SECURITIES AND EXCHANGE COMMISSION

FORM 10-K

Annual report pursuant to section 13 and 15(d)

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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, 2016

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	**4911**	**14-1798693**
(State or other jurisdiction of incorporation or organization)	**(Primary Standard Industrial Classification Code Number)**	**(I.R.S. Employer Identification No.)**
157 Church Street New Haven, Connecticut		**06506**
(Address of principal executive offices)		**(Zip Code)**

Telephone: (207) 688-6000

(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 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, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer	☒	Accelerated filer ☐
Non-accelerated filer	☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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, 2016) was $2,576 million based on a closing sales price of $46.06 per share.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: 309,068,730 shares of common stock, par value $0.01, were outstanding as of March 9, 2017.

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 2017 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, the terms "we," and "our" are used to refer to AVANGRID and its 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 Group refers to the group of companies controlled by Iberdrola, S.A.

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

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 proposal, filed with the NYPSC on February 19, 2016 by NYSEG, RG&E and 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.

Yankee Companies refers to the Maine Yankee Atomic Power Company, the Connecticut Yankee Power Corporation, and the Yankee Atomic Energy Corporation.

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
BMG	Bank Mendes Gans, N.V.

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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
CNG	Connecticut Natural Gas Corporation
DCF	Discounted cash flow
DEEP	Connecticut Department of Energy and Environmental Protection
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
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.

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HLPSA	Hazardous Liquids Pipeline Safety Act of 1979
IRP	Interstate Reliability Project
IRS	Internal Revenue Service
ISO	Independent system operator
ISO-NE	ISO New England, Inc.
Kinder Morgan	Kinder Morgan, Inc.
kV	Kilovolts
kWh	Kilowatt-hour
LIBOR	London Interbank Offer Rate
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
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

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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
OATT	Open Access Transmission Tariiff
OCC	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.
TEF	Tax equity financing arrangements
TGP	Tennessee Gas Pipeline Company LLC
TOTS	Transmission Owner Transmission Solutions

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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

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

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. 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,” “can,” “expects,” “believes,” “anticipates,” “intends,” “plans,” “estimates,” “projects,” “assumes,” “guides,” “targets,” “forecasts,” “is confident that” and “seeks” 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 beliefs and expectations 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 of the Company;
- 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 report. 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.

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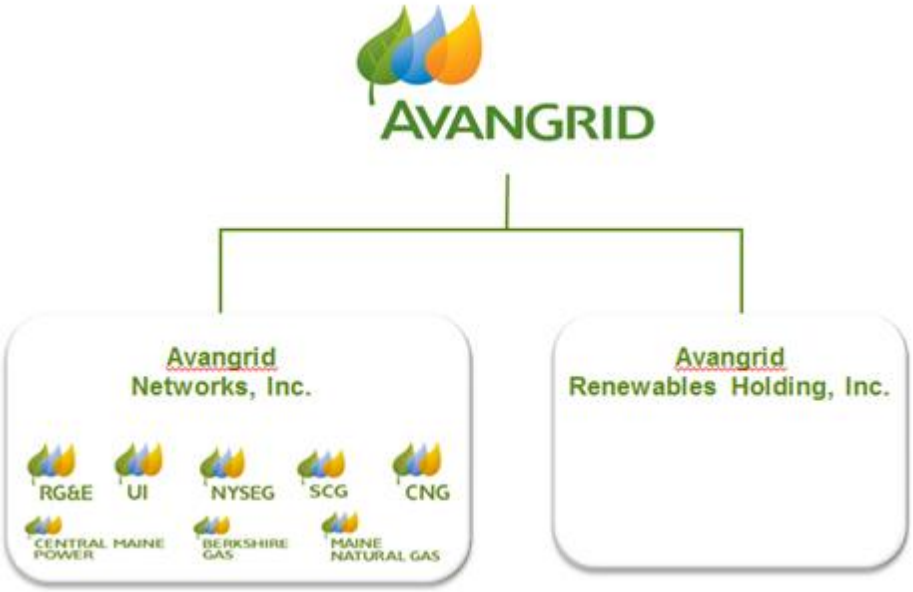
PART I

Item 1. *Business*

Overview

Avangrid, Inc., or AVANGRID, formerly Iberdrola USA, Inc., is a New York corporation headquartered in New Haven, Connecticut. AVANGRID is a diversified energy and utility company with more than $30 billion in assets and operations in 26 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 3.1 million customers in New York and New England. Avangrid Renewables operates 6.5 gigawatts of electricity capacity, primarily through wind power, in states across the United States. AVANGRID employs approximately 7,000 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 992,000 natural gas public utility customers as of December 31, 2016. 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 6,538 megawatts, or MW, as of December 31, 2016, including Renewables' share of joint projects, of which 5,852 MW was installed wind capacity. Approximately 62% of the capacity was contracted as of December 31, 2016, for an average period of 9.5 years. As the second largest wind operator in the United States based on installed capacity as of December 31, 2016, Renewables strives to lead the transformation of the U.S. energy industry to a competitive, clean energy future. Renewables currently operates 54 wind farms in 19 states across the United States.

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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, 2016, we own approximately 67.5 billion cubic feet, or Bcf, of net working gas storage capacity. Gas operates 52.4 Bcf of contracted or managed natural gas storage capacity in North America through Enstor Energy Services, LLC, as of December 31, 2016.

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 23 to our audited consolidated financial statements contained in this Annual Report on Form 10-K.

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 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 an acquisition of UIL, pursuant to which UIL merged with and into our wholly-owned subsidiary, Green Merger Sub, Inc., or Merger Sub, with Merger Sub surviving as our wholly-owned subsidiary. The acquisition was effected pursuant to the Agreement and Plan of Merger, dated as of February 25, 2015, or the Merger Agreement, by and among us, Merger Sub, and UIL. Following the completion of the acquisition, Merger Sub was renamed "UIL Holdings Corporation" and we were renamed Avangrid, Inc. Immediately following the completion of the acquisition, former UIL shareowners owned 18.5% of the outstanding shares of common stock of AVANGRID, and Iberdrola owned the remaining shares. Effective as of April 30, 2016, UIL and its subsidiaries were transferred to a wholly-owned subsidiary of Networks.

Networks

Overview

Networks, 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 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.

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For the year ended December 31, 2016, Networks distributed approximately 37,027,000 megawatt-hours, or MWh, of electricity. As of December 31, 2016, 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 8,482 miles of transmission lines, 70,916 miles of distribution lines and 826 substations as of December 31, 2016. Furthermore, for the year ended December 31, 2016, Networks delivered approximately 182 million dekatherms, or DTh, of natural gas, to approximately 992,000 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 for the year ended December 31, 2016:

Utility	Rate Base(1) (in billions) December 31, 2016	Electricity Customers December 31, 2016	Electricity Delivered (in MWh) For the year ended December 31, 2016	Natural Gas Customers December 31, 2016	Natural Gas Delivered (in DTh) For the year ended December 31, 2016
NYSEG	$ 2.3	890,258	15,461,000	264,825	53,446,000
RG&E	$ 1.5	375,912	7,187,000	310,621	49,373,000
CMP	$ 2.2	619,312	9,045,000	—	—
MNG	$ 0.1	—	—	4,456	1,204,000
UI	$ 1.5	332,998	5,334,000	—	—
SCG	$ 0.5	—	—	196,232	33,146,000
CNG	$ 0.4	—	—	176,420	35,673,000
BGC	$ 0.1	—	—	39,813	9,528,000

(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, 2016.

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, 2016, NYSEG served approximately 890,000 electricity customers and 265,000 natural gas customers across more than 40% of upstate New York's geographic area, while RG&E served approximately 375,000 electricity customers and 310,000 natural gas customers in a nine-county region centered around Rochester, in western New York.

In 2016, nine hydroelectric plants owned by NYSEG and RG&E generated nearly 327 million kilowatt-hours, or kWh, of clean hydropower, which is enough energy to power 45,000 homes across New York State, assuming an average electricity consumption of 600 kWh per month per customer. See "—Properties—Networks" for more information regarding Networks' electric generation plants.

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

Maine

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As of December 31, 2016, CMP delivered electricity to more than 619,000 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

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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.

MNG delivers natural gas to 4,456 customers in central and southern Maine. MNG continues to build out in 12 communities.

Connecticut

As of December 31, 2016, UI served more than 332,000 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 certain affiliates of NRG Energy, Inc., 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.

As of December 31, 2016, SCG and CNG provided local gas distribution services to approximately 373,000 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, 2016, 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 have been calculated using the best estimates as of December 31, 2016. The rate base of Networks' regulated utilities for the years indicated below have been as follows:

Rate base	**2014**	**2015**	**2016**
		(in millions)	
NYSEG Electric	$ 1,796	$ 1,825	$ 1,828
NYSEG Gas	508	531	490
RG&E Electric	1,111	1,175	1,061
RG&E Gas	444	446	407
Subtotal New York	3,859	3,977	3,786
CMP Dist	739	781	790
CMP Trans	1,467	1,472	1,447
MNG	64	60	69
Subtotal Maine	2,270	2,313	2,306
UI Dist	823	942	972
UI Trans	500	508	544
SCG	461	477	510
CNG	382	396	429
Subtotal Connecticut	2,166	2,323	2,456
BGC	72	91	91
Total	$ 8,367	$ 8,704	$ 8,638

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Earnings Sharing Mechanisms

The 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:

	2014	2015	2016
NYSEG Electric	50% / 50%: 10.90% - 11.65% 85% / 15%: over 11.65%; Based on Actual Equity Ratio up to 50%	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% *
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	No ESM
UI	50% / 50% over 9.15%	50% / 50% over 9.15%	50% / 50% over 9.15%
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.

Merger Settlement Agreement – Connecticut and Massachusetts

As part of the process of seeking and obtaining regulatory approval of the acquisition of UIL in Connecticut and Massachusetts, AVANGRID and UIL reached settlement agreements with the Office of Consumer Counsel, or OCC, in Connecticut and with the Attorney General of the Commonwealth of Massachusetts and the Department of Energy Resources in Massachusetts, which included commitments of certain actions to be taken after the transaction closed. See Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations – Networks" for more information.

In connection with the acquisition proceeding, UI signed a proposed partial consent order, or the consent order, that was issued by the Connecticut Department of Energy and Environmental Protection, or DEEP, in August 2016. The consent order requires UI to investigate and remediate certain environmental conditions within the perimeter of a former generation site on the Mill River in New Haven, the English Station site, that UI sold to Quinnipiac Energy in 2000 and which is currently owned by Evergreen Power, LLC and Asnat Realty LLC. Under the terms of the consent order, to the extent that costs of the investigation and remediation are 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 in 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. See Part I, Item 1, "Business – Environmental, Health and Safety - Management, Disposal and Remediation of Hazardous Substances" for more information.

