiss the complaints, the NETOs request that FERC consolidate the complaints for decision as the evidentiary records are either closed or advanced enough for FERC to address the requirements of the Court decision and expeditiously issue a final order.

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 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 $1.0 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.

Gas' current natural gas storage operations in the United States are subject to the jurisdiction of the FERC under the Natural Gas Act of 1938, or NGA, as a Section 7(c) natural gas storage provider and by providing interstate storage and storage related services under Section 311 of the Natural Gas Policy Act of 1978, at market based rates. Gas' interstate and intrastate high-deliverability multi-cycle natural gas storage service projects and operations are subject to FERC regulation under the NGA for rates and terms of service.

The gas distribution operations of NYSEG, RG&E, SCG, CNG and BGC, similar to Gas, are also subject to the FERC regulation 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 $1.0 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 $1.0 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.

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 May 20, 2015, NYSEG and RG&E initiated a distribution rate case to ensure that the companies are able to continue to provide safe, adequate and reliable service, continue to make investments to modernize infrastructure, enhance low income programs and improve both gas and electric reliability, while maintaining the Companies' financial integrity. On February 19, 2016, NYSEG, RG&E and other signatory parties filed a Joint Proposal, with the NYPSC for a three-year rate plan for electric and gas service at NYSEG and RG&E commencing May 1, 2016. The Joint Proposal was approved on June 15, 2016 by the NYPSC. For more information on rate case activity in New York, see Note 4 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.
- *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, reserve accounting and sharing of incremental storm costs, a separate proceeding for recovery of a new billing system and no earning sharing.

  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 10-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 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 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.

  On June 30, 2017, SCG filed an application with PURA for new tariffs to become effective January 1, 2018. SCG requested a three-year rate plan for calendar years 2018, 2019 and 2020 and a proposed ROE of 9.95%. SCG also requested to implement a RDM and Distribution Integrity Management Program, or DIMP, mechanism similar to the mechanisms authorized for CNG. PURA approved the rate case on December 13, 2017, and new tariffs became effective on January 1, 2018. For more information on rate case activity in Connecticut, see Note 4 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*. BGC's rates are established by the DPU. BGC's 10-year rate plan, which was approved by the DPU and included an approved ROE of 10.5%, expired on January 31, 2012. BGC continues to charge the rates that were in effect at the end of the rate plan. In accordance with the approval by the DPU of the acquisition, BGC agreed not to file a rate case for new rates effective before June 1, 2018.

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 receives 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 examining 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. 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.

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. Furthermore, Gas' natural gas storage operations are subject to certain state regulations, such as the Railroad Commission of Texas for its facilities located in Texas.

Tax Cuts and Jobs Act

On December 22, 2017, the Tax Cuts and Jobs Act of 2017, or the Tax Act, was signed into law. The Tax Act contains significant changes to the federal tax structure, including among other things, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017. The NYPSC, MPUC, PURA and DPU have instituted separate proceedings in New York, Maine, Connecticut and Massachusetts to review and address the implications associated with the Tax Act on the utilities providing service in those states. We expect the regulators in each jurisdiction, including the FERC, to issue requirements in 2018 regarding how all tax benefits associated with the Tax Act will be returned to customers.

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 regional transmission organizations, or 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 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 law Public Act 11-80, or PA 11-80, 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 will phase in over a six-year solicitation period, and are expected to peak at an annual commitment level of about $13.6 million per year after all selected projects are online. 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.

On October 23, 2013, PURA approved UI's renewable connections program filed in accordance with PA 11-80, pursuant to which UI has developed 10 MW of renewable generation. The costs for this program will be recovered on a cost of service basis. PURA established a base ROE to be calculated as the greater of: (A) the current UI authorized distribution ROE (currently 9.10%) plus 25 basis points and (B) the current authorized distribution ROE for The Connecticut Light and Power Company, or CL&P, (currently 9.17%), less target equivalent market revenues (reflected as 25 basis points). In addition, UI will retain a percentage of the market revenues from the project, which percentage is expected to equate to approximately 25 basis points on a levelized basis over the life of the project. The cost of this program, a 2.8 MW fuel cell facility in New Haven, solar photovoltaic and fuel cell facilities totaling 5 MW in Bridgeport, and a 2.2 MW fuel cell facility in Woodbridge, all of which are now operational, was $41.5 million.

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.

On May 25, 2017, UI entered into six 20-year power purchase agreements, or 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 Connecticut Public Act (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 RFP issued by the Connecticut Department of Energy and Environmental Protection, or

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.

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 MW Rollins wind farm in Penobscot County, Maine. CMP's purchase obligations under the Rollins contract are approximately $7 million per year. In accordance with subsequent MPUC orders, CMP periodically auctions the purchased Rollins energy 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.

Pursuant to Maine Law 35-A M.R.S.A §3604, the MPUC is authorized to direct Maine Transmission and Distribution Utilities to enter into long-term contracts to purchase capacity, energy and renewable energy credits from up to 50 MW of qualifying Community-Based Renewable Energy facilities. In accordance with §3604, on October 22, 2016, CMP commenced purchases from Athens Energy LLC for a contract term of three years. CMP purchase obligations under the Athens contract are approximately $6 million per year. Under the provisions of §3604 and MPUC implementing orders, CMP will periodically auction the purchased products from Athens for resale to wholesale market purchasers and recover any differences between power purchase costs and resale revenues through a reconcilable component of its retail distribution rates. Although the MPUC has certified several additional Community - Based Renewable Energy generation projects under §3604 and authorized similar PPAs between these sellers and CMP, no additional facilities have advanced to operational status.

Environmental, Health and Safety

Permitting and Other Regulatory Requirements

Networks. Similar to Renewables and Gas, 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 comply 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 recently entered into settlements with two large wind farm operators, pursuant to which those operators pled guilty to criminal violations of the MBTA and agreed to substantial penalties and mitigation measures.

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.

Gas. Gas' natural gas storage operations are regulated by the U.S. Department of Transportation Office of Pipeline Safety through the Pipeline and Hazardous Materials Safety Administration, or PHMSA, under the Natural Gas Pipeline Safety Act of 1968, or NGPSA, as amended by Pipeline Safety Act of 1979, and the Hazardous Liquids Pipeline Safety Act of 1979, or HLPSA. PHMSA, through the NGPSA and HLPSA, regulates the design, installation, testing, construction, operation, maintenance, repair, inspection, replacement and management of interstate and certain intrastate natural gas pipeline facilities. PHMSA has also developed regulations that require transportation pipeline operators to implement integrity management programs to comprehensively evaluate certain high risk areas along Gas' natural gas pipelines and take additional measures to protect natural gas pipeline segments located in highly populated areas.

Gas' natural gas storage operations are also regulated by the EPA, and equivalent state environmental agencies, with respect to the environmental effects of its operations, including air and water quality control, solid and hazardous waste disposal, greenhouse gas emissions, noise and limitations on land use.

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 that impact how we operate our business. We expect that any costs of these rules and regulations 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 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 the consent order that was 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.

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 72% of Renewables' wind generating capacity is fully committed under PPAs as of December 31, 2017, with an average duration of 9.6 years. Renewables also delivers thermal output to wholesale customers in the Western United States.

Gas' natural gas storage and management services customers include a diversified mix of natural gas distribution companies, power generators, natural gas marketers and producers, utilities using gas as fuel, gas storage customers, financial institutions and energy marketers.

Competition

Networks' regulated public utilities in New York, Maine, Connecticut and Massachusetts 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.

Gas, through its subsidiaries, Enstor, Inc. and Enstor Energy Services, LLC, faces competition from others in the natural gas market. Enstor, Inc. encounters regional competition, such as in the Gulf South region, from other independent natural gas storage providers, a combination of interstate and intrastate pipeline companies and local distribution companies. Furthermore, Enstor Energy Services, LLC competes with various entities, ranging from natural gas marketing companies, to financial institutions and producer/marketers.

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, 2017. 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	Auburn, NY(1)	Natural Gas Turbine	7.3	2000
NYSEG	Eastern New York (6 locations)	Hydroelectric	61.4	1921—1983
RG&E	Rochester, NY (3 locations)	Hydroelectric	57.5	1917—1960

(1) The Auburn, NY natural gas turbine generating unit is leased.

UI is also party to a 50-50 joint venture with certain affiliates of NRG 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, 2017.

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	430	4,513	32,254	2,827	35,081	893,782
RG&E	New York	154	1,094	5,934	2,874	8,808	378,461
CMP	Maine	209	2,911	22,072	1,484	23,556	624,378
UI	Connecticut	29	139	3,282	207	3,489	334,955

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, 2017.

Utility	State	Natural Gas Customers	Transmission Pipeline (in miles)	Distribution Pipeline (in miles)
NYSEG	New York	266,351	20	8,151
RG&E	New York	313,043	105	10,592
MNG	Maine	4,617	2	205
SCG	Connecticut	197,253	—	2,426
CNG	Connecticut	176,836	—	2,160
BGC	Massachusetts	40,136	—	764

CNG owns and operates a LNG plant which can store up to 1.2 Bcf of natural gas and can vaporize up to 115,000 Mcf per day of LNG to meet peak demand. SCG has contract rights to and operates a similar plant, which can also store up to 1.2 Bcf of natural gas. SCG's LNG facilities can vaporize up to 90,000 Mcf per day of LNG to meet peak demand. SCG and CNG have also contracted for 21 Bcf of storage with a maximum peak day delivery capability of 209,000 Mcf per day.

Renewables

The following table sets forth Renewables' portfolio of wind projects as of December 31, 2017. 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
	Dry Lake II	31 (Suzlon, 2.1 MW)	65	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 (Neg Micon (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(1)	54 (GE, 1.5 MW)	81	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	SERC
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
	Top of Iowa II	40 (Gamesa G87, 2.0 MW)	80	2008	MRO
	Winnebago I	10 (Gamesa G83, 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
	MinnDakota	100 (GE, 1.5 MW)	150	2008	MRO
	Trimont	67 (GE, 1.5 MW)	100	2005	MRO
	Elm Creek II	62 (Mitsubishi, 2.4)	149	2010	MRO
	Moraine I	34 (GE, 1.5 MW)	51	2003	MRO
	Moraine II	33 (GE, 1.5 MW)	50	2009	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, 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, 2MW)	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	Amazon Wind Farm US - East	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); 43 (Suzlon, 2.1 MW)	201	2011	WECC
	Pebble Springs	47 (Suzlon S88/2100, 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	51 (Gamesa G83, 2.0 MW)	102	2009	RFC
	South Chestnut	23 (Gamesa, 2.0 MW)	46	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
Texas	Baffin	101 (Gamesa G97, 2.0 MW)	202	2015	TRE
	Barton Chapel	60 (Gamesa, 2.0 MW)	120	2009	TRE
	Peñascal I	84 (Mitsubishi, 2.4 MW)	202	2009	TRE
	Peñascal II	84 (Mitsubishi, 2.4 MW)	202	2010	TRE

Vermont	Deerfield	7 (Gamesa G87, 2.0 MW); 8 (Gamesa G97, 2.0 MW)	30	2017	NPCC
Washington	Big Horn I	133 (GE, 1.5 MW)	200	2006	WECC
	Big Horn II	25 (Gamesa, 2.0 MW)	50	2010	WECC
	Juniper Canyon	63 (Mitsubishi, 2.4 MW)	151	2011	WECC

(1) Jointly owned with Shell Wind Energy; 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.

Additionally, set forth below are the solar and thermal facilities operated by Renewables as of December 31, 2017. Unless otherwise noted, Renewables owns each such facility.

Facility	Location	Type of Facility	Installed Capacity (MW)	Commercial Operation Date
Copper Crossing Solar Ranch	Pinal County, Arizona	Solar	20	2011
San Luis Valley Solar Ranch(1)	Alamosa County, Colorado	Solar	30	2012
Gala Solar	Deschutes County, Oregon	Solar	56	2017
Klamath Cogeneration	Klamath Falls, Oregon	Thermal	536	2001
Klamath Peakers	Klamath Falls, Oregon	Thermal	100	2009

(1) Operated pursuant to a sale-and-leaseback agreement.

Gas

Gas owns and operates four natural gas storage facilities, all near key trading hubs. The following table provides an overview of these storage facilities as of December 31, 2017. Unless noted otherwise, Enstor, Inc., a wholly-owned direct subsidiary of Gas, owns and operates each of these facilities.

Facility	Type of Facility	Storage capacity (Bcf)	Max Injection (MMcfd)/ Max Withdrawal (MMcfd)	Pipeline Connections	Commercial Operation Date
Caledonia Energy Partners, L.L.C., Mississippi	Depleted gas reservoir	18.5	558/550	Tennessee Gas Pipeline 500	2005
Freebird Gas Storage, LLC, Alabama(1)	Depleted gas reservoir	9.8	350/305	Tennessee Gas Pipeline 500	2001
Enstor Grama Ridge Storage and Transportation, LLC, New Mexico	Depleted gas reservoir	15.7	200/200	El Paso Natural Gas, Natural Gas Pipeline Company of America and the DCP Midstream Raptor Pipeline	1973
Enstor Katy Storage and Transportation, L.P., Texas	Depleted gas reservoir	23.5	750/700	Connected to 14 different pipelines	1992

(1) 13% owned by Northwest Alabama Gas District.

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 AVANGRID 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, we have appointed an officer responsible for security (chief security officer) and 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, 2017, we had 6,570 employees excluding 8 international assignees. Of these 6,570 employees, 48.4% are represented by a union. The following table provides an overview of the number of employees at each business segment as of December 31, 2017:

Business Segment	Number of Employees (excluding International Assignees)	% of Union Workforce Subject to Collective Bargaining Agreement
Networks	5,408	58.8%
Renewables	796	—
Gas	98	—
Corporate	268	—
Total	6,570	48.4%

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, and 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 requires the attention of our management and employees and may divert their attention from other regulatory, operational or financial matters. The last management audit of UI by PURA was completed in 2015. This audit resulted in 64 recommendations. The last management audit of CNG and SCG was completed in 2016. This audit resulted in approximately 94 recommendations. The

NYPSC completed an operations staffing audit of all NY utilities in January 2017. The audit resulted in 17 specific recommendations for NYSEG and RG&E and one general recommendation for all NY utilities. The NYPSC initiated a management audit of NYSEG and RG&E in 2017. The audit is expected to be completed in early 2018. We cannot predict the outcome of these audits.

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 EPA act 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 will result in increased NERC compliance requirements and additional compliance risks including increase in assets, budgets and experienced resources. This new registration as a Balancing Authority also changes the NERC audit cycle from 6 years down to 3 years for Renewables and may impact other AVANGRID NERC registrations at Networks. 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 $1.2 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. UIL will have an onsite NERC CIP audit in 2018.

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. PSC staff has conducted public statement hearings across New York State regarding REV.

Various other REV-related proceedings have also been initiated by the PSC, 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. As part of this initiative, NYSEG and RG&E entered into agreements with New York State Energy Research and Development Authority, or NYSERDA, for Renewable Energy Credits, or RECs and Zero-Emission Credits, or ZECs in 2017. Additionally, the PSC has issued an order requiring New York utilities, including NYSEG and RG&E, to implement energy storage projects within distribution substations prior to December 31, 2018.

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 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. 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. 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.

Certain of the current electric and gas rate plans of Networks' regulated utilities include revenue decoupling mechanisms, or RDMs, and the provisions for the recovery of energy costs, including reconciliation of the actual amount paid by such regulated utilities. There is no guarantee that such decoupling mechanisms or recovery and reconciliation mechanism will 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 actions against a development project, an operating facility, or the agency that oversees the alleged violation of law. Similar protections are offered to migratory birds under the MBTA, which implements various treaties and conventions between the United States and certain other nations for the protection of migratory birds and, pursuant to which the taking, killing or possessing of migratory birds is unlawful. 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. The DOJ has investigated Renewables for potential violations under the MBTA and the ESA at its Blue Creek facility due to an Indiana Bat and other bird fatalities. Although the investigation expired in October 2017 with no negative outcome, similar investigations may occur in the future that could have a material adverse effect on our business, results of operation, financial condition and cash flows.

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 states 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 cause delay a project and could materially adversely affect our businesses, results of operations or financial condition.

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. During 2017 federal and state siting legislation has increased its focus on potential conflicts with military installations. 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 EPA act 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 new regulations that have increased compliance costs and imposed new reporting requirements on our businesses. For example, the Dodd-Frank Act substantially increased regulation of the over-the-counter derivative contracts market and futures contract markets, which impacts our businesses. The new 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 and if the rules implementing the new regulations require us to post significant amounts of cash collateral with respect to swap transactions, this could have a material adverse effect on our liquidity. We cannot predict the impact these new regulations will have on our businesses' ability to hedge their commodity and interest rate risks or on over-the-counter derivatives markets as a whole, but they could potentially have a material adverse effect on our businesses' risk exposure, as well as reduce market liquidity and further increase the cost of hedging activities.

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 offtakers 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.

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 and the financial markets including severe volatility in stock and bond markets 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 and the amount of uncollectible customer accounts increases. 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 auction rate bonds which closely tracks movements in the London Interbank Offer Rate, or LIBOR. The cost of new long-term debt can be affected by the level of US 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 debt 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 securities and increase the expense and difficulty of financing our operations and investments. The Tax Act may negatively affect cash flows and financial ratios used by rating agencies, increasing the risk of adverse rating actions. 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 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. 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 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. Many of the operating facilities of Networks and Enstor, Inc., Gas' wholly-owned direct subsidiary, 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 or extended service interruptions. The cost of repairing damage to Networks' and Gas' 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. 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. The Company maintains a specific insurance program for cyber-risk in accordance with insurance market current offerings; and that 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, adversely impact 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 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. For example, Networks is at risk for copper wire theft, especially, due to an increased demand for copper in the United States and internationally. Theft of 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 and natural gas storage in addition to proprietary trading and hedging activities. Since market prices and temporal price spreads for natural gas reflect the demand for these products and their availability at a given time, the overall operating results of Gas' business may fluctuate substantially on a seasonal basis.

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, 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 related to 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. 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. For example, 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. In December 2015, the Consolidated Appropriations Act, 2016 extended the expiration date for this tax credit to December 31, 2019, for wind facilities commencing construction, with a phase-down beginning for wind projects commencing construction after December 31, 2016. The Tax Act enacted in December 2017 kept the 2015 tax credits agreement unchanged. Furthermore, as a result of Connecticut's Comprehensive Energy Strategy, CNG and SCG filed, jointly with Yankee Gas Services Company (Eversource) a comprehensive natural gas expansion plan, or Expansion Plan, outlining a structured approach to add approximately 280,000 new gas heating customers (approximately 200,000 of which relate to SCG and CNG) state-wide over a ten-year period through 2023. SCG and CNG have been executing on the Expansion Plan since 2014 and will continue to do so through 2023. In order to serve new customers to comply with the Expansion Plan, SCG and CNG need to lay significant miles of new pipeline, maintain, expand and potentially upgrade their existing distribution and/or storage infrastructure, and build new gate stations. Various factors may prevent or delay SCG and CNG from completing such projects or make completion more costly, such as the inability to obtain required approval from local or state regulatory and governmental bodies, public opposition to the project, lack of potential customers as a result of reduced economic benefits for switching to gas, inability to obtain adequate financing, construction delays, cost overruns, and inability to negotiate acceptable agreements relating to rights-of-way, construction or other material development components. As a result, SCG and CNG may not be able to adequately support the proposed customer growth, which would negatively impact their businesses, cash flows, results of operations and financial condition. 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.

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 certain of the regulated utilities of Networks are subject to RDMs, 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 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, as a result of new regulations, and incentives that favor alternative renewable 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 and Gas does not own all of the land on which its natural gas storage 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.

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 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 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 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 540 megawatts, or MW, of installed capacity in California subject to known earthquake risks and approximately 600 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, 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 natural gas storage 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 is 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.

Long-term low natural gas prices and/or seasonal or locational variation in natural gas price spreads could have a negative impact on the natural gas business and gas storage services.

The natural gas business benefits from price volatility and temporal price spreads. Variation in price spreads can impact the level of demand and the rates that can be charged for natural gas storage services. If natural gas prices and volatility remain low, or prices decline further, then the natural gas business could generate less revenue and lower demand for natural gas storage services. A sustained decline in these prices and volatility could have an adverse impact on gas business, results of operation, 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 have identified a material weakness in our internal control over financial reporting which, if not remediated, could adversely affect our reputation, business or stock price.

In connection with the preparation of our consolidated financial statements for the year ended December 31, 2017, management along with our independent registered public accounting firm identified a material weakness in the internal control over financial reporting related to the measurement and disclosure of income taxes primarily due to time compression surrounding our income tax controls compounded by the implementation of the Tax Cuts and Jobs Act of 2017 enacted by the U.S. federal government on December 22, 2017. A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of our annual or interim consolidated financial statements will not be prevented or detected on a timely basis.

In connection with the preparation of our consolidated financial statements for the year ended December 31, 2016, management along with our independent registered public accounting firm identified material weaknesses in the internal control over financial reporting. Management identified deficiencies related to: (1) the accounting for the change in the estimated useful life of certain elements of the wind farms at Renewables and other smaller deficiencies related to documentation of internal controls procedures, and enhancement of review controls at Renewables, (2) the preparation of the consolidated financial statements, specifically the classification and disclosure of financial information, and (3) the measurement and disclosure of income taxes.

We engaged in remediation efforts to address the material weaknesses in the internal control over financial reporting, including, among other things, (i) improving general internal control activities and policies, including processes to maintain sufficient documentation evidencing execution of these policies; (ii) increasing accounting personnel to devote additional time and resources related to financial reporting; (iii) educating and re-training internal control employees regarding internal control processes to mitigate identified risks and maintaining adequate documentation to evidence the effective design and operation of such processes; and (iv) implementing enhanced controls to monitor the effectiveness of the underlying business process controls. We believe that the material weaknesses have been remediated as of December 31, 2017 related to (1) the accounting for the change in the estimated useful life of certain elements of the wind farms at Renewables and other smaller deficiencies related to documentation of internal controls procedures, and enhancement of review controls at Renewables and (2) the preparation of the consolidated financial statements, specifically the classification and disclosure of financial information.

We are actively engaged in remediation efforts to address the material weakness in the internal control over financial reporting related to the measurement and disclosure of income taxes, including, among other things, (i) further acceleration of key activities to allow sufficient time for the execution of consolidated deferred income tax controls that were newly designed in fiscal year 2017; (ii) increasing capabilities of income tax accounting resources to devote additional time and internal control resources to consolidated income tax accounting and reporting processes and controls; and (iii) enhancing the automation of income tax processes and controls to allow for the more timely completion and enhanced review. We believe, based on our evaluation to date, that this material weakness will be remediated by December 31, 2018. However, we cannot assure you that this will occur within the contemplated timeframe.

If our remediation efforts are insufficient to address the identified material weakness or if additional material weaknesses in internal controls are discovered in the future, they may adversely affect our ability to record, process, summarize and report financial information timely and accurately and, as a result, our financial statements may contain material misstatements or omissions. The occurrence of or failure to remediate the material weakness may adversely affect our reputation and business and the market price of shares of our common stock.

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. The announcement of the completion of the strategic review of the Enstor Gas Storage business, including the trading business, and the decision to move forward with a plan to sell such business increases the risk of losing key employees during this period.

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. 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; 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 than yours. Additionally, future sales or issuances of our common stock by Iberdrola, S.A. 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. The directors designated by Iberdrola will 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. We and Iberdrola are parties to a shareholder agreement pursuant to which Iberdrola will be generally restricted from transferring shares of our common stock, subject to certain exceptions. Iberdrola will also be restricted, for a period of three years after the completion of the proposed merger, from transferring more than an aggregate of 10% of the outstanding shares of our common stock in any transaction or series of transactions, unless all of our shareholders are entitled to participate in such transaction (on a *pro rata* basis) and are entitled to the same per share consideration to be received in such transaction as Iberdrola. In addition, 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 and subject to the terms and conditions therein, Iberdrola will be entitled to customary registration rights of our common stock, including the right to choose the method by which the common stock are distributed, a choice as to the underwriter and fees and expenses to be borne by us. Iberdrola will also retain 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.

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, Renewables' headquarters is located in Portland, Oregon, while Gas is principally located in Houston, Texas. 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, 2017:

Location	Type of Facility	Lease/Owned	Size (square feet)
Orange, Connecticut	Office	Owned	401,982
Augusta, Maine	Office	Leased	220,400
Portland, Maine	Office	Leased	16,462
Rochester, New York	Office	Owned	122,494
Portland, Oregon	Office	Leased	57,082
Houston, Texas	Office	Leased	21,571

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 12 and 13 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.

Executive Officers of AVANGRID

The names and ages of all executive officers of AVANGRID as of March 26, 2018 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	65	Chief Executive Officer
Richard J. Nicholas (2)	62	Senior Vice President – Chief Financial Officer
Daniel Alcain (3)	44	Senior Vice President – Controller
Laura Beane	43	President and Chief Executive Officer of Renewables
Douglas A. Herling	54	President and Chief Executive Officer of CMP
Sheila Duncan	53	Senior Vice President – Human Resources & Corporate Administration
Ignacio Estella	47	Senior Vice President – Corporate Development
Daryl W. Gee	54	Chief Executive Officer of Gas
Robert D. Kump	56	President and Chief Executive Officer of Networks
Carl A. Taylor	53	President and Chief Executive Officer of NYSEG and RG&E
R. Scott Mahoney	52	Senior Vice President – General Counsel and Chief Compliance Officer; Secretary
Anthony Marone	54	President and Chief Executive Officer of UIL

(1) Age as of December 31, 2017.
(2) On March 9, 2018, Mr. Nicholas provided notice of his intention to retire from AVANGRID, effective July 7, 2018.
(3) On February 15, 2018, Mr. Alcain notified AVANGRID that his international assignment from Iberdrola, S.A., AVANGRID's majority shareholder, will conclude in April 2018, and he will be returning to a position with Iberdrola, S.A.

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 Midwest Independent Transmission System Operator. He is 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 and the American Gas Association, and trustee of the Hartford Bishops' Foundation for the Archdiocese of Hartford. 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.

Richard J. Nicholas. Mr. Nicholas was appointed Senior Vice President - Chief Financial Officer of AVANGRID on December 17, 2015, upon consummation of the acquisition of UIL. Previously, Mr. Nicholas served as executive vice president and chief financial officer of two subsidiaries of AVANGRID, UIL and UI, from March 2005 until December 2015. Mr. Nicholas was appointed chief financial officer of BGC, CNG and SCG, all of which are subsidiaries of AVANGRID, in November 2010. Mr. Nicholas earned his undergraduate degree in business and administration with a concentration in finance from Duquesne University and holds a M.B.A. from the University of New Haven.

Daniel Alcain. Mr. Alcain was appointed Senior Vice President – Controller of AVANGRID on December 17, 2015. Previously, Mr. Alcain served as the chief financial officer of Scottish Power, from April 2012 until December 2015, and Iberdrola USA, Inc., from December 2009 until March 2012. Mr. Alcain joined the Iberdrola Group in 2001 and worked for four years in Latin America within the Control area. He holds two degrees in economy and law from the University of Valladolid.

Laura Beane. Ms. Bean was appointed President and Chief Executive Officer of Renewables on April 25, 2017. She was formerly Vice President, Operations and Management Services at Avangrid Renewables from September 2015 to May 2017. Ms. Beane was Director of Market Structure/Policy at Avangrid Renewables from February 2007 to September 2015. Prior to joining Iberdrola/Avangrid Renewables, Ms. Beane worked for the Company's prior affiliate, PacifiCorp, where she held regulatory and project management positions beginning in 1995. Ms. Beane graduated with distinction from the Comillas and Strathclyde universities as part of Iberdrola's first MBA program in the Global Energy Industry cohort and has also earned an MBA and Bachelor of Science degree from the University of Utah.

Douglas A. Herling. Mr. Herling was appointed President and Chief Executive Officer of CMP effective January 2, 2018. Mr. Herling also has functional responsibility for AVANGRID's electrical operations. Previously, Mr. Herling served as Networks vice president – electric operations from 2016 to 2017. From 2001 to 2016 Mr. Herling held various executive management positions at Avangrid Networks and CMP, including vice president – special projects, vice president – engineering & asset management, and engineering and vice president of CMP field operations. Mr. Herling joined CMP in 1985. Mr. Herling earned his Bachelor of Science degree in Marine Engineering from the Maine Maritime Academy.

Sheila Duncan. Ms. Duncan was appointed Senior Vice President – Human Resources & Corporate Administration of AVANGRID on December 17, 2015. She previously served as human resources and shared services director of Scottish Power from March 2009 until December 2015. She holds a Master of Arts (Hons) from the University of Glasgow and is a chartered fellow of the Institute of Personnel & Development in the UK.

Ignacio Estella. Mr. Estella was appointed Senior Vice President – Corporate Development of AVANGRID on December 17, 2015. 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.

Daryl W. Gee. Mr. Gee was appointed Chief Executive Officer of Gas in May, 2014. He has also served as Chief Executive Officer and President of Enstor Energy Services LLC and Enstor, Inc. since 2014, both subsidiaries of AVANGRID. Previously, Mr. Gee served as chief compliance officer and vice president of Gas, Enstor Energy Services LLC and Enstor, Inc. between March, 2013 and May, 2014. From 2002 through March 2013, Mr. Gee served as director of regulatory affairs and director of business development for Enstor, Inc. Mr. Gee holds a bachelor of applied arts and sciences in petroleum land management /petroleum technology and marketing from the Stephen F. Austin State University.

Robert D. Kump. Mr. Kump was appointed President and Chief Executive Officer of Networks in November 2010. Mr. Kump served as AVANGRID's Chief Corporate Officer from January 2014 to December 2016. Mr. Kump also has served as a director of AVANGRID's subsidiaries CMP, NYSEG, and RG&E since 2009, as the President of the Avangrid Management Company, LLC since March 2012, and as the Chief Executive Officer of Avangrid Service Company since October 2009. 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, and has functional responsibility for AVANGRID's gas operations. 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 and Chief Compliance Officer 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 has served as AVANGRID's General Counsel since June 2012. 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.

Anthony Marone. Mr. Marone was appointed President and Chief Executive Officer of UIL on September 9, 2016. 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 & planning. Mr. Marone also serves as President – Connecticut and Massachusetts Operations of Networks. 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 New York Stock Exchange, or NYSE, on December 17, 2015, under the symbol "AGR." Prior to that time, there was no public market for shares of our common stock. The following table sets forth on a per share basis, for the periods indicated, the high and low sale prices of our common stock as reported by the NYSE.

	2017 Sales Price		2016 Sales Price	
	High	Low	High	Low
First Quarter	$ 44.11	$ 37.42	$ 42.40	$ 36.01
Second Quarter	$ 46.13	$ 42.42	$ 46.49	$ 37.07
Third Quarter	$ 49.04	$ 43.13	$ 46.74	$ 40.71
Fourth Quarter	$ 53.46	$ 47.18	$ 41.88	$ 35.42

As of March 20, 2018, there were 3,415 shareholders of record.

Dividends

The quarterly cash dividends declared in 2017 and 2016 were at a rate of $0.432 per share.

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 January 1, 2017 through December 31, 2017.

	January 1, 2017	December 31, 2017
AVANGRID	$ 100.00	$ 138.56
S&P 500	$ 100.00	$ 121.82
S&P Electric Utilities Index	$ 100.00	$ 110.61
S&P Utilities Index	$ 100.00	$ 112.11

The above information assumes that the value of the investment in shares of AVANGRID's common stock and each index was $100 on January 1, 2017, including dividend reinvestment during this time period. The changes displayed are not necessarily indicative of future returns.

Recent Sales of Unregistered Securities

None.

Issuer Repurchases of Equity Securities

AVANGRID repurchased 60,419 shares of common stock in open market transactions during the year ended December 31, 2017 to maintain the relative ownership percentage of Iberdrola at 81.5%. The total cost of these repurchases was approximately $3 million. There were no repurchases of common stock of AVANGRID during the fourth quarter of the year ended December 31, 2017. The effects of these transactions did not change the number of outstanding shares of AVANGRID common stock.

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 and combined 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.

During the year ended December 31, 2017, we identified immaterial corrections to prior periods related to our deferred income tax liabilities associated with our tax equity financing arrangements in our Renewables reportable segment. For further details, refer to Note 2 in our consolidated financial statements included in this Annual Report on Form 10-K. Accordingly, we have reflected the correction of these prior period amounts in the periods in which they originated and the following tables include our revised selected historical consolidated and combined statements of operations and balance sheet data as of and for the years ended December 31, 2016, 2015, 2014 and 2013.

	Year Ended December 31, (millions, except per share data)				
Consolidated and Combined Statements of Operations Data: *	**2017**	**2016**	**2015**	**2014**	**2013**
Operating Revenues	**$ 5,963**	**$ 6,018**	**$ 4,367**	**$ 4,594**	**$ 4,313**
Operating Income	385	1,194	513	885	179
Income (Loss) Before Income Tax	**123**	**1,009**	**302**	**707**	**(13)**
Income tax (benefit) expense	(259)	377	29	275	28
Net Income (Loss)	**382**	**632**	**273**	**432**	**(41)**
Less: Net income attributable to noncontrolling interests	1	—	—	—	1
Net Income (Loss) Attributable to AVANGRID, Inc.	**381**	**632**	**273**	**432**	**(42)**
Total Earnings (Loss) Per Common Share, Basic and Diluted	1.23	2.04	1.07	1.71	(0.17)
Weighted-average Number of Common Shares Outstanding:					
Basic	309,502,861	309,512,553	254,588,212	252,235,232	252,235,232
Diluted	309,661,883	309,817,322	254,605,111	252,235,232	252,235,232

Consolidated and Combined Balance Sheet Data:*			**(millions)**		
As of December 31,	**2017**	**2016**	**2015**	**2014**	**2013**
(Millions)					
Total Property, Plant and Equipment	**$ 22,669**	**$ 21,548**	**$ 20,711**	**$ 17,133**	**$ 16,715**
Total Other Assets	**3,589**	**3,976**	**3,795**	**2,075**	**2,137**
Total Assets	**$ 31,671**	**$ 31,309**	**$ 30,743**	**$ 24,162**	**$ 23,170**

As of December 31,	2017	2016	(millions) 2015	2014	2013
(Millions)					
Liabilities					
Current portion of debt	$ 183	$ 349	$ 206	$ 148	$ 25
Non-current debt	5,196	4,510	4,530	2,489	2,669
Total Liabilities	**16,575**	**16,101**	**15,593**	**11,607**	**11,050**
Total Stockholder's Equity	**15,077**	**15,195**	**15,137**	**12,538**	**12,105**
Total Equity	**$ 15,096**	**$ 15,208**	**$ 15,150**	**$ 12,555**	**$ 12,120**

*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 diversified energy and utility company with approximately $32 billion in assets and operations in 27 states. The Company operates regulated utilities and electricity generation through two primary lines of business. Avangrid Networks includes eight electric and natural gas utilities, serving 3.2 million customers in New York and New England. Avangrid Renewables operates 7.1 gigawatts of electricity capacity, primarily through wind power, with presence in 22 states across the United States. AVANGRID employs approximately 6,600 people. The Company was formed by a merger between Iberdrola USA, Inc. and UIL Holdings Corporation, or UIL, in 2015. 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. Our primary business is ownership of our 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, and Enstor Gas, LLC, or Gas. 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. Gas operates our natural gas storage facilities and gas trading businesses through Enstor Energy Services LLC (gas trading) and Enstor Inc. (gas storage).

In December 2017, our management committed to a plan to sell the gas storage and trading businesses because they represent non-core businesses that are not aligned with our strategic objectives. As a result, 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. The gas trading and storage businesses are being marketed for sale, and it is the Company's intention to complete the sales of these assets and liabilities within twelve months following their initial classification as held for sale. 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 February 16, 2018, the Company entered into a definitive agreement to sell Enstor Gas, LLC, which operates the AVANGRID's gas storage business, to Amphora Gas Storage USA, LLC. The agreement includes, among other things, a transition services agreement which obligates ARHI to provide certain transition services for up to one year after the closing date and includes a guarantee the Company will release certain obligations to Amphora Gas Storage USA, LLC. The transaction, which is subject to the satisfaction of customary closing conditions, is expected to be completed during the second quarter of 2018. Additional details on held for sale classification are provided in Note 25 to our consolidated financial statements contained in this Annual Report on Form 10-K.

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 2.2 million electric utility customers and delivering natural gas to approximately 1.0 million natural gas public utility customers as of December 31, 2017.

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, 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 7,129 megawatts, or MW, as of December 31, 2017, including Renewables' share of joint projects, of which 6,387 MW was installed wind capacity. Approximately 72% of the capacity was contracted as of December 31, 2017, for an average period of 9.6 years. Being among the top three largest wind operators in the United States based on installed capacity as of December 31, 2017, Renewables strives to lead the transformation of the U.S. energy industry to a competitive, clean energy future. Renewables currently operates 58 wind farms in 21 states across the United States.

Through Gas, as of December 31, 2017, we own approximately 67.5 billion cubic feet, or Bcf, of net working gas storage capacity. Gas operates 50.3 Bcf of contracted or managed natural gas storage capacity in North America through Enstor Energy Services, LLC, as of December 31, 2017.

Summary of Results of Operations

Our operating revenues decreased by 1%, from $6,018 million for the year ended December 31, 2016, to $5,963 million for the year ended December 31, 2017.

The Networks revenues decreased due to a decrease in electricity revenue driven by a lower demand in the current period along with a decrease in related regulatory activities, mainly due to decrease in recoveries on the Ginna Reliability Support Services Agreement, or Ginna RSSA. Renewables business revenues increased on the impact of favorable operating condition driven mainly by addition of new capacity and favorable mark-to-market (MtM) changes on derivatives. Gas business revenues decreased on the impact of lower spreads in storage business and unfavorable MtM changes on derivatives.

Net income decreased by 39% from $632 million for the year ended December 31, 2016, to $382 million for the year ended December 31, 2017, primarily driven by the Gas net loss increase in the period due to the loss from remeasurement of assets and liabilities held for sale in connection with the committed plan to sell the gas trading and storage businesses. Additionally, Networks net income saw improvements due to impacts from rate case activities in New York and Connecticut, offset by lower revenues driven by lower demand for electricity and decrease in regulatory activity in the current period. Renewables net income increased primarily as a result of impact from measurement of deferred income tax balances as a result of the Tax Cuts and Jobs Act of 2017, or Tax Act, enacted by the U.S. federal government on December 22, 2017.