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 50 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 represents approximately 90% of Renewables' combined installed capacity as of December 31, 2016. For the year ended December 31, 2016, Renewables produced approximately 14,167,000 MWh of energy through wind power generation. Renewables had a pipeline of approximately 5,900 MW of future renewable energy projects in various stages of development as of December 31, 2016.

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, Gamesa Wind US and GE Wind, in the aggregate supplied turbines which accounted for 70% of its installed wind capacity as of December 31, 2016. In June 2016, Siemens

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AG and Gamesa Corporación Tecnológica, S.A. signed a binding agreement to merge their wind power businesses. After completion of the merger, which is expected in the first quarter of 2017, Iberdrola will have 8.1% ownership of the new combined company.

Renewables currently operates 54 wind farms in 19 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 12 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, 2016. 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 two solar photovoltaic facilities with an installed capacity of 50 MW. The solar photovoltaic facilities produced over 132,000MWh of renewable energy for the year ended December 31, 2016. Solar accounted for 0.9% 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	61	122
Gamesa	G87	2.0	643	1,286
Gamesa	G90	2.0	237	474
Gamesa	G97	2.0	101	202
Gamesa	G114	2.0	104	208
GE	1.5s	1.5	133	200
GE	1.5sle	1.5	1,072	1,608
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			3,209	5,852

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

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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

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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 160 towers that are currently in operation. Additionally, a total of 8 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 52.4 Bcf of contracted or managed natural gas storage capacity in North America through Enstor Energy Services, LLC, as of December 31, 2016.

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 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 NY 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.

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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, including UI and CMP, 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, December 27, 2012, July 31, 2014 and April 29, 2016, respectively.

In 2014, the FERC determined that the base ROE 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 on the second and third complaints in mid-2017. The FERC has set the fourth complaint for settlement proceedings and hearing, with a final decision expected 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 New England transmission owners. Appeals of the FERC's decisions on the first complaint are currently pending before the United States Court of Appeals for the D.C. Circuit.

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 a settlement conference has convened. We are unable to predict the outcome of this proceeding at this time.

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.

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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 and the Commodity Exchange Act, including our businesses' energy transactions and operations in the United States. In July 2010, Congress passed the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which incorporated an expansion of the authority of the CFTC to prohibit market manipulation in the markets regulated by the CFTC. 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 in New York, Maine, Connecticut and Massachusetts 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, or the 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 proposal was approved on June 15, 2016 by the NYPSC. The 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 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 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%. The proposal includes an ESM applicable to each company. The customer share of earnings would increase at higher ROE levels, with customers receiving 50%, 75% and 90% of earnings over 9.5%, 10.0% and 10.5% of ROE, respectively, in the first rate year. Earnings are based on the lower of the actual equity ratio or 50%. Earnings thresholds increase in subsequent rate years. The 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 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.
- *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%.

  On March 5, 2015, MNG filed a rate case in order to further recover future investments and provide safe and adequate service.

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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 $57 million of cumulative distribution rate increases, an allowed ROE of 9.10% based on 50% equity, continued UI's existing earnings sharing mechanism, continued the existing decoupling mechanism (under which the actual energy delivery revenues are compared on a periodic basis with the authorized delivery revenues and the difference accrued, for refund to or recovery from customers, as applicable), and approved the continuation of the requested storm reserve

  The allowed ROEs established by PURA for CNG and SCG, are 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 base delivery rates for CNG, with an effective date of January 10, 2014, which, among other things, approved an allowed ROE of 9.18%, continued the purchased gas adjustment clause, instituted a revenue decoupling mechanism, established 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 rate cases for new rates effective before January 1, 2018.

- *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 Visions, 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. In this proceeding, the NYPSC is examining the establishment of a Distributed System Platform, or DSP, to manage and coordinate DER, and provide customers with market data and tools to manage their energy use. The NYPSC 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 proceeding objectives. The REV proceeding involves 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. The 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.

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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,

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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.

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 will develop up to 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. UI expects the cost of this program, a planned 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, to be approximately $47 million.

Pursuant to Section 8 of Connecticut Public Act 13-303, "An Act Concerning Connecticut's Clean Energy Goals," in January 2014, at DEEP's direction, UI entered into three contracts for the purchase of RECs associated with an aggregate of 5.7 MW of energy production from biomass plants in New England. The costs of these agreements will be fully recoverable through electric rates.

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

Under Maine law 35-A M.R.S.A §§ 3210-C, 3210-D, the MPUC is authorized to conduct periodic requests for proposals seeking long-term supplies of energy, capacity or RECs, from qualifying resources. The MPUC is further authorized to order Maine Transmission

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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

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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 power purchase agreements 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

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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

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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.

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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 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

Our operating subsidiaries 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

Our operating subsidiaries 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 operating subsidiary's owned or leased properties are contaminated, whether during or prior to their ownership or operation, the operating subsidiary 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 the operating subsidiary was 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 power purchase agreements,

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or PPAs, allowing Renewables to limit its exposure to market volatility. Approximately 62% of Renewables' wind generating capacity is fully committed under PPAs as of December 31, 2016, with an average duration of 9.5 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, 2016. Unless noted otherwise, Networks owns each of these facilities.

Operating Company	Facility Location	Facility Type	Installed Capacity (in MW)	Year(s) Commissioned
NYSEG	Newcomb, NY	Diesel Turbine	1.7	1967
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	57.1	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.

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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, 2016.

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	435	4,463	32,319	2,702	35,021	885,000
RG&E	New York	153	1,025	6,091	2,834	8,925	375,000
CMP	Maine	209	2,856	21,056	1,428	22,484	616,979
UI	Connecticut	29	138	3,284	202	3,486	331,216

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, 2016.

Utility	State	Natural Gas Customers	Transmission Pipeline (in miles)	Distribution Pipeline (in miles)
NYSEG	New York	265,000	20	8,151
RG&E	New York	310,000	105	10,592
MNG	Maine	4,588	2	199
SCG	Connecticut	196,232	—	2,391
CNG	Connecticut	176,420	—	2,118
BGC	Massachusetts	39,813	—	763

CNG owns and operates a liquefied natural gas, or LNG, plant which can store up to 1.2 Bcf of natural gas and can vaporize up to 97,000 Mcf per day of LNG to meet peak demand. SCG has contract rights to and operates a similar plant with the same capabilities to store up to 1.2 Bcf of natural gas. SCG's LNG facilities can vaporize up to 82,500 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.

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Renewables

The following table sets forth Renewables' portfolio of wind projects as of December 31, 2016. 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	
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	
Colorado	Colorado Green(1)	54 (GE, 1.5 MW)	81	2003	WECC
	Twin Buttes	50 (GE, 1.5 MW)	75	2007	
Illinois	Providence Heights	36 (Gamesa G87, 2.0 MW)	72	2008	MRO
	Streator Cayuga Ridge South	150 (Gamesa, 2.0MW)	300	2010	
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 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
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.

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

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Additionally, set forth below are the solar and thermal facilities operated by Renewables as of December 31, 2016. 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
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, 2016. 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 approved by the AVANGRID board and the Corporate Security Policy of Iberdrola, S.A. adopted by our 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 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.

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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-

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infrastructure assets, network architecture and physical security measures, and compliance with emerging industry best practice and regulation.

Employees

As of December 31, 2016, we had 6,801 employees excluding 15 international assignees. Of these 6,801 employees, 47.6% are represented by a union. The following table provides an overview of the number of employees at each business segment as of December 31, 2016:

Business Segment	Number of Employees (excluding International Assignees)	% of Union Workforce Subject to Collective Bargaining Agreement
Networks	5,737	56.4%
Renewables	731	—
Gas	107	—
Corporate	226	—
Total	6,801	47.6%

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 157 Church Street, New Haven, Connecticut, 06506.

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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

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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

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NYPSC completed an operations staffing audit of all NY utilities in January 2017. The audit is under review and we expect it will result in approximately 17 specific recommendations for NYSEG and RG&E and one general recommendation for all NY utilities. The NYPSC plans to conduct 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 EPAct 2005, owners, operators and users of bulk electric systems are subject to mandatory reliability standards developed by NERC and are subject to oversight by the FERC in the U.S. and governmental authorities in Canada. The standards are based on the functions that need to be performed to ensure that the bulk electric system operates reliably. Networks' and Renewables' businesses have been, and will continue to be, subject to routine audits and monitoring with respect to compliance with applicable NERC reliability standards, including standards approved by the FERC that could result in an increase in the number of assets (including cyber-security assets) designated as "critical assets," which would subject such assets to NERC cyber-security standards. 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 $1.0 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 and prospects. NYSEG and RG&E will have onsite NERC operational audit and NYSEG, RG&E and CMP will have onsite CIP audit in 2017. We cannot predict the outcome of these audits.

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 NYSERDA for Renewable Energy Credits (RECs) and Zero-Emission Credits (ZECs) in 2017 and have prepared updated tariffs for collection and payment.

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. A collaborative process to review the companies' petition is expected to begin in the first quarter of 2017.

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.

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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, the current trend toward more stringent standards, and stricter and more expansive application and enforcement of existing environmental regulations. 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'

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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

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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 is currently investigating Renewables for potential violations under the MBTA and the ESA at its Blue Creek facility. We cannot predict the outcome of this investigation.

Renewables relies in part on governmental policies that support utility-scale renewable energy. Any reductions to, or the elimination of, governmental 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

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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

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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 two 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. 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, having a material adverse effect on our businesses, results of operations, financial condition and cash flows.

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

Under the EPAct 2005 and the Dodd-Frank Act, our businesses are subject to enhanced FERC and CFTC statutory authority to monitor certain segments of the physical and financial energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of the electricity and gas markets. Under these laws, the FERC and CFTC have promulgated 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

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to forecast operations and negatively affect our business, results of operations, financial condition and cash flow. In addition, certain of Renewables' operating facilities' generation of electricity may be physically or

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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 credit crisis affecting the banking system and the financial markets and the resultant deterioration of macroeconomic conditions, including a global reduction in credit and liquidity in the financial markets and 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. Borrowings from our credit facilities and on our auction rate bonds are set by reference to the London Interbank Offer Rate, or LIBOR, and 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 are parties to revolving credit facilities that contain facility fees and borrowing spread pricing that are a function of the credit rating of the borrower. A lower credit rating automatically increases the cost of these facilities. A downgrade to the lowest investment grade rating of the borrower would likely preclude access to the commercial paper market for NYSEG and CMP, which each have commercial paper programs. Lower credit ratings would also increase the cost of debt and equity capital and, depending on the rating and market conditions, can 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 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 or regulatory penalties. For more information, see "*Risks Relating to Our Regulatory Environment*" above.

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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.

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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

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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. 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. 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.

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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. Furthermore, as required by Connecticut's Comprehensive Energy Strategy, CNG and SCG filed, jointly with Yankee Gas Services Company, a comprehensive natural gas expansion plan ("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 the next 10 years. 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. Additionally, RG&E's Rochester Area Reliability Project, which includes the development of a new substation and transmission lines and was approved by the NYPSC, has encountered significant delays due to the concerns of landowners. 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 power 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

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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

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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. 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.

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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 409 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.

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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.

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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 notional cash pooling account 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. Moreover, under the agreement governing the notional cash pooling account mentioned above, credit balances in the cash pooling account are pledged as collateral for the debit balances of other cash pooling participants. We are therefore subject to the credit risk of the affiliated parties to the cash pooling agreement and to Iberdrola's ability to manage the overall liquidity of the Iberdrola Group.

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, 2016, management along with our independent registered public accounting firm identified a material weakness in the internal control over financial

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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. 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.

We are actively engaged in remediation efforts to address the material weakness 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, based on our evaluation to date, that this material weakness will be remediated by December 31, 2017. 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.

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.

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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 internationally and within the U.S., including changes in interest rates;
- changes in electricity and natural gas prices;
- actual or anticipated fluctuations in our quarterly and annual results and those of its competitors;
- the businesses, operations, results and prospects of us;
- future mergers and strategic alliances;
- market conditions in the energy industry;
- changes in government regulation, taxes, legal proceedings or other developments;
- shortfalls in our operating results from levels forecasted by securities analysts;
- investor sentiment toward the stock of energy companies in general;
- announcements concerning us or its 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, our share price would likely decline. If one or more of

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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.

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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

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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

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frequency of dividends or discontinue the payment of dividends entirely. For these reasons, you will not be able to rely on dividends to receive a return on your investment.

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 this 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 New Gloucester, Maine, Rochester, New York and New Haven and Orange, Connecticut. 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, 2016:

Location	Type of Facility	Lease/Owned	Size (square feet)
New Haven, Connecticut	Office	Leased	51,307
Orange, Connecticut	Office	Owned	337,586
Augusta, Maine	Office	Leased	220,400
New Gloucester, Maine	Office	Leased	60,913
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.*

We are involved in various proceedings, legal actions and claims arising in the normal course of our respective businesses. The outcomes of these matters will generally not be known for an extended period of time. In certain of the legal proceedings, the claimants seek damages, as well as other compensatory relief, which could result in the payment of significant claims and settlements.

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While the ultimate outcome and impact of any proceeding cannot be predicted with certainty, management believes that the resolution of its pending proceedings will not have a material adverse effect on its financial condition or results of operations.

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. In January 2015, NYSEG sent FirstEnergy a demand for $16 million representing FirstEnergy's share of clean-up expenses incurred by NYSEG at the nine sites from January 2010 to November 2014 while the District Court appeal was pending. Nearly all of this amount has been paid by FirstEnergy. FirstEnergy would also be liable for a share of post 2014 costs, which, based on current projections, would be $26 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

NYSEG filed suit in federal court on August 14, 2013 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. Any recovery will be flowed through to NYSEG ratepayers.

Century Indemnity and One Beacon have answered admitting issuance of the excess policies, but contesting coverage and providing documentation proving they received notice of the claims in the 1990s. We cannot predict the outcome of this matter, however, any recovery will be flowed through to NYSEG ratepayers.

Shareholder Derivative Action

On February 27, 2015, a complaint was filed in Connecticut state court against us, UIL, its board of directors and others related to our acquisition of UIL. The complaint is a class action filed on behalf of all UIL shareowners. The complaint generally alleges that UIL's directors breached their fiduciary duties by failing to maximize shareowner value in negotiating and approving the acquisition, and that we, UIL, and/or Morgan Stanley aided and abetted the UIL Board's alleged breaches.

On November 30, 2015, the plaintiffs and the defendants executed a binding Memorandum of Understanding, or MOU, that sets forth the terms on which the parties have agreed to settle the consolidated action. The settlement terms do not include any change in the acquisition consideration but only additional disclosures relating to information included in our Registration Statement on Form S-4 filed with the SEC, which was declared effective on November 12, 2015, additional confirmatory discovery, and plaintiffs' counsel fees. The parties have agreed on the fees and submitted the unopposed settlement and dismissal to the Court on August 26, 2016. On November 4, 2016, the Court issued its preliminary approval of the settlement, there were no objections to the settlement, and on January 30, 2017, the Court held a final settlement hearing. A final decision is pending. We cannot predict the ultimate outcome of this matter.

Avangrid Renewables, LLC and Northern Indiana Public Service Company

Renewables has a contractual dispute with the Northern Indiana Public Service Company, or NIPSCO, concerning the interpretation of two November 2007 PPAs, entered into between two subsidiaries of Renewables and NIPSCO. Renewables and NIPSCO disagree regarding how, if at all, NIPSCO's response to a March 2013 change in the regulations of the Midcontinent Independent System Operator, or MISO, which administers the energy markets in which NIPSCO participates, affects their rights and obligations under the PPAs. Because of the disagreement, NIPSCO has refused to pay, and denied any obligation to pay, certain invoices Renewables' affiliates have issued to NIPSCO. These invoices seek compensation for periods during which Renewables' affiliates' power plants were not permitted to produce power as a result of NIPSCO's bids submitted under the new MISO regulations.

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To resolve this dispute, on July 25, 2013, Renewables filed a complaint against NIPSCO in the Federal District Court for the Northern District of Illinois. Fact discovery and expert discovery in that action is complete. The parties to the dispute are seeking dismissal of the case through summary judgment. The court is initially denied both summary judgment motions in early 2016, but in January 2017, the parties requested reconsideration of this ruling in light of a December 16, 2016, ruling by the Seventh Circuit Court of Appeals in another dispute arising out under the new MISO rules. No trial date has been set. We cannot predict the ultimate outcome of this matter.

California Energy Crisis Litigation

Two California agencies brought a complaint in 2001 against a long-term power purchase agreement entered into by Renewables, as seller, to the California Department of Water Resources, as purchaser, alleging that the terms and conditions of the power purchase agreement were unjust and unreasonable. 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 the 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 power purchase agreements unjust and unreasonable. However, the proposed ruling did conclude that price of the power purchase agreements imposed an excessive burden on customers in the amount of $259 million. Renewables position, as presented at hearings and agreed by the FERC Trial Staff, is that Renewables entered into bilateral power purchase contracts appropriately and complied with all applicable legal standards and requirements. The parties have submitted to the FERC briefs on exceptions to the administrative law judge's proposed ruling. There is no specific timetable to the FERC's ruling. We cannot predict the outcome of this proceeding.

Yankee Nuclear Spent Fuel Disposal Claim

CMP has an ownership interest in Maine Yankee Atomic Power Company, Connecticut Yankee Atomic Power Company, and Yankee Atomic Electric Company (the Yankee Companies), three New England single-unit decommissioned nuclear reactor sites, and UI has an ownership interest in Connecticut Yankee Atomic Power Company. Every six years, pursuant to the statute of limitations, the Yankee Companies file a lawsuit to recover damages from the Department of Energy (DOE) for breach of the Nuclear Spent Fuel Disposal Contract to remove spent nuclear fuel (SNF) and Greater than Class C Waste as required by contract and the Nuclear Waste Policy Act beginning in 1998. The damages are the incremental costs for the DOE's failure to take the spent nuclear fuel.

In 2012, the U.S. Court of Appeals issued a favorable decision in the Yankee Companies' claim for the first six year period (Phase I). Total damages awarded to the Yankee Companies were nearly $160 million. CMP's share of the award was approximately $36.5 million which was credited back to customers. UI's share of the award was $3.8 million which was credited back to customers.

In November 2013 the U.S. Court of Claims issued its decision in the Phase II case (the second six-year period, 2002-2008). The court's decision awarded the Yankee Companies a combined $235.4 million (Connecticut Yankee $126.3 million, Maine Yankee $37.7 million, and Yankee Atomic $73.3 million). In January 2014, the DOE informed the Yankee Companies it would not appeal the court's decision. As a result the Yankee Companies received full payment in April 2014. CMP's share of the award was approximately $28.2 million which was credited back to customers. UI received approximately $12 million of such award which was applied, in part, against its remaining storm regulatory asset balance. The remaining regulatory liability balance was applied to UI's generation service charge (GSC) "working capital allowance" and was returned to customers through the non-by-passable federally mandated congestion charge.

In March 2016 the U.S. Court of Claims issued its decision in the Phase III case (the third six-year period, 2009-2014), awarding the Yankee Companies a combined $76.8 million (Connecticut Yankee $32.6 million, Maine Yankee $24.6 million and Yankee Atomic $19.6 million). The damage awards, less any amount retained to reduce future customer charges, will potentially flow through the Yankee

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Companies to shareholders, including CMP and UI, upon FERC approval, and will reduce retail customer charges or otherwise as specified by law. CMP and UI will receive their proportionate share of the awards that flow through based on

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percentage ownership. On July 18, 2016, the notice of appeal period expired and the Phase III trial award became final. On October 14, 2016, the Yankee Companies received the DOE's payment of the damage award. We cannot predict the timing or amount of damage awards that may ultimately flow through to customers.

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 resolution of other proceedings before the Connecticut Department of Energy and Environmental Protection, or 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 and Asnat filed a subsequent lawsuit in Connecticut state court seeking among other things: (i) remediation of the property; (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 on or before August 1, 2017.

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. A status report was filed with the court in December 2016 and the next status report is due in May 2017.

On August 4, 2016, DEEP issued 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 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 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.

In connection with the consent order, on August 4, 2016, DEEP also issued a consent order to Evergreen Power, Asnat, and certain related parties that provides UI access to investigate and remediate the English Station site consistent with the terms of the August 2016 consent order. 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.

Other Legal Proceedings

We have included descriptions of the regulatory environment and environmental, health and safety in "Item 1. *Business*," general information about several significant risks in "Item 1A. *Risk Factors*" and other legal proceedings that we believe could be material to us in Notes 13 and 14 of our audited consolidated financial statements for the three years ended December 31, 2016, which are incorporated herein by reference.

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

Not Applicable.