Adjusted earnings before interest, tax, depreciation and amortization, or adjusted EBITDA (a non-GAAP financial measure), decreased by 7% from $1.9 billion for the year ended December 31, 2016, to $1.8 billion for the year ended December 31, 2017. Adjusted gross margin (a non-GAAP financial measure) decreased by 3%, from $4.5 billion for the year ended December 31, 2016, to $4.4 billion for the year ended December 31, 2017. The decrease in the non-GAAP adjusted EBITDA and non-GAAP adjusted gross margin is primarily due to a decrease in electricity revenue and related regulatory activities, partially offset by higher average rates at Networks, unfavorable prices and higher energy and transmission purchases at Renewables and unfavorable MtM changes on derivatives along with unfavorable results from the performance in the owned and contracted storage businesses at Gas. For additional information and reconciliation of the non-GAAP adjusted EBITDA to net income and the non-GAAP adjusted gross margin to net income, 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 2018, 70% of its standard service load for the second half of 2018, and 20% of its standard service load for the first half of 2019. Supplier of last resort service is procured on a quarterly basis, 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 FERC. Regulatory deferrals create regulatory assets and liabilities under FERC, consistent with U.S. GAAP financial accounting standards. Regulatory deferrals in New York include electric and gas supply costs, PPAs, net plant reconciliations (downward only), revenue decoupling, system benefit charges, renewable portfolio standards, energy efficiency portfolio standards, economic development programs, 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, REV initiatives, Nuclear Electric Insurance Limited, or NEIL, credits, credit and debit card fees, exogenous costs and certain legislative, accounting, regulatory and tax related actions. Regulatory deferrals in Maine include stranded costs, revenue decoupling, power tax regulatory asset, 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, 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 and certain other public policy costs.

NYSEG's and RG&E's electric and natural gas rate plans and CMP's and UI's electric rates and CNG's gas rates, each contain a 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. Effective January 1, 2018, SCG has implemented a revenue decoupling mechanism pursuant to the PURA approved amended settlement agreement dated June 30, 2017.

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 maximum equity ratio, utilized for the earnings sharing mechanism, 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 dividend 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

On June 30, 2017, SCG filed an application with PURA for new tariffs to become effective January 1, 2018. SCG requested a three-year rate plan for calendar years 2018, 2019 and 2020 and a proposed ROE of 9.95%. SCG also requested to implement a RDM and Distribution Integrity Management Program, or DIMP, mechanism similar to the mechanisms authorized for CNG. On October 16, 2017, SCG, Prosecutorial Staff from PURA, and the Connecticut Office of Consumer Counsel, or OCC, filed an amended settlement agreement with PURA for approval, which includes among other items the implementation of an RDM, ESM and the DIMP as proposed by SCG, the amortization of certain regulatory liabilities (most notably accumulated hardship deferral balances and certain accumulated deferred income taxes) and tariff increases based on an ROE of 9.25% and approximately 52% equity level. The parties also agreed on 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. PURA approved the amended rate case settlement agreement on December 13, 2017, and new tariffs became effective on January 1, 2018.

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.

On May 20, 2015, NYSEG and RG&E initiated a distribution rate case to ensure that the companies are able to continue to provide safe, adequate and reliable service, continue to make investments to modernize infrastructure, enhance low income programs and improve both gas and electric reliability, while maintaining their financial integrity. On February 19, 2016, the NYSEG, RG&E and other signatory parties filed a Joint Proposal, with the NYPSC for a three-year rate plan for electric and gas service at NYSEG and RG&E commencing May 1, 2016, which was approved on June 15, 2016 by the NYPSC. The Joint Proposal 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	
Utility	**Rate Increase (Millions)**	**Delivery Rate Increase %**	**Rate Increase (Millions)**	**Delivery Rate Increase %**	**Rate Increase (Millions)**	**Delivery Rate Increase %**
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 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 Joint Proposal reflects 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 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.

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%. On December 22, 2009, MPUC approved a stipulation which provided for a rate increase to MNG's base distribution rates for a three year period, with a 12% increase effective January 1, 2010, a 10% increase effective December 1, 2010 and another 10% increase effective December 1, 2011. The stipulation provided for the implementation of a revenue decoupling mechanism, reserve accounting and sharing of incremental storm costs, a separate proceeding for recovery of a new billing system and no earning sharing.

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 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 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. The reserve of $6 million for this case was reversed in May 2016.

On January 22, 2014, PURA approved base delivery rates for CNG, with an effective date of January 10, 2014, which, among other things, approved an allowed ROE of 9.18%, a decoupling mechanism, two separate ratemaking mechanisms that reconcile actual revenue requirements related to CNG's cast iron and bare steel replacement program and system expansion and an earnings sharing mechanism by which CNG and customers share on a 50/50 basis all earnings above the allowed ROE in a calendar year. In accordance with the approval by PURA of the acquisition, SCG and CNG agreed not to file a rate case for new rates effective before January 1, 2018.

BGC's rates are established by the DPU. BGC's ten-year rate plan, which was approved by the DPU and included an approved ROE of 10.5%, expired on January 31, 2012. BGC continues to charge the rates that were in effect at the end of the rate plan. In accordance with the approval by the DPU of the acquisition, BGC agreed not to file a rate case for new rates effective before June 1, 2018.

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 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 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 refund period of October 1, 2011 through December 31, 2012, or the refund period. The FERC issued an order in 2014 to reset the base ROE at 10.57% and capped the incentive rate at 11.74% for applicable projects for the refund period. Two additional complaints have also been filed for subsequent periods. The complaints have been 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 the second complaint, 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 the third complaint and prospectively, the base ROE should be 10.90% and that the ROE Cap should be 12.19%. The initial decision in the second and third complaints is the administrative law judge's recommendation to the FERC Commissioners. The FERC is expected to make its final decision in 2018.

In June 2015 the NETOs and complainants both filed an appeal in the U.S. Court of Appeals for the District of Columbia of the FERC's final order. On April 14, 2017, the Court of Appeals (the Court) vacated FERC's decision on Complaint I and remanded it to FERC. The Court held that FERC, as directed by statute, did not determine first that the existing ROE was unjust and unreasonable before determining a new ROE. The Court ruled that FERC should have first determined that the then existing 11.14% base ROE was unjust and unreasonable before selecting the 10.57% as the new base ROE. The Court also found that FERC did not provide reasoned judgment as to why 10.57%, the point ROE at the midpoint of the upper end of the zone of reasonableness, is a just and reasonable ROE. Instead, FERC had only explained in its order that the midpoint of 9.39% was not just and reasonable and a higher base ROE was warranted. On June 5, 2017, the NETOs made a filing with FERC seeking to reinstate transmission rates to the status quo ante (effect of the Court vacating order is to return the parties to the rates in effect prior to FERC Final decision) as of June 8, 2017, the date the Court decision became effective. In that filing, the NETOs stated that they will not begin billing at the higher rates until 60 days after FERC has a quorum of commissioners. On October 6, 2017, FERC issued an order rejecting the NETOs request to collect transmission revenue requirements at the higher ROE of 11.14%, pending FERC order on remand. In reaching this decision, FERC stated that it has broad remedial authority to make whatever ROE it eventually determines to be just and reasonable effective for the Complaint I refund period and prospectively from October 2014, the effective date of the Complaint I Order. Therefore the NETOs will not be harmed financially by not immediately returning to their pre-Complaint I ROE. We anticipate FERC to address the Court decision during 2018.

On April 29, 2016, a fourth ROE complaint (Complaint IV) was filed for a rate period subsequent to prior complaints requesting the then existing base ROE of 10.57% be reduced to 8.61% and the ROE Cap be set at 11.24%. The NETOs filed a response to the Complaint IV on June 3, 2016. On September 20, 2016, FERC accepted the Complaint IV, established a 15-month refund effective date of April 29, 2016, and set the matter for hearing and settlement judge procedures. On February 1, 2017, the complainants filed their initial testimony recommending a base ROE of 8.59%. On March 23, 2017, the NETOs filed their answering testimony supporting the continuation of the base ROE from Complaint I of 10.57%. In April 2017, the NETOs filed for a stay in the hearings pending FERC on the Court order described above. That request was denied by the Administrative Law Judge. On November 21, 2017, the parties submitted updates to their return on equity analyses and recommendations just prior to hearings with the NETOs continuing to advocate that the existing base ROE of 10.57% should remain in effect. Hearings were held in December 2017 with an expected Initial Decision from the Administrative Law Judge by March 31, 2018. A range of possible outcomes is not able to be determined at this time due to the preliminary state of this matter. We cannot predict the outcome of the fourth complaint proceeding.

On October 5, 2017, the NETOs filed a Motion for Dismissal of Pancaked Return on Equity Complaints in light of the decision by the Court in April 2017 that became effective on June 8, 2017. The NETOs assert that all four complaints should be dismissed because the complainants have not shown that the existing ROE of 11.14% is unjust and unreasonable as the Court decision requires. In addition, the NETOs assert that Complaints II, III and IV should also be dismissed because the Court decision implicitly found that FERC's acceptance of Pancaked FPA Section 206 complaints was statutorily improper as Congress intended that the 15-month refund period under Section 206 applies whenever FERC does not complete its review of a complaint within the 15-month period. In the event FERC chooses not to dismiss the complaints, the NETOs request that FERC consolidate the complaints for decision as the evidentiary records are either closed or advanced enough for FERC to address the requirements of the Court decision and expeditiously issue a final order. We cannot predict the outcome of action by FERC.

On December 28, 2015, the FERC issued an order instituting section 206 proceedings and establishing hearing and settlement judge procedures. Pursuant to section 206 of the FPA, the FERC found that the ISO-NE Transmission, Markets, and Services Tariff is unjust, unreasonable, and unduly discriminatory or preferential. The FERC stated that ISO-NE's Tariff lacks adequate transparency and challenge procedures with regard to the formula rates for ISO-NE participating transmission owners, including UI and CMP. The FERC also found that the current Regional network service, or RNS, and Local Network Service, or LNS, formula rates appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful as the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates. We cannot predict the outcome of this proceeding.

Merger Settlement Agreement – Connecticut and Massachusetts

As part of the process of seeking and obtaining regulatory approval of the acquisition 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.

As a result, the following commitments were made in Connecticut:

- A one-time, $20 million rate credit to customers in 2016, allocated among UI, SCG and CNG customers based on the total number of retail customers.
- Additional rate credits of $1.25 million/year for ten years (2018-2027) to CNG customers.
- Additional rate credits of $0.75 million/year for ten years (2018-2027) to SCG customers.
- $1.6 million in savings to SCG customers, associated with SCG making additional infrastructure capital investments over a three-year period without seeking recovery until the next SCG rate case.
- Agreement not to seek to increase UI distribution base rates effective before January 1, 2017, and agreement not to seek to increase CNG and SCG distribution base rates effective before January 1, 2018.
- Contribution of $2 million/year for three years to the DEEP, to stimulate investment in energy efficiency and clean energy technologies.
- $5 million in benefits to customers resulting from UI recovering only the debt rate rather than the equity return for two years, on an increased $50 million of investment in storm resiliency programs.
- Contribution of $1 million for disaster relief entities.
- Maintaining charitable contribution at historical contribution levels (between $500,000 and $800,000) for at least four years.
- Upon the resolution of all appeals of the PURA decision approving the acquisition, UI will withdraw its appeals of two PURA dockets relating to PURA's disallowance of certain reconciliation amounts. The appeals were withdrawn by UI in June 2016.

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.

The following commitments were made in Massachusetts:

- Customers of BGC will receive a total of $4.0 million in rate credits, to be spread over the months of November through April 2016-2017 and November through April 2017-2018.
- BGC will contribute $1 million to alternative heating programs.
- BGC will not seek to increase distribution base rates effective before June 1, 2018.

As a result of the merger settlement agreement we have recorded $44 million as regulatory liabilities relating to the rate credits and an additional $19.8 million as liabilities in 2015.

New England Clear 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 in the Commonwealth of Massachusetts's 83D clean energy Request for Proposal, or RFP, to move forward as the alternative if the Northern Pass Transmission project fails to win approval from the New Hampshire Site Evaluation Committee by March 27, 2018. 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 megawatts of transmission capacity to supply New England with power from reliable hydroelectric generation.

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 Connecticut law Public Act (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. UI has begun purchasing energy from Woods Hill Solar, LLC for UI's 2 MW share of the Woods Hill solar project.

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 DEEP's PA 15-107 1(b) RFP, and were entered into pursuant to PA 15-107, Section 1(b) PA 15-107 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.

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 DER, and empower customer choice. In this proceeding, the NYPSC is examining the establishment of a 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 the Track 1, and examines changes in current regulatory, tariff, and market designs, 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 is ongoing.

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.

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

On March 11, 2017, the New York State Department of Public Service, or the Department, commenced an investigation of NYSEG's and RG&E's preparation for and response to the March 2017 windstorm, which affected more than 219,000 customers. The Department investigation included a comprehensive review of NYSEG's and RG&E's preparation for and response to the windstorm, including all aspects of the companies' filed and approved emergency plan. The Department held public hearings on April 12 and 13, 2017.

On November 16, 2017, the NYPSC announced that the Department Staff had completed their investigation into the March 2017 Windstorm and the NYPSC issued an Order Instituting Proceeding and to Show Cause. The Staff's investigation found that RG&E and NYSEG violated certain parts of their emergency response plans, which makes them subject to possible financial penalties. NYSEG and RG&E responded to the order in a timely manner and have entered into settlement discussions with the Department Staff. The unprecedented weather that resulted in the March 2017 windstorm posed great challenges to the NYSEG's and RG&E's communities, employees, contractors, assisting utilities, and municipal partners who all worked tirelessly to safely restore power to all customers. NYSEG's and RG&E's priorities during any storm are the restoration of service to their respective customers and the safety of their communities, customers, employees and contractors. We cannot predict the outcome of this regulatory action.

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, NYISO produced a reliability study, confirming that the Ginna Facility needs to remain in operation to avoid bulk transmission and non-bulk local distribution system reliability violations in 2015 and 2018. In July 2014, GNPP filed a petition requesting that the NYPSC initiate a proceeding to examine a proposal for the continued operation of the Ginna Facility.

In November 2014, the NYPSC ruled that GNPP had demonstrated that the Ginna Facility is required to maintain system reliability and that its actions with respect to meeting the relevant retirement notice requirements were satisfactory. The NYPSC also accepted the findings of the 2014 reliability study and stated that it established "the reliability need for continued operation of the Ginna Facility that is the essential prerequisite to negotiating a Reliability Support Service Agreement, or RSSA." As such, the NYPSC ordered RG&E and GNPP to negotiate an RSSA.

On February 13, 2015, RG&E submitted to the NYPSC an executed RSSA between RG&E and GNPP. RG&E requested that the NYPSC accept the RSSA and approve cost recovery by RG&E from its customers of all amounts payable to GNPP under the RSSA utilizing the cost recovery surcharge mechanism.

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 provides 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 is entitled to 70% of revenues from Ginna's sales into the NYISO energy and capacity markets, while Ginna is 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 amount has been recovered by RG&E from customers.

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. In December 2014, New York TransCo filed for regulatory approval of its rates, terms, and conditions with the FERC. The filing requests a formula base ROE of 10.6%, 150 basis points ROE incentives, construction work in progress, a formula rate mechanism, and a proposed cost allocation.

Various parties, including the NYPSC, have protested the filing with the FERC, including the base ROE, the ROE incentives, and the cost allocation. New York TransCo will not make final decisions on transmission project development until the FERC decision.

On April 2, 2015, the FERC issued an order granting, inter alia, New York TransCo's owners' request for a 50 basis point adder for New York TransCo's membership in the NYISO RTO, subject to the adder being capped within the zone of reasonableness after a determination of where within that zone its base level ROE should be set. The FERC also set the formula rate and base ROE issue for hearing and settlement judge procedures. In addition, the FERC rejected New York TransCo's owners' cost allocation method for the transmission owner transmission solutions, or TOTS, projects because it would allocate costs to Power Supply Long Island and New York Power Authority that they did not voluntarily agree to pay.

On November 5, 2015, New York TransCo's owners filed the settlement with the FERC to resolve all outstanding issues associated with the TOTS projects, including issues related to the TOTS Projects that were set for hearing and issues pending on rehearing. The issues regarding certain other projects remain pending. The Settlement addressed the financial terms that are components of New York TransCo's revenue requirement for the proposed TOTS projects, including the base ROE of 9.50%, and a 50-basis point ROE adder, the capital structure of 53%, and the cost allocation under the NYISO Open Access Transmission Tariff, or OATT, for the TOTS projects. On March 17, 2016, the FERC approved the settlement.

On August 21, 2017, New York TransCo filed a settlement with the FERC to resolve all outstanding issues associated with the alternate current transmission project, or AC Project, for which selection of the developer remains pending with NYISO. The issues contained in the settlement include those related to the AC Project that were set for hearing and issues pending on rehearing. The Settlement addressed the financial terms that are components of New York TransCo's revenue requirement for the AC Project, including the base ROE of 9.65%, and a 100-basis point ROE adder, an equity ratio in the capital structure of up to 53%, risk sharing for project cost overruns, and the cost allocation under the NYISO OATT for the AC Project. On November 16, 2017, the FERC approved the settlement.

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, SCG and BGC, have approved revenue decoupling mechanisms, or RDMs, as part of the NYPSC, PURA and MPUC rate plans in place for the period ended December 31, 2017. Effective January 1, 2018 new tariffs became effective for SCG, which include an approved RDM. 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 law Public Act 11-80, or 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 will phase in over a six-year solicitation period, and are expected to peak at an annual commitment level of about $13.6 million per year after all selected projects are online. 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.

On October 23, 2013, PURA approved UI's renewable connections program filed in accordance with PA 11-80, through which UI has developed 10 MW of renewable generation. The costs for this program will be recovered on a cost of service basis. PURA established a base ROE to be calculated as the greater of: (A) the current UI authorized distribution ROE (currently 9.10%) plus 25 basis points and (B) the current authorized distribution ROE for CL&P, (currently 9.17%), less target equivalent market revenues (reflected as 25 basis points). In addition, UI will retain a percentage of the market revenues from the project, which percentage is expected to equate to approximately 25 basis points on a levelized basis over the life of the program. The cost of this project, a 2.8 MW fuel cell facility in New Haven, solar photovoltaic and fuel cell facilities totaling 5 MW in Bridgeport, and a 2.2 MW fuel cell facility in Woodbridge, all of which are now operational, was $41.5 million.

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, or Evergreen Power, on March 31, 2010, to purchase capacity and energy from Evergreen Power's 60 MW Rollins wind farm in Penobscot County, Maine. CMP's purchase obligations under the Rollins contract are approximately $7 million per year. In accordance with subsequent MPUC orders, CMP periodically auctions the purchased Rollins energy 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.

Pursuant to Maine law 35-A M.R.S.A §3604, the MPUC is authorized to direct Maine transmission and distribution utilities to enter into long-term contracts to purchase capacity, energy and renewable energy credits from up to 50 MW of qualifying community-based renewable energy facilities. In accordance with §3604, on October 22, 2016, CMP commenced purchases from Athens Energy LLC for a contract term of three years. CMP purchase obligations under the Athens contract are approximately $6 million per year. Under the provisions of §3604 and MPUC implementing orders, CMP will periodically auction the purchased products from Athens for resale to wholesale market purchasers and recover any differences between power purchase costs and resale revenues through a reconcilable component of its retail distribution rates. Although the MPUC has certified several additional community-based renewable energy generation projects under §3604 and authorized similar PPAs between these sellers and CMP, no additional facilities have advanced to operational status.

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. In support of this, on December 18, 2015, Congress passed and President Obama signed into law the Consolidated Appropriations Act, Public Law 114-113. This law extends the qualifying dates for the production tax credit available to wind energy generating facilities (Internal Revenue Code Section 45) and the investment tax credit available to commercial solar generating facilities (Internal Revenue Code Section 48). The law also extends an option for wind generation facilities to elect to receive an investment tax credit in lieu of the production tax credit. In general, both provisions allow new wind and solar facilities to qualify for the respective credits at full value over the next several years, with reductions in the value of the authorized tax credits for facilities phased in during subsequent periods. Production tax credits were reduced to 80% for facilities commenced construction in 2017, will be reduced to 60% for facilities commencing construction in 2018, and reduced to 40% for facilities commencing construction in 2019. Investment tax credits will be 30% for projects commencing construction through 2019, then reduce to 26%, 22% and 10% for projects commencing construction in 2020, 2021 and 2022, respectively. The Internal Revenue Service, or IRS, updated its guidance related to which projects will qualify for the production tax credits, including criteria for the beginning of construction for a project and the continuous program of construction or the continuous efforts to advance the project to completion. Multi-year extension of these credits provides opportunities for Renewables to develop, construct, and market new renewable generating facilities and partially repower existing renewable generating facilities in several U.S. markets.

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.

Renewable Energy Demand

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, cooperatives, and large commercial and industrial customers. As a result, there is a concentrated pool of potential buyers for electricity generated by Renewables' business, which may restrict their ability to negotiate favorable terms under new PPAs, and could impact their ability to find new customers for the electricity generated by their generation facilities should this become necessary. 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.

Energy Prices

Renewables has exposure to commodity price movements through its "natural" long positions in electricity from its generation. Renewables manages the exposure to risks of commodity price movements through internal risk management policies, enforcement of established risk limits and risk management procedures.

A portion of Renewables' fuel and energy output arrangements qualify as derivative contracts. Such derivative contracts are carried at fair value, with changes in fair value recognized to earnings as the changes occur. In 2015, Renewables began designating certain qualifying derivatives contracts as hedges. These hedge designations result in deferral of changes in fair value, to the extent the hedge is effective, to accumulated other comprehensive income until the contract settles, at which point the deferred amount is recognized to earnings.

Wind Conditions

If wind conditions are unfavorable, or if Renewables' wind turbines are not available for operation, Renewables electricity generation and related revenue may be substantially below our expectations. 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. These events could also degrade equipment or components and the interconnection and transmission facilities' lives or maintenance costs. Historically, Renewables wind production is greater in the first, second and fourth quarters.

Wind Turbine Supply

Replacement and spare parts for wind turbines and key pieces of electrical equipment may be difficult or costly to acquire or may be unavailable. Although Renewables has expanded and diversified its supplier base, the loss of any of these 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.

Gas

Gas benefits from price volatility and temporal price spreads, which impacts the level of demand for services and the rates that can be charged for natural gas storage services. On a system-wide basis, natural gas is typically injected into storage between April and October when natural gas prices are generally lower and withdrawn during the winter months of November through March when natural gas prices are typically higher. Largely due to the abundant supply of natural gas made available by hydraulic fracturing techniques, natural gas prices have dropped significantly to levels that are near historic lows. If prices and volatility remain low or declines further, then the demand for natural gas storage services, and the prices that Gas will be able to charge for those services, may decline or be depressed for a prolonged period of time. Conversely, if prices and volatility remain high or increase then the demand for natural gas storage services and the prices that Gas will be able to charge for these services may increase for a period of time. In 2015 we began designating those derivatives contracts at Gas that qualify as hedges. This designation was made prospectively, and in accordance with all the requirements of hedge accounting.

Results of Operations

Immaterial Corrections to Prior Periods

The following table sets forth our segment operating revenues, expenses and net income for each of the periods indicated. During the year ended December 31, 2017, we identified immaterial corrections to prior periods related to our deferred income tax liabilities associated with our tax equity financing arrangements in our Renewables reportable segment. For further details, refer to Note 2 in our consolidated financial statements included in this Annual Report on Form 10-K. Accordingly, we have reflected the correction of these prior period amounts in the periods in which they originated.

Results of operations discussed herein are based on the revised financial results for the years ended December 31, 2016 and 2015.

	Year Ended December 31, 2017				
	Total	Networks	Renewables	Gas	Other(1)
			(in millions)		
Operating Revenues	**$ 5,963**	**$ 4,961**	**$ 1,047**	**$ 15**	**$ (60)**
Operating Expenses					
Purchased power, natural gas and fuel used	1,338	1,153	225	—	(40)
Operations and maintenance	2,211	1,841	354	44	(28)
Impairment	642	—	—	642	—
Depreciation and amortization	824	474	325	25	—
Taxes other than income taxes	563	499	51	5	8
Total Operating Expenses	**5,578**	**3,967**	**955**	**716**	**(60)**
Operating Income (Loss)	**385**	**994**	**92**	**(701)**	—
Other Income (Expense)					
Other income (expense)	58	48	4	5	1
Earnings (losses) from equity method investments	(40)	15	(55)	—	—
Interest expense, net of capitalization	(280)	(244)	(28)	(24)	16
Income (Loss) Before Income Tax	**123**	**813**	**13**	**(720)**	**17**
Income tax (benefit) expense	(259)	316	(320)	(212)	(43)
Net Income (Loss)	**382**	**497**	**333**	**(508)**	**60**
Less: Net income attributable to noncontrolling interests	1	1	—	—	—
Net Income (loss) Attributable to Avangrid, Inc.	**$ 381**	**$ 496**	**$ 333**	**$ (508)**	**$ 60**

	Year Ended December 31, 2016				
	Total	Networks	Renewables	Gas	Other(1)
			(in millions)		
Operating Revenues	**$ 6,018**	**$ 5,030**	**$ 1,015**	**$ 32**	**$ (59)**
Operating Expenses					
Purchased power, natural gas and fuel used	1,286	1,174	152	—	(40)
Operations and maintenance	2,206	1,839	351	44	(28)
Impairment	—	—	—	—	—
Depreciation and amortization	804	466	313	25	—
Taxes other than income taxes	528	465	50	4	9
Total Operating Expenses	**4,824**	**3,944**	**866**	**73**	**(59)**
Operating Income (Loss)	**1,194**	**1,086**	**149**	**(41)**	**—**
Other Income (Expense)					
Other income (expense)	76	46	30	2	(2)
Earnings (losses) from equity method investments	7	15	(8)	—	—
Interest expense, net of capitalization	(268)	(252)	(50)	(25)	59
Income (Loss) Before Income Tax	**1,009**	**895**	**121**	**(64)**	**57**
Income tax expense (benefit)	377	415	7	(22)	(23)
Net Income (Loss)	**632**	**480**	**114**	**(42)**	**80**
Less: Net income attributable to noncontrolling interests	—	—	—	—	—
Net Income (loss) Attributable to Avangrid, Inc.	**$ 632**	**$ 480**	**$ 114**	**$ (42)**	**$ 80**

	Year Ended December 31, 2015				
	Total	Networks	Renewables	Gas	Other(1)
			(in millions)		
Operating Revenues	**$ 4,367**	**$ 3,386**	**$ 1,067**	**$ (19)**	**$ (67)**
Operating Expenses					
Purchased power, natural gas and fuel used	972	821	202	1	(52)
Operations and maintenance	1,808	1,389	363	38	18
Impairment	12	—	12	—	—
Depreciation and amortization	695	328	344	23	—
Taxes other than income taxes	367	311	46	4	6
Total Operating Expenses	**3,854**	**2,849**	**967**	**66**	**(28)**
Operating Income (Loss)	**513**	**537**	**100**	**(85)**	**(39)**
Other Income (Expense)					
Other income (expense)	56	44	106	3	(97)
Earnings (losses) from equity method investments	—	1	(5)	—	4
Interest expense, net of capitalization	(267)	(227)	(54)	(31)	45
Income Before Income Tax	**302**	**355**	**147**	**(113)**	**(87)**
Income tax expense (benefit)	29	146	8	(44)	(81)
Net Income (Loss)	**273**	**209**	**139**	**(69)**	**(6)**
Less: Net income attributable to noncontrolling interests	—	—	—	—	—
Net Income (loss) Attributable to Avangrid, Inc.	**$ 273**	**$ 209**	**$ 139**	**$ (69)**	**$ (6)**

(1) Other amounts represent corporate and company eliminations.

The following tables set forth our segment revenues and expenses by segment for each of the periods indicated and as a percentage of the total consolidated operating revenues and operating expenses, respectively:

Year Ended December 31, 2017

	Total	Networks	Renewables	Gas	Other(1)
			(in millions)		
Operating revenues	**$ 5,963**	**$ 4,961**	**$ 1,047**	**$ 15**	**$ (60)**
Operating revenues %		83%	18%	—	(1)%
Operating expenses	**$ 5,578**	**$ 3,967**	**$ 955**	**$ 716**	**$ (60)**
Operating expenses %		71%	17%	13%	(1)%

Year Ended December 31, 2016

	Total	Networks	Renewables	Gas	Other(1)
			(in millions)		
Operating revenues	**$ 6,018**	**$ 5,030**	**$ 1,015**	**$ 32**	**$ (59)**
Operating revenues %		84%	17%	—	(1)%
Operating expenses	**$ 4,824**	**$ 3,944**	**$ 866**	**$ 73**	**$ (59)**
Operating expenses %		82%	18%	1%	(1)%

Year Ended December 31, 2015

	Total	Networks	Renewables	Gas	Other(1)
			(in millions)		
Operating revenues	**$ 4,367**	**$ 3,386**	**$ 1,067**	**$ (19)**	**$ (67)**
Operating revenues %		78%	24%	—	(2)%
Operating expenses	**$ 3,854**	**$ 2,849**	**$ 967**	**$ 66**	**$ (28)**
Operating expenses %		75%	25%	2%	(2)%

(1) Other amounts represent corporate and company eliminations.

Comparison of Period to Period Results of Operations

Our operating revenues decreased by 1%, from $6,018 million for the year ended December 31, 2016, to $5,963 million for the year ended December 31, 2017.

Our purchased power, natural gas and fuel used increased by 4%, from $1,286 million for the year ended December 31, 2016, to $1,338 million for the year ended December 31, 2017.

Our operations and maintenance increased by less than 1%, from $2,206 million for the year ended December 31, 2016, to $2,211 million for the year ended December 31, 2017.

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

Year Ended December 31, 2017 Compared to the Year Ended December 31, 2016

Networks

Operating revenues for the year ended December 31, 2017 decreased by $69 million, or 1%, from $5,030 million for the year ended December 31, 2016, to $4,961 million. Electricity and gas revenues increased by $113 million and $83 million, respectively, due to primarily the impact of higher average rates in the year ended December 31, 2017 compared to the same period of 2016, from rate case activities in New York and Connecticut. Electricity revenue for the same period decreased by $11 million due to lower volumes largely driven by decrease in cooling degree days, while gas revenues increased by $49 million in the same period due to a migration in customers moving from retail access to full service and colder weather. Additionally, wholesale electricity revenue decreased by $33 million for the year ended December 31, 2017 compared to the same period of 2016 due to a decrease in overall units sold caused by a decrease in cooling degree days. Revenue related regulatory activities decreased by $269 million primarily due to an adjustment of $126 million in 2016 and an adjustment of $14 million in 2017, to unfunded future income tax to reflect the change from a flow through to normalization method, which were recorded as an increase to revenue, with an offsetting and equal increase to income tax expense in both periods, decreases in the energy supply reconciliation of $35 million, amortization of regulatory deferrals from previous rate case of $23 million that ended in 2016, decreases in recoveries on the Ginna RSSA of $75 million, property and power tax deferral of $17 million, stranded costs of $22 million, revenue decoupling mechanism of $11 million, $16 million in transmission true-ups, offset by an increase in non by-passable charges of $42 million.

Purchased power, natural gas and fuel used for the year ended December 31, 2017 decreased by $21 million, or 2%, from $1,174 million for the year ended December 31, 2016, to $1,153 million. The decrease is primarily driven by $50 million decrease in purchases from contracts that expired in December 2016 and $59 million decreases in overall units of electricity procured due to a reduction in cooling degree days, offset by $78 million increase in average gas prices and overall units of gas procured combined with $11 million increase in gas transportation related activity driven by a higher demand in the period.

Operations and maintenance during the year ended December 31, 2017 increased by $2 million, from $1,839 million for the year ended December 31, 2016, to $1,841 million. The increase is primarily due to a $36 million increase in purchases of renewable and zero-emission energy certificates related to a new program to adopt clean energy standards, increase in personnel costs of $32 million driven largely by overtime associated with non-deferrable storm costs, increase of $22 million in reserves for uncollectible accounts, and $19 million in transmission and generation charges in the period, offset by a decrease of $109 million in the Ginna RSSA driven by its completion.

Renewables

Operating revenues for the year ended December 31, 2017 increased by $32 million, or 3% from $1,015 million for the year ended December 31, 2016, to $1,047 million. Revenues from wind and solar facilities increased by $33 million due to increase in wind production with output increasing 353 GWh, or 2%, also driven by addition of a new capacity, and 1% increase in average prices. Additionally, favorable MtM changes of $13 million on energy derivative transactions entered into for economic hedging purposes were offset by a decline in thermal revenue of $2 million due to lower merchant prices and $12 million in other revenues mainly due to sale of transmission rights that occurred in 2016.

Purchased power, natural gas and fuel used for the year ended December 31, 2017 increased by $73 million, or 48%, from $152 million for the year ended December 31, 2016, to $225 million. Klamath power plant expense was $15 million lower due to lower production and reduced fuel costs, MtM changes on derivatives were unfavorable $48 million due to market price changes in the current period and transmission and energy purchases were higher by $40 million mainly due to the addition of a new capacity during the period.

Operations and maintenance for the year ended December 31, 2017 increased by $3 million or 1% from $351 million for the year ended December 31, 2016, to $354 million, primarily due to increase in salary costs of $3 million driven by headcount increases, $5 million additional costs from new windfarm assets, offset by $4 million lower asset retirement related expenses, as a result of the extension of the windfarm useful life in combination with revisions to expense estimates.

Gas

Operating revenues for the year ended December 31, 2017 decreased by $17 million, or 47%, from $32 million for the year ended December 31, 2016, to $15 million. The decrease in operating revenues was due to $10 million of unfavorable results from the performance of the owned and contracted storage businesses, with both capturing lower spreads relative to previous year, $3 million unfavorable results from transportation business driven by a loss recorded in the year ended December 31, 2017 due to the turn back of Iroquois transport capacity, $10 million of unfavorable MtM change driven by a decrease in gas prices, offset by $2 million favorable results from new transportation initiatives with Iberdrola Mexico and the remaining $4 million relating to right of way revenue.

The gas business had no purchased power, natural gas and fuel used for the years ended December 31, 2017 and 2016. As a predominantly trading business, such expenses are required to be netted with revenues.

Operations and maintenance for the years ended December 31, 2017 and 2016 were $44 million in both periods.

Depreciation, Amortization and Impairment

Depreciation, amortization and impairment expenses for the year ended December 31, 2017 increased by $662 million or 82% from $804 million for the year ended December 31, 2016, to $1,466 million. The primary drivers were the loss of $642 million from held for sale measurement in connection with the committed plan to sell the gas trading and storage businesses. Net plant additions in Networks increased depreciation expense by $14 million, and updates to asset lives from the rate case activities decreased depreciation expense by $9 million. Renewables added $18 million to depreciation expense due to a new operating capacity, and had $3 million favorable changes primarily due to assets lives increase driven by new contracts.

Other Income and (Expense) and Equity Earnings

Other income and (expense) and equity earnings for the year ended December 31, 2017 decreased by $65 million, or 78%, from $83 million for the year ended December 31, 2016, to $18 million, primarily due to the impact of a $31 million gain from the sale of the Iroquois equity investment during the year ended December 31, 2016, other than temporary impairment of $49 million on a Renewables equity method investment, offset by $13 million for increased 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, 2017 increased by $12 million or 4% from $268 million for the year ended December 31, 2016, to $280 million. Networks and Other added $14 million and $23 million of interest expense from outstanding debt during the period. Gas was $1 million favorable as a result of intercompany notes in the period. Renewables was $21 million favorable, as a result of lower tax equity investment obligations and intercompany notes. In addition, Networks had $3 million of lower interest expense on regulatory deferrals in the current period.

Income Tax Expense

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 predominately due to a $328 million tax benefit from measurement of deferred income tax balances as a result of the Tax Act enacted on December 22, 2017, by the U.S. federal government. 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. The effective tax rate, inclusive of federal and state income tax, for the year ended December 31, 2016, was 37.6%, which is slightly higher than the 35% statutory federal income tax rate due to offsetting income tax matters. Increases were predominantly due to the impact of an adjustment of $126 million to unfunded future income tax to reflect the change from a flow through to normalization method following the approval of the Joint Proposal by the NYPSC, which was recorded in the second quarter of 2016 as an increase to income tax expense and an offsetting increase to revenue. This was offset by the recognition of production tax credits associated with wind and state income tax amounts including unitary filing amounts for our various states of operations.

Year Ended December 31, 2016 Compared to the Year Ended December 31, 2015

Networks

Operating revenues for the year ended December 31, 2016 increased by $1.6 billion, or 49%, from $3.4 billion for the year ended December 31, 2015, to $5.0 billion. The addition of UIL increased revenues by $1.6 billion, for an underlying increase of $77 million. The milder winter weather in 2016 lowered demand for both electricity and gas, resulting in a revenue impact of $48 million. Wholesale electricity revenues also declined by $28 million due to a combination of lower volumes and wholesale market prices, which were down in 2016 as a result of the reduced demand due to milder weather. An increase of $36 million was due primarily to higher retail rates for electricity during the period. Regulatory recoveries increased by $117 million primarily due to an adjustment of $126 million to unfunded future income tax to reflect the change from a flow through to normalization method, which has been recorded as an increase to revenue, with an offsetting and equal increase to income tax expense, an increase of $17 million relating to recoveries on the Ginna RSSA together with other decreases in the amount of $26 million for items such as revenue decoupling mechanisms, nonbypassable wires charges and rate case impacts.

Purchased power, natural gas and fuel increased used for the year ended December 31, 2016 increased by $353 million, or 43%, from $821 million for the year ended December 31, 2015, to $1,174 million. UIL contributed $463 million in additional expense, resulting in underlying expense being $110 million lower. Purchase volume requirements were 3% lower for electricity and 3% lower for gas for the same reasons outlined under Networks revenues, that is, the milder weather in winter 2016. In addition, market prices were down 25% for electricity and 17% for gas.

Operations and maintenance during the year ended December 31, 2016 increased by $450 million or 32% from approximately $1.4 billion for the year ended December 31, 2015, to approximately $1.8 billion. UIL accounts for $463 million of this increase, with the remaining $13 million decrease attributable to the underlying business. The regulatory adjustment for the Ginna RSSA, which has offsets in revenue, accounts for a $35 million increase. Offsetting this are reductions relating to $22 million refunds received from the Spent Fuel Nuclear Trust from Maine Yankee, which will be refunded to customers, $8 million due to lower-write-offs in the current year due to lower commodity prices in the current year, $7 million due to reduced recovery of storm costs as compared to higher levels in prior years and of $11 million from lower expenditures on various state mandated energy efficiency programs, lower insurance claim expenses, and renewable energy credit purchases and adjustments to regulatory deferrals based on changes to rate plans.