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Executive Officers of AVANGRID

The names and ages of all executive officers of AVANGRID as of March 10, 2017 and a brief account of the business experience during the past five years of each executive officer are as follows:

Name	Age*	Title
James P. Torgerson	64	Chief Executive Officer
Richard J. Nicholas	61	Senior Vice President – Chief Financial Officer
Daniel Alcain	43	Senior Vice President – Controller
Frank Burkhartsmeyer	52	Chief Executive Officer of Renewables
Sara J. Burns	61	President and Chief Executive Officer of CMP
Sheila Duncan	52	Senior Vice President – Human Resources & Corporate Administration
Ignacio Estella	47	Senior Vice President – Corporate Development
Daryl W. Gee	53	Chief Executive Officer of Gas
Robert D. Kump	55	President and Chief Executive Officer of Networks
Mark S. Lynch	63	President and Chief Executive Officer of NYSEG and RG&E
R. Scott Mahoney	51	Senior Vice President – General Counsel and Chief Compliance Officer; Secretary
Anthony Marone	53	President and Chief Executive Officer of UIL

(*) Age as of December 31, 2016.

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 MISO. He is a trustee of the Yale-New Haven Hospital and a Director of Yale New Haven Health System. Mr. Torgerson is the chairman of the Connecticut Institute for the 21st Century. He is the former chairman and a director of the Connecticut Business and Industry Association and is a member of the board of the Edison Electric Institute and the American Gas Association. Mr. Torgerson is a trustee of the Hartford Bishops' Foundation for the Archdiocese of Hartford. Mr. Torgerson holds a bachelor's of business administration degree in accounting from Cleveland State University.

Richard J. Nicholas. Mr. Nicholas was appointed 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. Effective November 16, 2010, Mr. Nicholas was appointed chief financial officer of BGC, CNG and SCG, all of which are subsidiaries of AVANGRID. 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 was 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.

Frank Burkhartsmeyer. Mr. Burkhartsmeyer was appointed Chief Executive Officer of Renewables in April 2015. Mr. Burkhartsmeyer previously served as senior vice president of finance of ARHI from July 2012 until March 2015, and as vice president of strategy, planning and market fundamentals at Renewables from July 2006 until June 2012, both subsidiaries of AVANGRID. He also served as managing director of corporate strategy of Scottish Power between June 2004 and September 2005. Mr. Burkhartsmeyer earned a B.A. from the University of Montana and a M.B.A. from the University of Oregon.

Sara J. Burns. Ms. Burns was appointed President and Chief Executive Officer of CMP in 2005. She has served as President of CMP since 1998. Ms. Burns is the chairman of the board of directors of Maine & Company and serves on the board of directors of the Mitchell Institute and the Maine State Chamber of Commerce. She holds a B.A. in Political Science and Government from Colby College.

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.

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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 regulation and industry analysis and negotiation and conflict resolution 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 Chief Executive Officer of Networks in November 2010. Mr. Kump served as AVANGRID's Chief Corporate Officer in January 2014. 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.

Mark S. Lynch. Mr. Lynch was appointed President of NYSEG and RG&E in January 2010 and Chief Executive Officer in January, 2014, and serves on the board of directors of NYSEG and RG&E. Mr. Lynch also served as president and chief executive officer of NYISO from 2005 to 2008. Mr. Lynch earned a bachelor of electrical engineering from Villanova University.

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. Mr. Marone also serves as President – Connecticut and Massachusetts Operations and senior vice president of gas operations of Avangrid Service Company, overseeing the natural gas 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.

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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.

	2016 Sales Price		2015 Sales Price	
	High	Low	High	Low
First Quarter	$ 42.40	$ 36.01	—	—
Second Quarter	$ 46.49	$ 37.07	—	—
Third Quarter	$ 46.74	$ 40.71	—	—
Fourth Quarter	$ 41.88	$ 35.42	$ 38.90	$ 32.45

As of March 9, 2017, there were 3,463 shareholders of record.

Dividends

The quarterly cash dividends declared in 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 December 17, 2015 through December 31, 2016.

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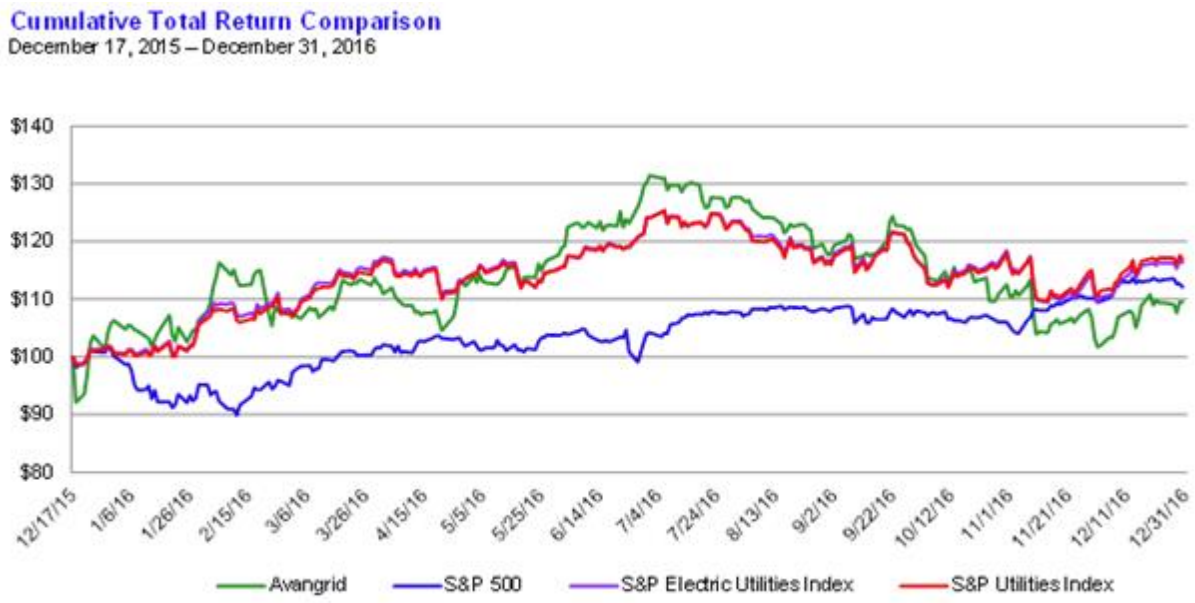

	December 17, 2015	December 31, 2015	December 31, 2016
AVANGRID	$ 100	$ 106.30	$ 109.46
S&P 500	$ 100	$ 100.70	$ 112.13
S&P Electric Utilities Index	$ 100	$ 100.50	$ 116.32
S&P Utilities Index	$ 100	$ 100.10	$ 117.02

The above information assumes that the value of the investment in shares of AVANGRID's common stock and each index was $100 on December 17, 2015, including dividend reinvestment during this time period. The changes displayed are not necessarily indicative of future returns.

Recent Sales of Unregistered Securities

None.

Issuer Repurchases of Equity Securities

AVANGRID repurchased 18,352 shares of common stock in open market transactions within the fourth quarter of the year ended December 31, 2016, to maintain the relative ownership percentage of Iberdrola at 81.5% as follows:

Period	Total Number of Shares Purchased*	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October 1-31	—	—	—	—
November 1-30	18,352	$ 37.14	None	None
December 1-31	—	—	—	—
Total	18,352	$ 37.14	None	None

* All shares were purchased in open market transactions. The effects of these transactions did not change the number of outstanding shares of AVANGRID common stock.

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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***

Consolidated and Combined Statements of Operations Data: *	Year Ended December 31, (millions, except per share data) 2016	2015	2014	2013	2012
Operating Revenues	**$ 6,018**	**$ 4,367**	**$ 4,594**	**$ 4,313**	**$ 4,055**
Operating Income From Continuing Operations	1,194	513	885	179	262
Income (Loss) Before Income Tax	**1,009**	**301**	**706**	**(15)**	**60**
Income tax expense (benefit)	379	34	282	35	(117)
Net Income (Loss) From Continuing Operations	**630**	**267**	**424**	**(50)**	**177**
Net Income From Discontinued Operations	**—**	**—**	**—**	**—**	**74**
Net Income (Loss)	**630**	**267**	**424**	**(50)**	**251**
Less: Net income attributable to noncontrolling interests	—	—	0	1	1
Net Income (Loss) Attributable to AVANGRID, Inc.	**630**	**267**	**424**	**(51)**	**250**
Earnings (Loss) Per Common Share, Basic and Diluted:					
Earnings (loss) from continuing operations per common share, basic and diluted	2.04	1.05	1.68	(0.20)	0.69
Earnings (loss) from discontinued operations per common share, basic and diluted	—	—	—	—	0.30
Total Earnings (Loss) Per Common Share, Basic and Diluted	$ 2.04	$ 1.05	$ 1.68	$ (0.20)	$ 0.99
Weighted-average Number of Common Shares Outstanding:					
Basic	309,512,553	254,588,212	252,235,232	252,235,232	252,235,232
Diluted	309,817,322	254,605,111	252,235,232	252,235,232	252,235,232

Consolidated and Combined Balance Sheet Data:* As of December 31, (Millions)	(millions) 2016	2015	2014	2013	2012
Total Property, Plant and Equipment	**$ 21,548**	**$ 20,711**	**$ 17,133**	**$ 16,715**	**$ 16,643**
Total Other Assets	**3,976**	**3,795**	**2,075**	**2,137**	**2,376**
Total Assets	**$ 31,309**	**$ 30,743**	**$ 24,162**	**$ 23,170**	**$ 23,671**

As of December 31, (Millions)	(millions) 2016	2015	2014	2013	2012
Liabilities					
Current portion of debt	$ 349	$ 206	$ 148	$ 25	$ 354
Non-current debt	4,510	4,530	2,489	2,669	2,780
Total Liabilities	**16,187**	**15,677**	**11,685**	**11,119**	**12,323**
Total Stockholder's Equity	**15,109**	**15,053**	**12,461**	**12,036**	**11,334**
Total Equity	**$ 15,122**	**$ 15,066**	**$ 12,477**	**$ 12,051**	**$ 11,348**

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

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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 more than $30 billion in assets and operations in 26 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 3.1 million customers in New York and New England. Avangrid Renewables operates 6.5 gigawatts of electricity capacity, primarily through wind power, in states across the United States. AVANGRID employs approximately 7,000 people. The company was formed by a merger between Iberdrola USA, Inc. and UIL Holdings Corporation in 2015. Iberdrola S.A., or Iberdrola, a corporation *(sociedad anónima)* organized under the laws of the Kingdom of Spain, a worldwide leader in the energy industry, directly owns 81.5% of the 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).

On December 16, 2015, we completed our acquisition of UIL Holdings Corporation, or 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. Further information regarding the accounting for the acquisition is provided in Note 4 of our audited consolidated financial statements for the three years ended December 31, 2016, which are incorporated herein by reference.

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 992,000 natural gas public utility customers as of December 31, 2016.

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 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;

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- 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 6,538 megawatts, or MW, as of December 31, 2016, including Renewables' share of joint projects, of which 5,852 MW was installed wind capacity. Approximately 62% of the capacity was contracted as of December 31, 2016, for an average period of 9.5 years. As the second largest wind operator in the United States based on installed capacity as of December 31, 2016, Renewables strives to lead the transformation of the U.S. energy industry to a competitive, clean energy future. Renewables currently operates 54 wind farms in 19 states across the United States.

Through Gas, as of December 31, 2016, we own approximately 67.5 billion cubic feet, or Bcf, of net working gas storage capacity. Gas operates 52.4 Bcf of contracted or managed natural gas storage capacity in North America through Enstor Energy Services, LLC, as of December 31, 2016.

Summary of Results of Operations

Our operating revenues increased by 38%, from $4.4 billion for the year ended December 31, 2015, to $6.0 billion for the year ended December 31, 2016.

The increase in operating revenues was largely due to the inclusion of UIL, which was not in the comparable period, adding $1.6 billion in revenues for the year ended December 31, 2016. The Networks and Gas business revenues increased on the impact of favorable operating conditions partially offset by unfavorable mark-to-market, or MtM, changes on derivatives at Renewables.

Net income increased by 136% from $267 million for the year ended December 31, 2015, to $630 million for the year ended December 31, 2016, primarily due to the additional contribution of UIL. Other Networks businesses' net income also significantly improved as higher electricity and gas revenues and rate case impacts occurred offset by increases in costs resulting from higher transmission support expense. Renewables net income decreased as a result of lower average prices and unfavorable MtM changes on derivatives offset by favorable changes from the revision of estimated useful lives of wind power station assets. Gas net loss decreased due to favorable MtM changes on derivatives and transport contracts.

Adjusted earnings before interest, tax, depreciation and amortization, or adjusted EBITDA (a non-GAAP financial measure), increased by 64% from $1.2 billion for the year ended December 31, 2015, to $1.9 billion for the year ended December 31, 2016, primarily as a result of a 113% increase in adjusted EBITDA at Networks due to the addition of UIL. Renewables increased by 1%, primarily due to lower operations and maintenance expenses, related to reductions in bad debt and asset retirement obligation expenses. Adjusted gross margin (a non-GAAP financial measure) increased by 38%, from $3.2 billion for the year ended December 31, 2015, to $4.5 billion for the year ended December 31, 2016, primarily as a result of the addition of UIL, which added $1.0 billion to adjusted gross margin in 2016. 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.

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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 2017, 80% of its standard service load for the second half of 2017, and 20% of its standard service load for the first half of 2018. 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, downward net plant reconciliations, revenue decoupling, system benefit charges, renewable portfolio standards, energy efficiency portfolio standards, economic development programs, low income programs, gross receipt taxes, pension costs, other post-employment benefits costs, environmental remediation costs, major storm costs, downward adjustments for vegetation management, research and development, incremental maintenance initiatives, property taxes, REV initiatives, 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.

NYSEG, RG&E and UI are energy delivery companies and 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.

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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.

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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 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, the NYSEG, RG&E and other signatory parties filed a joint proposal, or the 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 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%. The proposal includes an ESM applicable to each company. The customer share of earnings would increase at higher ROE levels, with customers receiving 50%, 75% and 90% of earnings over 9.5%, 10.0% and 10.5% of ROE, respectively, in the first rate year. Earnings are based on the lower of the actual equity ratio or 50%. Earnings thresholds increase in subsequent rate years. The 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 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

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period, with a 12% increase effective January 1, 2010, a 10% increase effective December 1, 2010 and another 10% increase effective December 1, 2011.

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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.

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 $57 million of cumulative distribution rate increases, an allowed ROE of 9.10% based on 50% equity, continued UI's existing earnings sharing mechanism, continued the existing decoupling mechanism, and approved the continuation of the requested storm reserve.

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 (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 New England transmission owners 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 is the administrative law judge's recommendation to the FERC commissioners. The FERC is expected to make its final decision in early 2017. The results of the decision in the initial complaint, as well as the results of any future decisions, will be reconciled in future transmission rates. On April 29, 2016, a fourth, related, complaint was filed for a subsequent rate period requesting the base ROE be 8.61% and ROE Cap be 11.24%. CMP and UI, as part of the NETOs group, filed a response on June 3, 2016. On September 20, 2016, the FERC accepted the forth compliant, established a refund effective date of April 29, 2016, and set the matter for hearing. We cannot predict the outcome of the fourth complaint proceeding.

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 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

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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.

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 Office of Consumer Counsel, or 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 in 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.

New England Clean Energy Request for Proposals

DEEP, Eversource Energy, National Grid Plc and Unitil Corporation conducted a request for proposals, or RFP, for clean energy and transmission in order to identify projects that will advance the clean energy goals of Connecticut, Massachusetts and

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Rhode Island. The RFP was issued in November 2015, and bids were received on January 28, 2016. AVANGRID companies offered two transmission projects and three wind projects as components of various joint bids with other parties. None of AVANGRID's bids were selected as winning bids. Any contracts negotiated with chosen projects would require regulatory approvals in the contracting utilities' states and the projects will need various regulatory and permitting approvals, including FERC approval for transmission tariffs. DEEP selected eight bids for Connecticut. DEEP has directed UI to negotiate and enter into contracts with the selected projects.

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 expected to begin in the first quarter of 2017.

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. The joint proposal provides a term of the RSSA from April 1, 2015, through March 31, 2017. RG&E shall make monthly payments to Ginna in the amount of $15.4 million. RG&E will be entitled to 70% of revenues from Ginna's sales into the NYISO energy and capacity markets, while Ginna will be entitled to 30% of such revenues. The signatory parties recommend that the NYPSC authorize RG&E to implement a rate surcharge effective January 1, 2016, to recover amounts paid to Ginna pursuant to the RSSA. RG&E's payment obligation to Ginna did not begin until the rate surcharge was in effect and the FERC issued an order authorizing the FERC settlement agreement in the Settlement Docket. RG&E will use 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. To the extent that the available credits are insufficient to satisfy the final payment from RG&E to Ginna then the RSSA surcharge would continue past March 31, 2017, to recover up to $2.3 million per month until the final payment has been recovered by RG&E from ratepayers. In the month following the expiration of the term on March 31, 2017, Ginna shall prepare and issue an invoice to RG&E for, and RG&E shall pay to Ginna, a one-time payment in the amount of $11.5 million. This amount is being accrued pro-rata over the term of the agreement and will be recovered from ratepayers. If Ginna continues to deliver energy to the NYISO transmission system or makes available capacity to the

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NYISO markets after seventy-five days following March 31, 2017, Ginna shall pay RG&E a capital recovery balance in eight quarterly installments as long as Ginna is continuing to deliver energy or making available capacity throughout this period. The estimated capital recovery balance that is expected to be in place on March 31, 2017 is $20.1 million and will accrue interest unless amounts are prepaid by Ginna. The capital recovery balance will be refunded to ratepayers, to the extent collected, which is based on the term of the delivery of energy or capacity being made available by Ginna. On February 23, 2016, the NYPSC unanimously adopted the joint proposal in the Ginna RSSA proceeding as in the public interest. On March 1, 2016, the FERC issued an order approving the contested settlement agreement, subject to conditions.

New York TransCo

Networks holds an approximately 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 (OATT) for the TOTS projects. On March 17, 2016, 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. 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 will develop up to 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

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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 project. UI expects the cost of this program, a planned 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, to be approximately $47 million. Pursuant to Section 8 of Public Act 13-303, "An Act Concerning Connecticut's Clean Energy Goals," in January 2014, at the DEEP's direction, UI entered into three contracts for the purchase of RECs associated with an aggregate of 5.7 MW of energy production from biomass plants in New England. The costs of these agreements will be fully recoverable through electric rates.

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

Under Maine law 35-A M.R.S.A §§ 3210-C, 3210-D, the MPUC is authorized to conduct periodic requests for proposals seeking long-term supplies of energy, capacity or RECs, from qualifying resources. The MPUC is further authorized to order Maine transmission and distribution utilities to enter into contracts with sellers selected from the MPUC's competitive solicitation process. Pursuant to a MPUC Order dated October 8, 2009, CMP entered into a 20-year agreement with Evergreen Wind Power III, LLC, 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 power purchase agreements 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 will be reduced to 80% for facilities commencing construction in 2017, 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.

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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

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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

The following table sets forth our operating revenues and expenses items for each of the periods indicated and as a percentage of operating revenues:

	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 of non-current assets	—	—	—	—	—
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	**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 Before Income Tax	**1,009**	**895**	**121**	**(64)**	**57**
Income tax expense	379	415	9	(22)	(23)
Net Income	**630**	**480**	**112**	**(42)**	**80**
Less: Net income attributable to noncontrolling interests	—	—	—	—	—
Net Income	**$ 630**	**$ 480**	**$ 112**	**$ (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 of non-current assets	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	**513**	**537**	**100**	**(85)**	**(39)**
Other Income (Expense)					
Other income (expense)	55	44	105	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	**301**	**355**	**146**	**(113)**	**(87)**
Income tax expense	34	146	13	(44)	(81)
Net Income	**267**	**209**	**133**	**(69)**	**(6)**
Less: Net income attributable to noncontrolling interests	—	—	—	—	—

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Net Income	**$ 267**	**$ 209**	**$ 133**	**$ (69)**	**$ (6)**

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	Year Ended December 31, 2014				
	Total	Networks	Renewables	Gas	Other(1)
			(in millions)		
Operating Revenues	**$ 4,594**	**$ 3,397**	**$ 1,189**	**$ 84**	**$ (76)**
Operating Expenses					
Purchased power, natural gas and fuel used	1,181	1,056	192	1	(68)
Operations and maintenance	1,560	1,191	336	40	(7)
Impairment of non-current assets	25	—	25	—	—
Depreciation and amortization	629	275	332	22	—
Taxes other than income taxes	314	259	47	5	3
Total Operating Expenses	**3,709**	**2,781**	**932**	**68**	**(72)**
Operating Income	**885**	**616**	**257**	**16**	**(4)**
Other Income (Expense)					
Other income (expense)	52	42	67	3	(60)
Earnings (losses) from equity method investments	12	—	2	—	10
Interest expense, net of capitalization	(243)	(198)	(64)	(28)	47
Income Before Income Tax	**706**	**460**	**262**	**(9)**	**(7)**
Income tax expense	282	172	61	(5)	54
Net Income	**424**	**288**	**201**	**(4)**	**(61)**
Less: Net income attributable to noncontrolling interests	—	—	—	—	—
Net Income	**$ 424**	**$ 288**	**$ 201**	**$ (4)**	**$ (61)**

(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, 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%	2%	—

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%	(0)%	(2)%
Operating expenses	**$ 3,854**	**$ 2,849**	**$ 967**	**$ 66**	**$ (28)**
Operating expenses %		75%	25%	2%	(2)%

Year Ended December 31, 2014

	Total	Networks	Renewables	Gas	Other(1)
			(in millions)		
Operating revenues	**$ 4,594**	**$ 3,397**	**$ 1,189**	**$ 84**	**$ (76)**
Operating revenues %		74%	26%	2%	(2)%
Operating expenses	**$ 3,709**	**$ 2,781**	**$ 932**	**$ 68**	**$ (72)**
Operating expenses %		75%	25%	2%	(2)%

(1) Other amounts represent corporate and company eliminations.