Renewables

Operating revenues for the year ended December 31, 2016 decreased by $52 million, or 5% from approximately $1.1 billion for the year ended December 31, 2015, to approximately $1.0 billion. Revenues from wind and solar facilities increased by $7 million due to 5% increase in wind generation on favorable wind resource and full year of operation in 2016 of a wind farm completed in 2015, offset in part by 4% lower average prices. New wind capacity added in 2016 did not contribute significantly to the increase in revenues or production for 2016. The decrease in average price results from general market conditions and mild weather in 2016 compared to 2015 and proportionately more output sold merchant due to expiring contracts. Revenues decreased by $46 million due to unfavorable MtM changes on energy derivative transactions entered into for economic hedging purposes and thermal revenues decreased by $13 million due to lower merchant prices.

Purchased power, natural gas and fuel used for the year ended December 31, 2016 decreased by $50 million, or 25%, from $202 million for the year ended December 31, 2015, to $152 million. Klamath power plant expense was $11 million lower due to lower production and reduced fuel costs, MtM changes on derivatives were favorable $41 million due to market price changes in the current period and transmission and energy purchases were higher by $2 million.

Operations and maintenance for the year ended December 31, 2016 decreased by $12 million or 3% from $363 million for the year ended December 31, 2015, to $351 million. Bad debt expense decreased by $7 million due to a specific reserve recorded in 2015 that did not occur in 2016. Asset retirement related expenses were $5 million lower, as a result of the extension of the windfarm useful life in combination with revisions to expense estimates.

Gas

Operating revenues for the year ended December 31, 2016 increased by $51 million, or 268%, from negative $19 million for the year ended December 31, 2015, to $32 million. The increase in operating revenues was due to $19 million of improved performance in the owned and contracted storage businesses, with both capturing higher spreads relative to previous year, $6 million favorable transportation contract, $15 million favorable MtM change and the remainder relating to various items including contract adjustments in the prior year.

The gas business had no purchased power, natural gas and fuel used for the year ended December 31, 2016 and insignificant amount for the year ended December 31, 2015. As a predominantly trading business, such expenses are required to be netted with revenues.

Operations and maintenance for the year ended December 31, 2016 increased by $6 million, or 16%, from $38 million for the year ended December 31, 2015, to $44 million. Increases in credit guarantee expenses and third party services account for the increase in 2016.

Depreciation, Amortization and Impairment

Depreciation, amortization and impairment expenses for the year ended December 31, 2016 increased by $97 million or 14% from $707 million for the year ended December 31, 2015, to $804 million. The primary movements were UIL contributing $160 million, with the underlying business $63 million lower. Networks depreciation expense was $22 million lower, mainly as a result of updates to asset lives from the rate case activities. Renewables expense was $43 million lower primarily as a result of lower project impairment expenses in 2016, as compared to that in 2015, and $52 million lower depreciation expense due to revision of useful lives of wind farm assets offset by $21 million due to increases from the Baffin Bay wind asset only being operational for part of the prior year, combined with additional expense from salvage values and from asset retirement obligation estimations.

Other Income and (Expense) and Equity Earnings

Other income and (expense) and equity earnings for the year ended December 31, 2016 increased by $27 million, or 48%, from $56 million other income for the year ended December 31, 2015, to $83 million. UIL contributed $22 million of income. Of the remaining $5 million, $31 million was as a result of the sale of the Iroquois equity investment, and $3 million was as a result of the sale of other investment. An additional $12 million of income results from the reversal of the Maine Natural Gas provision in the current period that was initially recorded at the end of 2015. Offsetting these amounts were a $13 million decrease primarily from interest income on regulatory deferrals, due to updates from the rate case activities, $5 million for reduced allowance for funds used during construction in Networks, $6 million for reduced earnings on equity method investments and $5 million due to a gain from tax equity financing arrangements' buyback recorded in 2015 that did not occur in 2016. Other various items caused a decrease of approximately $11 million in the period.

Interest Expense, Net of Capitalization

Interest expense for the year ended December 31, 2016 increased by $1 million or less than 1% from $267 million for the year ended December 31, 2015, to $268 million. Excluding the impact of UIL, which added $79 million of expense, underlying expense was $78 million favorable. Networks was $53 million favorable, mainly as a result of lower interest expense on regulatory deferrals, and Other was favorable by $18 million as a result of a reduction to the interest rate on outstanding debt and reduced outstanding debt.

Income Tax Expense

The effective tax rate, inclusive of federal and state income tax, for the year ended December 31, 2016 was 37.4%, which is slightly higher than the 35% statutory federal income tax rate due to offsetting income tax matters. Increases were predominantly due to the impact of an adjustment of $126 million to unfunded future income tax to reflect the change from a flow through to normalization method following the approval of the proposal by the NYPSC, which was recorded in the second quarter of 2016 as an increase to income tax expense and an offsetting increase to revenue. This was offset by the recognition of production tax credits associated with wind and state income tax amounts including unitary filing amounts for our various states of operations. Income tax expense for the year ended December 31, 2015, was $71 million lower than it would have been at the statutory federal income tax rate of 35%, primarily due to production tax credits, filing of amended returns in the State of New York and the impact of tax equity financing arrangements. This resulted in an effective tax rate of 11.30% for 2015.

Non-GAAP Financial Measures

To supplement our consolidated financial statements presented in accordance with U.S. GAAP, we consider certain non-GAAP financial measures that are not prepared in accordance with U.S. GAAP, including adjusted gross margin, adjusted EBITDA, adjusted net income and adjusted earnings per share, or adjusted EPS. 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 because it eliminates the impact of financing and 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 EBITDA as net income attributable to AVANGRID, adding back net income attributable to noncontrolling interests, income tax expense, depreciation, amortization, impairment and interest expense, net of capitalization, and then subtracting other income and earnings from equity method investments. We define adjusted net income as net income adjusted to reflect the full 12-month period of results for UIL and to exclude restructuring charges, gain on the sale of equity method and other investment, other than temporary impairment, or OTTI, of equity method and other investments, costs related to the merger with UIL, mark-to-market adjustments to reflect the effect of mark-to-market 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, 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. Additionally, we evaluate the nature of our revenues and expenses and adjust to reflect classification by nature for evaluation of our non-GAAP financial measures as opposed to by function. The most directly comparable U.S. GAAP measure to adjusted EBITDA and adjusted net income is net income. We also define adjusted gross margin as adjusted EBITDA adding back operations and maintenance and taxes other than income taxes and then subtracting transmission wheeling. 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.

Reconciliation of the Net Income attributable to AVANGRID to adjusted EBITDA (non-GAAP) and adjusted gross margin (non-GAAP) before reflecting the full 12-month period of results for UIL, excluding restructuring charges, gain on the sale of equity method and other investment, OTTI on equity method and other investments, costs related to the merger with UIL, loss from held for sale measurement, impact of the Tax Act and from mark-to-market activities in Renewables and Gas storage business, and before adjustments to reflect the classification of revenues and expenses by nature for the years ended December 31, 2017, 2016 and 2015, respectively, is as follows:

Years Ended December 31,	2017	2016	2015
(Millions)			
Net Income Attributable to Avangrid, Inc.	**$ 381**	**$ 632**	**$ 273**
Add: Net income attributable to noncontrolling interests	1	—	—
Income tax expense	(259)	377	29
Depreciation and amortization	824	804	695
Impairment	642	—	12
Interest expense, net of capitalization	280	268	267
Less: Other income	58	76	56
Earnings from equity method investments	(40)	7	—
Adjusted EBITDA (2)	**$ 1,851**	**$ 1,998**	**$ 1,220**
Add: Operations and maintenance (1)	2,211	2,206	1,808
Taxes other than income taxes	563	528	367
Less: Transmission wheeling (1)	278	260	149
Adjusted gross margin (2)	**$ 4,347**	**$ 4,472**	**$ 3,246**

(1) Transmission wheeling is a component of operations and maintenance and is considered a component of adjusted gross margin because it is directly associated with the power supply costs included in the cost of sales.

(2) Adjusted EBITDA and adjusted gross margin are non-GAAP financial measures and are presented before reflecting the full 12-month period of results for UIL results, excluding restructuring charges, gain on the sale of equity method and other investments, OTTI impairment on equity method and other investment, costs related to the merger with UIL, loss from held for sale measurement, impact of the Tax Act and from mark-to-market activities in Renewables and Gas storage business, and before adjustments to reflect the classification of revenues and expenses by nature. For additional details of these adjustments and reconciliation of net income to adjusted EBITDA and adjusted gross margin that reflect these adjustments see the tables on pages 71-72 of this Annual Report on Form 10-K.

The following tables set forth our adjusted EBITDA and adjusted gross margin by segment for each of the periods indicated and as a percentage of operating revenues:

Year Ended December 31, 2017

	Total	Networks	Renewables *(in millions)*	Gas	Other(1)
Adjusted gross margin (2)	**$ 4,347**	**$ 3,531**	**$ 821**	**$ 14**	**$ (19)**
Adjusted gross margin %		71%	78%	93%	32%
Adjusted EBITDA (2)	**$ 1,851**	**$ 1,468**	**$ 417**	**$ (34)**	**$ —**
Adjusted EBITDA %		30%	40%	(227)%	—

Year Ended December 31, 2016

	Total	Networks	Renewables *(in millions)*	Gas	Other(1)
Adjusted gross margin (2)	**$ 4,472**	**$ 3,596**	**$ 863**	**$ 33**	**$ (20)**
Adjusted gross margin %		71%	85%	103%	34%
Adjusted EBITDA (2)	**$ 1,998**	**$ 1,551**	**$ 462**	**$ (15)**	**$ —**
Adjusted EBITDA %		31%	46%	(47)%	—

Year Ended December 31, 2015

	Total	Networks	Renewables *(in millions)*	Gas	Other(1)
Adjusted gross margin (2)	**$ 3,246**	**$ 2,417**	**$ 865**	**$ (20)**	**$ (16)**
Adjusted gross margin %		71%	81%	105%	24%
Adjusted EBITDA (2)	**$ 1,220**	**$ 865**	**$ 456**	**$ (62)**	**$ (39)**
Adjusted EBITDA %		26%	43%	326%	59%

(1) Other amounts represent corporate and company eliminations.

(2) Adjusted EBITDA and adjusted gross margin are non-GAAP financial measures and are presented before reflecting the full 12-month period of results for UIL results, excluding restructuring charges, gain on the sale of equity method and other investment, OTTI on equity method and other investments, costs related to the merger with UIL, loss from held for sale measurement, impact of the Tax Act and from mark-to-market activities in Renewables and Gas storage business, and before adjustments to reflect the classification of revenues and expenses by nature. For additional details of these adjustments and reconciliation of net income to adjusted EBITDA and adjusted gross margin that reflect these adjustments see the tables on pages 71-72 of this Annual Report on Form 10-K.

Comparison of Period to Period Results of Operations

Our adjusted gross margin decreased by $125 million, or 3%, from $4,472 million for the year ended December 31, 2016 to $4,347 million for the year ended December 31, 2017.

Our adjusted EBITDA decreased by $147 million, or 7%, from $1,998 million for the year ended December 31, 2016 to $1,851 million for the year ended December 31, 2017.

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

Year Ended December 31, 2017 Compared to the Year Ended December 31, 2016

Networks

Adjusted gross margin for the year ended December 31, 2017 decreased by $65 million or 2%, from $3,596 million for the year ended December 31, 2016, to $3,531 million. The decrease is primarily driven by a decrease in revenue related regulatory activities driven by an adjustment of unfunded future income tax in the year ended December 31, 2017, partially offset by average higher rates from rate case activities in New York and Connecticut.

Adjusted EBITDA for the year ended December 31, 2017 decreased by $83 million or 5% from $1,551 million for the year ended December 31, 2016, to $1,468 million. The decrease was due to the same reasons discussed above for adjusted gross margin.

Renewables

Adjusted gross margin for the year ended December 31, 2017 decreased by $42 million or 5% from $863 million for the year ended December 31, 2016, to $821 million. The decrease was primarily due to unfavorable MtM changes on energy derivatives driven by market price changes in the current period and higher transmission and energy purchases.

Adjusted EBITDA for the year ended December 31, 2017 decreased by $45 million or 10% from $462 million for the year ended December 31, 2016, to $417 million. The decrease was due to the same reasons discussed above for adjusted gross margin.

Gas

Adjusted gross margin for the year ended December 31, 2017 decreased by $19 million, or 55%, from $33 million for the year ended December 31, 2016, to $14 million. The decrease is primarily associated with unfavorable MtM changes in the current period as compared to the same period of 2016 and unfavorable results from the performance of the owned and contracted storage businesses.

Adjusted EBITDA for the year ended December 31, 2017 decreased by $19 million, or 127%, from negative $15 million for the year ended December 31, 2016, to negative $34 million. The decrease was due to the same reasons discussed above for adjusted gross margin.

Year Ended December 31, 2016 Compared to the Year Ended December 31, 2015

Networks

Adjusted gross margin for the year ended December 31, 2016 increased by $1.2 billion from $2.4 billion for the year ended December 31, 2015, to $3.6 billion. The increase is associated primarily with the addition of UIL, which added $1.0 billion of gross margin. Underlying margins increased by $172 million. Although volume of both sales and purchased power were lower due to the mild winter in 2016, purchased power rates decreased comparatively more, due to declines in market prices in 2016, which, combined with increases in regulatory recoveries including the $126 million unfunded future income tax adjustment and impacts of the rate case activities, increased margins in 2016, partly offset by increases in the cost of transmission wheeling year over year.

Adjusted EBITDA for the year ended December 31, 2016 increased by $686 million or 79% from $865 million for the year ended December 31, 2015, to $1.6 billion. UIL added $493 million of adjusted EBITDA in 2016, with underlying business adjusted EBITDA increasing by $193 million for the year ended December 31, 2016, as compared to the same period of 2015. The increase was due to the same reasons discussed above for adjusted gross margin, partly offset by an increase in operations and maintenance expenses for transmission system reliability support.

Renewables

Adjusted gross margin for the year ended December 31, 2016 decreased by $2 million or less than 1% from $865 million for the year ended December 31, 2015, to $863 million. The decrease was primarily due to $5 million in unfavorable MtM changes on derivatives in 2016 compared to 2015 and a $2 million decrease in thermal results on lower merchant prices not offset by lower fuel costs. Underlying gross margin on wind and solar increased by $4 million due to increased production of 642 GWh or 5% with average prices 4% lower due to expiring contracts resulting in more generation being sold merchant.

Adjusted EBITDA for the year ended December 31, 2016 increased by $6 million or 1% from $456 million for the year ended December 31, 2015, to $462 million. The increase was due primarily to lower operations and maintenance expenses, related to reductions in bad debts expense recorded in 2015 not recurring in 2016 and lower asset retirement obligation expenses.

Gas

Adjusted gross margin for the year ended December 31, 2016 increased by $53 million, or 265%, from negative $20 million for the year ended December 31, 2015, to $33 million. The increase is associated with the increase in operating revenues due to favorable movement in spreads in the owned storage and gas transportation areas in 2016 as compared to 2015.

Adjusted EBITDA for the year ended December 31, 2016 increased by $47 million, or 76%, from negative $62 million for the year ended December 31, 2015, to negative $15 million. The increase was due primarily to the same reasons discussed above for adjusted gross margin offset by operations and maintenance expense increases in 2016 resulting from higher credit support costs and external services.

The following table provides a reconciliation between Net Income attributable to AVANGRID and adjusted gross margin (non-GAAP) and adjusted EBITDA (non-GAAP) by segment after the full 12-month period of results for UIL, after excluding restructuring charges, gain on the sale of equity method and other investment, OTTI on equity method and other investments, costs related to the merger with UIL, loss from held for sale measurement, impact of the Tax Act and from mark-to-market activities in Renewables and Gas storage business, and after adjustments to reflect the classification of revenues and expenses by nature for the years ended December 31, 2017, 2016 and 2015, respectively:

	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	**$ 682**	**$ 507**	**$ 120**	**$ 55**	**$ —**
Add: Net income attributable to noncontrolling interests	1	1	—	—	—
Income tax expense (2)	284	312	10	(38)	—
Depreciation and amortization (3)	1,021	594	427	—	—
Interest expense, net of capitalization (4)	120	107	27	(14)	—
Less: Other income and (expense)	1	1	—	—	—
Earnings (losses) from equity method investments	5	15	(10)	—	—
Adjusted EBITDA (6)	**$ 2,102**	**$ 1,505**	**$ 594**	**$ 3**	**$ —**
Add: Operations and maintenance (5)	1,443	1,202	249	(8)	—
Taxes other than income taxes	535	485	45	5	—
Adjusted gross margin (6)	**$ 4,080**	**$ 3,192**	**$ 888**	**$ —**	**$ —**

	Year Ended December 31, 2016				
	Total	Networks	Renewables	Corporate *	Gas Storage
			(in millions)		
Net Income (Loss) Attributable to Avangrid, Inc.	**$ 632**	**$ 480**	**$ 114**	**$ 80**	**$ (42)**
Adjustments:					
Sale of equity method and other investments	(36)	—	(3)	(33)	—
Impairment of investment	3	3	—	—	—
Mark-to-market adjustments - Renewables	(20)	—	(20)	—	—
Income tax impact of adjustments (1)	22	(1)	9	14	—
Gas Storage, net of tax	42	—	—	—	42
Adjusted Net Income	**$ 643**	**$ 482**	**$ 100**	**$ 61**	**$ —**
Add: Income tax expense (2)	285	290	33	(38)	—
Depreciation and amortization (3)	985	566	415	4	—
Interest expense, net of capitalization (4)	131	132	28	(28)	—
Less: Other income and (expense)	(2)	1	(3)	—	—
Earnings (losses) from equity method investments	4	15	(11)	—	—
Adjusted EBITDA (6)	**$ 2,042**	**$ 1,453**	**$ 589**	**$ (1)**	**$ —**
Add: Operations and maintenance (5)	1,319	1,089	234	(5)	—
Taxes other than income taxes	513	463	44	6	—
Adjusted gross margin (6)	**$ 3,873**	**$ 3,006**	**$ 867**	**$ —**	**$ —**

	Year Ended December 31, 2015				
	Total	Networks	Renewables	Corporate *	Gas Storage
			(in millions)		
Net Income (Loss) Attributable to Avangrid, Inc.	**$ 273**	**$ 208**	**$ 139**	**$ (6)**	**$ (69)**
Adjustments:					
Add: Net Income representing the full 12-month period of results for UIL	133	133	—	—	—
Merger costs	122	89	—	34	—
Mark-to-market adjustments - Renewables	(25)	—	(25)	—	—
Income tax impact of adjustments (1)	(45)	(49)	9	(5)	—
Gas Storage, net of tax	69	—	—	—	69
Adjusted Net Income	**$ 527**	**$ 381**	**$ 123**	**$ 23**	**$ —**
Add: Income tax expense (2)	198	241	32	(76)	—
Depreciation and amortization (3)	1,047	586	461	—	—
Impairment	12	—	12	—	—
Interest expense, net of capitalization (4)	190	163	(37)	64	—
Less: Other income and (expense)	2	1	1	—	—
Earnings from equity method investments	15	14	(4)	4	—
Adjusted EBITDA (6)	**$ 1,957**	**$ 1,356**	**$ 594**	**$ 7**	**$ —**
Add: Operations and maintenance (5)	1,339	1,122	229	(12)	—
Taxes other than income taxes	517	471	41	5	—
Adjusted gross margin (6)	**$ 3,813**	**$ 2,949**	**$ 864**	**$ 0**	**$ —**

(1) Income tax impact of adjustments: $(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. Income tax impact of $14 million from sale of equity method investment, $1 million from sale of other investment, $(1) million on impairment of investment and $8 million from MtM adjustment for the year ended December 31, 2016. Income tax impact of $54 million and $9 million relate, respectively, to merger costs and MtM adjustment for the year ended December 31, 2015.

(2) In addition to adjustments to include a full 12-month period of results for UIL, adjustments have been made for production tax credit for the amount of $53 million, $34 million and $33 million for the years ended December 31, 2017, 2016 and 2015, as they have been included in operating revenues in Renewables based on the by nature classification. Additionally, $14 million and $126 million for unfunded future income taxes have been reclassified from revenues based on the by nature classification in Networks for the years ended December 31, 2016 and 2015. After reflecting these by nature classification adjustments the calculated effective income tax rates are impacted for both periods presented under this by nature classification presentation.

(3) In addition to adjustments to include a full 12-month period of results for UIL, adjustments have been made for the inclusion of vehicle depreciation of $18 million, $22 million and $14 million and bad debt provision of $69 million, $50million and $48 million in Networks within depreciation and amortization from operations and maintenance based on the by nature classification for the years ended December 31, 2017,

2016 and 2015, respectively. Additionally, government grants of $5.6 million, $6.6 million and $6.8 million in Networks and investment tax credits amortization of $90 million, $91 million and $103 million in Renewables have been presented within other operating income and not within depreciation and amortization based on the by nature classification for the years ended December 31, 2017, 2016 and 2015, respectively

(4) In addition to adjustments to include a full 12-month period of results for UIL, adjustments have been made for allowance for funds used during construction, debt portion, to reflect these amounts within other income and expenses in Networks for the years ended December 31, 2017, 2016 and 2015, respectively.

(5) In addition to adjustments to include a full 12-month period of results for UIL, adjustments have been made for regulatory amounts to reflect amounts in revenues based on the by nature classification of these items. In addition, the vehicle depreciation and bad debt provision have been reflected within depreciation and amortization in Networks.

(6) Adjusted EBITDA and adjusted gross margin are non-GAAP financial measures and are presented after reflecting the full 12-month period of results for UIL, after excluding restructuring charges, gain on the sale of equity method and other investments, OTTI on equity method and other investment, costs related to the merger with UIL, loss from held for sale measurement, impact of the Tax Act and from mark-to-market activities in Renewables and Gas storage business, and after adjustments to reflect the classification of revenues and expenses by nature explained in notes (1)-(5) above.

* Includes corporate and other non-regulated entities.

The following tables provide a reconciliations between Net Income attributable to AVANGRID and Adjusted Net Income (non-GAAP), and EPS attributable to AVANGRID and adjusted EPS (non-GAAP) after reflecting the full 12- month period of results for UIL, after excluding restructuring charges, gain on the sale of equity method and other investments, OTTI on equity method and other investment, costs related to the merger with UIL, loss from held for sale measurement, impact of the Tax Act and from mark-to-market activities in Renewables and Gas storage business, for the years ended December 31, 2017, 2016 and 2015, respectively:

	Year Ended December 31,		
	2017	**2016**	**2015**
		(in millions)	
Networks	$ 496	$ 480	$ 208
Renewables	333	114	139
Corporate (1)	60	80	(6)
Gas Storage	(508)	(42)	(69)
Net Income	**$ 381**	**$ 632**	**$ 273**
Adjustments:			
Net income representing the full 12-month period of results for UIL	—	—	133
Merger Costs	—	—	122
Sale of equity method and other investments	—	(36)	—
Impairment of equity method and other investment (2)	49	3	—
Restructuring charges (3)	20	—	—
Mark-to-market adjustments - Renewables (4)	15	(20)	(25)
Loss from held for sale measurement (5)	642	—	—
Impact of the Tax Act (6)	(328)	—	—
Income tax impact of adjustments	(162)	22	(45)
Gas Storage , net of tax	64	42	69
Adjusted Net Income (7)	**$ 682**	**$ 643**	**$ 527**

	Year Ended December 31,		
	2017	2016	2015
Networks	1.60	1.55	0.83
Renewables	1.07	0.37	0.55
Corporate (1)	0.19	0.26	(0.03)
Gas Storage	(1.64)	(0.14)	(0.28)
Earnings Per Share	**1.23**	**2.04**	**1.07**
Adjustments:			
Reduction for acquisition of UIL shares	—	—	(0.19)
Net income representing the full 12-month period of results for UIL	—	—	0.43
Merger costs	—	—	0.40
Sale of equity method and other investments	—	(0.12)	—
Impairment of equity method and other investment (2)	0.16	0.01	—
Restructuring charges (3)	0.07	—	—
Mark-to-market adjustments - Renewables (4)	0.05	(0.07)	(0.08)
Loss from held for sale measurement (5)	2.08	—	—
Impact of the Tax Act (6)	(1.06)	—	—
Income tax impact of adjustments	(0.52)	0.07	(0.15)
Gas Storage, net of tax	0.21	0.14	0.22
Adjusted Earnings Per Share (7)	**$ 2.20**	**$ 2.08**	**$ 1.70**

(1) Includes corporate and other non-regulated entities as well as intersegment eliminations.
(2) Includes OTTI on equity method investment recorded in 2017.
(3) 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.
(4) Mark-to-market adjustments relate to 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 and gas.
(5) 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.
(6) 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.
(7) Adjusted net income and adjusted earnings per share are non-GAAP financial measures and are presented after reflecting the full 12-month period of results for UIL, after excluding restructuring charges, gain on the sale of equity method and other investments, OTTI on equity method and other investment, costs related to the merger with UIL, loss from held for sale measurement, impact of the Tax Act and from mark-to-market activities in Renewables and Gas storage business.

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, 2017, we had cash and cash equivalents of $41 million, as compared to $91 million at December 31, 2016. In addition to cash on hand, we and our subsidiaries have access to committed credit facilities totaling $1.5 billion. See discussion of AVANGRID commercial paper program and AVANGRID credit facility 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. The balance in this account at December 31, 2017 was zero. Any deposit amounts would be reflected in our consolidated balance sheet under cash and cash equivalents because our deposited surplus funds under the cash pooling agreement are highly-liquid short-term investments, available for next day withdrawal. 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 $29 million at December 31, 2017.

AVANGRID Commercial Paper Program

On May 13, 2016, AVANGRID established a commercial paper program with a limit of $1 billion that is backstopped by the AVANGRID credit facility (described below). As of December 31, 2017 and March 20, 2018, there was $507 million and $635 million of commercial paper outstanding, respectively.

AVANGRID Credit Facility

On April 5, 2016, AVANGRID and its subsidiaries, NYSEG, RG&E, CMP, UI, CNG, SCG and BGC entered into a revolving credit facility with a syndicate of banks, or the AVANGRID Credit Facility, that provides for maximum borrowings of up to $1.5 billion in the aggregate. At December 31, 2017, NYSEG and UI had borrowed, in total, $250 million under the facility and the facility was backstopping $507 million of outstanding commercial paper. The amounts available under the facility at December 31, 2017 and March 20, 2018, were $743 million and $865 million, respectively.

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 established by the banks. AVANGRID's maximum sublimit is $1 billion, NYSEG, RG&E, CMP and UI have maximum sublimits of $250 million, CNG, and SCG have maximum sublimits of $150 million and BGC has a maximum sublimit of $25 million. Under the AVANGRID credit facility, each of the borrowers will pay an annual facility fee that is dependent on their credit rating. The facility fees will range from 10.0 to 17.5 basis points. The maturity date for the AVANGRID credit facility is April 5, 2021.

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 borrowing. 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 May 24, 2017, RG&E issued $300 million in aggregate principal amount of 3.10% First Mortgage Bonds, or the Bonds, due in 2027. Interest on the Bonds is payable semi-annually in arrears on June 1 and December 1 of each year, beginning December 1, 2017. The Bonds will mature on June 1, 2027. The Bonds are secured equally and ratably with RG&E's other mortgage bonds from time to time outstanding by a valid and direct first mortgage on substantially all of RG&E's property (except accounts receivable and cash), subject to excepted encumbrances, reservations, contracts and certain exceptions. Proceeds of the offering were used to reduce short-term debt, to fund capital expenditures and for general corporate purposes. Net proceeds of the offering after the price discount and issuance-related expenses were $294 million.

On November 21, 2017, Avangrid, Inc. issued $600 million aggregate principal amount of its 3.150% notes due 2024. Interest on the notes is payable semi-annually in arrears on June 1 and December 1 of each year, commencing on June 1, 2018, and on the maturity date for the notes. The notes will mature on December 1, 2024. The notes are our direct unsecured and unsubordinated obligations and rank equally with our other unsecured and unsubordinated indebtedness from time to time outstanding. The notes are structurally subordinated to all existing and future obligations at our subsidiaries. Proceeds of the offering were used to reduce AVANGRID's commercial paper balance 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.

At December 31, 2017, we had $4,266 million of long-term 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. Network's 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, 2017.

At December 31, 2017, we had $54 million of long-term debt (including the current portion thereof) 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 particular wind farm projects. The arrangements allocate tax losses and production tax credits to the tax equity investor in exchange for an initial contribution. The obligations created under the tax equity financing arrangements are recorded as a liability with an aggregate balance of $98 million, of which $38 million is current, at December 31, 2017.

At December 31, 2017, we had $1,059 million of long-term debt (including the current portion thereof) outstanding in the corporate and no long-term debt in the Gas segment. Long-term debt in the corporate consists mainly of $450 million of 4.625% notes due in 2020 originally issued by UIL in 2010 and transferred to Avangrid, Inc. in December 2016 and $600 million of 3.150% notes due 2024 issued in November 2017.

In our credit facilities, long-term borrowing 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, 2017.

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 a revolving credit facility 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:

	2017	2016	2015
		(in millions)	
NYSEG	$ 364	$ 282	$ 259
RG&E	303	268	157
CMP (non-MPRP(1))	252	207	120
CMP (MPRP)	—	—	108
MNG	3	3	3
UI	176	170	187
SCG	53	54	62
CNG	70	73	62
BGC	18	17	16
Total	**$ 1,239**	**$ 1,074**	**$ 974**

(1) MPRP refers to the Maine Power Reliability Program.

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

	2017	2016	2015
		(in millions)	
Wind & solar	$ 902	$ 751	$ 58
Thermal	17	8	11
Corporate(1)	10	7	8
Total capital expenditures	**929**	**766**	**77**

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

Networks increased its capital expenditures during the period from 2015 to 2017 to upgrade and expand electricity and natural gas transmission and distribution infrastructure. In 2017, NYSEG and RG&E increased their capital investments in a number of programs disclosed in Appendix P Schedule I of the Joint Proposal, including the FERC Bright Line project, Auburn transmission project, Columbia County transmission project, Rochester Area Reliability Project, or RARP, and Ginna Retirement Transmission Alternative, or GRTA. In 2017, CMP completed the Lewiston Loop project, which complements the already completed MPRP, a project which enhanced the bulk power transmission grid in Maine. UIL's capital projects remained relatively flat for the same period and the most relevant projects were the ones related to new customers, system and corrective reliability, system resiliency, infrastructure replacement and system operations.

Renewables also made capital investments during this three-year period. 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 gas-fired cogeneration facility, or the Klamath Plant, $11 million on improvements to operating wind assets and $35 million in development costs.

In 2016 there were capital expenditures of $728 million on construction of the Amazon Wind Farm US - East (formerly Desert Wind) and other wind assets, $8 million in capital expenditures on the Klamath gas-fired cogeneration facility, or the Klamath Plant, $10 million on improvements to operating wind assets and $13 million in development costs.

In 2015 there were capital expenditures of $73 million on construction of the Amazon Wind Farm US - East (formerly Desert Wind) and other wind assets, $11 million in capital expenditures on the Klamath Plant, $31 million on improvements to operating wind assets and $9 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 $7.99 billion from 2018 to 2022 to upgrade and expand electricity and natural gas transmission and distribution infrastructure. In the next 12 months, CMP plans to invest $214 million, including the Coopers Mills Sub Station, Spectrum Project, Line Inspection, and Lakes Region Transmission Project. In addition, CMP plans to continue developing its new customer relationship management and billing system and new transmission investments in the Maine Electric Power Corporation, or MEPCO, 388 rebuild. MEPCO plans to invest $51 million in the next 12 months. NYSEG plans to invest $539 million in the next 12 months, including a number of programs disclosed in Appendix P Schedule I of the proposal dated June 15, 2016, the most relevant ones: NYSEG Grid Automation, NYSEG Breaker Program, NYSEG Telcom Project, NYSEG Distribution Line Project, Columbia County Transmission Project, Gas Distribution Mains and Leak Prone Main replacement. RG&E plans to invest $340 million in the next 12 months, including a number of programs disclosed in Appendix P Schedule I of the proposal dated June 15, 2016, the most relevant ones: RARP, Underground Line 23 to 137 Circuit Project, Gas Distribution Mains and Leak Prone Main replacement. UIL plans to invest $333 million in the next 12 months, including a number of programs disclosed in the UI-Distribution PURA Order dated December 14 2016 related to new customers, system and corrective reliability, system resiliency, infrastructure replacement (substations and distribution system), and system operations. The most relevant investment for CNG will be the Rocky Hill LNG.

Through Renewables we plan to invest a total of approximately $4.0 billion from 2018 to 2022 and add 2,200 MWs of generation capacity. 411 MW are approved for construction in 2018 and 2019 and these projects have long-term associated PPA contracts.

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. 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, 2017, 2016 and 2015:

	Year Ended December 31,		
	2017	2016	2015
		(in millions)	
Cash Flows			
Net cash provided by operating activities	$ 1,763	$ 1,561	$ 1,363
Net cash used in investing activities	(2,341)	(1,527)	(1,518)
Net cash provided by (used in) from financing activities	528	(372)	102
Net decrease in cash, cash equivalents and restricted cash	**$ (50)**	**$ (338)**	**$ (53)**

Operating Activities

Our primary sources of operating cash inflows are proceeds from transmission and distribution of electricity and natural gas, sales of wholesale energy and energy related products and services, and natural gas revenues from natural gas storage 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.

In 2017, net cash provided by operating activities was $1.8 billion. During the period, Renewables contributed $734 million of operating cash flow associated with wholesale sales of energy, Networks contributed $970 million of operating cash as the result of regulated transmission and distribution sales of electricity and natural gas, and Gas provided $100 million in cash associated with gains on marketing of wholesale gas and gas storage services. Additionally, $60 million in cash was provided in support of the operating segments and changes in working capital used $100 million in cash. The cash from operating activities in 2017 compared to 2016 increased by $202 million, primarily attributable to increased operating revenues, excluding the impact of a non-cash adjustment of unfunded future income tax discussed above. The net change in operating assets and liabilities in 2017 was primarily attributable to a net increase of $33 million in accounts receivable and payable due to impacts from sales and purchases, cash distributions from equity method investments of $16 million, increase in taxes accrued of $41 million, offset by decrease in inventories of $12 million, net decrease of $55 million in other assets/liabilities and regulatory assets/liabilities of $47 million.

In 2016, net cash provided by operating activities was $1.6 billion. During the period, Renewables contributed $420 million of operating cash flow associated with wholesale sales of energy, Networks contributed $1.0 billion of operating cash as the result of regulated transmission and distribution sales of electricity and natural gas, and Gas used $17 million in cash associated with losses on marketing of wholesale gas and gas storage services. Additionally, $82 million in cash was provided in support of the operating segments and changes in working capital provided $40 million in cash. The cash from operating activities in 2016 compared to 2015 increased by $198 million, primarily attributable to the increased operating revenues. The $338 million net change in operating assets and liabilities in 2016 was primarily attributable to a net increase of $26 million in accounts receivable and payable due to impacts from sales and purchases, cash distributions from equity method investments of $14 million, offset by net decrease of $340 million in in other assets/liabilities, decrease in inventories of $46 million and regulatory assets/liabilities of $81 million.

In 2015, net cash provided by operating activities was approximately $1.4 billion. During the period, Renewables contributed $531 million of operating cash associated with wholesale sales of energy, Networks contributed $867 million of operating cash as the result of regulated transmission and distribution sales of electricity and natural gas, and Gas used cash of $42 million associated with gains on marketing of wholesale gas and gas storage services. We used $5 million in cash associated with operating expenses in support of our segments. In addition, changes in working capital contributed $12 million in cash. The cash from operating activities for the year ended December 31, 2015, compared to the year ended December 31, 2014, increased by $30 million and this is primarily driven by a slight increase in Networks revenues. The $19 million net change in our net operating assets and liabilities during the year ended December 31, 2015, was primarily attributable to a decrease in inventory costs driven by a decrease in inventory levels of $4 million, partially offset by environmental cost deferrals of $32 million.

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 2017, net cash used in investing activities was $2,341 million, which was comprised of $1,305 million associated with capital expenditures at Networks and $1,097 million of capital expenditures at Renewables primarily associated with payments in support of the new capacity construction projects. This was 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 property, plant and equipment.

In 2016, net cash used in investing activities was $1.5 billion, which was comprised of $1.1 billion associated with capital expenditures at Networks and $561 million of capital expenditures at Renewables primarily associated with payments in support of the Amazon Wind Farm US - East (formerly Desert Wind) construction project and safe harbor payments for turbines. This was offset by $69 million of contributions in aid of construction, proceeds of $57 million from the sale of our equity method investment in Iroquois and other investment, $43 million from asset sale to the New York TransCo and $7 million from sale of property.

In 2015, the cash used in investing activities was $1.5 billion, which was comprised of $773 million of capital expenditures at Networks and $304 million of capital expenditures at Renewables primarily associated with payments for construction of the Baffin Bay wind asset. Under a turbine supply agreement, with Siemens-Gamesa, payment for the supplied turbines did not take place until first quarter of 2015. The remaining cash outflow in 2015 is primarily related to cash paid for acquisition of UIL (net of cash acquired) of $547 million.

Financing Activities

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

In 2017, financing activities provided $528 million in cash reflecting primarily an issuance of First Mortgage Bonds 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, capital lease of $33 million and dividends of $535 million.

In 2016, cash used in financing activities was $372 million reflecting primarily an increase in non-current notes payable of $493 million less maturities and redemptions of $355 million, $88 million in payments on the tax equity financing arrangements, repurchase of common stock of $5 million and dividends of $401 million.

In 2015, cash provided by financing activities was $102 million reflecting primarily a net increase in non-current notes payable of $350 million less maturities of $141 million and $102 million in payments on the tax equity financing arrangements.

Contractual Obligations

As of December 31, 2017, our contractual obligations (excluding any tax reserves) were as follows:

	Total	2018	2019	2020	2021	2022	Thereafter
				(in millions)			
Operating leases(1)	$ 931	$ 36	$ 35	$ 36	$ 36	$ 31	$ 757
Projected future pension benefit plan contributions(2)	375	49	78	81	79	88	—
Long-term debt (including current maturities)(3)	5,379	183	357	722	307	369	3,441
Interest payments(4)	2,371	222	205	186	169	141	1,448
Material purchase commitments(5)	3,503	979	563	327	258	195	1,181
Total Contractual Obligations	**$ 12,559**	**$ 1,469**	**$ 1,238**	**$ 1,352**	**$ 849**	**$ 824**	**$ 6,827**

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

(2) 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 2022 are not included as projections beyond 2022 are not available.

(3) Includes sinking fund obligations and obligations under capital leases. See debt payment discussion in "Long-term Capital Resources."

(4) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2017, 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, 2017.

(5) 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, 2017.

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.