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Comparison of Period to Period Results of Operations

Our operating revenues increased by 38%, from $4.4 billion for the year ended December 31, 2015, to $6.0 billion for the year ended December 31, 2016.

Our purchased power, natural gas and fuel used increased by 32%, from $972 million for the year ended December 31, 2015, to $1,286 million for the year ended December 31, 2016.

Our operations and maintenance increased by 22%, from $1.8 billion for the year ended December 31, 2015, to $2.2 billion for the year ended December 31, 2016.

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

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, with a corresponding 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

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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.

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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 of Non-Current Assets

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 $28 million, or 49%, from $55 million other income for the year ended December 31, 2015, to $83 million. UIL contributed $22 million of income. Of the remaining $6 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 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 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

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$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.

Year Ended December 31, 2015 Compared to the Year Ended December 31, 2014

Networks

Operating revenues for the year ended December 31, 2015, decreased by $11 million or less than 1% from $3,397 million for the year ended December 31, 2014, to $3,386 million. UIL contributed $36 million in additional revenue, offset by underlying revenue being $47 million lower due to lower gas rates in 2015 as compared to 2014. There were also lower gas sales volumes, as consumption declined due to milder weather.

Purchased power, natural gas and fuel used for the year ended December 31, 2015, decreased by $235 million, or 22%, from $1.1 billion for the year ended December 31, 2014, to $821 million. UIL contributed $34 million in additional expense, resulting in underlying expense being $269 million lower. Purchased power decreased by $189 million, resulting from a decrease in the market price of electricity in 2015, with 2014 prices being higher due to colder temperatures causing less efficient generation to be used, increasing the marginal price of electricity. Additionally, gas purchase expenses decreased by $80 million due to a decrease in gas market prices, with prices lower in 2015 due to continuing shale gas production increasing supply, and a decline in oil prices, which are closely correlated with gas prices.

Operations and maintenance during the year ended December 31, 2015, increased by $206 million or 17% from approximately $1.2 billion for the year ended December 31, 2014, to approximately $1.4 billion. Excluding the impact of UIL, underlying expense increased by $153 million, with the main drivers being increased spending in 2015 on reliability support services of $80 million, combined with regulatory refunds received from the DOE in 2014 for the Phase II of the Yankee Companies Case of $28 million together with smaller increases in energy efficiency programs and corporate recharges.

Renewables

Operating revenues for the year ended December 31, 2015 decreased $122 million or 10% from approximately $1.2 billion for the year ended December 31, 2014, to approximately $1.1 billion. In 2015, revenues increased by $17 million due to the addition of a 202 MW newly constructed wind farm. Revenues decreased $87 million from existing wind farms on lower wind generation due to poor wind resource (amount of wind in actual weather lower than the prior year) and lower revenues from merchant wind farms due to lower prices of approximately 6%. The decrease in prices is attributed to general market conditions and milder weather in 2015 as compared to 2014. Power trading revenues were $34 million lower due to reduced trading opportunities created by lower price volatility in the northwest markets and a decrease of $9 million attributable to unfavorable MtM changes on derivative transactions entered into for economic hedging purposes.

Purchased power, natural gas and fuel used for the year ended December 31, 2015, increased by $9 million, or 5%, from $193 million for the year ended December 31, 2014, to $202 million. The increase is attributable to costs for our thermal power plant.

Operations and maintenance for the year ended December 31, 2015, increased by $27 million or 8% from $336 million for the year ended December 31, 2014, to $363 million, primarily as a result of higher corporate recharges, combined with several non-recurring expenses and lower capitalization of expenses.

Gas

Operating revenues for the year ended December 31, 2015 decreased by $103 million, or 123%, from $84 million for the year ended December 31, 2014 to negative $19 million. The decrease in operating revenues was due to $105 million unfavorable MtM changes on derivatives, with unrealized losses in 2015 compared to unrealized gains in 2014. The unrealized MtM change recorded within operating revenues is related to the change in average prices for storage derivatives. The 2015 losses resulted primarily from the settlement of 2014 MtM gains on short-term derivatives that rolled-off in 2015 based on the Company's derivative strategies as disclosed in Note 12, Derivative Instruments and Hedging. In 2014, a decrease in average prices for storage derivatives resulted in significant MtM gains.

Purchased power, natural gas and fuel used for the year ended December 31, 2015, remained consistent over the periods at $1 million.

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Operations and maintenance for the year ended December 31, 2015, decreased by $2 million, or 4%, from $40 million for the year ended December 31, 2014, to $38 million. The decrease is mainly due to reduction in operational expense in the trading and storage businesses.

Depreciation, Amortization and Impairment of Non-Current Assets

Depreciation, amortization and impairment expenses for the year ended December 31, 2015, increased by $53 million or 8% from $654 million for the year ended December 31, 2014, to $707 million. The depreciation expense for Gas, Renewables and Networks increased by $67 million. Asset increases at Networks accounted for $43 million and a further $10 million at Renewables, and UIL accounts for a further $6 million. Partially offsetting this is a reduction of $12 million on impairment expense related to renewable development projects.

Other Income and (Expense) and Equity Earnings

Other income and (expense) and equity earnings for the year ended December 31, 2015, decreased by $9 million, or 14%, from $64 million other income for the year ended December 31, 2014, to $55 million. The decrease in other income is associated with lower equity earnings of $11 million due to the impact of lower power prices and production on the joint venture windfarms of Renewables.

Interest Expense, Net of Capitalization

Interest expense for the year ended December 31, 2015, increased by $24 million or 10% from $243 million for the year ended December 31, 2014 to $267 million. Networks expense increased by $30 million, consistent with the change in debt and UIL contributed $4 million in additional expense. Renewables expense decreased corresponding with a decrease as their debt amortized.

Income Tax Expense

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% due predominately 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%. Income tax expense for the year ended December 31, 2014, was $35 million higher than it would have been at the statutory federal income tax rate of 35% due predominately to remeasurement of the deferred income tax liability caused by the imposition of a unitary tax regime in New York effective January 1, 2015, production tax credits, and the impact of tax equity financing arrangements. This resulted in an effective tax rate of 39.94%.

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 income tax expense, depreciation, amortization, impairment of non-current assets 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 gain on the sale of equity method and other investment, impairment of investment, 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 and adjustments for the non-core Gas storage business, for which we are exploring strategic options. 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

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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 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 gain on the sale of equity method and other investment, impairment of investment, costs related to the merger with UIL, impact 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, 2016, 2015 and 2014, respectively, is as follows:

Years Ended December 31, (Millions)	2016	2015	2014
Net Income Attributable to Avangrid, Inc.	**$ 630**	**$ 267**	**$ 424**
Add: Income tax expense	379	34	282
Depreciation and amortization	804	695	629
Impairment of non-current assets	—	12	25
Interest expense, net of capitalization	268	267	243
Less: Other income	76	55	52
Earnings from equity method investments	7	—	12
Adjusted EBITDA (2)	**$ 1,998**	**$ 1,220**	**$ 1,539**
Add: Operations and maintenance (1)	2,206	1,808	1,560
Taxes other than income taxes	528	367	314
Less: Transmission wheeling (1)	260	149	143
Adjusted gross margin (2)	**$ 4,472**	**$ 3,246**	**$ 3,270**

(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 gain on the sale of equity method and other investment, impairment of investment, costs related to the merger with UIL, impact 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 table on pages 70-71 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, 2016

	Total	Networks	Renewables	Gas	Other(1)
			(in millions)		
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)%	58%

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Year Ended December 31, 2015

	Total	Networks	Renewables	Gas	Other(1)
			(in millions)		
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%

Year Ended December 31, 2014

	Total	Networks	Renewables	Gas	Other(1)
			(in millions)		
Adjusted gross margin (2)	**$ 3,270**	**$ 2,199**	**$ 997**	**$ 83**	**$ (9)**
Adjusted gross margin %		65%	84%	99%	12%
Adjusted EBITDA (2)	**$ 1,539**	**$ 891**	**$ 613**	**$ 38**	**$ (3)**
Adjusted EBITDA %		26%	52%	45%	4%

(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 gain on the sale of equity method and other investment, impairment of investment, costs related to the merger with UIL, impact 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 table on pages 70-71 of this Annual Report on Form 10-K.

Comparison of Period to Period Results of Operations

Our adjusted gross margin increased by $1.3 billion, or 39%, from $3.2 billion for the year ended December 31, 2015, to $4.5 billion for the year ended December 31, 2016.

Our adjusted EBITDA increased by $778 million, or 64%, from $1.2 billion for the year ended December 31, 2015 to $1.9 billion for the year ended December 31, 2016.

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

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

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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 2016and 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.

Year Ended December 31, 2015 Compared to the Year Ended December 31, 2014

Networks

Adjusted gross margin for the year ended December 31, 2015, increased by $218 million, from $2.2 billion for the year ended December 31, 2014, to $2.4 billion. The increase is associated primarily with the decrease of purchased power by $189 million due to a decrease in the market price of electricity in 2015, with 2014 prices being higher due to colder temperatures causing less efficient generation to be used, increasing the marginal price of electricity. The remaining difference represents the cost of transmission wheeling year over year.

Adjusted EBITDA for the year ended December 31, 2015, decreased by $26 million or 3% from $891 million for the year ended December 31, 2014, to $865 million. The decrease is primarily due to the reasons discussed above regarding adjusted gross margin and increase in operations and maintenance with the main drivers being increased spending in 2015 on reliability support services.