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. Our management recorded the net assets of ARHI in these consolidated financial statements at the historical accounting basis of AVANGRID. The historical accounting basis of AVANGRID includes purchase accounting adjustments related to AVANGRID's acquisition of ARHI in 2007. Prior to the 2013 reorganization of AVANGRID, Networks was not considered to be a substantive operating entity as it did not hold any direct operations and had always been a part of AVANGRID. As a result, the net assets of Networks in these consolidated financial statements are recorded at the historical accounting basis of AVANGRID, which do not include purchase accounting adjustments related to Iberdrola, S.A.'s acquisition of AVANGRID in 2008.

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 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 its 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. Delayed recognition of differences between actual results and those assumed allows for a smoother recognition of changes in benefit obligations and plan performance over the working lives of the employees who benefit under the AVANGRID plans. The primary assumptions include the discount rate, the expected return on plan assets, health care cost trend rate, mortality assumptions and demographic assumptions. 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, 2017, 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 which closely match the expected payments to participants.

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.

During 2017, the Society of Actuaries issued updated mortality tables and projection scales. AVANGRID, in conjunction with its actuaries, performed an analysis to determine the appropriateness of adopting these tables and the related mortality projections. As a result, our pension and post-retirement plan liabilities as of December 31, 2017, reflect updated mortality assumptions.

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 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 at least annually 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 goodwill is tested 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 it is determined, 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, a quantitative two step, fair value based test is performed. 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, an impairment loss is recorded 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 our 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 loss is required to be recognized if the carrying amount of the asset exceeds the undiscounted future net cash flows associated with that asset.

We determine the fair value of a long-lived asset (asset group) by applying the approaches prescribed under the fair value measurement accounting framework. Generally, the market approach and income approach are most relevant in the fair value measurement of our long-lived assets; however, due to the lack of available relevant observable market information in many circumstances, we often rely on the income approach. We develop the underlying assumptions consistent with our internal budgets and forecasts for such valuations. 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 discount rate. Management applies considerable judgment in selecting several input assumptions during the development of our internal budgets and cash flow forecasts. Examples of the input assumptions that our budgets and forecasts are sensitive to include macroeconomic factors such as growth rates, industry demand, inflation, power prices and commodity prices. Whenever appropriate, management obtains these input assumptions from observable market data sources and extrapolates the market information if an input assumption is not observable for the entire forecast period. 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 most significant to our budgets and 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 budgets and cash flow forecasts.

A considerable amount of judgment is also applied in the estimation of the discount rate used in the DCF model. To the extent practical, inputs to the discount rate are obtained from market data sources.

Fair value of a long-lived asset (asset group) is sensitive to both input assumptions related to our budgets and cash flow forecasts and the 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.

Capitalization and Recovery of Project Development Costs

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, salaries and wages for persons directly involved in the project, and engineering, permits, licenses, wind measurement and insurance costs are capitalized.

Development projects in construction are reviewed periodically for any indications of impairment. Furthermore, we assess the recoverability of development costs that have been capitalized using several criteria to assess economic recoverability and probability of future economic benefit including energy prices, government regulation, and the internal rate of return to be earned on the project. If based on these factors, we conclude that we will not proceed with the related project, or that the project is no longer viable, the cost of the project is expensed in full.

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.

We use valuation techniques and methodologies that maximize the use of observable inputs and minimize the use of unobservable inputs. Where available, fair value is based on observable market prices or parameters or derived from such prices or parameters. Where observable prices are not available, valuation models are applied to estimate the fair value using the available observable inputs. The valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the price transparency for the instruments or market and the instruments' complexity.

To increase consistency and enhance disclosure of the fair value of financial instruments, the fair value measurement standard includes a fair value hierarchy to prioritize the inputs used to measure fair value into three categories. An asset or liability's level within the fair value hierarchy is based on the lowest level of input significant to the fair value measurement, where Level 1 is the highest and Level 3 is the lowest.

Income Tax

AVANGRID will file a consolidated federal income tax return that includes the taxable income or loss of all its subsidiaries for the 2017 tax period, which is consistent with the 2016 tax period.

For the 2015 tax year, AVANGRID filed a consolidated federal income tax return, which included the UIL taxable income or loss for the period from December 17, 2015 to December 31, 2015. UIL filed a separate consolidated federal income tax return for the period from January 1, 2015 to December 16, 2015.

AVANGRID filed a consolidated federal income tax return that includes the taxable income or loss of all its subsidiaries (excluding UIL), including ARHI, which are 80% or more owned for the 2014 tax period. UIL filed separate consolidated federal income tax returns including the income or loss of its subsidiaries for all tax years including the filed 2014 return.

AVANGRID (excluding ARHI and UIL), and ARHI each filed separate consolidated federal income tax returns that included the taxable income or loss of all their respective subsidiaries, which are 80% or more owned, for all tax periods prior to 2013.

We use the liability method of accounting for income taxes. Deferred tax assets and liabilities reflect the expected future tax consequences based on enacted tax law 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, 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. The investment tax credits are deferred when used and amortized 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. 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 excess of state franchise tax computed as the higher of a tax based on income or a tax based on capital is recorded in “Taxes other than income taxes” and “Taxes accrued” in the accompanying 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)” of the consolidated statements of income.

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

Federal production tax credits applicable to our renewable facilities, that are not part of a tax equity financing arrangement, are shown in the financial statements as a reduction in Income tax expense and as a 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.

On December 22, 2017, the President of the United States signed into law legislation referred to as the “Tax Cuts and Jobs Act”, or the Tax Act. The Tax Act includes significant changes to the Internal Revenue Code of 1986 (as amended, the Code), including amendments which significantly change the taxation of business entities, and includes specific provisions related to regulated public utilities. The most significant change that impacted the Company was the permanent reduction in the corporate federal income tax rate from 35% to 21%, which required us to measure existing net deferred tax liabilities using the lower rate in the period of enactment, resulting in an income tax benefit. The specific provisions in the Tax Act related to regulated public utilities generally allow for the continued deductibility of interest expense, the elimination of full expensing for tax purposes of certain property acquired after September 27, 2017, and continues certain rate normalization requirements for accelerated depreciation benefits.

The staff of the US Securities and Exchange Commission, or the SEC, has recognized the complexity of reflecting the impacts of the Tax Act, and on December 22, 2017, issued guidance in Staff Accounting Bulletin 118, or SAB 118, which clarifies accounting for income taxes under Accounting Standards Codification (ASC), Topic 740, Income Taxes (ASC 740), if information is not yet available or complete and provides for up to a one year period in which to complete the required analyses and accounting, or the measurement period.

The Company has completed or has made a reasonable estimate for the measurement and accounting of certain effects of the Tax Act which have been reflected in the December 31, 2017 financial statements. The Company has reported provisional amounts for the income tax effects related to the remeasurement of our deferred tax assets and liabilities. The ultimate impact may differ (materially) from the provisional amounts, among other things, as a result of additional analysis, changes in interpretations and assumptions, the release of additional guidance by the Internal Revenue Service, Treasury Department, and other standard-setting bodies. There were no specific impacts that could not be reasonably estimated.

Off-Balance Sheet Arrangements

As of December 31, 2017, we had approximately $2.4 billion 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, 2017, neither we nor our subsidiaries have any liabilities recorded for these instruments.

New Accounting Standards

Revenue from contracts with customers - In May 2014 the FASB issued an amendment related to the recognition of revenue from contracts with customers and required disclosures.

Classifying and measuring financial instruments - In January 2016 the FASB issued final guidance on the classification and measurement of financial instruments.

Leases - In February 2016 the FASB issued new guidance that affects all companies and organizations that lease assets, and requires them to record on their balance sheet assets and liabilities for the rights and obligations created by those leases.

Measurement of credit losses on financial instruments - In June 2016 the FASB issued an accounting standards update that requires more timely recording of credit losses on loans and other financial instruments.

Certain classifications in the statement of cash flows - In August 2016 the FASB issued amendments to address existing diversity in practice concerning eight cash flows issues.

Clarifying the definition of a business - In January 2017 the FASB issued amendments to clarify the definition of a business.

Simplifying the test for goodwill impairment – In January 2017 the FASB issued amendments to eliminate Step 2 of the goodwill impairment test.

Clarifying the scope of asset derecognition guidance and accounting for partial sales of nonfinancial assets - In February 2017 the FASB issued amendments concerning asset derecognition and partial sales of nonfinancial assets.

Improving the presentation of net periodic benefit costs - In March 2017 the FASB issued amendments to improve the presentation of net periodic pension cost and net periodic postretirement benefit cost in the financial statements.

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.

Reclassification of certain tax effects from accumulated other comprehensive income - In February 2018 the FASB issued amendments to address a narrow-scope financial reporting issue that arose as a consequence of the Tax Act enacted by the U.S. federal government on December 22, 2017.

For further discussion of new the accounting pronouncements that affect AVANGRID refer to Note 3 of our consolidated financial statements for the three years ended December 31, 2017, which are incorporated herein by reference.

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 and Gas face 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. Contracted natural gas storage exposures are affected by gas price differentials across time. We manage this exposure with fixed price, basis, and index gas derivatives. In addition, contracted transport positions are subject to gas price risk across location (i.e., the price differentials between the receipt and delivery points associated with the leased pipelines). We hedge this exposure with basis swaps. 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 Mark to Market volatility into yearly profit and losses accounts.

Renewables and Gas use 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 and Gas use 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 2017 was $15.0 million compared to a 2016 average of $17.7 million.

As noted above, VaR is a statistical technique and is not intended to be a guarantee of the maximum loss ARHI 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 for the three years ended December 31, 2017, which are incorporated herein by reference.

Interest Rate Risk

Total debt outstanding, including tax equity of $98 million, notes payable to affiliates of $29 million, drawn credit facility of $250 million and commercial paper of $507 million, was $6.3 billion at December 31, 2017, of which $848 million had a floating interest rate; a change of 25 basis points in this interest rate would result in an interest expense fluctuation of approximately $2.1 million annually. The estimated fair value of our long-term debt excluding the debt associated with tax equity at December 31, 2017 was $5.8 billion, in comparison to a book value of $5.4 billion.

There are no interest rate derivative contracts outstanding at December 31, 2017 and 2016.

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 2017, we contributed $32 million to our pension plans. Our contribution to the pension plans in 2018 is expected to be approximately $49 million.

The discount rate used in accounting for pension and other benefit obligations in 2017 ranged from 3.63% to 4.24%. The expected rate of return on plan assets for qualified pension benefits in 2017 ranged from 5.50% to 7.50%. 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 2017 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 asset	50 basis points	(13)	(1)
Decrease in return on plan asset	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 and Gas are also exposed to credit risk through their energy management and gas storage operations. We manage counterparty credit risk for our subsidiaries with energy management and gas storage operations 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. As a consequence of the sale of the Gas trading business, AVANGRID will be exposed to contingent credit risks, due to the temporary use of outgoing guarantees by the buyer during a transition period, until all outgoing guarantees are replaced and obligations released. This risk will be covered by a buyer's parent guarantee and a letter of credit. We expect this amount to be reduced quickly and this risk to be immaterial once the transition period is completed.

Some relevant considerations when assessing the credit risk exposure of the energy management and gas storage 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 and gas storage functions.
- 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 and gas storage operations in ARHI, we do not anticipate a material adverse effect on our financial statements as a result of counterparty nonperformance. As of December 31, 2017, approximately 92% of our energy management and gas storage counterparty credit risk exposure is associated with companies that have investment grade credit ratings.

The following table displays the credit quality of our energy management and gas storage counterparties as of December 31, 2017:

	Credit Exposure Before Cash Collateral	Cash Collateral	Net Credit Exposure
		(in millions)	
A- and Greater	$ 2,263	$ —	$ 2,263
BBB+ and BBB	547	—	547
BBB-	6	—	6
Total Investment Grade(1)	2,816	—	2,816
Non-investment grade(2) (3) (4) (5)	232	11	221
Total	$ 3,048	$ 11	$ 3,037

(1) This category includes counterparties with minimum credit ratings of Baa3 assigned by Moody's and BBB- assigned by Standard & Poor's, if rated by both agencies. The five largest counterparty exposures, combined, for this category represented approximately 35.1% of the total gross credit exposure.

(2) This category includes counterparties with credit ratings that are below investment grade. The five largest counterparty exposures, combined, for this category represented approximately 5.1% of the total gross credit exposure.

(3) This category includes counterparties that have not been rated by Moody's or Standard & Poor's, but are considered investment grade based on our evaluation of the counterparty's creditworthiness. The five largest counterparty exposures, combined, for this category represented approximately 0.8% of the total gross credit exposure.

(4) This category includes counterparties that have not been rated by Moody's or Standard & Poor's, and are considered non-investment grade based on our evaluation of the counterparty's creditworthiness. The five largest counterparty exposures, combined, for this category represented approximately 0.4% of the total gross credit exposure.

(5) This category includes exposure under two separate PPA agreements, the counterparty of which was downgraded to non-investment grade by Moody's and Standard & Poor's following their announcement to complete a strategic review of its competitive operations and alternatives for the certain generation assets. The targeted implementation of changes in connection with such strategic review could result in, among other things, material asset impairments or a potential bankruptcy filing. The current combined estimated exposure under the two PPAs represents approximately 5% of the total gross credit exposure.

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 $1 billion commercial paper program and the $1.5 billion AVANGRID Credit Facility which backstops the commercial paper program. 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 access 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

Prior to becoming a subsidiary of AVANGRID in November 2013, Renewables was principally funded by equity contributions from Iberdrola, S.A. The last such equity contribution of $800 million was made in February 2013. Renewables has also raised a small percentage of its capital through tax equity partnerships, project loans and sale-leaseback arrangements. The balance of the outstanding tax equity financing arrangement at December 31, 2017, was $98 million and the balance of leases was $54 million.

Presently, 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 July 2017, Renewables recorded a net dividend of $418 million to Avangrid, Inc. to zero out account balances that had principally accumulated prior to June 2017. Additionally, Avangrid, Inc. made a net non-cash capital contribution of $921 million in Renewables in 2017, which was used by Renewables to settle outstanding intercompany debt payables of Gas segment accumulated prior to August 2017.

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

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

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheet of Avangrid, Inc. and subsidiaries (the Company) as of December 31, 2017, the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for the year ended December 31, 2017, 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, 2017, and the results of its operations and its cash flows for the year ended December 31, 2017, 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, 2017, 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 26, 2018 expressed an adverse 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 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 the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audit 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 audit 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 audit provides a reasonable basis for our opinion.

/s/ KPMG LLP

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

New York, New York
March 26, 2018

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders
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, 2017, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, because of the effect of the material weakness, described below, on the achievement of the objectives of the control criteria, the Company has not maintained effective internal control over financial reporting as of December 31, 2017, 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 sheet of the Company as of December 31, 2017, the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for the year ended December 31, 2017, and the related notes and financial statement schedule I (collectively, the consolidated financial statements), and our report dated March 26, 2018 expressed an unqualified opinion on those consolidated financial statements.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company's annual or interim financial statements will not be prevented or detected on a timely basis. A material weakness related to the measurement and disclosure of income taxes has been identified and included in management's assessment. The material weakness was considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2017 consolidated financial statements, and this report does not affect our report 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 26, 2018

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Avangrid, Inc.

We have audited the accompanying consolidated balance sheet of Avangrid, Inc. and subsidiaries (the “Company”) as of December 31, 2016, and the related consolidated statements of income, comprehensive income, changes in equity and cash flows for each of the two years in the period ended December 31, 2016. Our audits also included the financial statement schedule listed in the Index at Item 15(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Avangrid, Inc. and subsidiaries at December 31, 2016, and the consolidated results of their operations and their cash flows for each of the two years in the period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ Ernst & Young LLP

New York, New York
March 10, 2017

except for Note 2, as to which the date is
March 26, 2018

Avangrid, Inc. and Subsidiaries
Consolidated Statements of Income

Years Ended December 31,	2017	2016	2015
(Millions, except for number of shares and per share data)			
Operating Revenues	**$ 5,963**	**$ 6,018**	**$ 4,367**
Operating Expenses			
Purchased power, natural gas and fuel used	1,338	1,286	972
Operations and maintenance	2,211	2,206	1,808
Impairment	642	—	12
Depreciation and amortization	824	804	695
Taxes other than income taxes	563	528	367
Total Operating Expenses	**5,578**	**4,824**	**3,854**
Operating Income	**385**	**1,194**	**513**
Other Income and (Expense)			
Other income	58	76	56
Earnings from equity method investments	(40)	7	—
Interest expense, net of capitalization	(280)	(268)	(267)
Income Before Income Tax	**123**	**1,009**	**302**
Income tax (benefit) expense	(259)	377	29
Net Income	**382**	**632**	**273**
Less: Net income attributable to noncontrolling interests	1	—	—
Net Income Attributable to Avangrid, Inc.	**$ 381**	**$ 632**	**$ 273**
Earnings Per Common Share, Basic:	**$ 1.23**	**$ 2.04**	**$ 1.07**
Earnings Per Common Share, Diluted:	**$ 1.23**	**$ 2.04**	**$ 1.07**
Weighted-average Number of Common Shares Outstanding:			
Basic	309,502,861	309,512,553	254,588,212
Diluted	309,661,883	309,817,322	254,605,111
Cash Dividends Declared Per Common Share	**$ 1.728**	**$ 1.728**	**$ —**

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,	2017	2016	2015
(Millions)			
Net Income	**$ 382**	**$ 632**	**$ 273**
Other Comprehensive Income			
Amounts arising during the year:			
Gain on defined benefit plans, net of income taxes of $4.3 and $2.2, respectively	—	7	4
Amortization of pension cost for nonqualified plans, net of income taxes of $0.2, $0.4 and $1.7 respectively	1	1	3
Unrealized gain (loss) during the year on derivatives qualifying as cash flow hedges, net of income taxes of $15.2, $(15.8) and $20.9, respectively	25	(26)	33
Reclassification to net income of losses (gains) on cash flow hedges, net of income taxes of $9.3, $(11.0) and $4.9, respectively	14	(16)	7
Other Comprehensive Income (Loss)	**40**	**(34)**	**47**
Comprehensive Income	**422**	**598**	**320**
Less: Net income attributable to noncontrolling interests	1	—	—
Comprehensive Income Attributable to Avangrid, Inc.	**$ 421**	**$ 598**	**$ 320**

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

Avangrid, Inc. and Subsidiaries
Consolidated Balance Sheets

As of December 31,	2017	2016
(Millions)		
Assets		
Current Assets		
Cash and cash equivalents	$ 41	$ 91
Accounts receivable and unbilled revenues, net	1,040	1,119
Accounts receivable from affiliates	10	25
Derivative assets	18	99
Fuel and gas in storage	99	246
Materials and supplies	115	132
Prepayments and other current assets	273	255
Assets held for sale	357	—
Regulatory assets	307	285
Total Current Assets	**2,260**	**2,252**
Total Property, Plant and Equipment ($1,303 and $1,144 related to VIEs, respectively)	**22,669**	**21,548**
Equity method investments	352	387
Other investments	63	55
Regulatory assets	2,738	3,091
Other Assets		
Goodwill	3,127	3,124
Intangible assets	328	538
Derivative assets	63	73
Other	71	241
Total Other Assets	**3,589**	**3,976**
Total Assets	**$ 31,671**	**$ 31,309**

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

Avangrid, Inc. and Subsidiaries
Consolidated Balance Sheets

As of December 31,	2017	2016
(Millions, except share information)		
Liabilities		
Current Liabilities		
Current portion of debt	$ 183	$ 349
Tax equity financing arrangements - VIEs	38	96
Notes payable	757	151
Notes payable to affiliate	29	10
Interest accrued	57	60
Accounts payable and accrued liabilities	1,071	1,096
Accounts payable to affiliates	89	218
Dividends payable	134	134
Taxes accrued	89	52
Derivative liabilities	22	75
Liabilities held for sale	137	—
Other current liabilities	330	279
Regulatory liabilities	178	192
Total Current Liabilities	**3,114**	**2,712**
Regulatory liabilities	3,239	1,753
Deferred income taxes regulatory	13	565
Other Non-current Liabilities		
Deferred income taxes	1,452	2,890
Deferred income	1,446	1,483
Pension and other postretirement	1,049	1,106
Tax equity financing arrangements - VIEs	60	103
Derivative liabilities	92	78
Asset retirement obligations	196	161
Environmental remediation costs	358	398
Other	360	342
Total Other Non-current Liabilities	**5,013**	**6,561**
Non-current Debt	5,196	4,510
Total Non-current Liabilities	**13,461**	**13,389**
Total Liabilities	**16,575**	**16,101**
Commitments and Contingencies	—	—
Equity		
Stockholders' Equity:		
Common stock, $.01 par value, 500,000,000 shares authorized, 309,670,932 and 309,600,439 shares issued; 309,005,272 and 308,993,149 shares outstanding, respectively	3	3
Additional paid-in capital	13,653	13,653
Treasury Stock	(8)	(5)
Retained earnings	1,475	1,630
Accumulated other comprehensive loss	(46)	(86)
Total Stockholders' Equity	**15,077**	**15,195**
Noncontrolling interests	19	13
Total Equity	**15,096**	**15,208**
Total Liabilities and Equity	**$ 31,671**	**$ 31,309**

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

Avangrid, Inc. and Subsidiaries
Consolidated Statements of Cash Flows

Years Ended December 31,	**2017**	**2016**	**2015**
(Millions)			
Cash Flow from Operating Activities			
Net income	**$ 382**	**$ 632**	**$ 273**
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	824	804	695
Impairment	642	—	12
Accretion expenses	10	10	14
Regulatory assets/liabilities amortization	47	49	101
Regulatory assets/liabilities carrying cost	15	13	41
Pension cost	112	110	115
Stock-based compensation	1	1	6
Earnings from equity method investments	40	(7)	—
Amortization of debt (premium) cost	(5)	(28)	3
Gain on disposal of property and equity method investment	(2)	(33)	—
Unrealized losses (gains) on marked to market derivative contracts	17	(4)	10
Deferred taxes	(251)	375	82
Other non-cash items	(69)	(23)	(5)
Changes in operating assets and liabilities:			
Accounts receivable and unbilled revenues	(48)	(158)	160
Inventories	12	46	4
Other assets	(3)	107	(39)
Cash distribution from equity method investments	16	14	—
Accounts payable and accrued liabilities	81	184	(10)
Other liabilities	(52)	(447)	(194)
Taxes accrued	41	(3)	21
Regulatory assets/liabilities	(47)	(81)	74
Net Cash Provided by Operating Activities	**1,763**	**1,561**	**1,363**
Cash Flow from Investing Activities			
Capital expenditures	(2,416)	(1,707)	(1,082)
Contributions in aid of construction	57	69	38
Government grants	—	—	17
Acquisition of business, net of $48 million cash acquired	—	—	(547)
Proceeds from sale of equity method and other investment	—	57	3
Proceeds from sale of property, plant and equipment	12	50	—
Receipts from (payments to) affiliates	—	6	(6)
Cash distribution from equity method investments	4	6	12
Other investments and equity method investments, net	2	(8)	47
Net Cash Used in Investing Activities	**(2,341)**	**(1,527)**	**(1,518)**
Cash Flow from Financing Activities			
Non-current note issuances	888	493	350
Repayments of non-current debt	(305)	(355)	(141)
Proceeds (repayments) of other short-term debt, net	625	(2)	10
Repayments of capital leases	(33)	(12)	(12)
Payments on tax equity financing arrangements	(113)	(88)	(102)
Dividends to noncontrolling interests	—	—	(3)
Repurchase of common stock	(3)	(5)	—
Issuance of common stock	(1)	(2)	—
Transaction with noncontrolling interest	5	—	—
Dividends paid	(535)	(401)	—
Net Cash Provided by (Used in) Financing Activities	**528**	**(372)**	**102**
Net Decrease in Cash, Cash Equivalents and Restricted Cash	**(50)**	**(338)**	**(53)**
Cash, Cash Equivalents and Restricted Cash, Beginning of Year	**96**	**434**	**487**
Cash, Cash Equivalents and Restricted Cash, End of Year	**$ 46**	**$ 96**	**$ 434**
Supplemental Cash Flow Information			
Cash paid for interest, net of amounts capitalized	$ 202	$ 229	$ 132
Cash paid for income taxes	13	9	7

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, 2014 (as revised)	**252,235,232**	**$ 3**	**11,375**	**$ —**	**1,260**	**(99)**	**$ 12,539**	**$ 16**	**$ 12,555**
Net income	—	—	—	—	273	—	273	—	273
Other comprehensive income, net of tax of $29.7	—	—	—	—	—	47	47	—	47
Comprehensive income									320
Issuance of common stock	57,255,850	—	2,278	—	—	—	2,278	—	2,278
Common stock held in trust	(626,473)	—	—	—	—	—	—	—	0
Dividends to noncontrolling interests	—	—	—	—	—	—	—	(3)	(3)
Balances, December 31, 2015	**308,864,609**	**3**	**13,653**	**—**	**1,533**	**(52)**	**15,137**	**13**	**15,150**
Net income	—	—	—	—	632	—	632	—	632
Other comprehensive income, net of tax of $(22.1)	—	—	—	—	—	(34)	(34)	—	(34)
Comprehensive income									598
Dividends declared	—	—	—	—	(535)		(535)		(535)
Release of common stock held in trust	135,014	—	—	—	—	—	—	—	—
Issuance of common stock	109,357	—	(2)	—	—	—	(2)	—	(2)
Repurchase of common stock	(115,831)	—	—	(5)	—	—	(5)	—	(5)
Stock-based compensation	—	—	2	—	—	—	2	—	2
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 $24.7	—	—	—	—	—	40	40	—	40
Comprehensive income									422
Dividends declared	—	—	—	—	(535)	—	(535)	—	(535)
Release of common stock held in trust	5,649	—	—	—	—	—	—	—	—
Issuance of common stock	70,493	—	(1)	—	—	—	(1)	—	(1)
Repurchase of common stock	(64,019)	—	—	(3)	—	—	(3)	—	(3)
Stock-based compensation	—	—	1	—	—	—	1	—	1
Transaction with noncontrolling interests	—	—	—	—	(1)	—	(1)	5	4
Balances, December 31, 2017	**309,005,272**	**$ 3**	**$ 13,653**	**$ (8)**	**$ 1,475**	**$ (46)**	**$ 15,077**	**$ 19**	**$ 15,096**

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

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

Avangrid, Inc. and Subsidiaries
Notes to 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 distribution business through its principal subsidiary, Avangrid Networks, Inc. (Networks) and in the renewable energy generation and gas storage and trading businesses through its principal subsidiary, Avangrid Renewables Holding, Inc. (ARHI). ARHI in turn holds subsidiaries including Avangrid Renewables, LLC (Renewables) and Enstor Gas, LLC (Gas). 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 represent non-core businesses that are not aligned with our strategic objectives. As a result, 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. The gas trading and storage businesses are being marketed for sale, and it is the Company's intention to complete the sales of these assets and liabilities within twelve months following their initial classification as held for sale. 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 February 16, 2018, the Company entered into a definitive agreement to sell Enstor Gas, LLC, which operates the AVANGRID's gas storage business, to Amphora Gas Storage USA, LLC. The agreement includes, among other things, a transition services agreement which obligates ARHI to provide certain transition services for up to one year after the closing date and includes a guarantee the Company will release certain obligations to Amphora Gas Storage USA, LLC. The transaction, which is subject to the satisfaction of customary closing conditions, is expected to be completed during the second quarter of 2018. Additional details on held for sale classification are provided in Note 25 to our consolidated financial statements.

Acquisition of UIL

On December 16, 2015 (acquisition date), UIL Holdings Corporation, a Connecticut corporation (UIL), became a wholly-owned subsidiary of AVANGRID as a result of the merger of Green Merger Sub, Inc., a Connecticut corporation and a wholly-owned subsidiary of AVANGRID (Merger Sub), with UIL, with Merger Sub surviving as a wholly-owned subsidiary of AVANGRID (the acquisition). The acquisition was effected pursuant to the Agreement and Plan of Merger, dated as of February 25, 2015, by and among AVANGRID, Merger Sub, and UIL. Following the completion of the acquisition, Merger Sub was renamed "UIL Holdings Corporation." In connection with the acquisition, we issued 309,490,839 shares of common stock of AVANGRID, out of which 252,234,989 shares were issued to Iberdrola through a stock dividend, accounted for as a stock split, with no change to par value, at par value of $0.01 per share, and 57,255,850 shares (including those held in trust as treasury stock) were issued to UIL shareowners in addition to payment of $10.50 in cash per each share of the common stock of UIL issued and outstanding at the acquisition date. 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 regulated utility businesses of UIL consist of the electric distribution and transmission operations of UI and the natural gas transportation, distribution and sales operations of The Southern Connecticut Gas Company (SCG), Connecticut Natural Gas Corporation (CNG) and The Berkshire Gas Company (BGC).

UI is also a party to a joint venture with NRG Yield Operating LLC, a subsidiary of NRG Yield, Inc. (NYLD, and collectively with NRG Yield Operating LLC, NRG affiliates), which is an affiliate of NRG Energy, Inc. (NRG), pursuant to which UI holds 50% of the membership interests in GCE Holding LLC, whose wholly owned subsidiary, GenConn Energy LLC (collectively with GCE Holding LLC, GenConn) operates peaking generation plants in Devon, Connecticut (GenConn Devon) and Middletown, Connecticut (GenConn Middletown). In February 2018, NRG announced that it has agreed to sell its ownership stake in NYLD. This sale is expected to close during the second half of 2018 and is not expected to have an impact on GenConn.

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.

Consolidated accounts of UIL have been included in the consolidated financial statements of AVANGRID since December 16, 2015, the date of acquisition of UIL. All intercompany transactions and accounts have been eliminated in all periods presented. All share and per share information included in the consolidated financial statements has been retroactively adjusted to reflect the impact of the stock dividend.

Immaterial Corrections to Prior Periods

During the year ended December 31, 2017, we identified immaterial corrections to prior periods related to our deferred income tax liabilities associated with our tax equity financing arrangements in our Renewables reportable segment. We evaluated the effects of these corrections on our previously-issued consolidated financial statements, individually and in the aggregate, in accordance with the guidance in Accounting Standards Codification (ASC) Topic 250, Accounting Changes and Error Corrections, ASC Topic 250-10-S99-1, Assessing Materiality, and ASC Topic 250-10-S99-2, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements, and concluded that no prior period is materially misstated. Accordingly, we have revised our consolidated financial statements for the prior periods presented herein.

As a result of the correction to our deferred tax liabilities, the revisions resulted in a decrease in income tax expense of $2.4 million and $5.0 million and an increase in other income of $0.2 million and $0.4 million for the years ended December 31, 2016 and 2015, respectively. The cumulative effect of the changes to retained earnings at the beginning of 2015, the earliest date presented in these consolidated financial statements for the year ended December 31, 2017, was an increase of $77.2 million. The revision also resulted in a decrease in deferred taxes of $2.4 million and $5.0 million and a decrease in amortization of debt (premium) cost of $0.2 million and $0.4 million in the consolidated statements of cash flow for the years ended December 31, 2016 and 2015, respectively, with no net impact on our net cash provided by operating activities for the years ended December 31, 2016 and 2015. The information provided in Note 14 - Income Taxes, Note 21 – Other Financial Statement Items and the segment information related to our Renewables reportable segment provided in Note 22 for the years ended December 31, 2016 and 2015 has also been revised to reflect these corrections.

A summary of the effect of the correction on the consolidated balance sheet as of December 31, 2016 is as follows:

As of December 31, 2016 (Millions)	As Reported	Correction	As Revised
Deferred income taxes	$ 2,976	$ (86)	$ 2,890
Total Other Non-current Liabilities	6,647	(86)	6,561
Total Non-current Liabilities	13,475	(86)	13,389
Total Liabilities	16,187	(86)	16,101
Retained earnings	1,544	86	1,630
Total Stockholders' Equity	15,109	86	15,195
Total Equity	15,122	86	15,208
Total Liabilities and Equity	$ 31,309	$ —	$ 31,309

A summary of the effect of the correction on the consolidated statements of income for the years ended December 31, 2016 and 2015 is as follows:

Year Ended December 31, 2016 (Millions, except per share data)	As Reported	Correction	As Revised
Other income	$ 76	$ —	$ 76
Income Before Income Tax	1,009	—	1,009
Income tax expense	379	(2)	377
Net Income	630	2	632
Net Income Per Common Share, Basic and Diluted:	$ 2.04	$ —	$ 2.04

Year Ended December 31, 2015 (Millions, except per share data)	As Reported	Correction	As Revised
Other income	$ 55	$ 1	$ 56
Income Before Income Tax	301	1	302
Income tax expense	34	(5)	29
Net Income	267	6	273
Net Income Per Common Share, Basic and Diluted:	$ 1.05	$ 0.02	$ 1.07

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 critical 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. Investments in common stock where we have the ability to exercise significant influence, but not control, are accounted for using the equity method of accounting.

(b) Revenue recognition

Revenue from the sale of energy by our regulated utilities is recognized in the period during which the sale occurs. The calculation of revenue earned but not yet billed is 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 usually immaterial.

Revenues on sales of wholesale energy and energy related products and natural gas are recognized either when the service is provided or the product is delivered.

We also provide natural gas storage services to customers. The natural gas remains the property of these customers at all times. Customers pay a two part rate that includes (i) a fixed fee reserving the right to store natural gas in our facilities and, (ii) a per unit rate for volumes actually injected into or withdrawn from storage. The fixed fee component of the overall rate is recognized as revenue in the period the service is provided. The per-unit charge is recognized as revenue when the volumes are injected into or withdrawn from our storage facilities.

(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 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) 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).

(f) 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 at least annually or more frequently if events occur or circumstances change that will more likely than not reduce the fair value of the reporting unit to which goodwill is assigned below its carrying amount. A reporting unit is an operating segment or one level below an operating segment and is the level at which goodwill is tested 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 it is determined, 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, a quantitative two step fair value based test is performed. 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, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense.

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 the consolidated statements of income as the expense category that is consistent with the function of the intangible assets.

(g) 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, the estimated cost of removal or reconditioning is recorded 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, salaries and wages for persons directly involved in the project, and engineering, permits, licenses, wind measurement and insurance costs are capitalized. 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)
Plant	Combined cycle plants	35-75
	Hydroelectric power stations	35-90
	Wind power stations	20-40
	Transport facilities	33-70
	Distribution facilities	15-82
Equipment	Conventional meters and measuring devices	15-41
	Computer software	4-10
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 of to accumulated depreciation.

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

Allowance for funds used during construction (AFUDC) is a noncash item which 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.

(h) 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 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.

(i) 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.

(j) Available for sale securities

Securities that do not qualify as either securities held-to-maturity or trading securities, and which have a readily available fair value, are classified as securities available-for-sale and reported at fair value, with unrealized gains and losses excluded from earnings and reported, net of taxes, in other comprehensive income or loss.

(k) Derivatives and hedge accounting

Derivatives are recognized on the 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. Changes in the fair value of a derivative contract are recognized in earnings unless specific hedge accounting criteria are met.

Derivatives that qualify and are designated for hedge accounting are classified as cash flow hedges. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the hedged cash flows of the underlying exposure is deferred in Other Comprehensive Income (OCI) and later reclassified into earnings when the underlying transaction occurs. 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, hedge accounting will be discontinued 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, hedge gains and losses previously recorded in OCI are immediately recognized in earnings.

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. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. Changes in the fair value of electric and natural gas hedge contracts are recorded to derivative assets or liabilities with an offset to regulatory assets or regulatory liabilities for our regulated operations.

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.

(l) Cash and cash equivalents

Cash and cash equivalents comprises 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 those investments are included 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 the consolidated balance sheets. Book overdrafts representing outstanding checks in excess of funds on deposit are classified as “Accounts payable and accrued liabilities” on the consolidated balance sheets. Changes in book overdrafts are reported in the operating activities section of the consolidated statements of cash flows.

(m) 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, which are settled on a net basis. Receivables and payables subject to such agreements are presented in 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 bad debts account is established by using both historical average loss percentages to project future losses, and a specific allowance is established for known credit issues. Amounts are written off when we believe that a receivable will not be recovered.

(n) Variable interest entities

We evaluate whether an entity is a variable interest entity (VIE) whenever reconsideration events as defined by the accounting guidance occur (See Note 18). An entity is considered to be a 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 have undertaken several structured institutional partnership investment transactions that bring in external investors in certain of our wind farms in exchange for cash and notes receivable. Following an analysis of the economic substance of these transactions, we classify the consideration received at the inception of the arrangement as a liability in the consolidated balance sheets. Subsequently, this liability is amortized based on the cash and tax benefits provided to the tax equity investors.

(o) 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 amortized 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 the consolidated balance sheets.

(p) Inventory

Inventory comprises fuel and gas in storage and materials and supplies. Through our gas trading operations, we own natural gas that is stored in both self-owned and third-party owned underground storage facilities. This gas is recorded as inventory. Injections of inventory into storage are priced at the market purchase cost at the time of injection, and withdrawals of working gas from storage are priced at the weighted-average cost in storage. We continuously monitor the weighted-average cost of gas value to ensure it remains at the lower of cost and net realizable value. Inventories to support gas operations are reported on the balance sheet 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 the balance sheets within “Materials and supplies.”

Inventory items are combined for the statement of cash flow presentation purposes.

(q) Government grants

Our unregulated subsidiaries record government grants related to depreciable assets within deferred income and subsequently amortize them to earnings consistent with 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 the consolidated statements of income in the period in which the expenses are incurred.

(r) Deferred income

Apart from government grants, we occasionally receive revenues from transactions in advance of the resulting obligations arising from the transaction. It is our policy to defer such revenues on the consolidated balance sheets and amortize them to earnings consistent with the obligations.

(s) Asset retirement obligations

The fair value of the liability for an ARO and a conditional ARO is recorded 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, the obligation will be either settled at its recorded amount or a gain or a loss will be incurred. 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.

(t) 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 2054.

(u) 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. For NYSEG, RG&E and UIL, we amortize unrecognized actuarial gains and losses over ten years from the time they are incurred as required by the NYPSC, PURA and DPU. For our other companies we 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. 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.

(v) Income tax

AVANGRID will file a consolidated federal income tax return that includes the taxable income or loss of all its subsidiaries for the 2017 tax period, which is consistent with the 2016 tax period.

For the 2015 tax year, AVANGRID filed a consolidated federal income tax return, which included the UIL taxable income or loss for the period from December 17, 2015 to December 31, 2015. UIL filed a separate consolidated federal income tax return for the period from January 1, 2015 to December 16, 2015.

AVANGRID filed a consolidated federal income tax return that includes the taxable income or loss of all its subsidiaries (excluding UIL), including ARHI, which are 80% or more owned for the 2014 tax period. UIL filed separate consolidated federal income tax returns including the income or loss of its subsidiaries for all tax years including the filed 2014 return.

AVANGRID (excluding ARHI and UIL), and ARHI each filed separate consolidated federal income tax returns that included the taxable income or loss of all their respective subsidiaries, which are 80% or more owned, for all tax periods prior to 2013.

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 generally accepted accounting principles 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. The investment tax credits are deferred when used and amortized 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 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. 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. Deferred tax assets and liabilities are classified as non-current in the consolidated balance sheets.

The excess of state franchise tax computed as the higher of a tax based on income or a tax based on capital is recorded in "Taxes other than income taxes" and "Taxes accrued" in the accompanying 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)" of the consolidated statements of income.

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

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

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

On December 22, 2017, the President of the United States signed into law legislation referred to as the "Tax Cuts and Jobs Act" (the Tax Act). The Tax Act includes significant changes to the Internal Revenue Code of 1986 (as amended, the Code), including amendments which significantly change the taxation of business entities, and includes specific provisions related to regulated public utilities. The most significant change that impacted the Company was the permanent reduction in the corporate federal income tax rate from 35% to 21%, which required us to measure existing net deferred tax liabilities using the lower rate in the period of enactment, resulting in an income tax benefit. The specific provisions in the Tax Act related to regulated public utilities generally allow for the continued deductibility of interest expense, the elimination of full expensing for tax purposes of certain property acquired after September 27, 2017, and continues certain rate normalization requirements for accelerated depreciation benefits.

The staff of the US Securities and Exchange Commission (SEC) has recognized the complexity of reflecting the impacts of the Tax Act, and on December 22, 2017, issued guidance in Staff Accounting Bulletin 118 (SAB 118) which clarifies accounting for income taxes under ASC 740 if information is not yet available or complete and provides for up to a one year period in which to complete the required analyses and accounting (the measurement period).

The Company has completed or has made a reasonable estimate for the measurement and accounting of certain effects of the Tax Act which have been reflected in the December 31, 2017 financial statements. The Company has reported provisional amounts for the income tax effects related to the remeasurement of our deferred tax assets and liabilities. The ultimate impact may differ (materially) from the provisional amounts, among other things, as a result of additional analysis, changes in interpretations and assumptions, the release of additional guidance by the Internal Revenue Service, Treasury Department, and other standard-setting bodies. There were no specific impacts that could not be reasonably estimated

(w) 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 begin 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.

(x) Assets held for sale

We record assets held for sale at the lower of the carrying value or fair value less costs to sell. The following criteria are used to determine if an entity or a group of components of an entity is held for sale: (i) management has the authority and commits to a plan to sell the entity; (ii) the entity is available for immediate sale in its present condition; (iii) there is an active program to locate a buyer and the plan to sell the entity has been initiated; (iv) the sale of the entity is probable within one year; (v) the entity is being actively marketed at a reasonable price relative to its current fair value; and (vi) it is unlikely that the plan to sell will be withdrawn or that significant changes to the plan will be made.

In determining the fair value of the assets less costs to sell, we consider factors including recent market analysis studies, recent offers, and fair value models. If the estimated fair value less costs to sell of an entity is less than its current carrying value, the entity is written down to its estimated fair value less costs to sell. Due to uncertainties in the estimation process, actual results could differ from the estimates used in our historical analysis. We estimate the fair values of assets held for sale based on current market and industry conditions, which include assumptions made by management, which may differ from actual results and may result in additional impairments if market conditions deteriorate.

Once assets are classified as held for sale, we do not record depreciation or amortization for our property, plant, and equipment and intangible assets.

New Accounting Standards and Interpretations

(a) Revenue from contracts with customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Codification (ASC), Topic 606, Revenue from Contracts with Customers (ASC 606) replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. ASC 606 was further amended through various updates the FASB issued thereafter. The core principle is for an entity to recognize revenue to represent the transfer of goods or services to customers in amounts that reflect the consideration to which the entity expects to be entitled in exchange for those goods or services. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers. The amended effective date for public entities is for annual reporting periods beginning after December 15, 2017, and interim periods therein, with early adoption permitted as of the original effective date of annual reporting periods beginning after December 15, 2016. Entities may apply the standard retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). Effective January 1, 2018, we have adopted ASC 606 and applied the modified retrospective method. Revenues from our Networks segment are derived primarily from tariff-based sales of electric and natural gas service to customers in New York, Connecticut, Maine, and Massachusetts with no defined contractual term. For such revenues, we will recognize revenues in an amount derived from the commodities delivered to customers. Revenues from our Renewables segment are derived primarily from the sale of energy, transmission, capacity and other related charges from renewable energy sources. For such revenues, we will recognize revenues in an amount derived from the commodities delivered and from services as they are made available. Based on our assessment of existing contracts and revenue streams, we do not expect ASC 606 to have a material impact on the amount and timing of our revenue recognition from the superseded revenue standard and therefore, we did not record a material cumulative adjustment to retained earnings. We have identified other changes primarily related to the presentation and disclosure of revenues. We will classify production tax credits as income tax expense (benefit) rather than as operating revenues. We plan to disaggregate revenues from contracts with customers in our note disclosure by segment and by the source of the commodity sold. We will also disaggregate revenues not accounted for in scope of the new standard, as required, including alternative revenue programs.

(b) Classifying and measuring financial instruments

In January 2016 the FASB issued final guidance on the classification and measurement of financial instruments. The new guidance requires that all equity investments in unconsolidated entities (other than those accounted for using the equity method of accounting) to be measured at fair value through earnings. There will no longer be an available-for-sale classification (changes in fair value reported in other comprehensive income) for equity securities with readily determinable fair values. For equity investments without readily determinable fair values, the cost method is also eliminated. However, entities (other than those following “specialized” accounting models, such as investment companies and broker-dealers) are able to elect to record equity investments without readily determinable fair values at cost, less impairment, and plus or minus subsequent adjustments for observable price changes. Changes in the basis of these equity investments will be reported in current earnings. That election only applies to equity investments that do not qualify for the NAV practical expedient. When the fair value option has been elected for financial liabilities, changes in fair value due to instrument-specific credit risk will be recognized separately in other comprehensive income. The accumulated gains and losses due to those changes will be reclassified from accumulated other comprehensive income to earnings if the financial liability is settled before maturity. Public entities are required to use the exit price notion when measuring the fair value of financial instruments measured at amortized cost for disclosure purposes. In addition, the new guidance requires financial assets and financial liabilities to be presented separately in the notes to the financial statements, grouped by measurement category (e.g., fair value, amortized cost, lower of cost or market) and form of financial asset (e.g., loans, securities).

The classification and measurement guidance is effective for public entities in fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. An entity will record a cumulative-effect adjustment to beginning retained earnings as of the beginning of the first reporting period in which the guidance is adopted, with two exceptions. The amendments related to equity investments without readily determinable fair values (including disclosure requirements) will be effective prospectively. The requirement to use the exit price notion to measure the fair value of financial instruments for disclosure purposes will also be applied prospectively. We expect our adoption of the guidance will not materially affect our consolidated results of operations, financial position, or cash flows.

(c) Leases

In February 2016 the FASB issued new guidance that affects all companies and organizations that lease assets, and requires them to record on their balance sheet assets and liabilities for the rights and obligations created by those leases. 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. Concerning lease expense recognition, after extensive consultation, the FASB has ultimately concluded that the economics of leases can vary for a lessee, and those economics should be reflected in the financial statements. As a result, the amendments retain a distinction between finance leases and operating leases, while requiring both types of leases to be recognized on the 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 current GAAP. By retaining a distinction between finance leases and operating leases, the effect of leases on the statement of comprehensive income and the statement of cash flows is largely unchanged from previous GAAP. Lessor accounting will remain substantially the same as current GAAP, but with some targeted improvements to align lessor accounting with the lessee accounting model and with the revised revenue recognition guidance issued in 2014. The FASB issued an update in January 2018 to clarify the application of the new leases guidance to land easements and provide relief concerning adoption efforts for existing land easements that are not accounted for as leases under current GAAP. The updated guidance is effective for public entities for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, and early application is permitted. We are currently reviewing our contracts and are in the process of determining the proper application of the standard to these contracts in order to determine the impact that the adoption will have on our consolidated financial statements. We expect our adoption of the new guidance will materially affect our financial position through the recording of operating leases on the balance sheet as right-of-use assets, along with the corresponding liabilities.

(d) Measurement of credit losses on financial instruments

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 amendments are effective for public entities that are SEC filers for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, with early adoption permitted. Entities are to apply the amendments on a modified retrospective basis for most instruments. We expect our adoption will not materially affect our consolidated results of operations, financial position, and cash flows.

(e) Certain classifications in the statement of cash flows

The FASB issued amendments in August 2016 to address existing diversity in practice concerning eight cash flows issues. The guidance addresses classification as operating, investing or financing activities in the statement of cash flows for these issues: 1) Debt prepayment or debt extinguishment costs (financing), 2) Settlement of zero-coupon bonds (interest is operating, principal is financing), 3) Contingent consideration payments made after a business combination (investing or financing based on timing, or operating, as specified), 4) Proceeds from the settlement of insurance claims (based on the nature of the loss), 5) Proceeds from the settlement of corporate-owned life insurance policies (COLI) (investing; with cash payments for COLI premiums as investing, operating or a combination of investing/operating), 6) Distributions received from equity method investees (based on an entity's accounting policy election: either cumulative earnings or nature of distribution), 7) Beneficial interests in securitization transactions (noncash or investing as specified), 8) Separately identifiable cash flows and application of the predominance principle (cash receipts/payments with aspects of more than one classification by applying specific GAAP guidance; or if there is no guidance, based on the nature of the related activity or the activity that is the predominant source or use of the cash flows). The amendments are effective for public entities for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years, with early adoption permitted. The amendments are to be applied retrospectively to each prior period presented, unless impracticable for some issues and then the application would be prospective for those affected issues. We expect our adoption will not materially affect cash flows and disclosures.

(f) Clarifying the definition of a business

The FASB issued amendments in January 2017 to clarify the definition of a business. The revised definition of a business sets out a new framework for a company to apply in classifying transactions as acquisitions (or disposals) of assets versus businesses. According to the revised definition, an integrated set of activities and assets is a business if it has, at a minimum, an input and a substantive process that together significantly contribute to the ability to create outputs. The definition of outputs is narrowed and aligned with how outputs are described in ASC 606. The amendments create a two-step method for assessing whether a transaction is an acquisition (disposal) of assets or a business. A set of activities would not be a business when substantially all of the fair value of the gross assets acquired (disposed) is concentrated in a single identifiable asset or group of similar identifiable assets. Fewer transactions are expected to involve acquiring or selling a business as a result of the amendments.

The amendments are effective for public entities for annual and interim periods in fiscal years beginning after December 15, 2017, with early adoption permitted. We early adopted the amendments in the third quarter of 2017 and, as required, are applying the amendments prospectively as of the beginning of the period of adoption. Other than with respect to the transaction described in Note 7 of these consolidated financial statements, our adoption of the amendments did not affect our consolidated results of operations, financial position, cash flows, and disclosures.

(g) 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. In computing the implied fair value of goodwill under Step 2, an entity had to perform procedures to determine the fair value at the impairment testing date of its assets and liabilities (including unrecognized assets and liabilities) following the procedure that would be required in determining the fair value of assets acquired and liabilities assumed in a business combination. 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 is required to disclose the amount of goodwill allocated to each reporting unit with a zero or negative carrying amount of net assets. 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 modify the concept of impairment from the condition that exists when the carrying amount of goodwill exceeds its implied fair value to the condition that exists when the carrying amount of a reporting unit exceeds its fair value. 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. We expect our adoption of the amendments will not materially affect our results of operations, financial position, cash flows, and disclosures.

(h) Clarifying the scope of asset derecognition guidance and accounting for partial sales of nonfinancial assets

The FASB issued amendments in February 2017 concerning asset derecognition and partial sales of nonfinancial assets. The amendments clarify the scope of asset derecognition guidance and accounting for partial sales of nonfinancial assets, and also define in-substance nonfinancial assets. Those amendments apply to a company that: sells nonfinancial assets (land, buildings, materials and supplies, intangible assets) to noncustomers; sells nonfinancial assets and financial assets (cash, receivables) when the value is concentrated in the nonfinancial assets; or sells partial ownership interests in nonfinancial assets. The amendments do not apply to sales to customers or to sales of businesses. The new guidance in ASC 610-20 on accounting for derecognition of a nonfinancial asset and an in-substance nonfinancial asset applies only when the asset (or asset group) does not meet the definition of a business and is not a not-for-profit activity.

The amendments are effective for public entities for annual and interim periods in fiscal years beginning after December 15, 2017, with early adoption permitted. An entity must apply the amendments at the same time that it applies the new ASC 606 revenue recognition standard and may elect to apply the amendments retrospectively following either a full retrospective approach or a modified retrospective approach, but does not have to apply the same transition method as for ASC 606. Effective January 1, 2018, we have adopted ASC 610-20 and applied the modified retrospective method, which affected the accounting for our tax equity investments. Based on our assessment, we have recorded a cumulative adjustment that decreased retained earnings and additional paid in capital by an amount less than $100 million rather than retrospectively adjusting prior periods. The cumulative adjustment relates to the requirement that we reclassify our tax equity investments to noncontrolling interests. As a result, our tax equity investments will be recorded based on the Hypothetical Liquidation at Book Value (HLBV) model and changes in the HLBV at each reporting period will be recorded within net income attributable to noncontrolling interests, which will not result in a material difference to net income attributable to the Company for our current tax equity investments.

(i) Improving the presentation of net periodic benefit costs

In March 2017, the FASB issued amendments to improve the presentation of net periodic pension cost and net periodic postretirement benefit cost in the financial statements. The amendments require an entity to present service cost separately from the other components of net benefit cost, and to report the service cost component in the income statement line item(s) where it reports the corresponding compensation cost. An entity is to present all other components of net benefit cost outside of operating cost. The amendments also allow only the service cost component to be eligible for capitalization when applicable (for example, as a cost of a self-constructed asset). The amendments are effective for public entities for annual and interim periods in fiscal years beginning after December 15, 2017, with early adoption permitted. We do not plan to early adopt. An entity is required to apply the amendments retrospectively for the presentation of the service cost component and the other components of net periodic pension cost and net periodic postretirement benefit cost in the income statement and prospectively, on and after the effective date, for the capitalization of the service cost component of net periodic pension cost and net periodic postretirement benefit in assets. A practical expedient allows an entity to retrospectively apply the amendments on adoption to net benefit costs for comparative periods by using the amounts disclosed in the notes to financial statements for pension and postretirement benefit plans for those periods. We expect our adoption of the amendments will not materially affect our consolidated results of operations, financial position, cash flows, and disclosures.

(j) 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. Changes to the hedge accounting guidance to address those concerns will: 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 are effective for public entities for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted in any interim period after issuance of the amendments. We do not expect to early adopt. For cash flow and net investment hedges existing at the date of adoption, a company must apply a cumulative-effect adjustment related to the separate measurement of ineffectiveness to accumulated other comprehensive income (AOCI) with a corresponding adjustment to the opening balance of retained earnings as of the beginning of the fiscal year of adoption. The amended presentation and disclosure guidance is required only prospectively. An entity may make certain elections upon adoption to allow for existing hedging relationships to transition to newly allowable alternatives. We expect our adoption of the guidance will not materially affect our consolidated results of operations, financial position, or cash flows, but we expect the amendments will ease the administrative burden of hedge documentation requirements and assessing hedge effectiveness.

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

In February 2018, the FASB issued amendments to address a narrow-scope financial reporting issue that arose as a consequence of the Tax Cuts and Jobs Act of 2017 (the Tax Act) enacted on December 22, 2017, by the U.S. federal government. Under current guidance, the adjustment of deferred taxes for the effect of a change in tax laws or rates is required to be included in income from continuing operations, thus the associated tax effects of items within AOCI (referred to as stranded tax effects) do not reflect the appropriate tax rate. The amendments allow a reclassification from AOCI to retained earnings for stranded tax effects resulting from the Tax Act. As a result, the amendments eliminate the stranded tax effects resulting from the Tax Act and will improve the usefulness of information reported to financial statement users. 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. The amendments are effective for all entities for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted including, for public entities, adoption in any interim period for which financial statements have not been issued. An entity has the option to apply the amendments either in the period of adoption or retrospectively to each period (or periods) in which it recognizes the effect of the change in the U.S. federal corporate income tax rate in the Tax Act. An entity is required to disclose its accounting policy election, including its policy for reclassifying material stranded tax effects in AOCI to earnings (specific identification or portfolio method). We have not early adopted the amendments as of December 31, 2017. We expect our adoption of the amendments will not materially affect our consolidated results of operations, financial position, cash flows, and disclosures.

Use of Estimates and Assumptions

The preparation of our consolidated financial statements in conformity with U.S. GAAP requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the reporting periods. Significant estimates and assumptions are used for, but not limited to: (1) allowance for 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; and (12) AROs. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our 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 48% of the employees covered by a collective bargaining agreement. Agreements which will expire within the coming year apply to approximately 8% of our employees.

Note 4. Industry Regulation

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

The Maine distribution rate stipulation, the Federal Energy Regulatory Commission (FERC) Transmission Return on Equity (ROE) case, the New York and Connecticut rate plans, Reforming Energy Vision (REV), the New York Transmission Company (New York TransCo) filings, the Storm proceedings in NY and ME 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 regulated activities in the U.S. are approved by the regulatory commissions of the different states and are based on the cost of providing service. The revenues of each regulated utility are set to be sufficient to cover all its operating costs, including energy costs, finance costs, and the costs of equity, the last of which reflect our capital ratio and a reasonable ROE.

Energy costs that are set on 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 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 the four Networks' New York and Maine supply 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, and automatic adjustments for exceptional costs incurred and efficiency incentives. The distribution rates and allowed ROEs for Networks' regulated utilities in Connecticut and Massachusetts are subject to regulation by the Connecticut Public Utilities Regulatory Authority (PURA) and the Massachusetts Department of Public Utilities (DPU), respectively.

CMP Distribution Rate Stipulation and New Renewable Source Generation

On May 1, 2013, CMP submitted its required distribution rate request with the Maine Public Utilities Commission (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 protects CMP from variations in sales due to energy efficiency and weather. 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 $3.0 million annually.

CMP has made a separate regulatory filing for a new customer billing system replacement. In accordance with the stipulation agreement, a new billing system is 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 has 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 earning sharing requirements.

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 MW Rollins wind farm in Penobscot County, Maine. CMP's purchase obligations under the Rollins contract are approximately $7 million per year. In accordance with subsequent MPUC orders, CMP periodically auctions the purchased Rollins energy 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.

NYSEG and RG&E Rate Plans

On September 16, 2010, the New York Public Service Commission (NYPSC) approved a new rate plan for electric and natural gas service provided by NYSEG and RG&E effective from August 26, 2010 through December 31, 2013. The rate plans contain continuation provisions beyond 2013 if NYSEG and RG&E do not request new rates to go into effect and the current base rates will stay in place. The rates stayed effective until May 1, 2016, at which time a newly approved rate plan became effective.

The 2010 revenue requirements were based on a 10% allowed ROE applied to an equity ratio of 48%. If annual earnings exceed the allowed return, a tiered Earnings Sharing Mechanism (ESM) will capture a portion of the excess for the ratepayers' benefit. The ESM is subject to specified downward adjustments if NYSEG and RG&E fail to meet certain reliability and customer service measures. Key components of the rate plan include electric reliability performance mechanisms, natural gas safety performance measures, customer service quality metrics and targets, and electric distribution vegetation management programs that establish threshold performance targets. There will be downward revenue adjustments if NYSEG and RG&E fail to meet the targets.

The 2010 rate plans established revenue decoupling mechanism (RDM), intended to remove company disincentives to promote increased energy efficiency. Under RDM, electric revenues are based on revenue per customer class rather than billed revenue, while natural gas revenues are based on revenue per customer. Any shortfalls or excesses between billed revenues and allowed revenues will be accrued for future recovery or refund.

In August 2010, NYSEG began amortizing $15.2 million per year of its $303.9 million theoretical excess depreciation reserve. On September 1, 2012, RG&E began amortizing $5.3 million per year of its $105 million theoretical excess depreciation reserve. Both amortization amounts reflect a twenty year amortization period. Theoretical excess depreciation is the difference between actual accumulated depreciation taken to date and a theoretical reserve. The actual accumulated depreciation is the result of depreciation rates allowed in prior rate orders based on estimates of useful lives and net salvage values as determined in those cases. The theoretical reserve is the amount that would have accumulated if the depreciation rates in the new rate plan had been in place for the entire useful lives of the affected assets. Differences between the actual reserve and the theoretical reserve are normal aspects of utility ratemaking. The usual treatment is to flow any excess or deficiency back as an adjustment to depreciation expense over the remaining life of the property. However, in accordance with the new rate plan, NYSEG and RG&E moderate electric rates by recording the theoretical reserve amortization as a debit to accumulated depreciation and a credit to other revenues, and normalize a portion of the amortization from a tax perspective.

On May 20, 2015, NYSEG and RG&E filed electric and gas rate cases with the NYPSC. The companies requested rate increases for NYSEG electric, NYSEG gas and RG&E gas. RG&E electric proposed a rate decrease.

On February 19, 2016, NYSEG, RG&E and other signatory parties filed a Joint Proposal with the NYPSC for a three-year rate plan for electric and gas service at NYSEG and RG&E commencing May 1, 2016. The Joint Proposal, which was approved by the NYPSC on June 15, 2016, 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 increase in the Joint Proposal can be summarized as follows:

Utility	May 1, 2016 Rate Increase (Millions)	May 1, 2016 Delivery Rate Increase %	May 1, 2017 Rate Increase (Millions)	May 1, 2017 Delivery Rate Increase %	May 1, 2018 Rate Increase (Millions)	May 1, 2018 Delivery Rate Increase %
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 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 main, 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 will serve as a test-bed for implementation and deployment of Reforming the Energy Vision (REV) initiatives. The ESC Project will be supported by NYSEG's planned Distribution Automation upgrades and Advanced Metering Infrastructure (AMI) implementation for customers on circuits in the Ithaca region. The companies will also pursue Non-Wires Alternative projects as described in the proposal. Other REV-related incremental costs and fees will be included in the Rate Adjustment Mechanism (RAM) to the extent cost recovery is not provided for elsewhere. Under the proposal, each company will implement the RAM, which will be applicable to all customers, to return or collect RAM Eligible Deferrals and Costs, including: (1) property taxes; (2) Major Storm deferral balances; (3) gas leak prone pipe replacement; (4) REV costs and fees which are not covered by other recovery mechanisms; and (5) NYSEG Electric Pole Attachment revenues.

The Joint Proposal provides for partial or full reconciliation of certain expenses including, but not limited to: pensions, 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.

UI, CNG, SCG and BGC Rate Plans

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 Service Charge, or GSC, charge on their bills.

UI has wholesale power supply agreements in place for its entire standard service load for the first half of 2018, 70% of its standard service load for the second half of 2018 and 20% of its standard service load for the first half of 2019. Supplier of last resort service is procured on a quarterly basis, 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 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.

The allowed ROEs established by PURA for CNG and SCG for 2017, were 9.18% and 9.36%, respectively. SCG and CNG each have purchased gas adjustment clauses that enable them to pass their reasonably incurred cost of gas purchases through to customers. These clauses allow utilities to recover costs associated with changes in the market price of purchased natural gas, substantially eliminating exposure to natural gas price risk.

On January 22, 2014, PURA approved new base delivery rates for CNG, with an effective date of January 10, 2014, which, among other things, approved an allowed ROE of 9.18%, a decoupling mechanism, and two separate ratemaking mechanisms that reconcile actual revenue requirements related to CNG's cast iron and bare steel replacement program and system expansion. Additionally, the final decision requires the establishment of an ESM by which CNG and customers share on a 50/50 basis all earnings above the allowed ROE in a calendar year. In accordance with the approval by PURA of the acquisition, SCG and CNG agreed not to initiate a rate case for new rates effective before at least January 1, 2018.

On June 30, 2017, SCG filed an application with PURA for new tariffs to become effective January 1, 2018. SCG requested a three-year rate plan for calendar years 2018, 2019 and 2020 and a proposed ROE of 9.95%. SCG also requested to implement a RDM and Distribution Integrity Management Program (DIMP) mechanism similar to the mechanisms authorized for CNG. On October 16, 2017, SCG, Prosecutorial Staff from PURA, and the Connecticut Office of Consumer Counsel (OCC) filed an amended settlement agreement with PURA for approval, which included, among other items, the implementation of an RDM, ESM and the DIMP as proposed by SCG, the amortization of certain regulatory liabilities (most notably accumulated hardship deferral balances and certain accumulated deferred income taxes) and tariff increases based on an ROE of 9.25% and approximately 52% equity level. The parties also agreed on 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. PURA approved the amended rate case settlement agreement on December 13, 2017, and new tariffs became effective on January 1, 2018.

BGC's rates are established by the DPU. BGC's 10-year rate plan, which was approved by the DPU and included an approved ROE of 10.5%, expired on January 31, 2012. BGC continues to charge the rates that were in effect at the end of the rate plan. In accordance with the approval by the DPU of the acquisition, BGC agreed not to initiate a rate case for new rates effective before at least June 1, 2018.

Transmission - FERC ROE Proceeding

See Note 12, Commitments and Contingent Liabilities, for a further discussion.

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

On December 28, 2015, the FERC issued an order instituting section 206 proceedings and establishing hearing and settlement judge procedures. Pursuant to section 206 of the FPA, the FERC instituted proceedings because it found that ISO-NE Transmission, Markets, and Services Tariff is unjust, unreasonable, and unduly discriminatory or preferential. The FERC stated that ISO-NE's Tariff lacks adequate transparency and challenge procedures with regard to the formula rates for ISO-NE Participating Transmission Owners, including UI, Maine Electric Power Corporation (MEPCO) and CMP. The FERC also found that the current Regional Network Service, or RNS and Local Network Service, or LNS, formula rates appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful as the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates. A settlement judge has been appointed and a settlement conference has convened. We are unable to predict the outcome of this proceeding at this time.

REV

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

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 distributed energy resources to promote load management and greater system efficiency, including peak load reductions. NYSEG and RG&E are participating in the initiative with other New York utilities and are providing their unique perspective. 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. The companies filed the DSIP, which also included information regarding the potential deployment of Automated Metering Infrastructure (AMI) across its entire service territory. The companies, in December 2016, filed a petition to the NYPSC requesting approval for cost recovery associated with the full deployment of AMI, and a collaborative associated with this petition began in in the first quarter of 2017, was suspended in the second quarter of 2017 and resumed in the first quarter of 2018.

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 Renewable Energy Credits 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 which 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 is on going.

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.

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

On March 11, 2017, the New York State Department of Public Service (the Department) commenced an investigation of NYSEG's and RG&E's preparation for and response to the March 2017 windstorm, which affected more than 219,000 customers. The Department investigation included a comprehensive review of NYSEG's and RG&E's preparation for and response to the windstorm, including all aspects of the companies' filed and approved emergency plan. The Department held public hearings on April 12 and 13, 2017.

On November 16, 2017, the NYPSC announced that the Department Staff had completed their investigation into the March 2017 Windstorm and the NYPSC issued an Order Instituting Proceeding and to Show Cause. The Staff's investigation found that RG&E and NYSEG violated certain parts of their emergency response plans, which makes them subject to possible financial penalties. NYSEG and RG&E responded to the order in a timely manner and have entered into settlement discussions with the Department Staff. The unprecedented weather that resulted in the March 2017 windstorm posed great challenges to the NYSEG's and RG&E's communities, employees, contractors, assisting utilities, and municipal partners who all worked tirelessly to safely restore power to all customers. NYSEG's and RG&E's priorities during any storm are the restoration of service to their respective customers and the safety of their communities, customers, employees and contractors. We cannot predict the outcome of this regulatory action.

MPUC Investigation into the Response by Public Utilities to the October 2017 Storm

On December 19, 2017, the Commission issued a Notice of Investigation regarding utility response to the October 2017 Storm. The wind storm of October 2017 was unprecedented in the number of customers impacted and the magnitude of the damage across the entire Central Maine Power service territory. During the event, thousands of trees were broken or uprooted and many caused damage to the electrical delivery system. The vast majority of tree related damage was from trees that were located outside of the maintenance clearance zone. Damage occurred on nearly every CMP distribution circuit, resulting in more than 1,400 broken poles. CMP currently estimates that the total incremental costs are approximately $70.2 million, of which approximately $32.4 million are capital costs associated with the replacement of damaged infrastructure, including poles, cross arms, transformers and related equipment. Additionally, approximately $744,000 of the incremental amount is operations and maintenance expense for repairs to CMP transmission facilities. Accordingly, the net incremental operations and maintenance expense for restoration of the distribution system are approximately $37 million. With regard to the recovery of incremental storm restoration costs in CMP distribution rates, CMP expects that recovery will be addressed in the Company's 2018 Annual Compliance Filing proceeding pursuant to the applicable provisions of the stipulation approved by the Commission in Docket No. 2013-00168.

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 contains significant changes to the federal tax structure, including among other things, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017. The NYPSC, MPUC, PURA and DPU have instituted separate proceedings in New York, Maine, Connecticut and Massachusetts to review and address the implications associated with the Tax Act on the utilities providing service in those states. We expect the regulators in each jurisdiction, including the FERC, to issue requirements in 2018 regarding how all tax benefits associated with the Tax Act will be returned to customers.

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 New York Independent System Operator (NYISO) produced a Reliability Study, confirming that the Ginna Facility needs to remain in operation to avoid bulk transmission and non-bulk local distribution system reliability violations in 2015 and 2018. In July, 2014, GNPP filed a petition requesting that the NYPSC initiate a proceeding to examine a proposal for the continued operation of the Ginna Facility.

In November 2014, the NYPSC ruled that GNPP had demonstrated that the Ginna Facility is required to maintain system reliability and that its actions with respect to meeting the relevant retirement notice requirements were satisfactory. The NYPSC also accepted the findings of the 2014 Reliability Study and stated that it established "the reliability need for continued operation of the Ginna Facility that is the essential prerequisite to negotiating a Reliability Support Services Agreement (RSSA)." As such, the NYPSC ordered RG&E and GNPP to negotiate an RSSA.

On February 13, 2015, RG&E submitted to the NYPSC an executed RSSA between RG&E and GNPP. RG&E requested that the NYPSC accept the RSSA and approve cost recovery by RG&E from its customers of all amounts payable to GNPP under the RSSA utilizing the cost recovery surcharge mechanism.

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 provides 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 is entitled to 70% of revenues from Ginna's sales into the NYISO energy and capacity markets, while Ginna is 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.

New York TransCo

Networks holds an approximate 20% ownership interest in the New York TransCo, LLC (New York TransCo). New York TransCo was established by the New York transmission utilities to develop, own, and operate electric transmission in New York. In December 2014, New York TransCo filed for regulatory approval of its rates, terms, and conditions with the FERC. The filing requests a formula base ROE of 10.6%, one-hundred fifty basis points ROE incentives, construction work in progress, a formula rate mechanism, and a proposed cost allocation. Various parties, including the NYPSC, have protested the filing with the FERC, including the base ROE, the ROE incentives, and the cost allocation. New York TransCo will not make final decisions on transmission project development until a FERC decision.

On April 2, 2015, the FERC issued an order granting, inter alia, New York TransCo's owners' request for a 50 basis point adder for New York TransCo's membership in the NYISO regional transmission organization (RTO), subject to the adder being capped within the zone of reasonableness after a determination of where within that zone its base level ROE should be set. The FERC also set the formula rate and base ROE issue for hearing and settlement judge procedures. In addition, the FERC rejected New York TransCo's owners' cost allocation method for the Transmission Owner Transmission Solutions (TOTS) Projects because it would allocate costs to Power Supply Long Island (LIPA) and New York Power Authority (NYPA) that they did not voluntarily agree to pay.

On November 5, 2015, the New York TransCo's owners, filed the Settlement with the FERC to resolve all outstanding issues associated with the TOTS Projects, including issues related to the TOTS Projects that were set for hearing and issues pending on rehearing. The issues regarding certain other projects remain pending. The Settlement addressed the financial terms that are components of New York TransCo's revenue requirement for the proposed TOTS Projects, including the base ROE of 9.50%, and a 50-basis point ROE adder, the capital structure of 53%, and the cost allocation under the New York Independent System Operator, Inc. (NYISO) Open Access Transmission Tariff (OATT) for the TOTS Projects. On March 17, 2016, the FERC approved the Settlement.

On August 21, 2017, New York TransCo filed a settlement with the FERC to resolve all outstanding issues associated with the alternate current transmission project (AC Project) for which selection of the developer remains pending with NYISO. The issues contained in the settlement include those related to the AC Project that were set for hearing and issues pending on rehearing. The Settlement addressed the financial terms that are components of New York TransCo's revenue requirement for the AC Project, including the base ROE of 9.65%, and a 100-basis point ROE adder, an equity ratio in the capital structure of up to 53%, risk sharing for project cost overruns, and the cost allocation under the NYISO Open Access Transmission Tariff (OATT) for the AC Project. On November 16, 2017, the FERC approved the settlement.

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. The regulated utility subsidiaries are prohibited by regulation from lending to unregulated affiliates. The 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 $4,550 million associated with the minimum equity requirements as of December 31, 2017.

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

New Renewable Source Generation

Under Connecticut law Public Act (PA 11-80), 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 an approximate 21-year period. The obligations will phase in over a six-year solicitation period, and are expected to peak at an annual commitment level of about $13.6 million per year after all selected projects are online. 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.

On October 23, 2013, PURA approved UI's renewable connections program filed in accordance with PA 11-80, through which UI has developed 10 MW of renewable generation. The costs for this program will be recovered on a cost of service basis. PURA established a base ROE to be calculated as the greater of: (A) the current UI authorized distribution ROE (currently 9.10%) plus 25 basis points and (B) the current authorized distribution ROE for Connecticut Light and Power Company, or CL&P (currently 9.17%), less target equivalent market revenues (reflected as 25 basis points). In addition, UI will retain a percentage of the market revenues from the program, which percentage is expected to equate to approximately 25 basis points on a levelized basis over the life of the program. The cost of this program, a 2.8 MW fuel cell facility in New Haven, solar photovoltaic and fuel cell facilities totaling 5 MW in Bridgeport, and a 2.2 MW fuel cell facility in Woodbridge, all of which are now operational, was approximately $41.5 million.

On May 25, 2017, UI entered into six 20-year power purchase agreements (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 Connecticut law Public Act (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. UI has begun purchasing energy from Woods Hill Solar, LLC for UI's 2 MW share of the Woods Hill solar project.

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 the Connecticut Department of Energy and Environmental Protection's (DEEP) PA 15-107 1(b) RFP, and were entered into pursuant to PA 15-107, Section 1(b) PA 15-107 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.

Equity Investment in Peaking Generation

UI is party to a 50-50 joint venture with NRG affiliates 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-New England markets. PURA has approved revenue requirements for the period from January 1, 2018 through December 31, 2018 of $28.8 million and $35.8 million for GenConn Devon and GenConn Middletown, respectively. PURA has ruled previously that GenConn project capital costs incurred were prudently incurred. Such costs are included in the 2017 approved revenue requirements.

Note 5. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations, our utilities capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric and natural gas rates. We base our assessment of whether recovery is probable on the existence of regulatory orders that allow for recovery of certain costs over a specific period, or allow for reconciliation or deferral of certain costs. When costs are not treated in a specific 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 is 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 $1,887 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.

On June 15, 2016, the NYPSC approved the Joint Proposal in connection with a three-year rate plan for electric and gas service at NYSEG and RG&E effective May 1, 2016. Following the approval of the Joint Proposal most of these items related to NYSEG are amortized over a five-year period, except the portion of storm costs to be recovered over ten years, and plant related tax items which are amortized over the life of associated plant. Annual amortization expense for NYSEG is approximately $16.5 million per rate year. RG&E items that are being amortized are plant related tax items, which are amortized over the life of associated plant, and unfunded deferred taxes being amortized over a period of fifty years. A majority of the other items related to RG&E, which net to a regulatory liability, remains deferred and will not be amortized until future proceedings. Following the approval of the Joint Proposal by the NYPSC, unfunded future income taxes were adjusted for the amount of $126 million to reflect the change from a flow through to normalization method, which has been recorded as an increase to income tax expense and an offsetting increase to revenue, during the year ended December 31, 2016. These amounts will be collected over a period of fifty years.

Current and non-current regulatory assets as of December 31, 2017 and 2016 consisted of:

As of December 31,	2017	2016
(Millions)		
Current		
Pension and other post-retirement benefits cost deferrals	$ 24	$ 22
Pension and other post-retirement benefits	7	7
Storm costs	46	40
Temporary supplemental assessment surcharge	—	4
Reliability support services	27	27
Revenue decoupling mechanism	21	15
Transmission revenue reconciliation mechanism	8	12
Electric supply reconciliation	—	13
Hedges losses	3	10
Contracts for differences	9	14
Hardship programs	14	16
Deferred property tax	10	10
Plant decommissioning	6	6
Deferred purchased gas	31	14
Deferred transmission expense	37	13
Environmental remediation costs	13	14
Other	51	48
Total Current Regulatory Assets	**307**	**285**
Non-current		
Pension and other post-retirement benefits cost deferrals	110	134
Pension and other post-retirement benefits	1,162	1,320
Storm costs	254	187
Deferred meter replacement costs	29	32
Unamortized losses on reacquired debt	17	20
Environmental remediation costs	283	287
Unfunded future income taxes	376	542
Asset retirement obligations	18	18
Deferred property tax	14	33
Federal tax depreciation normalization adjustment	155	161
Merger capital expense target customer credit	2	11
Debt premium	131	151
Reliability support services	10	29
Plant decommissioning	9	14
Contracts for differences	84	61
Hardship programs	13	18
Other	71	73
Total Non-current Regulatory Assets	**$ 2,738**	**$ 3,091**

"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. Storm costs in the amount of $123 million at NYSEG are being recovered over ten-year period and the remaining portion is being amortized over five years following the approval of the Joint Proposal by the NYPSC. UI is allowed to defer costs associated with any storm totaling $1 million or greater for future recovery. UI's storm regulatory asset balance was $0 as of December 31, 2017.

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

“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.

“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.

“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. Following the approval of the Joint Proposal by the NYPSC, these amounts will be 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.

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

“Deferred property taxes” represents the customer portion of the difference between actual expense for property taxes and the amount provided for in rates. The amount for NYSEG and RG&E is being amortized over a five year period following the approval of the Joint Proposal by the NYPSC.

“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 NY is from 27 to 39 years and for CMP this will be determined in future Maine Public Utility Commission (MPUC) rate proceedings.

“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.

“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.

“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.