Renewables

Adjusted gross margin for the year ended December 31, 2015, decreased by $132 million or 13% from $997 million for the year ended December 31, 2014, to $865 million. The decrease was due primarily to a reduction in output from our renewable generation facilities, which were 592 GWh lower, and lower merchant prices with a resulting reduction of $70 million, unfavorable results from power trading activities of $34 million, due to reduced trading opportunities created by lower price volatility in the northwest markets and a decrease of $9 million attributable to unrealized losses from changes in fair value of energy derivative transactions entered into for economic hedging purposes.

Adjusted EBITDA for the year ended December 31, 2015, decreased by $157 million or 26% from $613 million for the year ended December 31, 2014, to $456 million. The increase was due primarily to the same reasons discussed above for adjusted gross margin.

Gas

Adjusted gross margin for the year ended December 31, 2015, decreased by $103 million, or 124%, from $83 million for the year ended December 31, 2014, to negative $20 million. The decrease is associated with the decrease in operating revenues due to $105 million in changes relating to change in value of derivatives, with unrealized losses in 2015 compared to unrealized gains in 2014.

Adjusted EBITDA for the year ended December 31, 2015 decreased by $100 million, or 263%, from $38 million for the year ended December 31, 2014 to negative $62 million. The decrease was due primarily to the same reasons discussed above for adjusted gross margin.

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, excluding gain on the sale of equity method and other investment, impairment of investment, costs related to the merger with UIL, impact from mark-to-market

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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, 2016, 2015 and 2014, respectively:

	Year Ended December 31, 2016				
	Total	Networks	Renewables	Corporate *	Gas Storage
			(in millions)		
Net Income Attributable to Avangrid, Inc.	**$ 630**	**$ 480**	**$ 112**	**$ 80**	**$ (42)**
Adjustments:					
Sale of equity method and other investment	(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	**$ 641**	**$ 482**	**$ 98**	**$ 61**	**$ —**
Add: Income tax expense (2)	287	290	35	(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 Attributable to Avangrid, Inc.	**$ 267**	**$ 208**	**$ 133**	**$ (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	**$ 521**	**$ 381**	**$ 117**	**$ 23**	**$ —**
Add: Income tax expense (2)	203	241	37	(76)	—
Depreciation and amortization (3)	1,047	586	461	—	—
Impairment of non-current assets	12	—	12	—	—
Interest expense, net of capitalization (4)	190	163	(37)	64	—
Less: Other income	1	1	—	—	—
Earnings (losses) from equity method investments	15	14	(4)	4	—
Adjusted EBITDA (6)	**$ 1,957**	**$ 1,356**	**$ 595**	**$ 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**	**$ 865**	**$ —**	**$ —**

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	Year Ended December 31, 2014				
	Total	Networks	Renewables	Corporate *	Gas Storage
			(in millions)		
Net Income Attributable to Avangrid, Inc.	**$ 424**	**$ 288**	**$ 201**	**$ (61)**	**$ (4)**
Adjustments:					
Add: Net Income representing the full 12-month period of results for UIL	110	110	—	—	—
Merger costs	8	8	—	—	—
Mark-to-market adjustments - Renewables	(34)	—	(34)	—	—
Income tax impact of adjustments (1)	10	(3)	13	—	—
Gas Storage, net of tax	4	—	—	—	4
Adjusted Net Income	**$ 522**	**$ 403**	**$ 180**	**$ (61)**	**$**
Add: Income tax expense (2)	363	238	76	54	(5)
Depreciation and amortization (3)	877	523	332		22
Impairment of non-current assets	25	—	25	—	—
Interest expense, net of capitalization (4)	300	255	64	(47)	28
Less: Other income and (expense)	52	42	67	(60)	3
Earnings from equity method investments	23	11	2	10	—
Adjusted EBITDA (6)	**$ 2,012**	**$ 1,366**	**$ 608**	**$ (4)**	**$ 42**
Add: Operations and maintenance (5)	1,521	1,152	336	(7)	40
Taxes other than income taxes	500	445	47	3	5
Adjusted gross margin (6)	**$ 4,033**	**$ 2,963**	**$ 991**	**$ (8)**	**$ 87**

(1) Income tax impact of adjustments: $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 $3 million relate to merger costs for the years ended December 31, 2015 and 2014, respectively. Income tax impact of $9 million and $13 million relate to MtM adjustment for the years ended December 31, 2015 and 2014, respectively.

(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 $34 million, $33 million and $28 million for the years ended December 31, 2016, 2015 and 2014, as they have been included in operating revenues in Renewables based on the by nature classification. Additionally, $126 million for unfunded future income taxes have been reclassified from revenues based on the by nature classification in Networks for the year ended December 31, 2015.

(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 $22 million, $14 million and $16 million and bad debt provision of $50 million, $48 million and $87 million in Networks within depreciation and amortization from operations and maintenance based on the by nature classification for the years ended December 31, 2016, 2015 and 2014, respectively. Additionally, government grants of $6.6 million and $6.8 million in Networks and investment tax credits amortization of $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, 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, 2016, 2015 and 2014, 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, excluding gain on the sale of equity method and other investment, impairment of investment, costs related to the merger with UIL, impact 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.

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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, excluding gain on the sale of equity method and other investment, impairment of investment, costs related to the merger with UIL, impact from mark-to-market activities in Renewables and Gas storage business, for the years ended December 31, 2016, 2015 and 2014, respectively:

	Year Ended December 31,		
	2016	2015	2014
	(in millions)		
Networks	$ 480	$ 208	$ 288
Renewables	112	133	201
Corporate (1)	80	(6)	(61)
Gas Storage	(42)	(69)	(4)
Net Income	**$ 630**	**$ 267**	**$ 424**
Adjustments:			
Net income representing the full 12-month period of results for UIL	—	133	110
Merger Costs	—	122	8
Sale of equity method and other investment	(36)	—	—
Impairment of investment	3	—	—
Mark-to-market adjustments - Renewables (2)	(20)	(25)	(34)
Income tax impact of adjustments	22	(45)	10
Gas Storage , net of tax	42	69	4
Adjusted Net Income (3)	**$ 641**	**$ 521**	**$ 522**

	Year Ended December 31,		
	2016	2015	2014
Networks	1.55	0.83	1.14
Renewables	0.37	0.53	0.80
Corporate (1)	0.26	(0.03)	(0.24)
Gas Storage	(0.14)	(0.28)	(0.02)
Earnings Per Share	**2.04**	**1.05**	**1.68**
Adjustments:			
Reduction for acquisition of UIL shares	—	(0.18)	(0.31)
Net income representing the full 12-month period of results for UIL	—	0.43	0.36
Merger costs	—	0.40	0.03
Sale of equity method and other investment	(0.12)	—	—
Impairment of investment	0.01	—	—
Mark-to-market adjustments - Renewables (2)	(0.07)	(0.08)	(0.11)
Income tax impact of adjustments	0.07	(0.15)	0.03
Gas Storage, net of tax	0.14	0.22	0.02
Adjusted Earnings Per Share (3)	**$ 2.07**	**$ 1.68**	**$ 1.69**

(1) Includes corporate and other non-regulated entities.

(2) 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.

(3) 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, excluding gain on the sale of equity method and other investment, impairment of investment, costs related to the merger with UIL, impact from mark-to-market activities in Renewables and Gas storage business.

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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 programs as our primary sources of liquidity. Our long-term capital requirements have been met primarily through retention of earnings, equity contributions from Iberdrola 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, 2016, we had cash and cash equivalents of $91 million, as compared to $427 million at December 31, 2015. 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 notional cash pooling agreement with Bank Mendes Gans, N.V., BMG, along with other members of the Iberdrola Group. The notional cash pooling 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 BMG, provided that the net balance of funds deposited or borrowed by all pool participants in the aggregate is not less than zero. Deposits are available for next day withdrawal. Deposit in the cash pooling account was $353 million at December 31, 2015. In advance of the United Kingdom "BREXIT" vote, we took steps to reposition our liquidity and our deposits with BMG were withdrawn and reinvested in money market accounts. The BMG balance at December 31, 2016 was zero. The deposit amounts are 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. 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 $10 million at December 31, 2016.

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, 2016 and March 9, 2017, there was $150 million and $300 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. Since the facility is a backstop to the AVANGRID commercial paper program, the amounts available under the facility at December 31, 2016 and March 9, 2017, were $1,350 million and $1,200 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.

As a condition of closing on the AVANGRID credit facility, three existing credit facilities were terminated: i) the AVANGRID revolving credit facility which provided for maximum borrowings of up to $300 million and had a scheduled termination date in May 2019; ii) a joint utility revolving credit facility, to which NYSEG, RG&E and CMP were parties, which provided for borrowings of up to $600 million and which had a scheduled termination date in July 2018; iii) the UIL credit facility, to which UIL, UI, SCG, CNG and BGC were parties, which provided for maximum borrowings of $400 million and which had a scheduled termination date in November 2016. At December 31, 2015, no amounts were outstanding under the AVANGRID revolving credit facility, and the joint utility revolving credit facility, and there was $160 million outstanding under the UIL credit facility.

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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.

In November 2016, NYSEG issued $500 million principal amount of senior unsecured notes bearing a coupon of 3.25% and a December 1, 2026 maturity date. The notes were priced at a discount to yield 3.335%. Net proceeds of the offering after the price discount and underwriters' discount were $493 million.

At December 31, 2016, we had $4,307 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. Networks' regulated utilities were in compliance with these regulatory orders as of December 31, 2016. 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.

At December 31, 2016, we had $70 million of long-term debt (including the current portion thereof) outstanding in the Renewables segment consistently principally of a sale-leaseback arrangement on a solar generation facility. Renewables has historically been financed primarily with equity contributions from Iberdrola. The last such contribution of $800 million was made in February 2013. 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 $199 million, of which $96 million is current, at December 31, 2016.

At December 31, 2016, we had $470 million and $12 million of long-term debt (including the current portion thereof) outstanding in the corporate and Gas, respectively. Long-term debt in the corporate consists principally of $450 million of 4.625% notes due in 2020 originally issued by UIL in 2010. The obligations relating to those notes were transferred to Avangrid, Inc. in December 2016. For further details see details Note 10 and Note 3 of Schedule I of our audited consolidated financial statements for the three years ended December 31, 2016, which are incorporated herein by reference.

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, 2016.

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, 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.