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

“Other” includes post term amortization and various items subject to reconciliation including rate change levelization, loss on re-acquired debt and power tax deferral.

Current and non-current regulatory liabilities as of December 31, 2017 and 2016 consisted of:

As of December 31,	2017	2016
(Millions)		
Current		
Reliability support services (Cayuga)	$ —	$ 3
Non by-passable charges	5	22
Energy efficiency portfolio standard	37	45
Gas supply charge and deferred natural gas cost	4	6
Transmission revenue reconciliation mechanism	14	5
Pension and other post-retirement benefits	1	3
Pension and other post-retirement benefits cost deferrals	14	14
Carrying costs on deferred income tax bonus depreciation	21	15
Carrying costs on deferred income tax - Mixed Services 263(a)	5	5
Yankee DOE refund	4	24
Merger-related rate credits	1	3
Revenue decoupling mechanism	4	9
Stranded costs	17	—
Other	51	38
Total Current Regulatory Liabilities	**178**	**192**
Non-current		
Accrued removal obligations	1,132	1,117
Tax Act - remeasurement	1,515	—
Asset sale gain account	10	9
Carrying costs on deferred income tax bonus depreciation	72	95
Economic development	32	35
Merger capital expense target customer credit account	6	15
Pension and other post-retirement benefits	74	76
Positive benefit adjustment	39	42
New York state tax rate change	6	9
Post term amortization	—	3
Theoretical reserve flow thru impact	19	24
Deferred property tax	19	19
Net plant reconciliation	10	10
Variable rate debt	33	28
Carrying costs on deferred income tax - Mixed Services 263(a)	20	25
Rate refund – FERC ROE proceeding	27	22
Transmission congestion contracts	19	18
Merger-related rate credits	20	21
Accumulated deferred investment tax credits	13	15
Asset retirement obligation	13	13
Earning sharing provisions	22	12
Middletown/Norwalk local transmission network service collections	19	19
Excess generation service charge	2	—
Low income programs	42	46
Non-firm margin sharing credits	8	7
Deferred income taxes regulatory	13	565
Other	67	73
Total Non-current Regulatory Liabilities	**$ 3,252**	**$ 2,318**

"Reliability support services (Cayuga)" represents the difference between actual expenses for reliability support services and the amount provided for in rates. This will be refunded to customers within the next year.

“Non by-passable charges” represent the non by-passable charge paid by all customers. An asset or liability is recognized resulting from differences between actual revenues and the underlying cost being recovered. This liability will be refunded to customers within the next year.

“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.

“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 following the approval of the Joint Proposal by the NYPSC.

“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.

“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 ratepayers. The amortization period is five years following the approval of the Joint Proposal by the NYPSC.

“Merger capital expense target customer credit” account was created as a result of NYSEG and RG&E not meeting certain capital expenditure requirements established in the order approving the purchase of AVANGRID (formerly Energy East Corporation) by Iberdrola. The amortization period is five years following the approval of the Joint Proposal by the NYPSC.

“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.

“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 following the approval of the Joint Proposal by the NYPSC and included in the Ginna RSSA settlement.

“New York state tax rate change” represents excess funded accumulated deferred income tax balance caused by the 2014 New York state tax rate change from 7.1% to 6.5%. The amortization period is five years following the approval of the Joint Proposal by the NYPSC.

“Post term amortization” represents the revenue requirement associated with certain expired joint proposal amortization items. The amortization period is five years following the approval of the Joint Proposal by the NYPSC.

“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 following the approval of the Joint Proposal by the NYPSC.

“Tax Act - remeasurement” represents the impact from remeasurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates from 35% to 21% under the provisions of the Tax Act will result in amounts previously collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates. The NYPSC, MPUC, PURA and DPU have instituted separate proceedings in New York, Maine, Connecticut and Massachusetts to review and address the implications associated with the Tax Act on the utilities providing service in those states. We expect the regulators in each jurisdiction, including the FERC, to issue requirements in 2018 regarding how all tax benefits associated with the Tax Act will be returned to customers.

"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, 2017 and 2016, respectively, $2 million and $20 million of rate credits were applied against customer bills.

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

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

"Other" includes cost of removal being amortized through rates and various items subject to reconciliation including variable rate debt, Medicare subsidy benefits and stray voltage collections.

Note 6. Goodwill and Intangible assets

Goodwill by reportable segment as of December 31, 2017 and 2016 consisted of:

As of December 31,	2017	2016
(Millions)		
Networks	$ 2,747	$ 2,744
Renewables	380	380
Total	**$ 3,127**	**$ 3,124**

As of December 31, 2017 and 2016, there were no changes in gross amounts and accumulated losses of goodwill for the Networks and Renewables reportable segments, except for various immaterial adjustments in 2017 related to the gross amount of goodwill for the Networks reportable segment.

Goodwill Impairment Assessment

For impairment testing purposes our reporting units are the same as operating segments, except for Networks, which contained 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 amounted to $1,765 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 our 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 2017 and 2016 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, 2017	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
(Millions)			
Wind development	$ 583	$ (264)	$ 319
Other	21	(12)	9
Total Intangible Assets	**$ 604**	**$ (276)**	**$ 328**

As of December 31, 2016	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
(Millions)			
Gas Storage rights	$ 319	$ (120)	$ 199
Wind development	587	(254)	333
Other	17	(11)	6
Total Intangible Assets	**$ 923**	**$ (385)**	**$ 538**

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. Amortization expense for the years ended December 31, 2017, 2016 and 2015 amounted to $22 million, $25 million and $54 million, respectively. We believe our future cash flows will support the recoverability of our intangible assets.

We expect amortization expense for the five years subsequent to December 31, 2017, to be as follows:

Year ending December 31,	
(Millions)	
2018	$ 16
2019	19
2020	18
2021	21
2022	22

As a result of writing off fully amortized intangible assets relating to Gas Storage rights, $4.1 million and $6.5 million were removed from both cost and accumulated amortization during the years ended December 31, 2016 and 2015, respectively.

As of December 31, 2017, we reclassified $193 million from intangible assets related to gas storage rights to assets held for sale in the consolidated balance sheet (see Note 25 - Assets Held for Sale). There was no amount classified as assets held for sale as of December 31, 2016.

Note 7. Property, Plant and Equipment

Property, plant and equipment as of December 31, 2017, consisted of:

As of December 31, 2017	Regulated	Nonregulated	Total
(Millions)			
Electric generation, distribution, transmission and other	$ 13,108	$ 11,517	$ 24,625
Natural gas transportation, distribution and other	3,728	13	3,741
Other common operating property	—	375	375
Total Property, Plant and Equipment in Service (a)	**16,836**	**11,905**	**28,741**
Total accumulated depreciation (b)	(4,172)	(3,325)	(7,497)
Total Net Property, Plant and Equipment in Service	**12,664**	**8,580**	**21,244**
Construction work in progress	987	438	1,425
Total Property, Plant and Equipment	**$ 13,651**	**$ 9,018**	**$ 22,669**

(a) Includes capitalized leases of $204 million primarily related to electric generation, distribution, transmission and other.
(b) Includes accumulated amortization of capitalized leases of $68 million.

Property, plant and equipment as of December 31, 2016, consisted of:

As of December 31, 2016	Regulated	Nonregulated	Total
(Millions)			
Electric generation, distribution, transmission and other	$ 12,259	$ 10,375	$ 22,634
Natural gas transportation, distribution and other	3,433	661	4,094
Other common operating property	—	335	335
Total Property, Plant and Equipment in Service (a)	**15,692**	**11,371**	**27,063**
Total accumulated depreciation (b)	(3,839)	(3,147)	(6,986)
Total Net Property, Plant and Equipment in Service	**11,853**	**8,224**	**20,077**
Construction work in progress	966	505	1,471
Total Property, Plant and Equipment	**$ 12,819**	**$ 8,729**	**$ 21,548**

(a) Includes capitalized leases of $208 million primarily related to electric generation, distribution, transmission and other.
(b) Includes accumulated amortization of capitalized leases of $60 million.

As of December 31, 2017, we reclassified $489 million from non-regulated property, plant and equipment to assets held for sale in the consolidated balance sheet (see Note 25 - Assets Held for Sale). There was no amount classified as assets held for sale as of December 31, 2016. In addition, certain amounts in the regulated and non-regulated property, plant and equipment of the table above have been reclassified to conform to the 2017 presentation.

Capitalized interest costs were $28 million, $20 million, and $13 million for the years ended December 31, 2017, 2016 and 2015, respectively. Accrued liabilities for property, plant and equipment additions were $209 million, $338 million and $148 million as of December 31, 2017, 2016 and 2015, respectively.

We impaired or wrote off amounts of $5 million, $0 and $12 million for the years ended December 31, 2017, 2016 and 2015, respectively, resulting from reassessment of the economic feasibility of our various Renewables development projects in construction.

Depreciation expense for the years ended December 31, 2017, 2016 and 2015, amounted to $802 million, $779 million and $641 million, respectively.

In September 2017, we acquired all of the membership interest in Solar Star Oregon II, that is constructing a 56MW solar project in Prineville, Oregon called Gala (Gala transaction), which had a PPA in place. The total purchase price for the Gala transaction is $121 million, $105 million of which was paid at the date of acquisition, with the remaining to be paid upon a substantial completion of construction of the Gala solar farm. According to the revised guidance on assessing whether a transaction is an acquisition of assets or a business we performed a screening test to determine whether substantially all of the fair value of the gross assets acquired is concentrated in a single asset (in-place lease intangibles and related leased assets) or group of similar assets in the Gala transaction. The Gala solar farm meets the screening test, being a single asset, and constitutes substantially all of the value of the consideration paid to the seller and therefore the Gala transaction is considered an asset acquisition. Additionally, at the acquisition date the Gala project, being at its development stage, would require a workforce that is capable to develop or convert inputs into outputs. As scheduling and balancing services, which will be performed by our workforce, are the primary functions required to convert the solar output into revenues under the PPA, the Gala transaction is not an acquisition of a business. Based on the fair value of assets acquired the purchase price in the Gala transaction was mainly allocated to the Gala solar farm in construction of approximately $122 million. The liability recognized for contingent consideration payable is $13 million, which was based on an amount that was probable and estimable, as of the acquisition date, September 20, 2017.

Note 8. 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, 2017 and 2016 consisted of:

(Millions)	
As of December 31, 2015	**$ 184**
Liabilities settled during the year	(7)
Liabilities incurred during the year	3
Accretion expense	10
Revisions in estimated cash flows	(29)
As of December 31, 2016	**$ 161**
Liabilities settled during the year	(1)
Liabilities incurred during the year	13
Accretion expense	10
Revisions in estimated cash flows	13
As of December 31, 2017	**$ 196**

Several of the wind generation facilities have restricted cash for purposes of settling AROs. Restricted cash related to AROs was $2.0 million as of both December 31, 2017 and 2016. These amounts have been included as other non-current assets in the consolidated balance sheets. Accretion expenses are included in “Operations and maintenance” in the 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.

In 2017, the addition of new wind and solar facilities, revision of the estimated useful lives of wind and solar facilities, and the subsequent measure of the amount of the original ARO estimate of undiscounted cash flows resulted in higher discounted AROs. We estimate that the revisions will result in approximately $2 million annual increase in expense going forward.

Note 9. Debt

Long- term debt as of December 31, 2017 and 2016 consisted of:

As of December 31,		2017		2016	
(Millions)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
First mortgage bonds - fixed (a)	2018-2045	$ 2,054	3.07%-10.60%	$ 1,752	3.07%-10.60%
Unsecured pollution control notes - fixed	2020	200	2.00%-2.375%	200	2.00%-2.375%
Unsecured pollution control notes – variable	2032	62	1.94%	62	1.32%
Other various non-current debt - fixed	2018-2045	3,027	2.89%-10.48%	2,772	2.89%-10.48%
Obligations under capital leases	2018-2030	74	4%-4.44%	104	4%-4.44%
Unamortized debt issuance costs and discount		(38)		(31)	
Total Debt		**5,379**		**4,859**	
Less: debt due within one year, included in current liabilities		183		349	
Total Non-current Debt		**$ 5,196**		**$ 4,510**	

(a) The first mortgage bonds have pledged collateral of substantially all the respective utility's in service properties of approximately $6,365 million.

On May 24, 2017, RG&E issued $300 million in aggregate principal amount of 3.10% First Mortgage Bonds maturing in 2027. Proceeds of the offering were used to reduce short-term debt, to fund capital expenditures and for general corporate purposes. Net proceeds of the offering after the price discount and issuance-related expenses were $294 million.

On November 21, 2017, Avangrid, Inc. 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.

Non-current debt, including sinking fund obligations and capital lease payments, due over the next five years consists of:

(Millions)

2018	2019	2020	2021	2022	Total
$ 183	$ 357	$ 722	$ 307	$ 369	$ 1,938

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 December 31, 2017 and 2016.

Fair Value of Debt

The estimated fair value of debt amounted to $5,799 million and $5,204 million as of December 31, 2017 and 2016, respectively. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the electricity industry and the credit ratings of the borrowers in each case. The fair value hierarchy pertaining to the fair value of debt is considered as Level 2, except for unsecured pollution control notes-variable with a fair value of $61 million as of both December 31, 2017 and 2016, which are considered Level 3. The fair value of these unsecured pollution control notes-variable are determined using unobservable interest rates as the market for these notes is inactive.

Short-term Debt

Outstanding Notes Payable

AVANGRID had $786 million and $161 million of notes payable as of December 31, 2017 and 2016, respectively. As of December 31, 2017, the balance consisted of $507 million of commercial paper, $250 million of drawn credit facility and $29 million in notes payable to an affiliate. As of December 31, 2016, the balance consisted of $150 million of commercial paper, $10 million in notes payable to an affiliate and $1 million in other notes payable. AVANGRID's commercial paper program was established on May 13, 2016, has a limit of $1 billion and is backstopped by the AVANGRID credit facility described below.

AVANGRID Credit Facility

On April 5, 2016, AVANGRID and its subsidiaries, NYSEG, RG&E, CMP, UI, CNG, SCG and BGC entered into a revolving credit facility with a syndicate of banks, or the AVANGRID credit facility, that provides for maximum borrowings of up to $1.5 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 established by the banks. AVANGRID's maximum sublimit is $1 billion, NYSEG, RG&E, CMP and UI have maximum sublimits of $250 million, CNG, and SCG have maximum sublimits of $150 million and BGC has a maximum sublimit of $25 million. Under the AVANGRID credit facility, each of the borrowers will pay an annual facility fee that is dependent on their credit rating. The facility fees will range from 10.0 to 17.5 basis points. The maturity date for the AVANGRID credit facility is April 5, 2021.

As of December 31, 2017 and 2016, there was $250 million and $0 drawn under the AVANGRID credit facility, and the capacity to borrow under the facility is reduced by the amount of outstanding commercial paper, leaving available credit of, respectively, $743 million and $1,350 million.

Note 10. Fair Value of Financial Instruments and Fair Value Measurements

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

- We measure the fair value of our noncurrent investments using quoted market prices in active markets for identical assets and include the measurements in Level 1. The available for sale investments which are Rabbi Trusts for deferred compensation plans primarily consist of money market funds and are included in Level 1 fair value measurement.
- 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 New York Independent System Operator (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 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.
- Contracts for differences (CfDs) entered into by UI 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 11 for further discussion on CfDs).

We determine the fair value of our derivative assets and liabilities associated with Renewables and Gas 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 product with no adjustment are included in the Level 1 fair value. 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 Level 2 fair value. 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 Level 3 fair value. 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.

The carrying amounts for cash and cash equivalents, restricted cash, accounts receivable, accounts payable, notes payable and interest accrued approximate their estimated fair values and are considered as Level 1.

Restricted cash was $5 million as of both December 31, 2017 and 2016, which is included in "Other Assets" on the balance sheet.

The financial instruments measured at fair value as of December 31, 2017 and 2016 consisted of:

As of December 31, 2017	Level 1	Level 2	Level 3	Netting	Total
(Millions)					
Securities portfolio (available for sale)	**$ 41**	**$ —**	**$ —**	**$ —**	**$ 41**
Derivative assets					
Derivative financial instruments - power	14	30	74	(49)	69
Derivative financial instruments - gas	89	18	64	(146)	25
Contracts for differences	—	—	12	—	12
Total	**103**	**48**	**150**	**(195)**	**106**
Derivative liabilities					
Derivative financial instruments - power	(14)	(17)	(15)	37	(9)
Derivative financial instruments - gas	(80)	(20)	(25)	110	(15)
Contracts for differences	—	—	(104)	—	(104)
Total	**$ (94)**	**$ (37)**	**$ (144)**	**$ 147**	**$ (128)**

As of December 31, 2016	Level 1	Level 2	Level 3	Netting	Total
(Millions)					
Securities portfolio (available for sale)	**$ 40**	**$ —**	**$ —**	**$ —**	**$ 40**
Derivative assets					
Derivative financial instruments - power	11	48	58	(42)	75
Derivative financial instruments - gas	180	32	104	(239)	77
Contracts for differences	—	—	20	—	20
Total	**191**	**80**	**182**	**(281)**	**172**
Derivative liabilities					
Derivative financial instruments - power	(24)	(27)	(3)	39	(15)
Derivative financial instruments - gas	(213)	(34)	(53)	257	(43)
Contracts for differences	—	—	(95)	—	(95)
Total	**$ (237)**	**$ (61)**	**$ (151)**	**$ 296**	**$ (153)**

Included in the derivative financial instruments – gas are derivative assets and liabilities of Gas segment classified as held for sale as of December 31, 2017. See Note 25 – Assets Held For Sale for further discussion.

The reconciliations of changes in the fair value of financial instruments based on Level 3 inputs for the years ended December 31, 2017, 2016 and 2015 consisted of:

(Millions)	2017	2016	2015
Fair value as of January 1,	**$ 31**	**$ (19)**	**$ 57**
Gains for the year recognized in operating revenues	18	67	33
Losses for the year recognized in operating revenues	(1)	—	(8)
Total gains or losses for the period recognized in operating revenues	17	67	25
Gains recognized in OCI	2	1	2
Losses recognized in OCI	(1)	—	(3)
Total gains or losses recognized in OCI	1	1	(1)
Net change recognized in regulatory assets and liabilities	(17)	(8)	—
Purchases	(5)	3	(73)
Settlements	(17)	(9)	(14)
Transfers out of Level 3 (a)	(4)	(4)	(13)
Fair value as of December 31,	**$ 6**	**$ 31**	**$ (19)**
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	$ 17	$ 67	$ 25

(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 tables below illustrate 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, 2017

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)	$ 3.07	$ 3.93	$ 2.35
				Indiana hub ($/MWh)	$ 31.77	$ 65.55	$ 18.53
				Mid C ($/MWh)	$ 24.59	$ 46.50	$ (0.50)
				Minn hub ($/MWh)	$ 26.40	$ 62.33	$ 9.56

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 both gas inventory in firm storage and 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 gas storage inventory and 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 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 11 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 extended 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, 2017
Risk of non-performance	0.11% - 0.49%
Discount rate	1.89% - 2.40%
Forward pricing ($ per MW)	$5.30 - $9.55

Note 11. 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 the consolidated balance sheets in accordance with the accounting requirements concerning derivative instruments and hedging activities.

(a) Networks activities

NYSEG and RG&E have an electric commodity charge that passes through rates costs for the market price of electricity. They 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.

The amount recognized in regulatory assets and liabilities for electricity derivatives was a loss of $0.2 million and $12.3 million as of December 31, 2017 and 2016, respectively. The loss reclassified from regulatory assets into income, which is included in electricity purchased, was $36.9 million, $66.7 million, and $46.9 million for the years ended December 31, 2017, 2016 and 2015, respectively.

NYSEG and RG&E have purchased gas adjustment clauses that allow them 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 amount recognized in regulatory assets for natural gas hedges was a loss of $2.5 million as of December 31, 2017 and the amount recognized in regulatory liabilities was a gain of $3.5 million as of December 31, 2016. The loss reclassified from regulatory assets into income, which is included in natural gas purchased, was $0.2 million, $1.9 million, and $6.3 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Pursuant to PURA directive, 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, 2017, UI has recorded a gross derivative asset of $12 million ($0 of which is related to UI's portion of the CfD signed by CL&P), a regulatory asset of $93 million, a gross derivative liability of $104 million ($90 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, 2016, UI has recorded a gross derivative asset of $19 million ($0 of which is related to UI's portion of the CfD signed by CL&P), a regulatory asset of $75 million, a gross derivative liability of $95 million ($70 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, 2017 and 2016, and for the period from December 17, 2015 to December 31, 2015, respectively, were as follows:

	Year Ended December 31, 2017	Year Ended December 31, 2016	Period from December 17, 2015 to December 31, 2015
(Millions)			
Derivative Assets	$ (8)	$ (7)	$ (1)
Derivative Liabilities	$ (9)	$ (1)	$ —

The net notional volumes of the outstanding derivative instruments associated with Networks activities as of December 31, 2017 and 2016, respectively, consisted of:

As of December 31,	2017	2016
(Millions)		
Wholesale electricity purchase contracts (MWh)	3.9	5.6
Natural gas purchase contracts (Dth)	6.1	5.8
Fleet fuel purchase contracts (Gallons)	2.1	2.3

The offsetting of derivatives, location in the consolidated balance sheet and amounts of derivatives associated with Networks activities as of December 31, 2017 and 2016, respectively, consisted of:

As of December 31, 2017 (Millions)	Current Assets	Noncurrent Assets	Current Liabilities	Noncurrent Liabilities
Not designated as hedging instruments				
Derivative assets	$ 20	$ 5	$ 13	$ —
Derivative liabilities	(13)	—	(32)	(88)
	7	5	(19)	(88)
Designated as hedging instruments				
Derivative assets	—	—	—	—
Derivative liabilities	—	—	—	—
	—	—	—	—
Total derivatives before offset of cash collateral	7	5	(19)	(88)
Cash collateral receivable	—	—	3	—
Total derivatives as presented in the balance sheet	$ 7	$ 5	$ (16)	$ (88)

As of December 31, 2016 (Millions)	Current Assets	Noncurrent Assets	Current Liabilities	Noncurrent Liabilities
Not designated as hedging instruments				
Derivative assets	$ 19	$ 16	$ 7	$ 5
Derivative liabilities	(7)	(5)	(40)	(79)
	12	11	(33)	(74)
Designated as hedging instruments				
Derivative assets	—	—	—	—
Derivative liabilities	—	—	—	—
	—	—	—	—
Total derivatives before offset of cash collateral	12	11	(33)	(74)
Cash collateral receivable	—	—	10	2
Total derivatives as presented in the balance sheet	$ 12	$ 11	$ (23)	$ (72)

The effect of derivatives in cash flow hedging relationships on OCI and income for the years ended December 31, 2017, 2016 and 2015, respectively, consisted of:

Year Ended December 31, (Millions)	(Loss) Recognized in OCI on Derivatives Effective Portion (a)	Location of Loss Reclassified from Accumulated OCI into Income	Loss Reclassified from Accumulated OCI into Income
		Effective Portion (a)	
2017			
Interest rate contracts	$ —	Interest expense	$ 8
Commodity contracts	(1)	Operating expenses	1
Total	**$ (1)**		**$ 9**
2016			
Interest rate contracts	$ —	Interest expense	$ 8
Commodity contracts	—	Operating expenses	2
Total	**$ —**		**$ 10**
2015			
Interest rate contracts	$ —	Interest expense	$ 9
Commodity contracts	(3)	Operating expenses	3
Total	**$ (3)**		**$ 12**

(a) Changes in OCI are reported in pre-tax dollars, the reclassified amounts of commodity contracts are included within “Purchase power, natural gas and fuel used” line item within operating expenses in the consolidated statements of income.

The net loss in accumulated OCI related to previously settled forward starting swaps and accumulated amortization is $68.8 million and $76.7 million, as of December 31, 2017 and 2016, respectively. We recorded $8.0 million, $8.0 million, and $8.6 million in net derivative losses related to discontinued cash flow hedges for the years ended December 31, 2017, 2016 and 2015, respectively. We will amortize approximately $8.0 million of discontinued cash flow hedges in 2018. During the years ended December 31, 2017, 2016 and 2015, there was no ineffective portion for cash flow hedges.

The unrealized loss of $0.1 million on hedge derivatives is reported in OCI because the forecasted transaction is considered to be probable as of December 31, 2017. We expect that $0.1 million 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

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.

Our gas business purchases and sells both fixed-price gas and basis swaps to hedge the value of contracted storage positions. The intent of entering into these swaps is to fix the margin of gas injected into storage for subsequent resale in future periods. We also enter into basis swaps to hedge the value of our contracted transport positions. The intent of buying and selling these basis swaps is to fix the location differential between the price of gas at the receipt and delivery point of the contracted transport in future periods.

Both Renewables and Gas have 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. To the extent that the derivative contracts are effective in offsetting the variability of cash flows associated with future power sales and gas purchases, the fair value changes are recorded in OCI. Any hedge ineffectiveness is recorded in current period earnings. 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.

Gas also periodically designates NYMEX fixed price derivative contracts as cash flow hedges related to its firm storage trading activities. To the extent that the derivative contracts are effective in offsetting the variability of cash flows associated with future gas sales and purchases, the fair value changes are recorded in OCI. Any hedge ineffectiveness is recorded in current period earnings. Derivative contracts entered into to hedge the gas transport trading activities are not designated as cash flow hedges, with all changes in fair value of such derivative contracts recorded in current period earnings.

The below presented information includes derivative financial instruments associated with Gas activities, which were classified as held for sale in the consolidated balance sheet (see Note 25 - Assets Held for Sale). There were no derivative financial instruments classified as assets held for sale as of December 31, 2016.

The net notional volumes of outstanding derivative instruments associated with Renewables and Gas activities as of December 31, 2017 and 2016, respectively, consisted of:

As of December 31,	2017	2016
(MWh/Dth in Millions)		
Wholesale electricity purchase contracts	4	3
Wholesale electricity sales contracts	6	7
Natural gas and other fuel purchase contracts	285	329
Financial power contracts	12	8
Basis swaps - purchases	68	49
Basis swaps - sales	62	45

The fair values of derivative contracts associated with Renewables and Gas activities as of December 31, 2017 and 2016, respectively, consisted of:

As of December 31, (Millions)	2017	2016
Wholesale electricity purchase contracts	$ (3)	$ (2)
Wholesale electricity sales contracts	8	6
Natural gas and other fuel purchase contracts	19	30
Financial power contracts	55	56
Basis swaps- purchases	(13)	3
Basis swaps- sales	4	(2)
Total	**$ 70**	**$ 91**

The offsetting of derivatives, location in the consolidated balance sheet and amounts of derivatives associated with Renewables and Gas activities as of December 31, 2017 and 2016, respectively, consisted of:

As of December 31, 2017 (Millions)	Current Assets	Noncurrent Assets	Current Liabilities	Noncurrent Liabilities
Not designated as hedging instruments				
Derivative assets	$ 111	$ 99	$ 31	$ 4
Derivative liabilities	(82)	(5)	(51)	(10)
	29	94	(20)	(6)
Designated as hedging instruments				
Derivative assets	24	4	—	2
Derivative liabilities	—	(1)	(3)	(3)
	24	3	(3)	(1)
Total derivatives before offset of cash collateral	53	97	(23)	(7)
Cash collateral receivable (payable)	(17)	(39)	3	3
Total derivatives as presented in the balance sheet, including assets and liabilities held for sale	$ 36	$ 58	$ (20)	$ (4)

As of December 31, 2016 (Millions)	Current Assets	Noncurrent Assets	Current Liabilities	Noncurrent Liabilities
Not designated as hedging instruments				
Derivative assets	$ 198	$ 108	$ 78	$ 7
Derivative liabilities	(118)	(4)	(132)	(16)
	80	104	(54)	(9)
Designated as hedging instruments				
Derivative assets	25	4	—	—
Derivative liabilities	(1)	—	(39)	(21)
	24	4	(39)	(21)
Total derivatives before offset of cash collateral	104	108	(93)	(30)
Cash collateral receivable (payable)	(17)	(46)	41	24
Total derivatives as presented in the balance sheet	$ 87	$ 62	$ (52)	$ (6)

The effect of trading derivatives associated with Renewables and Gas activities for the years ended December 31, 2017, 2016 and 2015 consisted of:

Years Ended December 31,	2017	2016	2015
(Millions)			
Wholesale electricity purchase contracts	$ (3)	$ 3	$ 6
Wholesale electricity sales contracts	4	(7)	(5)
Financial power contracts	(1)	4	—
Financial and natural gas contracts	(8)	(22)	(26)
Total Loss	**$ (8)**	**$ (22)**	**$ (25)**

The effect of non-trading derivatives associated with Renewables and Gas activities for the years ended December 31, 2017, 2016 and 2015 consisted of:

Years Ended December 31,	2017	2016	2015
(Millions)			
Wholesale electricity purchase contracts	$ 1	$ 9	$ (8)
Wholesale electricity sales contracts	(3)	(20)	(5)
Financial power contracts	(5)	(10)	24
Natural gas and other fuel purchase contracts	(8)	34	18
Total Gain	**$ (15)**	**$ 13**	**$ 29**

Such gains and losses are included in "Operating revenues" and in "Purchased power, natural gas and fuel used" operating expenses in the consolidated statements of income, depending upon the nature of the transaction.

The effect of derivatives in cash flow hedging relationships on OCI and income for the years ended December 31, 2017, 2016 and 2015 consisted of:

Year Ended December 31,	(Loss) Gain Recognized in OCI on Derivatives	Location of Gain Reclassified from Accumulated OCI into Income	Loss (Gain) Reclassified from Accumulated OCI into Income
(Millions)	Effective Portion (a)	Effective Portion (a)	
2017			
Commodity contracts	$ 41	Revenues	$ 14
	$ 41		**$ 14**
2016			
Commodity contracts	$ (42)	Revenues	$ (43)
	$ (42)		**$ (43)**
2015			
Commodity contracts	$ 57	Revenues	$ (2)
Total	**$ 57**		**$ (2)**

(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 $20.9 million of gain included in accumulated OCI at December 31, 2017 is expected to be reclassified into earnings within the next 12 months. During the years ended December 31, 2017, 2016 and 2015, we recorded a net gain of $2.6 million, a net loss of $6.8 million, and a net gain $4.8 million, respectively, in earnings as a result of ineffectiveness from cash flow hedges. We recorded $0.5 million in net derivative loss and $0.4 million and $2.3 million in net derivative gain related to discontinued cash flow hedge for the years ended December 31, 2017, 2016 and 2015, respectively. The net loss in accumulated OCI of $0.2 million as of December 31, 2017 related to a discontinued cash flow hedge will amortize through 2018.

(c) 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 dependent on the counterparty's or the counterparty's guarantor's applicable credit rating, normally 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, 2017, UI would have had to post an aggregate of approximately $15.8 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 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 amounts of cash collateral under master netting arrangements that have not been offset against net derivative positions were $30 million and $20 million as of December 31, 2017 and 2016, respectively. Derivative instruments settlements and collateral payments are included in "Other assets" and "Other liabilities" 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, 2017 is $3 million, for which we have posted collateral.

Note 12. Commitments and Contingent Liabilities

We are party to various legal disputes arising as part of our normal business activities. 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, Massachusetts Department of Public Utilities, Connecticut Public Utilities Regulatory Authority, New Hampshire Public Utilities Commission, Rhode Island Division of Public Utilities and Carriers, Vermont Department of Public Service, numerous New England consumer advocate agencies and transmission tariff customers collectively filed a complaint (Complaint I) with the FERC pursuant to sections 206 and 306 of the Federal Power Act. The filing parties seek an order from the FERC reducing the 11.14% base return on equity used in calculating formula rates for transmission service under the ISO-New England Open Access Transmission Tariff (OATT) to 9.2%. CMP, MEPCO and UI are New England Transmission Owners (NETOs) with assets and service rates that are governed by the OATT and will thereby be affected by any FERC order resulting from the filed complaint.

On June 19, 2014, the FERC issued its decision in Complaint I, establishing a methodology and setting an issue for a paper hearing. On October 16, 2014, FERC issued its final decision in the Complaint I setting the base ROE at 10.57%, and a maximum total ROE of

11.74% (base plus incentive ROE) for the October 2011 – December 2012 period as well as prospectively from October 16, 2014 and ordered the NETOs to file a refund report. On November 17, 2014 the NETOs filed a refund report.

On March 3, 2015, the FERC issued an order on requests for rehearing of its October 16, 2014 decision. The March order upheld the FERC's June 19, 2014 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. In June 2015 the NETOs and complainants both filed an appeal in the U.S. Court of Appeals for the District of Columbia of the FERC's final order. On April 14, 2017, the Court of Appeals (the Court) vacated FERC's decision on Complaint I and remanded it to FERC. The Court held that FERC, as directed by statute, did not determine first that the existing ROE was unjust and unreasonable before determining a new ROE. The Court ruled that FERC should have first determined that the then existing 11.14% base ROE was unjust and unreasonable before selecting the 10.57% as the new base ROE. The Court also found that FERC did not provide reasoned judgment as to why 10.57%, the point ROE at the midpoint of the upper end of the zone of reasonableness, is a just and reasonable ROE. Instead, FERC had only explained in its order that the midpoint of 9.39% was not just and reasonable and a higher base ROE was warranted. On June 5, 2017, the NETOs made a filing with FERC seeking to reinstate transmission rates to the status quo ante (effect of the Court vacating order is to return the parties to the rates in effect prior to FERC Final decision) as of June 8, 2017, the date the Court decision became effective. In that filing, the NETOs stated that they will not begin billing at the higher rates until 60 days after FERC has a quorum of commissioners. On October 6, 2017, FERC issued an order rejecting the NETOs request to collect transmission revenue requirements at the higher ROE of 11.14%, pending FERC order on remand. In reaching this decision, FERC stated that it has broad remedial authority to make whatever ROE it eventually determines to be just and reasonable effective for the Complaint I refund period and prospectively from October 2014, the effective date of the Complaint I Order. Therefore FERC reasoned that the NETOs will not be harmed financially by not immediately returning to their pre-Complaint I ROE. We anticipate FERC to address the Court decision during 2018. We cannot predict the outcome of action by FERC.

On December 26, 2012, a second, ROE complaint (Complaint II) for a subsequent rate period was filed requesting the then effective ROE of 11.14% be reduced to 8.7%. On June 19, 2014, FERC accepted Complaint II, established a 15-month refund effective date of December 27, 2012, and set the matter for hearing using the methodology established in the Complaint I.

On July 31, 2014, a third, ROE complaint (Complaint III) was filed for a subsequent rate period requesting the then effective ROE of 11.14% be reduced to 8.84%. On November 24, 2014, FERC accepted the Complaint III, established a 15-month refund effective date of July 31, 2014, and set this matter consolidated with Complaint II for hearing in June 2015. Hearings relating to the refund periods and going forward period were held in June 2015 on Complaints II and III before a FERC Administrative Law Judge. On July 29, 2015, post-hearing briefs were filed by parties and on August 26, 2015 reply briefs were filed by parties. On July 13, 2015, the NETOs filed a petition for review of FERC's orders establishing hearing and consolidation procedures for Complaints II and III with the U.S. Court of Appeals. The FERC Administrative Law Judge issued an Initial Decision on March 22, 2016. The Initial Decision determined that: (1) for the 15-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 15 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 is the Administrative Law Judge's recommendation to the FERC Commissioners. The FERC is expected to make its final decision in 2018.

CMP and UI reserved for refunds for Complaints I, II and III consistent with the FERC's March 3, 2015 final 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 $22.5 million and $4.4 million, respectively, as of December 31, 2017, which has not changed since December 31, 2016, except for the accrual of carrying costs. If adopted as final, the impact of the initial decision would be an additional aggregate reserve for Complaints II and III of $17.1 million, which is based upon currently available information for these proceedings. We cannot predict the outcome of the Complaint II and III proceedings.

On April 29, 2016, a fourth ROE complaint (Complaint IV) was filed for a rate period subsequent to prior complaints requesting the then existing base ROE of 10.57% be reduced to 8.61% and the ROE Cap be set at 11.24%. The NETOs filed a response to the Complaint IV on June 3, 2016. On September 20, 2016, FERC accepted the Complaint IV, established a 15-month refund effective date of April 29, 2016, and set the matter for hearing and settlement judge procedures. In April 2017, the NETOs filed for a stay in the hearings pending FERC on the Court order described above. That request was denied by the Administrative Law Judge. On November 21, 2017, the parties submitted updates to their ROE analyses and recommendations just prior to hearings with the NETOs continuing to advocate that the existing base ROE of 10.57% should remain in effect. Hearings were held in December 2017 with an expected Initial Decision from the Administrative Law Judge by March 31, 2018. A range of possible outcomes is not able to be determined at this time due to the preliminary state of this matter. We cannot predict the outcome of the Complaint IV proceeding.

On October 5, 2017, the NETOs filed a Motion for Dismissal of Pancaked Return on Equity Complaints in light of the decision by the Court in April 2017 that became effective on June 8, 2017. The NETOs assert that all four complaints should be dismissed because the complainants have not shown that the existing ROE of 11.14% is unjust and unreasonable as the Court decision requires. In addition, the NETOs assert that Complaints II, III and IV should also be dismissed because the Court decision implicitly found that FERC's acceptance of Pancaked FPA Section 206 complaints was statutorily improper as Congress intended that the 15-month refund period under Section 206 applies whenever FERC does not complete its review of a complaint within the 15-month period. In the event FERC chooses not to dismiss the complaints, the NETOs request that FERC consolidate the complaints for decision as the evidentiary records are either closed or advanced enough for FERC to address the requirements of the Court decision and expeditiously issue a final order. FERC has not yet ruled on this Motion. We cannot predict the outcome of action by FERC.

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. FERC dismissed Renewables from the proceedings; however, the Ninth Circuit Court of Appeals reversed FERC's dismissal of Renewables.

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 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 an administrative law judge of FERC 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 contract that would justify finding the Renewables PPAs unjust and unreasonable. However, the proposed ruling did conclude that 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 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 to FERC briefs on exceptions to the administrative law judge's proposed ruling. There is no specific timetable to FERC's ruling. 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 2017 Windstorm

On March 11, 2017, the New York State Department of Public Service (the Department) commenced an investigation of NYSEG's and RG&E's preparation for and response to the March 2017 windstorm, which affected more than 219,000 customers. The Department investigation included a comprehensive review of NYSEG's and RG&E's preparation for and response to the windstorm, including all aspects of the companies' filed and approved emergency plan. The Department held public hearings on April 12 and 13, 2017.

On November 16, 2017, the NYPSC announced that the Department Staff had completed their investigation into the March 2017 Windstorm and the NYPSC issued an Order Instituting Proceeding and to Show Cause. The Staff's investigation found that RG&E and NYSEG violated certain parts of their emergency response plans, which makes them subject to possible financial penalties. NYSEG and RG&E responded to the order in a timely manner and have entered into settlement discussions with the Department Staff. The unprecedented weather that resulted in the March 2017 windstorm posed great challenges to the NYSEG's and RG&E's communities, employees, contractors, assisting utilities, and municipal partners who all worked tirelessly to safely restore power to all customers. NYSEG's and RG&E's priorities during any storm are the restoration of service to their respective customers and the safety of their communities, customers, employees and contractors. We cannot predict the outcome of this regulatory action.

Class Action Regarding LDC Gas Transportation Service on Algonquin Gas Transmission

On November 16, 2017, a class action lawsuit was filed in the U.S. District Court in 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 White Paper 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. The Company filed a Motion to Dismiss all of the claims on January 29, 2018. 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 White Paper. 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. Nevertheless, we cannot predict the outcome of this class action lawsuit.

Leases

Operating lease expense relating to operational facilities, office building leases, and vehicle and equipment leases was $71.5 million, $70.6 million and $47.7 million for the years ended December 31, 2017, 2016 and 2015, respectively. Amounts related to contingent payments predominantly linked to electricity generation at the respective facilities were $18.6 million, $22.2 million and $22.2 million for the years ended December 31, 2017, 2016 and 2015, 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 pays Cayuga a monthly fixed price and also pays for capital expenditures for specified capital projects. NYSEG is entitled to a share of any capacity and energy revenues earned by Cayuga. We account for this arrangement as an operating lease. The net expense incurred under this operating lease was $17.6 million, $37.8 million and $25.5 million for the years ended December 31, 2017, 2016 and 2015, respectively.

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 provides 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 $15.4 million. RG&E is entitled to 70% of revenues from GNPP’s sales into the energy and capacity markets, while GNPP is entitled to 30% of such revenues. We account for this arrangement as an operating lease. The net expense incurred under this operating lease was $5.6 million, $114.9 million and $79.9 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Total future minimum lease payments as of December 31, 2017 consisted of:

Year	Operating Leases	Capital Leases (Millions)	Total
2018	$ 36	$ 7	$ 43
2019	35	8	43
2020	36	8	44
2021	36	5	41
2022	31	2	33
Thereafter	757	47	804
Total	**$ 931**	**$ 77**	**$ 1,008**

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 US 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 UI's long-term contracts to purchase RECs and contractual obligations for property, plant and equipment, material and services on order but not yet delivered at December 31, 2017.

Power, Gas, and Other Arrangements – Renewables and Gas

Gas purchase commitments include multi-year contracted storage and transport capacity contracts that allow the Gas business to participate in seasonal and locational gas price differentials. The agreements contain fixed payment obligations for the use of both storage and transport capacity throughout the U.S. Power purchase commitments include the following: (i) a 55MW Biomass PPA for 12 years (four years remaining) with a guaranteed output of 34.4MW 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 three year purchase of hydro capacity and energy to provide balancing services to the NW wind assets that has monthly fixed payments (one year remaining) and (iv) a five 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 2023). Power sales commitments include: (i) a 55MW Biomass off-take agreement for 12 years (four years remaining) with guaranteed annual production of 34.4MW flat with a schedule of fixed price rates depending on season and time of day, (ii) fixed price, fixed volume power sales off the Klamath Cogen facility in addition to tolling arrangements that have fixed capacity charges and (iii) fixed price, fixed volume renewable energy credit sales off merchant wind facilities.

Forward purchases and sales commitments under power, gas, and other arrangements as of December 31, 2017 consisted of:

	Purchases				Sales			
Year	**Gas**	**Power**	**Other**	**Total**	**Gas**	**Power**	**Other**	**Total**
				(Millions)				
2018	$ 280	$ 171	$ 528	$ 979	$ 26	$ 127	$ 4	$ 157
2019	239	123	201	563	9	104	1	114
2020	186	102	39	327	7	71	—	78
2021	149	89	20	258	4	51	—	55
2022	120	63	12	195	—	23	—	23
Thereafter	638	443	100	1,181	—	42	—	42
Totals	**$ 1,612**	**$ 991**	**$ 900**	**$ 3,503**	**$ 46**	**$ 418**	**$ 5**	**$ 469**

Guarantee Commitments to Third Parties

As of December 31, 2017, we had approximately $2.4 billion 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, 2017, neither we nor our subsidiaries have any liabilities recorded for these instruments.

Note 13. 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. Fifteen 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, nine of the twenty-five sites are also included on the National Priorities list. Any liability may be joint and severable 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 ten sites where we believe it is probable that we will incur remediation costs and or monitoring costs, although we have not been notified that we are among the potentially responsible parties 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, 2017. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination, and the portion of remediation attributed to us.

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; twelve sites are included in the New York Voluntary Cleanup Program; three sites are part of Maine's Voluntary Response Action Program and with two of such sites being 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-nine of the fifty-three sites.

Our estimate for all costs related to investigation and remediation of the fifty-three sites ranges from $213 million to $442 million as of December 31, 2017. 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 other 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 in respect of these sites as of December 31, 2017 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, 2017 and 2016, the liability associated with 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 $100 million and $97 million, respectively.

The liability to investigate and perform remediation at the known inactive MGP sites and other sites was $389 million and $388 million as of December 31, 2017 and 2016, 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 2054.

FirstEnergy

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

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

FirstEnergy remains liable for a substantial share of clean up expenses at nine MPG sites. Based on current projections, FirstEnergy's share is estimated at approximately $22 million. This amount is being treated as a contingent asset and has not been recorded as either a receivable or a decrease to the environmental provision. Any recovery will be flowed through to NYSEG ratepayers.

Century Indemnity and OneBeacon

On August 14, 2013, NYSEG filed suit in federal court against two excess insurers, Century Indemnity and OneBeacon, who provided excess liability coverage to NYSEG. NYSEG seeks payment for clean-up costs associated with contamination at twenty-two former manufactured gas plants. Based on estimated clean-up costs of $282 million, the carriers' allocable share is approximately $89 million, excluding pre-judgment interest, although this amount may change substantially depending upon the determination of various factual matters and legal issues during the case.

Century Indemnity and OneBeacon have answered admitting issuance of the excess policies, but contesting coverage and providing documentation proving they received notice of the claims in the 1990s. On March 31, 2017, the District Court granted motions filed by Century Indemnity and One Beacon dismissing all of NYSEG's claims against both defendants on the grounds of late notice. NYSEG filed a motion with the District Court on April 14, 2017 seeking reconsideration of the Court's decision and is researching grounds for further appeal if the reconsideration motion is denied. We cannot predict the outcome of this matter, however, any recovery will be flowed through to NYSEG ratepayers.

English Station

In January 2012, Evergreen Power, LLC (Evergreen Power) and Asnat Realty LLC (Asnat), then and current 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 against UI seeking, among other things: (i) an order directing UI to reimburse the plaintiffs for costs they have incurred and will incur for the testing, investigation and remediation of hazardous substances at the English Station site and (ii) an order directing UI to investigate and remediate the site. This proceeding had been 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 in Connecticut state court seeking among other things: (i) remediation of the English Station site; (ii) reimbursement of remediation costs; (iii) termination of UI's easement rights; (iv) reimbursement for costs associated with securing the property; and (v) punitive damages. This lawsuit had been stayed in May 2014 pending mediation. Due to lack of activity in the case, the court terminated the stay and scheduled a status conference for July 6, 2017. On July 5, 2017, Asnat filed a pretrial memorandum claiming damages of $10 million for "environmental remediation activities" and lost use of the property. In December 2017 Plaintiffs filed a Request for Leave to Amend Complaint and Motion to Cite-In Additional Parties, including former UIL officers and employees and other UI officers, which motion was approved in February 2018. 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. Mediation of the matter began in the fourth quarter of 2013 and concluded unsuccessfully in April 2015. 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 the 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, 2017 we reserved $25 million for this matter. We cannot predict the outcome of this matter.

Note 14. Income Taxes

The Tax Act changes significantly the federal taxation of business entities, including among other things, a federal corporate tax rate decrease from 35% to 21% for tax years beginning after December 31, 2017. We have made a reasonable estimate of the effects of the Tax Act and recorded provisional amounts for the income tax effects related to the remeasurement of our deferred tax assets and liabilities and the associated regulatory liabilities established by our regulated utility companies in our consolidated financial statements as of December 31, 2017. As we complete our analysis of the Tax Act, collect and prepare necessary data, and interpret any additional guidance issued by the U.S. Treasury Department, the IRS, and other standard-setting bodies, we may make adjustments to the provisional amounts. Those adjustments may materially impact our provision for income taxes in the period in which the adjustments are made.

Current and deferred taxes charged to (benefit) expense for the years ended December 31, 2017, 2016 and 2015 consisted of:

Years Ended December 31,	2017	2016	2015
(Millions)			
Current			
Federal	$ (20)	$ (6)	$ (20)
State	12	8	(33)
Current taxes charged to (benefit) expense	**(8)**	**2**	**(53)**
Deferred			
Federal	(124)	412	131
State	(73)	2	(6)
Deferred taxes charged to (benefit) expense	**(197)**	**414**	**125**
Production tax credits	(53)	(38)	(42)
Investment tax credits	(1)	(1)	(1)
Total Income Tax (Benefit) Expense	**$ (259)**	**$ 377**	**$ 29**

The differences between tax expense per the statements of income and tax expense at the 35% statutory federal tax rate for the years ended December 31, 2017, 2016 and 2015 consisted of:

Years Ended December 31,	2017	2016	2015
(Millions)			
Tax expense at federal statutory rate	$ 43	$ 353	$ 106
Depreciation and amortization not normalized	9	61	15
Investment tax credit amortization	(1)	(1)	(1)
Tax return related adjustments	7	(2)	6
Production tax credits	(53)	(38)	(42)
Tax equity financing arrangements	(10)	(27)	(42)
Federal tax rate impact on held for sale classification	82	—	—
State tax (benefit) expense, net of federal benefit	(40)	7	(25)
Tax Act - remeasurement	(328)	—	—
Non-deductible acquisition costs	—	—	9
Other, net	32	24	3
Total Income Tax (Benefit) Expense	**$ (259)**	**$ 377**	**$ 29**

Deferred tax assets and liabilities as of December 31, 2017 and 2016 consisted of:

As of December 31, (Millions)	2017	2016
Non-current Deferred Income Tax Liabilities (Assets)		
Property related	$ 3,543	$ 5,195
Unfunded future income taxes	75	216
Federal and state tax credits	(574)	(417)
Accumulated deferred investment tax credits	14	14
Federal and state NOL's	(975)	(1,397)
Joint ventures/partnerships	302	565
Nontaxable grant revenue	(449)	(581)
Pension and other post-retirement benefits	(33)	52
Tax Act - tax on regulatory remeasurement	(401)	—
Other	(58)	(223)
Non-current Deferred Income Tax Liabilities	1,444	3,424
Add: Valuation allowance	21	31
Total Non-current Deferred Income Tax Liabilities	1,465	3,455
Less amounts classified as regulatory liabilities		
Non-current deferred income taxes	13	565
Non-current Deferred Income Tax Liabilities	$ 1,452	$ 2,890
Deferred tax assets	$ 2,490	$ 2,617
Deferred tax liabilities	3,955	6,072
Net Accumulated Deferred Income Tax Liabilities	$ 1,465	$ 3,455

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, 2017 and 2016 was $21 million and $31 million, respectively. Valuation allowances have been established on various state net operating losses and tax credit carryforwards. The Company has not recorded a valuation allowance on its federal net operating losses or tax credit carryforwards. The $10 million decrease (net of federal benefit) in valuation allowance was primarily driven by a reduction of $15.9 million for Connecticut general business credits resulting from a change in state tax law, an increase of $8.5 million for additional valuation on state net operating losses, a release of $5.3 million in Maine super credits, offset by an increase of $3.0 million resulting from the change in corporate tax rate from 35% to 21%, reducing the federal benefit of state taxes.

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2017, 2016 and 2015 consisted of:

Years ended December 31, (Millions)	2017	2016	2015
Beginning Balance	$ 40	$ 36	$ 38
Increases for tax positions related to prior years	23	8	1
Decreases for tax positions related to prior years	(16)	(4)	—
Reduction for tax position related to settlements with taxing authorities	(2)	—	(3)
Ending Balance	**$ 45**	**$ 40**	**$ 36**

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 $0.4 million, $2 million, and $2 million for the years ended December 31, 2017, 2016 and 2015, respectively. If recognized, $14 million of the total gross unrecognized tax benefits would affect the effective tax rate.

It is estimated that no unrecognized tax benefits are anticipated to result in a net increase or decrease within 12 months of December 31, 2017.

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. Generally, the adjustment period for the individual states we filed in is at least as long as the federal period.

As of December 31, 2017, UIL is subject to audit of its federal tax return for years 2013 and 2014. UIL income tax years 2010 through 2014 are open and subject to Connecticut and Massachusetts audit.

As of December 31, 2017, we had 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 $404 million, state tax net operating losses of $231 million in several jurisdictions and miscellaneous state tax credits of $37 million available to carry forward and reduce future income tax liabilities. For state purposes, we recognized a valuation allowance of $21 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.

Note 15. Post-retirement and Similar Obligations

Networks has funded noncontributory defined benefit pension plans that cover the majority of Networks employees. The plans provide defined benefits based on years of service and final average salary for employees hired before 2002. Most employees hired in 2002, or later based upon the plan, are covered under a cash balance plan or formula where their benefit accumulates based on a percentage of annual salary and credited interest. During 2013, 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 the cash balance plans 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 participate in an enhanced 401(k) plan.

Networks has other postretirement health care benefit plans covering the majority of Networks employees. 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 a majority of their union and management employees. The union plans are all closed to new hires, and the nonunion plans were closed as of December 31, 2017. These entities also have non-qualified supplemental pension plans for certain employees and retires. 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.

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 healthcare plans are contributory and participants' contributions are adjusted annually. For Medicare eligible non-union retirees, UI provides a subsidy through a Health Reimbursement Account 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 a majority of their employees. 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 a 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 funded defined benefit pension plans for eligible employees hired prior to January 1, 2008. The benefit is based on 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.

Obligations and funded status of Networks and ARHI as of December 31, 2017 and 2016 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2017**	**2016**	**2017**	**2016**
(Millions)				
Change in benefit obligation				
Benefit obligation as of January 1,	**$ 3,448**	**$ 3,509**	**$ 495**	**$ 525**
Service cost	42	44	4	5
Interest cost	139	142	22	21
Plan participants' contributions	—	—	7	7
Actuarial loss (gain)	188	(43)	3	(24)
Special termination benefits	—	—	—	—
Benefits paid	(219)	(204)	(39)	(39)
Reclassified to held for sale	(5)	—	(1)	—
Benefit Obligation as of December 31,	**3,593**	**3,448**	**491**	**495**
Change in plan assets				
Fair value of plan assets as of January 1,	**2,672**	**2,664**	**160**	**162**
Actual return on plan assets	382	169	17	11
Employer contributions	33	43	20	30
Plan participants' contributions	—	—	7	7
Benefits paid	(219)	(204)	(39)	(39)
Reclassified to held for sale	(3)	—	—	—
Withdrawals from VEBA	—	—	—	(11)
Fair Value of Plan Assets as of December 31,	**2,865**	**2,672**	**165**	**160**
Funded Status as of December 31,	**$ (728)**	**$ (776)**	**$ (326)**	**$ (335)**

Amounts recognized as of December 31, 2017 and 2016 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2017**	**2016**	**2017**	**2016**
(Millions)				
Current liabilities	$ —	$ —	$ (5)	$ (5)
Non-current liabilities	(728)	(776)	(321)	(330)
Total	**$ (728)**	**$ (776)**	**$ (326)**	**$ (335)**

Amounts recognized in OCI for ARHI for the years ended December 31, 2017, 2016 and 2015, consisted of:

	Pension Benefits			Postretirement Benefits		
Years Ended December 31,	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
(Millions)						
Net (gain) loss	$ 25	$ 23	$ 25	$ (4)	$ (3)	$ (1)

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, 2017, 2016 and 2015 for Networks consisted of:

Years Ended December 31,	Pension Benefits 2017	2016	2015	Postretirement Benefits 2017	2016	2015
(Millions)						
Net loss	$ 737	$ 860	$ 994	$ 35	$ 44	$ 76
Prior service cost (credit)	6	7	9	(31)	(40)	(49)

Our accumulated benefit obligation for all defined benefit pension plans of Networks and ARHI was $3,363 million and $3,214 million as of December 31, 2017 and 2016, respectively. CMP's and NYSEG's postretirement benefits were partially funded as of December 31, 2017 and 2016.

The projected benefit obligation (PBO) and the accumulated benefit obligation (ABO) exceeded the fair value of pension plan assets for all plans of Networks and ARHI as of December 31, 2017 and 2016.

The aggregate PBO and ABO and the fair value of plan assets for underfunded plans of Networks and ARHI as of December 31, 2017 and 2016 consisted of:

As of December 31,	PBO in excess of plan assets 2017	2016
(Millions)		
Projected benefit obligation	$ 3,593	$ 3,448
Fair value of plan assets	2,865	2,672

As of December 31,	ABO in excess of plan assets 2017	2016
(Millions)		
Accumulated benefit obligation	$ 3,363	$ 3,214
Fair value of plan assets	2,865	2,672

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, 2017, 2016 and 2015 consisted of:

(Millions) For the years ended December 31,	Pension Benefits 2017	2016	2015	Postretirement Benefits 2017	2016	2015
Net Periodic Benefit Cost:						
Service cost	$ 42	$ 44	$ 36	$ 5	$ 5	$ 4
Interest cost	137	140	97	21	20	15
Expected return on plan assets	(195)	(199)	(156)	(8)	(8)	(7)
Amortization of prior service cost (benefit)	2	2	3	(9)	(9)	(9)
Amortization of net loss	126	123	130	5	8	7
Special termination benefit charge	—	—	2	—	—	—
Settlement charge	—	—	2	—	—	—
Net Periodic Benefit Cost	**112**	**110**	**114**	**14**	**16**	**10**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities:						
Settlements	—	—	(2)	—	—	—
Net loss (gain)	3	(11)	69	(5)	(24)	(12)
Amortization of net loss	(126)	(123)	(130)	(5)	(8)	(7)
Current year prior service cost	—	—	—	—	—	(1)
Amortization of prior service (cost) benefit	(2)	(2)	(3)	9	9	9
Total Other Changes	**(125)**	**(136)**	**(66)**	**(1)**	**(23)**	**(11)**
Total Recognized	**$ (13)**	**$ (26)**	**$ 48**	**$ 13**	**$ (7)**	**$ (1)**

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, 2017, 2016 and 2015 consisted of:

(Millions)	Pension Benefits			Postretirement Benefits		
For the years ended December 31,	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Net Periodic Benefit Cost:						
Service cost	$ —	$ —	$ —	$ —	$ —	$ 1
Interest cost	2	2	2	1	1	1
Expected return on plan assets	(2)	(2)	(2)	—	—	—
Amortization of net loss	1	1	1	—	—	—
Settlement charge	—	1	—	—	—	—
Net Periodic Benefit Cost (income)	**1**	**2**	**1**	**1**	**1**	**2**
Other Changes in plan assets and benefit obligations recognized in OCI:						
Net loss (gain)	2	—	4	(1)	(2)	(8)
Amortization of net loss	(1)	(1)	(1)	—	—	—
Total Other Changes	**1**	**(1)**	**3**	**(1)**	**(2)**	**(8)**
Total Recognized	**$ 2**	**$ 1**	**$ 4**	**$ —**	**$ (1)**	**$ (6)**

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 net periodic benefit cost in other operating expenses net of capitalized portion.

Amounts expected to be amortized from regulatory assets or liabilities into net periodic benefit cost for the year ending December 31, 2018 consists of:

(Millions)	Pension Benefits	Postretirement Benefits
Estimated net loss	$ 150	$ 5
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, 2018 consists of:

(Millions)	Pension Benefits	Postretirement Benefits
Estimated net loss	$ 1	$ —
Estimated prior service cost (benefit)	—	—

We expect that no pension benefit or postretirement benefit plan assets will be returned to us during the year ending December 31, 2018.

The weighted-average assumptions used to determine benefit obligations for Networks and ARHI as of December 31, 2017 and 2016 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2017**	**2016**	**2017**	**2016**
Discount rate - Networks	3.63% / 3.80%	4.12% / 4.24%	3.63% / 3.80%	4.12% / 4.24%
Discount rate - ARHI	3.80%	3.81%	3.80%	3.81%
Rate of compensation increase - Networks	3.50% - 4.20%	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, 2017, 2016 and 2015 consisted of:

	Pension Benefits			Postretirement Benefits		
Years Ended December 31,	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Discount rate - Networks	4.12% / 4.24%	4.12% / 4.24%	3.80% / 4.24%	4.12% / 4.24%	4.12% / 4.24%	3.80% / 4.24%
Discount rate - ARHI	3.81%	3.90%	3.90%	3.81%	3.90%	3.90%
Expected long-term return on plan assets - Networks	7.00% / 7.50%	7.40% / 7.75%	7.50%	6.13%	7.16%	—
Expected long-term return on plan assets - ARHI	5.50%	5.50%	5.50%	5.50%	5.50%	5.75%
Expected long-term return on plan assets - nontaxable trust - Networks	—	—	—	6.50%	7.00%	7.50%
Expected long-term return on plan assets - taxable trust - Networks	—	—	—	4.25%	4.50%	5.00%
Rate of compensation increase - Networks	3.50% - 4.20%	3.50% - 4.20%	4.10%	—	—	—

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, 2017 and 2016 consisted of:

As of December 31,	**2017**	**2016**
Health care cost trend rate assumed for next year - Networks	6.75%/8.50%	7.00%/9.00%
Health care cost trend rate assumed for next year - ARHI	7.50%/8.50%	6.75%/8.50%
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	2026 / 2028	2026 / 2028
Year that the rate reaches the ultimate trend rate - ARHI	2028 / 2030	2026 / 2028

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

(Millions)	**1% Increase**	**1% Decrease**
Effect on total of service and interest cost	$ 1	$ (1)
Effect on postretirement benefit obligation	$ 15	$ (12)

Contributions

We make annual contributions in accordance with our funding policy of not less than the minimum amounts as required by applicable regulations. Networks expect to contribute $48 million to the pension benefit plans during 2018.

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, 2017 consisted of:

(Millions)	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
2018	$ 234	$ 33	$ —
2019	215	33	—
2020	218	33	—
2021	221	33	—
2022	225	33	—
2023 - 2027	1,122	165	4

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, was $55 million and $57 million at December 31, 2017 and 2016, respectively.

Plan Assets

Our pension benefits plan assets for Networks and ARHI are held in three master trusts. This 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.

Networks' asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets within broad categories of asset classes made up of Return-Seeking and Liability-Hedging investments. Within the Return-Seeking category, we have targets of 35%-54% in equity securities and 3%-20% in equity alternative investments. The Liability-Hedging asset class has a target allocation percentage of 43%-45%. Return-Seeking investments generally consist of domestic, international, global, and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking assets also include investments in real estate, absolute return, and strategic markets. 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.

ARHI's investment portfolio contains a diversified blend of equity, fixed income, and other investments. In ARHI's asset allocation policy we have established targets of 33% for equity investments, 50% for fixed income investments and 17% for other assets classes. 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 real estate, absolute return, and real return, 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, annual liability measurements, and periodic asset and liability studies.

The fair values of pension benefits plan assets, by asset category, as of December 31, 2017, consisted of:

As of December 31, 2017		**Fair Value Measurements**		
(Millions)	**Total**	**Level 1**	**Level 2**	**Level 3**
Asset Category				
Cash and cash equivalents	$ 18	$ —	$ 18	$ —
U.S. government securities	13	13	—	—
Common stocks	129	129	—	—
Registered investment companies	134	134	—	—
Corporate bonds	447	—	447	—
Preferred stocks	4	—	4	—
Equity commingled funds	436	186	250	—
Other, principally annuity, fixed income	553	—	553	—
	$ 1,734	**$ 462**	**$ 1,272**	**$ —**
Other investments measured at net asset value	1,131			
Total	**$ 2,865**			

The fair values of pension benefits plan assets, by asset category, as of December 31, 2016, consisted of:

As of December 31, 2016 *		**Fair Value Measurements**		
(Millions)	**Total**	**Level 1**	**Level 2**	**Level 3**
Asset Category				
Cash and cash equivalents	$ 49	$ —	$ 49	$ —
U.S. government securities	172	172	—	—
Common stocks	120	120	—	—
Registered investment companies	122	122	—	—
Corporate bonds	358	—	358	—
Preferred stocks	4	—	4	—
Equity commingled funds	371	—	371	—
Other, principally annuity, fixed income	386	—	386	—
	$ 1,582	**$ 414**	**$ 1,168**	**$ —**
Other investments measured at net asset value	1,090			
Total	**$ 2,672**			

*Certain amounts in this table have been reclassified to conform to 2017 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, common stocks and registered investment companies - at the closing price reported in the active market in which the security is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks - at the closing price reported in the active market in which the individual investment is traded.
- Equity commingled funds – the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.

- Other investments, principally annuity and fixed income - Level 1: at the closing price reported in the active market in which the individual investment is traded. Level 2: based on yields currently available on comparable securities of issuers with similar credit ratings. Level 3: when quoted prices are not available for identical or similar instruments, under a discounted cash flows approach that maximizes observable inputs such as current yields of similar instruments but includes adjustments for certain risks that may not be observable such as credit and liquidity risks.
- Other investments measured at net asset value (NAV) – alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

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 46%-66% for equity securities, 30%-31% for fixed income, and 3%-23% for all other investment types. In ARHI's asset allocation policy we have established targets of 48% in equity securities, 49% in fixed income and 3% in all other investment types. The target allocations within allowable ranges are further diversified into 27%-66% large cap domestic equities, 5% small cap domestic equities, 8% international developed market, and 6% emerging market equity securities. Fixed income investment targets and ranges are segregated into core fixed income at 24%-31%, global high yield fixed income at 4%, and international developed market debt at 3%. Other alternative investment targets are 6% for real estate, 6% for tangible assets, and 3%-11% for other funds. Systematic rebalancing within target ranges increases the probability that the annualized return on investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair value of other postretirement benefits plan assets, by asset category, as of December 31, 2017 consisted of:

As of December 31, 2017		Fair Value Measurements		
(Millions)	Total	Level 1	Level 2	Level 3
Asset Category				
Money market funds	$ 4	$ 4	$ —	$ —
Mutual funds, fixed	35	35	—	—
Government and corporate bonds	2	—	2	—
Mutual funds, equity	77	50	27	—
Common stocks	20	20	—	—
Mutual funds, other	27	19	8	—
Total	**$ 165**	**$ 128**	**$ 37**	**$ —**

The fair values of other postretirement benefits plan assets, by asset category, as of December 31, 2016 consisted of:

As of December 31, 2016		Fair Value Measurements		
(Millions)	Total	Level 1	Level 2	Level 3
Asset Category				
Money market funds	$ 6	$ 4	$ 2	$ —
Mutual funds, fixed	41	39	2	—
Government and corporate bonds	2	—	2	—
Mutual funds, equity	72	43	29	—
Common stocks	23	23	—	—
Mutual funds, other	16	9	7	—
Total	**$ 160**	**$ 118**	**$ 42**	**$ —**

Valuation Techniques

We value our postretirement benefits plan assets as follows:

- Money market funds and mutual funds - based upon quoted market prices in active markets.
- Government bonds, and common stocks - 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.

Pension and postretirement benefit plan equity securities did not include any Iberdrola common stock as of both December 31, 2017 and 2016.

Defined contribution plans

We also have defined contribution plans defined as 401(k)s. The annual contributions made through these plans for Networks and ARHI amounted to $36 million, $34 million and $17 million for 2017, 2016, and 2015 respectively.

Note 16. Equity

As of December 31, 2017, our share capital consisted of 500,000,000 shares of common stock authorized, 309,670,932 shares issued and 309,005,272 shares outstanding, 81.5% of which is 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 $13,653 million. As of December 31, 2016, our share capital consisted of 500,000,000 shares of common stock authorized, 309,600,439 shares issued and 308,993,149 shares outstanding, 81.5% of which was 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 $13,653 million. We had 485,810 and 491,459 shares of common stock held in trust and no convertible preferred shares outstanding as of December 31, 2017 and December 31, 2016, respectively. During the year ended December 31, 2017, we issued 70,493 shares of common stock and released 5,649 shares of common stock held in trust each having a par value of $0.01. During the year ended December 31, 2016, we issued 109,357 shares of common stock and released 135,014 shares of common stock held in trust each having a par value of $0.01.

On April 28, 2016, we entered into 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 179,850 treasury shares of common stock of AVANGRID as of December 31, 2017, 115,831 shares were repurchased during 2016 and 64,019 shares were repurchased in May 2017, all in the open market. The total cost of repurchases, including commissions, was $8 million as of December 31, 2017.

On December 15, 2015, the board of directors approved our common stock dividend, accounted for as a stock split. The stock split, effected through a stock dividend, resulted in the issuance of 252,234,989 shares, which in addition to the 243 previously existing shares increased the total shares outstanding to 252,235,232. The stock dividend was effective upon the board of directors' approval. All share and per share information included in the consolidated financial statements has been retroactively adjusted to reflect the impact of the stock dividend.

Accumulated OCI (Loss)

Accumulated OCI for the years ended December 31, 2017, 2016 and 2015 consisted of:

Accumulated Other Comprehensive Income (Loss)	As of December 31, 2014	2015 Change	As of December 31, 2015	2016 Change	As of December 31, 2016	2017 Change	As of December 31, 2017
(Millions)							
(Loss) gain on revaluation of defined benefit plans, net of income tax expense of $2.2 for 2015, and $4.3 for 2016	$ (25)	$ 4	$ (21)	$ 7	$ (14)	$ —	$ (14)
Loss for nonqualified pension plans, net of income tax expense (benefit) of $1.7 for 2015, $0.4 for 2016 and $0.2 for 2017	(11)	3	(8)	1	(7)	1	(6)
Unrealized (loss) gain on derivatives qualifying as cash flow hedges:							
Unrealized (loss) gain during period on derivatives qualifying as cash flow hedges, net of income tax expense (benefit) of $20.9 for 2015, $(15.8) for 2016 and $15.2 for 2017	(2)	33	31	(26)	5	25	30
Reclassification to net income of losses on cash flow hedges, net of income tax expense (benefit) of $4.9 for 2015, $(11.0) for 2016 and $9.3 for 2017 (a)	(61)	7	(54)	(16)	(70)	14	(56)
Gain (loss) on derivatives qualifying as cash flow hedges	(63)	40	(23)	(42)	(65)	39	(26)
Accumulated Other Comprehensive (Loss) Income	**$ (99)**	**$ 47**	**$ (52)**	**$ (34)**	**$ (86)**	**$ 40**	**$ (46)**

(a) Reclassification is reflected in the operating expenses line item in the consolidated statements of income.

Note 17. 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 2017, 2016 and 2015, 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, 2017, 2016 and 2015. In accordance with Accounting Standards Codification (ASC) Topic 260, Earnings per Share, we retroactively applied the stock split to prior periods presented.

The calculations of basic and diluted earnings per share attributable to AVANGRID for the years ended December 31, 2017, 2016 and 2015, consisted of:

Years Ended December 31,	2017	2016	2015
(Millions, except for number of shares and per share data)			
Numerator:			
Net income attributable to AVANGRID	$ 381	$ 632	$ 273
Denominator:			
Weighted average number of shares outstanding - basic	309,502,861	309,512,553	254,588,212
Weighted average number of shares outstanding - diluted	309,661,883	309,817,322	254,605,111
Earnings per share attributable to AVANGRID			
Earnings Per Common Share, Basic	$ 1.23	$ 2.04	$ 1.07
Earnings Per Common Share, Diluted	$ 1.23	$ 2.04	$ 1.07

Note 18. Variable Interest Entities

We participate in certain partnership arrangement that qualify as variable interest entities (VIEs). These arrangements consist of tax equity financing arrangements (TEFs) and partnerships in which an investor holds a noncontrolling interest and the investor 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 in substance real estate. Under existing guidance for real estate financings, the membership interests in the TEFs we sold to the third-party investors are reflected as a financing obligation in the consolidated balance sheets. We continue to fully consolidate the TEFs' assets and liabilities in the consolidated balance sheets and to report the results of the TEFs' operations in the consolidated statements of income. The presentation reflects revenues and expenses from the TEFs' operations on a fully consolidated basis. We consolidate the TEFs based on being the primary beneficiary for these VIEs. The liabilities are increased for cash contributed by the third-party investors, interest accrued, and the federal income tax impact to the third-party investors of the allocation of taxable income. Interest is accrued on the balance using the effective interest method and the third-party investors' targeted rate of return. The balance accrued interest at an average rate of 8.4% and 5.4% as of December 31, 2017 and 2016, respectively. The liabilities are reduced by cash distributions to the third-party investors, the allocation of production tax credits to the third-party investors, and the federal income tax impact to the third-party investors of the allocation of taxable losses.

The assets and liabilities of the VIEs totaled approximately $1,441 million and $185 million, respectively, at December 31, 2017. As of December 31, 2016 the assets and liabilities of VIEs totaled approximately $1,343 million and $244 million, respectively. At December 31, 2017 and 2016, the assets and liabilities of the VIEs consisted primarily of property, plant and equipment, equity method investments and other liabilities. At December 31, 2017 and 2016, equity method investments of VIEs were approximately $107 million and $161 million, respectively.

At December 31, 2017, we consider Aeolus Wind Power II LLC and Aeolus Wind Power IV LLC, (collectively, Aeolus) to be TEFs. In February and November 2017, we acquired the tax equity investor's interest in other TEFs, Locust Ridge Wind Farm, LLC and Aeolus Wind Power III LLC, for $5 million and $15 million, respectively. These acquisitions converted the partnerships to single member limited liability companies and they no longer qualify as VIEs. Lastly, at December 31, 2017, we consider El Cabo Wind, LLC to be a VIE.

We retain a class of membership interest and day-to-day operational and management control of Aeolus, subject to investor approval of certain major decisions. The third-party investors do not receive a lien on any Aeolus assets and have no recourse against us for their upfront cash payments.

Wind power generation is subject to certain favorable tax treatments in the U.S. In order to monetize the tax benefits generated by Aeolus, we have entered into the Aeolus structured institutional partnership investment transactions related to certain wind farms. Under the Aeolus 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 Aeolus 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 issuance of fixed and contingent notes.

The third party investors receive a disproportionate amount of the profit or loss, cash distributions and tax benefits resulting from the wind farm energy generation 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 Company taking a disproportionate share of such amounts 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.

Our Aeolus 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.

Note 19. Grants, Government Incentives and Deferred Income

The changes in deferred income as of December 31, 2017 and 2016 consisted of:

(Millions)	Government grants	Other deferred income	Total
As of December 31, 2015	$ 1,529	$ 24	$ 1,553
Additions	—	—	—
Recognized in income	(68)	(2)	(70)
As of December 31, 2016	$ 1,461	$ 22	$ 1,483
Additions	33	2	35
Reclassified to held for sale	—	(2)	(2)
Recognized in income	(67)	(3)	(70)
As of December 31, 2017	$ 1,427	$ 19	$ 1,446

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 14 – 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, 2017 and 2016.

Other deferred income relates predominantly to gas storage transactions where revenues are recognized as services are provided. As of December 31, 2017, we reclassified $2 million of other deferred income to liabilities held for sale in the consolidated balance sheet (see Note 25 - Assets Held for Sale). There was no amount classified as liabilities held for sale as of December 31, 2016.

Note 20. Equity method investments

We have a 50-50 joint venture with Shell Wind Energy, Inc., which owns and operates a 162- megawatt (MW) wind farm located in southeast Colorado (Colorado Wind Ventures LLC), which commenced operations in January 2004. We account for this venture under the equity method of accounting. The carrying amount of this investment was $18 million and $45 million as of December 31, 2017 and 2016, respectively. 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.

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 $120 million and $128 million for Flat Rock Wind Power LLC, and $57 million and $64 million for Flat Rock Wind Power II LLC, as of December 31, 2017 and 2016, respectively.

In 2017 we also acquired a 50% ownership in Vineyard Wind, LLC joint venture from Copenhagen Infrastructure Partners to build and operate the offshore wind facility to be developed off of Martha's Vineyard with a nameplate capacity of approximately 1,600 MW. We account for this venture under the equity method of accounting. The carrying amount of this investment was $10 million as of December 31, 2017.

Through UI, we are party to a 50-50 joint venture with NRG affiliates 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 $124 million and $128 million as of December 31, 2017 and 2016, respectively.

Networks holds an approximate 20% ownership interest in New York TransCo. New York TransCo was established by the New York transmission utilities to develop, own, and operate electric transmission in New York. The investment in New York TransCo is being accounted for as an equity investment, the carrying value of which was $23 million and $22 million as of December 31, 2017 and 2016, respectively (See also Note 23).

None of our joint ventures have any contingent liabilities or capital commitments. Distributions received from equity method investments amounted to $20 million, $20 million, and $12 million for the years ended December 31, 2017, 2016, and 2015 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 year ended December 31, 2017, we received $3.5 million of distributions in RECs from our equity method investments. As of December 31, 2017, there was an immaterial amount of undistributed earnings from our equity method investments.

During the year ended December 31, 2016, we completed the sale of our interest in Iroquois Gas Transmission System L.P. (Iroquois) to an unaffiliated third party for proceeds of $53.8 million and an impact to net income of $19.0 million. The carrying value of this equity method investment was $22 million.

Note 21. Other Financial Statements Items

Other income

Other income for the years ended December 31, 2017, 2016 and 2015 consisted of:

Years ended December 31, (Millions)	2017	2016	2015
Allowance for funds used during construction	$ 36	$ 26	$ 21
Carrying costs on regulatory assets	11	14	28
Other	11	36	7
Total Other Income	**$ 58**	**$ 76**	**$ 56**

In 2016 included in "Other" is a gain of $33 million resulted from the sale of our interest in Iroquois in 2016 (See Note 20).

Accounts Receivable

Accounts receivable as of December 31, 2017 and 2016 consisted of:

As of December 31, (Millions)	2017	2016
Trade receivables	$ 1,104	$ 1,183
Allowance for bad debts	(64)	(64)
Total Accounts Receivable	**$ 1,040**	**$ 1,119**

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, 2017 and 2016 consisted of:

(Millions)	
As of December 31, 2014	**$ 49**
Current period provision	46
Write-off as uncollectible	(33)
As of December 31, 2015	**$ 62**
Current period provision	48
Write-off as uncollectible	(46)
As of December 31, 2016	**$ 64**
Current period provision	69
Write-off as uncollectible	(69)
As of December 31, 2017	**$ 64**

DPA receivable balances were $55 million and $54 million as of December 31, 2017 and 2016, respectively.

Prepayments and Other Current Assets

Prepayments and other current assets as of December 31, 2017 and 2016 consisted of:

As of December 31, (Millions)	2017	2016
Prepaid other taxes	$ 194	$ 153
Broker margin and collateral accounts	32	32
Loans to third parties	2	3
Fixed-term deposits	—	3
Other pledged deposits	9	8
Prepaid expenses	33	53
Other	3	3
Total	**$ 273**	**$ 255**

Other Non-current Assets

Included in "Other non-current assets" as of December 31, 2016, are $186 million of safe harbor turbine payments made for production tax credit qualification purposes.

Other current liabilities

Other current liabilities as of December 31, 2017 and 2016 consisted of:

As of December 31, (Millions)	2017	2016
Advances received	$ 113	$ 107
Accrued salaries	87	84
Short-term environmental provisions	69	34
Collateral deposits received	43	45
Pension and other postretirement	5	5
Other	13	4
Total	**$ 330**	**$ 279**

Note 22. 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 three reportable segments:

- Networks: including all the energy transmission and distribution activities, and 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.
- Gas: including gas trading and storage businesses carried on by the AVANGRID Group

Products and services are sold between reportable segments and affiliate companies at cost. The chief operating decision maker evaluates segment performance based on segment adjusted EBITDA (Earnings Before Interest, Taxes, Depreciation and Amortization) defined as net income adding back net income attributable to other non-controlling interests, income tax expense, impairment, depreciation and amortization and interest expense net of capitalization, and then subtracting other income and (expense) and earnings from equity method investments per segment. Segment income, expense, and assets presented in the accompanying tables include all intercompany transactions that are eliminated in the consolidated financial statements.

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

For the year ended December 31, 2017 (Millions)	**Networks**	**Renewables**	**Gas**	**Other(a)**	**AVANGRID Consolidated**
Revenue - external	$ 4,950	$ 1,038	$ (26)	$ 1	$ 5,963
Revenue - intersegment	11	9	41	(61)	—
Impairment	—	—	642	—	642
Depreciation and amortization	474	325	25	—	824
Operating income (loss)	994	92	(701)	—	385
Adjusted EBITDA	1,468	417	(34)	—	1,851
Earnings (loss) from equity method investments	15	(55)	—	—	(40)
Interest expense, net of capitalization	244	28	24	(16)	280
Income tax expense (benefit)	316	(320)	(212)	(43)	(259)
Capital expenditures	1,305	1,097	7	7	2,416
As of December 31, 2017					
Property, plant and equipment	13,876	8,786	—	7	22,669
Equity method investments	147	205	—	—	352
Total assets	$ 21,411	$ 11,308	$ 383	$ (1,431)	$ 31,671

(a) Does not represent a segment. It mainly includes Corporate and intercompany eliminations.

Included in revenue-external for the year ended December 31, 2017 are: $3,585 million from regulated electric operations, $1,375 million from regulated gas operations and $(10) million from other operations of Networks; $1,038 million from renewable energy generation of Renewables; $(25) million from gas storage services and $1 million from gas trading operations of Gas.

AVANGRID made a net non-cash capital contribution of $921 million in Renewables in 2017, which was used by Renewables to settle outstanding intercompany debt payables of Gas segment accumulated prior to August 2017. The elimination of this activity between Renewables and Gas is included in Other at December 31, 2017.

Segment information as of and for the year ended December 31, 2016 consisted of:

For the year ended December 31, 2016 (Millions)	**Networks**	**Renewables**	**Gas**	**Other(a)**	**AVANGRID Consolidated**
Revenue - external	$ 5,027	$ 1,000	$ (7)	$ (2)	$ 6,018
Revenue - intersegment	3	15	39	(57)	—
Depreciation and amortization	466	313	25	—	804
Operating income (loss)	1,086	149	(41)	—	1,194
Adjusted EBITDA	1,552	462	(16)	—	1,998
Earnings (loss) from equity method investments	15	(8)	—	—	7
Interest expense, net of capitalization	252	50	25	(59)	268
Income tax expense (benefit)	415	7	(22)	(23)	377
Capital expenditures	1,140	561	6	—	1,707
As of December 31, 2016					
Property, plant and equipment	13,032	8,015	501	—	21,548
Equity method investments	151	236	—	—	387
Total assets	$ 20,753	$ 9,884	$ 1,124	$ (452)	$ 31,309

(a) Does not represent a segment. It mainly includes Corporate and intercompany eliminations.

Included in revenue-external for the year ended December 31, 2016 are: $3,686 million from regulated electric operations, $1,306 million from regulated gas operations and $35 million from other operations of Networks; $1,000 million from renewable energy generation of Renewables; $7 million from gas storage services and $(14) million from gas trading operations of Gas.

Segment information as of and for the year ended December 31, 2015 consisted of:

For the year ended December 31, 2015 (Millions)	Networks	Renewables	Gas	Other(a)	AVANGRID Consolidated
Revenue - external	$ 3,386	$ 1,051	$ (71)	$ 1	$ 4,367
Revenue - intersegment	—	16	52	(68)	—
Impairment	—	12	—	—	12
Depreciation and amortization	328	344	23	—	695
Operating income (loss) from continuing operations	537	100	(85)	(39)	513
Adjusted EBITDA	865	456	(62)	(39)	1,220
Earnings from equity method investments	1	(5)	—	4	—
Interest expense, net of capitalization	227	54	31	(45)	267
Income tax expense (benefit)	146	8	(44)	(81)	29
Capital expenditures	773	304	5	—	1,082
As of December 31, 2015					
Property, plant and equipment	12,363	7,835	513	—	20,711
Equity method investments	110	253	—	22	385
Total assets	$ 20,126	$ 10,685	$ 1,265	$ (1,333)	$ 30,743

(a) Does not represent a segment. It mainly includes Corporate and intercompany eliminations.

Included in revenue-external for the year ended December 31, 2015 are: $2,779 million from regulated electric operations, $605 million from regulated gas operations and $2 million from other operations of Networks; $1,051 million from renewable energy generation of Renewables; $21 million from gas storage services and $(92) million from gas trading operations of Gas.

Reconciliation of consolidated Adjusted EBITDA to the AVANGRID consolidated Net Income for the years ended December 31, 2017, 2016 and 2015, respectively, is as follows:

Years Ended December 31, (Millions)	2017	2016	2015
Consolidated Adjusted EBITDA	**$ 1,851**	**$ 1,998**	**$ 1,220**
Less:			
Impairment	642	—	12
Depreciation and amortization	824	804	695
Interest expense, net of capitalization	280	268	267
Income tax expense	(259)	377	29
Add:			
Other income	58	76	56
Earnings from equity method investments	(40)	7	—
Consolidated Net Income	**$ 382**	**$ 632**	**$ 273**

Note 23. 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, 2017, 2016 and 2015, respectively, consisted of:

Years Ended December 31,	2017		2016		2015	
(Millions)	Sales To	Purchases From	Sales To	Purchases From	Sales To	Purchases From
Iberdrola Financiación, S.A.	$ —	$ (2)	$ —	$ (2)	$ —	$ (1)
Iberdrola Renovables Energia, S.L.	—	(9)	—	(8)	—	(9)
Iberdrola Canada Energy Services, Ltd	—	(33)	—	(37)	—	(55)
Iberdrola, S.A.	1	(36)	—	(31)	—	(35)
Iberdrola Energia Monterrey, S.A. de C.V.	46	—	18	—	—	—
Other	1	(1)	3	(1)	3	(2)

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 $266 million and $269 million for the years ended December 31, 2017 and 2016, respectively. In addition, included in "Other non-current assets" were $92 million of safe harbor turbine payments we made to Siemens-Gamesa as of December 31, 2016 (see Note 21).

Related party balances as of December 31, 2017 and 2016, respectively, consisted of:

As of December 31,	2017		2016	
(Millions)	Owed By	Owed To	Owed By	Owed To
Iberdrola Canada Energy Services, Ltd	$ —	$ (31)	$ —	$ (14)
Siemens-Gamesa	2	(51)	1	(181)
Iberdrola, S.A.	1	(32)	—	(30)
Iberdrola Renovables Energía, S.L.	—	—	2	—
Iberdrola Energia Monterrey, S.A. de C.V.	1	—	11	—
Other	6	(4)	11	(3)

Transactions with our parent company, Iberdrola, relate predominantly to the provision and allocation of corporate services and management fees. Also included within the Purchases From category are charges for credit support relating to guarantees Iberdrola has provided to third parties guaranteeing our performance. 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 charge are allocated using agreed upon cost allocation methods designed to allocate those 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 generation facility at Klamath, Oregon. Included in the amounts owed to ICES is the balance of notes payable of $29 million and $10 million as of December 31, 2017 and December 31, 2016, respectively.

Transactions with Iberdrola Energia Monterrey predominantly relate to the sale of gas by 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, other than a $10 million write-off related to an arrangement to purchase turbines from Siemens-Gamesa, which was recorded in impairment in the consolidated statements of income for the year ended December 31, 2015.

Networks holds an approximate 20% ownership interest in the regulated New York TransCo. Through New York TransCo, Networks has formed a partnership with Central Hudson Gas and Electric Corporation, Consolidated Edison, Inc., National Grid, plc and Orange and Rockland Utilities, Inc. to develop a portfolio of interconnected transmission lines and substations to fulfill the objectives of the New York energy highway initiative, which is a proposal to install up to 3,200 MW of new electric generation and transmission capacity in order to deliver more power generated from upstate New York power plants to downstate New York. In 2016, Networks has increased its equity method investment in the New York TransCo by approximately $21 million (included in "Other investments and equity method investments, net" of investing activities in the consolidated statements of cash flows) for a total equity method investment of $22 million. Additionally, in 2016, Networks received approximately $67 million from the New York TransCo in the form of $43 million for assets constructed and transferred to the New York TransCo (included in "Proceeds from sale of property, plant and equipment" of investing activities in the consolidated statements of cash flows), $22 million in contributions in aid of construction and approximately $2 million in advanced lease payments for a 99 year lease of land and attachment rights. As of December 31, 2017 and 2016, the amount receivable from New York TransCo was $6 million and $11 million, respectively.

AVANGRID manages its overall liquidity position as part of the broader Iberdrola Group and is a party to a liquidity agreement with a financial institution, along with certain members of the Iberdrola Group. Cash surpluses remaining after meeting the liquidity requirements of AVANGRID and its subsidiaries may be deposited at the financial institution. Deposits, or credit balances, serve as collateral against the debit balances of other parties to the liquidity agreement. The balance at both December 31, 2017 and 2016, was zero.

Note 24. 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 March and October 2017 an additional 85,759 PSUs 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, 2017, 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 connection with the acquisition of UIL, certain PSUs granted under the UIL 2008 Stock and Incentive Compensation Plan are outstanding, which are payable in our shares in 2018 and vest based upon the achievement of certain pre-determined performance objectives.

The total stock-based compensation expense, which is included in operations and maintenance of the consolidated statements of income for the years ended December 31, 2017, 2016 and 2015 was $1.2 million, $0.6 million and $6.0, respectively. The total income tax benefit recognized for stock-based compensation arrangements for the years ended December 31, 2017, 2016 and 2015, was $0.5 million, $0.2 million and $2.4 million, respectively.

Before 2016, AVANGRID's historical stock-based compensation expense and liabilities were based on shares of Iberdrola and not on shares of AVANGRID. These Iberdrola shares-based awards were early terminated at the end of 2015, and the remaining liability will be settled in March 30, 2018. The total liability relating to those awards, which is included in other current and non-current liabilities, was $5.5 million and $9.5 million as of December 31, 2017 and 2016, respectively.

A summary of the status of the AVANGRID's nonvested PSUs as of December 31, 2017, and changes during the fiscal year ended December 31, 2017, is presented below:

	Number of PSUs	Weighted Average Grant Date Fair Value
Nonvested Balance – December 31, 2016	1,523,981	$ 33.01
Granted	94,509	$ 32.89
Forfeited	(113,256)	$ 31.91
Vested	(120,975)	$ 40.07
Nonvested Balance – December 31, 2017	1,384,259	$ 32.57

As of December 31, 2017, total unrecognized costs for non-vested PSUs were $5.1 million. The weighted-average period over which the PSU costs will be recognized is approximately 4 years.

The weighted-average grant date fair value of PSUs granted during the year was $32.89 per share for the year ended December 31, 2017.

Note 25. Assets Held For Sale

In December 2017, our management committed to a plan to sell the gas trading and storage businesses because they represent non-core businesses that are not aligned with our strategic objectives. As a result, 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. The gas trading and storage businesses are being marketed for sale, and it is the Company's intention to complete the sales of these assets and liabilities within twelve months following their initial classification as held for sale. 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) for $64.5 million, subject to working capital, cash, and other adjustments. The transaction price does not differ materially from the estimated fair value of our gas trading business at December 31, 2017, subject to adjustment based on closing and other contract provisions, including certain transition services. On February 16, 2018, the Company entered into a definitive agreement to sell Enstor Gas, LLC, which operates AVANGRID's gas storage business, to Amphora Gas Storage USA, LLC for $75 million, subject to working capital, cash, and other adjustments. The agreement to sell Enstor Gas, LLC contains, among other things, a transition services agreement which obligates ARHI to provide certain transition services for up to one year after the closing date and includes a guarantee that the Company will release certain obligations to Amphora Gas Storage USA, LLC, along with representations, warranties, and covenants customary for a transaction of this nature. The transaction, which is subject to the satisfaction of customary closing conditions, is expected to be completed during the second quarter of 2018. The transaction price differs from the estimated fair value of our gas storage business at December 31, 2017 by approximately $11 million, in which we expect to recognize an additional after-tax loss of $8.1 million in 2018, subject to additional adjustment based on closing and other contract provisions. In connection with the held for sale classification, we recorded a loss on held for sale measurement of $642 million, which is included in "Impairment" in the consolidated statements of income. Loss before income tax, adjusted for corporate overhead, attributed to the gas businesses was $715 million, $58 million and $108 million for the years ended December 31, 2017, 2016, and 2015, respectively. The current assets and current liabilities held for sale relating to our gas trading and storage businesses consisted of the following:

As of December 31,		**2017**
(Millions)		
Accounts receivable, net	$	137
Derivative assets		25
Fuel and gas in storage		77
Prepayments and other current assets		19
Property, plant and equipment		71
Intangible assets		28
Assets held for sale	**$**	**357**
Accounts payable and accrued liabilities		107
Derivative liabilities		14
Other liabilities		16
Liabilities held for sale	**$**	**137**

The fair values of the assets held for sale were determined using Level 3 inputs and were estimated based on recent market analysis studies, recent offers, and management has performed its own fair valuation modeling using discounted cash flows updated for market participant assumptions as completed by third party valuation firms. Unobservable inputs obtained from third parties were adjusted as necessary for the condition and attributes of the specific assets.

Note 26. Restructuring and Severance Related Expenses

In the second and third quarters of 2017, we announced targeted voluntary workforce reductions, predominantly within the Networks segment. Those actions primarily include: reducing our workforce through voluntary programs in various other 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. Those decisions and transactions resulted in restructuring charges recorded in the year ended December 31, 2017 for: severance expenses of $15.2 million and lease termination expenses of $4.0 million, which are included in "Operations and maintenance", and approximately $1.2 million of accelerated amortization of leasehold improvements, which are included in "Depreciation and amortization" in the consolidated statements of income. The remaining costs for severance agreements are being accrued ratably over the service periods, which span intermittent periods through December 2018. Accordingly, the Company expects additional costs to be incurred in 2018 related to the remaining employee service periods under the severance plans. For the year ended December 31, 2017, the severance and lease restructuring charges reserves, which are recorded in "Other current liabilities" and "Other liabilities", consisted of:

Year Ended December 31,		2017
		(Millions)
Beginning Balance	$	—
Restructuring and severance related expenses		19
Payments		(14)
Ending Balance	$	5

Note 27. Quarterly financial data (unaudited)

Selected quarterly financial data for 2017 and 2016 are set forth below:

(Millions, except per share data)		1st Quarter		2nd Quarter		3rd Quarter		4th Quarter
2017								
Operating revenues	$	1,758	$	1,331	$	1,341	$	1,533
Operating Income	$	398	$	223	$	189	$	(425)
Net Income	$	239	$	120	$	100	$	(77)
Net Income attributable to Avangrid, Inc.	$	239	$	120	$	99	$	(77)
Earnings Per Common Share, Basic and Diluted: (1)	$	0.77	$	0.39	$	0.32	$	(0.25)
2016								
Operating revenues	$	1,670	$	1,439	$	1,418	$	1,491
Operating Income	$	349	$	322	$	217	$	306
Net Income	$	213	$	101	$	109	$	209
Net Income attributable to Avangrid, Inc.	$	213	$	101	$	109	$	209
Earnings Per Common Share, Basic and Diluted: (1)	$	0.69	$	0.33	$	0.35	$	0.67

(1) Based on weighted average number of 309.5 million and 309.8 million shares outstanding each quarter in 2017 and 2016 for basic and diluted earnings per share, respectively.

The first quarter of 2017 includes an adjustment of $14 million to unfunded future income tax to reflect the change from a flow through to normalization method, which was recorded as an increase to income tax expense and an offsetting increase to revenue. The third and fourth quarters of 2017 include severance and lease restructuring charges of, respectively, $2.1 million and $17.1 million. Additionally the fourth quarter includes a loss of $642 million associated with measurement of held for sale assets of gas trading and storage business, $463 million after income taxes, and an impact of $328 million from measurement of deferred income tax balances as a result of the Tax Act enacted on December 22, 2017 by the U.S. federal government.

The first quarter of 2016 includes a $19.0 million impact to net income from the sale of our interest in Iroquois to an unaffiliated third party for proceeds of $53.8 million. The second quarter of 2016 includes an adjustment of $126 million to unfunded future income tax to reflect the change from a flow through to normalization method following the approval of the Joint Proposal by the NYPSC, which was recorded as an increase to income tax expense and an offsetting increase to revenue.

Note 28. Subsequent events

On February 15, 2018, the board of directors of AVANGRID declared a quarterly dividend of $0.432 per share on its common stock. This dividend is payable on April 2, 2018 to shareholders of record at the close of business on March 9, 2018.

On March 7, 2018, we issued 81,208 shares of common stock, each having a par value of $0.01, which was approved by the board of directors of AVANGRID on February 15, 2018.

Schedule I –Financial Statements of Parent

AVANGRID, INC. (PARENT)
CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF INCOME
FOR THE YEARS ENDED DECEMBER 31, 2017, 2016, AND 2015
(Millions)

Years Ended December 31,	2017	2016	2015
Operating Revenues	$ —	$ —	$ —
Operating Expenses			
Operating expense	3	5	38
Taxes other than income taxes	5	5	5
Total Operating Expenses	8	10	43
Operating Loss	(8)	(10)	(43)
Other Income and (expense)			
Other income and (expense)	58	68	10
Equity earnings of subsidiaries	312	567	50
Interest expense	(29)	(32)	(14)
Income Before Income Tax	333	593	3
Income tax benefit	(48)	(39)	(270)
Net Income	**$ 381**	**$ 632**	**$ 273**

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, 2017, 2016, AND 2015
(Millions)

Years Ended December 31,	2017	2016	2015
Net Income	$ 381	$ 632	$ 273
Other comprehensive income (loss) of subsidiaries	40	(34)	47
Comprehensive Income	**$ 421**	**$ 598**	**$ 320**

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, 2017 AND 2016
(Millions)

As of December 31,	2017	2016
Assets		
Current Assets		
Cash and cash equivalents	$ 8	$ 67
Accounts receivable from subsidiaries	55	66
Notes receivable from subsidiaries	1,129	1,908
Prepayments and other current assets	—	11
Total current assets	1,192	2,052
Investments in subsidiaries	15,531	14,183
Other assets		
Deferred income taxes	285	220
Other	9	3
Total other assets	294	223
Total Assets	**$ 17,017**	**$ 16,458**
Liabilities		
Current Liabilities		
Current portion of debt	$ 7	$ 8
Notes payable	507	150
Notes payable to subsidiaries	208	454
Accounts payable and accrued liabilities	6	4
Accounts payable to subsidiaries	1	3
Interest accrued	8	6
Interest accrued subsidiaries	4	29
Dividends payable	134	134
Taxes accrued	8	2
Other current liabilities	—	3
Total current liabilities	883	793
Non-current debt	1,057	470
Total non-current liabilities	1,057	470
Total Liabilities	**1,940**	**1,263**
Equity		
Stockholders' Equity:		
Common stock	3	3
Additional paid-in capital	13,653	13,653
Treasury Stock	(8)	(5)
Retained earnings	1,475	1,630
Accumulated other comprehensive loss	(46)	(86)
Total Equity	**15,077**	**15,195**
Total Liabilities and Equity	**$ 17,017**	**$ 16,458**

See accompanying notes to Schedule I.

Schedule I –Financial Statements of Parent

AVANGRID, INC. (PARENT)
CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2017, 2016, AND 2015
(Millions)

Years Ended December 31,	**2017**	**2016**	**2015**
Net Cash (used in) provided by Operating Activities	**$ (1)**	**$ 324**	**$ (380)**
Cash Flow from Investing Activities			
Notes receivable from subsidiaries	(532)	(627)	317
Acquisition of subsidiary	—	—	(595)
Investments in subsidiaries	—	(533)	—
Return of capital from investments in subsidiaries	308	420	1,111
Net Cash (used in) provided by Investing Activities	**(224)**	**(740)**	**833**
Cash Flow from Financing Activities			
Proceeds (repayments) of short-term notes payable from subsidiaries, net	(246)	133	(331)
Proceeds from short-term notes payable	357	150	—
Proceeds of non-current debt	594	483	—
Repurchase of common stock	(3)	(5)	—
Issuance of common stock	(1)	(2)	—
Dividends paid	(535)	(401)	—
Net Cash provided by (used in) Financing Activities	**166**	**358**	**(331)**
Net (Decrease) Increase in Cash and Cash Equivalents	**(59)**	**(58)**	**122**
Cash and Cash Equivalents, Beginning of Year	**$ 67**	**$ 125**	**$ 3**
Cash and Cash Equivalents, End of Year	**$ 8**	**$ 67**	**$ 125**
Supplemental Cash Flow Information			
Cash paid for interest	$ 52	$ 4	$ 20
Cash (refund) payment for income taxes	(8)	71	—

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 2017 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.

Immaterial Corrections to Prior Periods

During the year ended December 31, 2017, a correction necessary to certain subsidiary's deferred income tax liabilities associated with tax equity financing arrangements that originated in prior periods was identified. AVANGRID assessed the materiality and determined that the cumulative impact of the amount was not material to the results of operation, financial position or cash flows in the previously issued financial statements and therefore, amendments of previously filed condensed financial information of AVANGRID are not required. However, management has determined to revise the prior periods included within these financial statements to reflect these updated amounts. Accordingly, the correction of these prior period amounts has been reflected in the periods in which they originated and the statements of income for the years ended December 31, 2016 and 2015 and the balance sheet as of December 31, 2016 have been revised. The correction resulted in a $2 million and $6 million increase in equity earnings and net income in the statements of income for the years ended December 31, 2016 and 2015, respectively, and an $86 million increase in retained earnings and investments in subsidiaries in the balance sheet as of December 31, 2016. The revision had no net impact on the net cash provided by operating activities for the years ended December 31, 2016 and 2015.

Note 2. Acquisition of UIL and Issuance of Common Stock

On December 16, 2015 (acquisition date), UIL Holdings Corporation, a Connecticut corporation (UIL), became a wholly-owned subsidiary of AVANGRID as a result of the merger of Green Merger Sub, Inc., a Connecticut corporation and a wholly-owned subsidiary of AVANGRID (Merger Sub), with UIL, with Merger Sub surviving as a wholly-owned subsidiary of AVANGRID (the acquisition). The acquisition was effected pursuant to the Agreement and Plan of Merger, dated as of February 25, 2015, by and among AVANGRID, Merger Sub, and UIL. Following the completion of the acquisition, Merger Sub was renamed "UIL Holdings Corporation." In connection with the acquisition, AVANGRID issued 309,490,839 shares of its common stock, out of which 252,234,989 shares were issued to Iberdrola through a stock dividend, accounted for as a stock split, with no change to par value, at par value of $0.01 per share, and 57,255,850 shares (including held in trust as treasury stock) were issued to UIL shareowners in addition to payment of $10.50 in cash per each share of the common stock of UIL issued and outstanding at the acquisition date. 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.

AVANGRID had 485,810 and 491,459 shares of common stock held in trust and no convertible preferred shares outstanding as of December 31, 2017 and December 31, 2016, respectively. During the year ended December 31, 2017, AVANGRID issued 70,493 shares of common stock and released 5,649 shares of common stock held in trust each having a par value of $0.01. During the year ended December 31, 2016, AVANGRID issued 109,357 shares of common stock and released 135,014 shares of common stock held in trust each having a par value of $0.01.

On April 28, 2016, AVANGRID entered into 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 179,850 treasury shares of common stock of AVANGRID as of December 31, 2017, 115,831 shares were repurchased during 2016 and 64,019 shares were repurchased in May 2017, all in the open market. The total cost of repurchase, including commissions, was $8 million as of December 31, 2017.

On February 15, 2018, the board of directors of AVANGRID declared a quarterly dividend of $0.432 per share on its common stock. This dividend is payable on April 2, 2018 to shareholders of record at the close of business on March 9, 2018.

Note 3. Non-current 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 the predecessor company to UIL in 2010. 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.

Note 4. Cash Dividends Paid by Subsidiaries

Cash dividends paid by subsidiaries are as follows:

Years ended December 31,	2017	2016	2015
(In millions)			
AVANGRID Networks	$ 308	$ 220	$ 59
AVANGRID Renewables	—	200	750
Other AVANGRID subsidiaries	—	—	302
	$ 308	$ 420	$ 1,111

In December 2016, AVANGRID made a capital contribution of $50 million to its subsidiary, CMP. During 2017 and 2016, AVANGRID recorded a net non-cash contribution and dividend of $1,318 million and $(827) 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 not effective, due to a material weakness in internal control over financial reporting described below.

To address the material weakness described below, management completed additional procedures prior to filing this Annual Report on Form 10-K. Based on these procedures, notwithstanding the 2017 material weakness, management believes that our consolidated financial statements included in this Annual Report on Form 10-K have been prepared in accordance with generally accepted accounting principles. Our CEO and CFO have certified that, based on such officer’s knowledge, the financial statements, and other financial information included in this Annual Report on Form 10-K, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this Annual Report on Form 10-K.

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, 2017. 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 upon that assessment and those criteria, management has identified certain deficiencies that rose to the level of a material weakness in controls related to the measurement and disclosure of income taxes, or the 2017 material weakness.

A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis.

Control deficiencies that aggregated to a material weakness in 2016 contributed to immaterial corrections of prior period amounts as disclosed in the Company’s Form 10-K in Note 2 of the Company’s 2017 consolidated financial statements.

AVANGRID’s independent registered public accounting firm, KPMG LLP, has expressed an adverse report on the effectiveness of AVANGRID’s internal control over financial reporting as of December 31, 2017, which appears in Part II, Item 8, “Financial Statements and Supplementary Data – Report of Independent Registered Public Accounting Firm,” of this Annual Report on Form 10-K.

Changes in Internal Control

Other than the control deficiencies discussed above in connection with the 2017 material weakness and the remediation efforts identified below to remediate the first and second of the 2016 material weaknesses disclosed in the 2016 Form 10-K, 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 period covered by this Annual Report on Form 10-K that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Remediation Efforts Related to the 2016 Material Weaknesses

As disclosed in Part II. Item 9A. Controls and Procedures in our Annual Report on Form 10-K for the year ended December 31, 2016, we identified three material weaknesses in internal control over financial reporting, or the 2016 material weaknesses, related to (1) the accounting for the change in the estimated useful life of certain elements of the wind farms at Renewables and other smaller deficiencies related to documentation of internal controls procedures, and enhancement of review controls at Renewables, (2) the preparation of the consolidated financial statements, specifically the classification and disclosure of financial information, and (3) the measurement and disclosure of income taxes.

Our management, with oversight from the Audit and Compliance Committee of the Board of Directors, conducted the following remediation efforts that effectively remediated items 1 and 2 of the 2016 material weaknesses as of December 31, 2017:

- Educated and re-trained internal control employees regarding internal control processes to mitigate identified risks and maintain adequate documentation to evidence the effective design and operation of such processes;
- Implemented and enhanced controls to monitor the effectiveness of the underlying business process controls that depend on the data and financial reports generated from the relevant information systems;
- Increased accounting personnel and internal control resources in order to devote additional time to accounting and reporting processes and controls;
- Implemented and enhanced additional management review controls for the Renewables business and in the preparation of the consolidated financial statements;
- Finalized implementation of controls previously designed during the third and fourth quarters of 2016 and further enhanced during 2017;
- Implemented specific enhanced review procedures in the property, plant and equipment area at Renewables, including the estimation of useful lives; and
- Identified and implemented internal control activities where control activities related to certain financial statement assertions could be performed at lower levels of management (e.g., completeness and accuracy of data) to allow senior management to focus their review on higher risk and technical areas.

Remediation Plans for the 2017 Material Weakness

Our management, with oversight from the Audit and Compliance Committee of the Board of Directors, is actively engaged in remediation efforts to address the 2017 material weakness. The remediation plans for the 2017 material weakness include the following:

- Further acceleration of the deadline of key activities to allow sufficient time for the execution of consolidated deferred income tax controls that were newly designed during the third and fourth quarter of 2017 that management has determined through testing are more precise;
- Further increase of capabilities of income tax accounting resources to devote additional time and internal control resources to consolidated income tax accounting and reporting processes and controls; and
- Enhancing the automation of income tax processes and controls to allow for the more timely completion and enhanced review of internal controls surrounding consolidated deferred income tax financial information and disclosures.

These improvements are targeted at strengthening the Company’s internal control over financial reporting and remediating the material weakness. The remediation efforts that had been previously initiated were impacted by the required implementation of the Tax Cuts and Jobs Act of 2017 enacted by the U.S. federal government on December 22, 2017.

Nevertheless, the Company remediated a number of aspects of the material weakness for the measurement and disclosure of income taxes disclosed within Part II. Item 9A. Controls and Procedures in our Annual Report on Form 10-K for the year ended December 31, 2016 including the following:

- Implemented enhanced review procedures through the completion of a full risk assessment for income taxes and enhanced the design of controls for an increased level of precision;
- Accelerated all key activities within the income tax accounting and reporting process and controls;
- Educated and re-trained income tax employees regarding internal controls;
- Increased certain capabilities of income tax accounting resources to devote additional time and internal control resources; and

- Identified areas where income tax control activities could be performed at lower levels of management to allow senior management to focus their review on higher risk and technical areas.

The Company remains committed to an effective internal control environment and management believes that these actions, and the improvements management expects to achieve as a result, will remediate the material weakness. However, the material weakness in our internal control over financial reporting will not be considered remediated until the controls operate for a sufficient period of time and management has concluded, through testing that these controls operate effectively. We currently expect that the remediation of this material weakness will be completed by December 31, 2018.

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 2018 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2017.

Item 11. ***Executive Compensation.***

The information required by this item is incorporated by reference to our Proxy Statement for the 2018 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2017.

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 2018 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2017.

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 2018 Annual Meeting of Shareholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2017.

Item 14. ***Principal Accounting Fees and Services.***

The information required by this item is incorporated by reference to our Proxy Statement for the 2018 Annual Meeting of Shareholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2017.

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).
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).

Exhibit Number	Exhibit Description
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	Iberdrola USA Networks, Inc. Annual Incentive Plan, amended and restated January 1, 2014 (incorporated herein by reference to Exhibit 10.21 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015).†
10.9	Iberdrola USA, Inc. Performance Share Plan effective as of January 1, 2009 (incorporated herein by reference to Exhibit 10.22 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015). †
10.10	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). †
10.11	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). †
10.12	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).†
10.13	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).
10.14	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).
10.15	Agreement and Release dated September 25, 2009 between Robert Daniel Kump and Iberdrola USA Management Corporation (formerly Energy East Management Corporation) (incorporated herein by reference to Exhibit 10.31 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015). †
10.16	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).†
10.17	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).†
10.18	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).†
10.19	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).†
10.20	Employment Agreement, dated as of July 8, 2005, between The United Illuminating Company and Richard J. Nicholas (incorporated herein by reference to Exhibit 10.4 of UIL Holdings Corporation's Current Report on Form 8-K filed with the Securities and Exchange Commission on July 11, 2005).†
10.21	First Amendment, dated August 4, 2008, to Employment Agreement, dated as of July 8, 2005, between The United Illuminating Company and Richard J. Nicholas (incorporated herein by reference to Exhibit 10.14a of UIL Holdings Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).†

Exhibit Number	Exhibit Description
10.22	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).†
10.23	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).†
10.24	Amended and Restated Employment Agreement, dated as of June 14, 1999, among Avangrid, Inc. (formerly Energy East Corporation), Central Maine Power Company and Sara J. Burns (incorporated herein by reference to Exhibit 10.2 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016).†
10.25	Employment Agreement, dated as of January 1, 2012, among Central Maine Power Company, Avangrid, Inc. (formerly Iberdrola USA, Inc.) and Sara J. Burns (incorporated herein by reference to Exhibit 10.3 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016).†
10.26	Agreement and Release, dated as of November 25, 2009, between Central Maine Power Company and Sara J. Burns (incorporated herein by reference to Exhibit 10.4 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016).†
10.27	Revolving Credit Agreement, dated April 5, 2016, 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 and The Berkshire Gas Company, as Borrowers, the Lenders, JPMorgan Chase Bank N.A., as Administrative Agent, Bank of America, N.A., as Syndication Agent, and J.P. Morgan Chase Bank, N.A, Merrill Lynch, Pierce, Fenner & Smith Incorporated, The Bank of Tokyo-Mitsubishi UFJ, Ltd. and Santander Bank, N.A. as Joint Lead Arrangers and Joint Bookrunners (incorporated herein by reference to Exhibit 10.1 to AVANGRID's Current Report on Form 8-K filed with the SEC on April 5, 2016).
10.28	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).
10.29	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).
10.30	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).†
10.31	Avangrid, Inc. Omnibus Incentive Plan (incorporated herein by reference to Form S-8 filed with the SEC on July 21, 2016).†
10.32	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).
10.33	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).
10.34	Avangrid, Inc. Executive Annual Incentive Plan (incorporated herein by reference to Exhibit 10.1 to AVANGRID's Current Report on Form 8-K filed with the SEC on February 23, 2017).†
10.35	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).†
10.36	Offer Letter, dated March 5, 2015, between Sheila Duncan and Avangrid Management Company (as assignee of Avangrid Service Company, which was formerly known as Iberdrola USA Management Corporation) (incorporated herein by reference to Exhibit 10.2 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017).†
10.37	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.*

Exhibit Number	Exhibit Description
10.38	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).
21.1	Significant subsidiaries of the Registrant.*
23.1	Consent of KPMG LLP, independent registered public accounting firm of Avangrid, Inc.*
23.2	Consent of Ernst & Young LLP, independent registered public accounting firm of Avangrid, Inc.*
31.1	Chief Executive Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
31.2	Chief Financial Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
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	XBRL Instance Document.*
101.SCH	XBRL Taxonomy Extension Schema Document.*
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.*
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.*
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.*
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.*

* Filed herewith.
† Compensatory plan or agreement.
0 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.

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 26, 2018

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 26, 2018
/s/ Richard J. Nicholas Richard J. Nicholas	Chief Financial Officer (Principal Financial Officer)	March 26, 2018
/s/ Daniel Alcain Daniel Alcain	Controller (Principal Accounting Officer)	March 26, 2018
/s/ Ignacio Sánchez Galán Ignacio Sánchez Galán	Chairman of the Board	March 26, 2018
/s/ John E. Baldacci John E. Baldacci	Director	March 26, 2018
/s/ Pedro Azagra Blázquez Pedro Azagra Blázquez	Director	March 26, 2018
/s/ Arnold L. Chase Arnold L. Chase	Director	March 26, 2018
/s/ Alfredo Elías Ayub Alfredo Elías Ayub	Director	March 26, 2018
/s/ Carol L. Folt Carol L. Folt	Director	March 26, 2018
/s/ John L. Lahey John L. Lahey	Director	March 26, 2018
/s/ Santiago Martinez Garrido Santiago Martinez Garrido	Director	March 26, 2018
/s/ Juan Carlos Rebollo Liceaga Juan Carlos Rebollo Liceaga	Director	March 26, 2018
/s/ José Sáinz Armada José Sáinz Armada	Director	March 26, 2018
/s/ Alan D. Solomont Alan D. Solomont	Director	March 26, 2018
/s/ Elizabeth Timm Elizabeth Timm	Director	March 26, 2018
/s/ Felipe de Jesús Calderón Hinojosa Felipe de Jesús Calderón Hinojosa	Director	March 26, 2018

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 26, 2018

/s/ James P. Torgerson
James P. Torgerson
Director and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Richard J. Nicholas, 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 26, 2018

/s/ Richard J. Nicholas
Richard J. Nicholas
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 Richard J. Nicholas, 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 26, 2018

/s/ Richard J. Nicholas
Richard J. Nicholas
Chief Financial Officer
Avangrid, Inc.
March 26, 2018

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Additional Information

Executive Offices

Avangrid, Inc.
180 Marsh Hill Road
Orange, CT 06477
207.629.1200
www.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."

Annual Meeting

The 2018 annual meeting of shareholders will be held at 10:30 a.m. (local time) on June 7, 2018, at WilmerHale, 60 State Street, Boston, Massachusetts.

Financial Information

Comprehensive financial and other information about Avangrid, Inc. can be obtained by visiting the Investor Relations section of our website at **www.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 and Secretary;
Chief Compliance Officer
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 **www.avangrid.com**. In addition, our website allows investors and other interested persons to sign up to automatically receive email alerts when the company posts news releases, SEC filings and certain other information on our website.

Shareholder Inquiries

Shareholder inquiries can be directed to Investor Relations via email at **Investors@avangrid.com** or by writing to:

Investor Relations
Avangrid, Inc.
180 Marsh Hill Road
Orange, CT 06477

Transfer Agent and Registrar

Shareholders with inquiries regarding address corrections, dividend payments, lost certificates or changes in registered ownership should contact the Avangrid, Inc. stock transfer agent:

Broadridge Corporate Issuer Solutions, Inc.
Brentwood, NY 11717
P.O. Box 1342
1.877.681.8024
shareholder@broadridge.com

2017 Sustainability Report

Copies of the company's 2017 Sustainability Report can be obtained on by visiting our website at **www.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 2017 Annual Report for any purpose.

AVANGRID