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Capital Expenditures

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

	2016	2015	2014
		(in millions)	
NYSEG	$ 282	$ 259	$ 247
RG&E	268	157	181
CMP (non-MPRP(1))	207	120	172
CMP (MPRP)	—	108	112
MNG	3	3	15
UI	170	187	142
SCG	54	62	64
CNG	73	62	55
BGC	17	16	13
Total	**$ 1,074**	**$ 974**	**$ 1,001**

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

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

	2016	2015	2014
		(in millions)	
Wind & solar	$ 751	$ 58	$ 270
Thermal	8	11	14
Corporate(1)	7	8	9
Total capital expenditures	**766**	**77**	**293**

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

Capital expenditures have remained relatively flat across Networks during the period from 2014 to 2016.

Renewables also made capital investments during this three-year period. 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.

In 2014 there were capital expenditures of $257 million primarily for construction of the Baffin Bay wind asset, $14 million for capital expenditures on the Klamath gas-fired cogeneration facility, or the Klamath Plant, $14 million on improvements to operating wind assets and $13 million in development costs, partially offset by $16 million in net refunds of wind turbine deposits.

Capital Improvement Projects

An important part of our business strategy involves capital improvement projects. Through Networks we plan to invest a total of approximately $7.8 billion from 2017 to 2021 to upgrade and expand electricity and natural gas transmission and distribution infrastructure. In the next 12 months, CMP plans to invest $204 million, including the program to complete the Lewiston Loop project, which complements the already completed MPRP, a project which enhanced the bulk power transmission grid in Maine. 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. NYSEG plans to invest $336 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: The FERC Bright Line project, Auburn transmission project, Columbia County transmission project, Gas Distribution Mains and Leak Prone Main replacement. RG&E plans to invest $299 million in the next 12 months, including a number of programs disclosed in Appendix P

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Schedule I of the proposal dated June 15, 2016, the most relevant ones: The FERC Bright Line, Rochester Area Reliability Project (RARP), Ginna Retirement Transmission Alternative (GRTA), Station 23 - New Downtown 115kV source,

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Gas Distribution Mains and Leak Prone Main replacement. UIL plans to invest $393 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 Liquefied Natural Gas, or LNG, Plant Liquefaction System Replacement Project.

On July 24, 2015, UIL announced its participation in Tennessee Gas Pipeline Company LLC's, or TGP, proposed Northeast Energy Direct project, or NED pipeline, through an acquisition of a 2.5% equity interest in Northeast Expansion LLC. Northeast Expansion LLC is a joint venture between an affiliate of Kinder Morgan, Inc., or Kinder Morgan, and Liberty Utilities Corp., which had planned to construct and own the NED pipeline, a new, "market path" natural gas pipeline segment of approximately 188 miles from Wright, New York, to Dracut, Massachusetts. In addition, as a condition to making this investment, UIL entered into a 20-year precedent agreement with TGP for pipeline capacity of 70,000 DTh/day on the NED pipeline, which capacity commitment, under the terms of the precedent agreement, would be reduced in the event that TGP enters into additional precedent agreements with third parties for capacity on the NED pipeline. In April 2016, citing inadequate capacity commitments from prospective customers, TGP elected to suspend all activities on the NED pipeline.

Through Renewables we plan to invest a total of approximately $4.0 billion from 2017 to 2021 in order to add 2,000 MWs of generation capacity. 601 MW are approved for construction in 2017 and 2018 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, 2016, 2015 and 2014:

	Year Ended December 31,		
	2016	2015	2014
		(in millions)	
Cash Flows			
Net cash from operating activities	$ 1,561	$ 1,363	$ 1,331
Net cash used in investing activities	(1,527)	(1,518)	(888)
Net cash (used in) from financing activities	(372)	102	(180)
Net (decrease) increase in cash, cash equivalents and restricted cash	**$ (338)**	**$ (53)**	**$ 263**

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 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.

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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.

In 2014, net cash provided by operating activities was approximately $1.3 billion. During the period, Renewables contributed $724 million of operating cash associated with wholesale sales of energy, Networks contributed $734 million of operating cash as the result of regulated transmission and distribution sales of electricity and natural gas, and Gas contributed cash of $17 million associated with gains on marketing of wholesale gas and gas storage services. We used $60 million in cash associated with operating expenses in support of our segments. In addition, changes in working capital used $84 million in cash. The cash from operating activities for the year ended December 31, 2014, compared to the year ended December 31, 2013, increased by $154 million and this is primarily driven by the increased revenues at Renewables due to increase in wind source, prices, power trading activities and abundant hydro conditions as well as Gas due to lower gas prices. The $35 million net change in our net operating assets and liabilities during the year ended December 31, 2014, was primarily attributable to a decrease in inventory costs driven by a decrease in inventory levels of $58 million, partially offset by storm cost deferrals of $20 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. The increase in cash outflows related to capital expenditures in 2016 was largely due to the inclusion of UIL, which was not in the comparable period, adding $356 million. The cost of investments has been offset, partially, by contributions in aid of construction and proceeds from the sale of equity investments in 2016.

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, compared to $888 million in 2014. The increase in 2015 compared to 2014 is primarily related to cash paid for acquisition of UIL (net of cash acquired) of $547 million. The cash outflows related to capital expenditures for Networks were $773 million in 2015 and $775 million in 2014. The remaining capital expenditure related cash outflows in 2015 represent principally capital expenditures in Renewables of $304 million. This amount is driven by significant progress in construction of the Baffin Bay wind asset in 2014. Under a turbine supply agreement, with Gamesa, payment for the supplied turbines did not take place until first quarter of 2015.

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 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.

In 2014, cash used in financing activities was $180 million reflecting primarily maturities of notes payable and $119 million in payments on the tax equity financing arrangements.

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Contractual Obligations

As of December 31, 2016, our contractual obligations (excluding any tax reserves) were as follows:

	Total	2017	2018	2019	2020	2021	Thereafter
				(in millions)			
Operating leases(1)	$ 703	$ 106	$ 28	$ 28	$ 26	$ 28	$ 487
Projected future pension benefit plan contributions(2)	151	33	51	54	13	—	—
Long-term debt (including current maturities)(3)	4,859	349	180	358	723	308	2,941
Interest payments(4)	2,371	222	205	186	169	141	1,448
Material purchase commitments(5)	2,587	487	376	287	238	191	1,008
Total Contractual Obligations	**$ 10,671**	**$ 1,197**	**$ 840**	**$ 913**	**$ 1,169**	**$ 668**	**$ 5,884**

(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. Obligations under operating lease significantly decrease from 2016 onwards as commitments on Cayuga and Ginna facilities are scheduled to terminate from 2017.

(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 2020 are not included as projection beyond 2020 are not available.

(3) Includes 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, 2016, 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, 2016

(5) Represents forward purchase commitments under power, gas, and other arrangements.

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.

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. 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.

Revision of estimated useful lives of wind power station assets at Renewables

Renewables' wind power station assets in service less salvage value, if any, are depreciated using the straight-line method over their estimated useful lives. Renewables' effective depreciation rate, excluding decommissioning, was 4.0% in both 2015 and 2014. Renewables reviews the estimated useful lives of its fixed assets on an ongoing basis. In the first quarter of 2016, this review indicated that the actual lives of certain assets at wind power stations are expected to be longer than the previously estimated useful lives used for depreciation purposes. As a result, effective January 1, 2016, Renewables changed the estimates of the useful lives of certain assets from 25 years to 40 years, capped at the lease term if lower, to better reflect the estimated periods during which these assets are expected to remain in service. The weighted average useful life of our wind farm assets is now approximately 31 years. We are continuing to assess lease extensions with leaseholders to potentially increase the average useful life of our wind farm assets to more than 31 years. The effect of this change in estimate was to reduce depreciation and amortization expense by approximately $52 million, reduce asset retirement obligation accretion expense recorded within operations and maintenance by approximately $3 million, increase earnings from equity method investments by approximately $4 million, increase income before income tax and net income by approximately $59 million and approximately $36 million, respectively, and increase basic and diluted earnings per share by approximately $0.12 for the year ended December 31, 2016.

Accounting for Regulated Public Utilities

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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

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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, 2016, 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 2016, 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, 2016, reflect updated mortality assumptions.

Business Combinations

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.

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.

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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

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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.

Networks

Provided recent relevant events, such as acquisition of UIL in December 2015 and approval of the proposal by the NYPSC, we conducted a quantitative analysis (step one) in 2016. Based on the results of our step one impairment test the estimated fair value of each of the Networks reporting units was substantially in excess of their respective carrying values.

Renewables

Based on the results of our step one impairment test for the Renewables reporting unit conducted in 2016, its estimated fair value was in excess of the carrying value. The assumptions used to estimate fair value were based on projections incorporated in our current operating plans as well as other available information. The current operating plans included significant assumptions and estimates associated with sales growth, profitability and related cash flows, along with cash flows associated with taxes and capital spending. The discount rate used to estimate fair value was risk adjusted in consideration of the economic conditions of the reporting unit. We also considered other assumptions that market participants may use. By their nature, projections are uncertain. Potential events and circumstances, such as declining wind energy output and prices obtained per MWh, changes in incentives established to promote renewable energies and increases in capital expenditures per MW could have an adverse effect on our assumptions.

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.

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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

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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 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 most recently filed 2014 return.

AVANGRID (excluding ARHI and UIL), and ARHI 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.

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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 not more-likely-than not that all or a portion of a tax benefit will 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.

Off-Balance Sheet Arrangements

As of December 31, 2016, we had approximately $2.6 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, 2016, 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.

Fair Value Measurement Disclosures for Certain Investments - In May 2015 the FASB issued amendments that affect reporting entities that elect to estimate the fair value of certain investments within scope using the net asset value, or NAV, per share (or its equivalent) practical expedient, as specified.

Simplifying the Measurement of Inventory - In July 2015 the FASB issued amendments that require entities to measure inventory at the lower of cost and net realizable value, rather than the lower of cost or market.

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

Simplifying the Accounting for Measurement-Period Adjustments - In September 2015 the FASB issued amendments that require an acquirer to 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.

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.

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Derivative contract novations **-** In March 2016 the FASB issued amendments concerning the effect of derivative contract novations on existing hedge accounting relationships.

Improvements to Employee Share-Based Payment Accounting **-** In March 2016 the FASB issued amendments regarding the simplification of several aspects of accounting for share-based payment transactions.

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 the amendments to address existing diversity in practice concerning eight cash flows issues.

Presentation of restricted cash in the statement of cash flows **-** In November 2016 the FASB issued the amendment to address existing diversity in the classification and presentation of changes in restricted cash on the statement of cash flows.

For further discussion of new accounting pronouncements affecting AVANGRID refer to Note 3 of our audited consolidated financial statements for the three years ended December 31, 2016, 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 2016 was $17.7 million compared to a 2015 average of $14.0 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

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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 audited consolidated financial statements for the three years ended December 31, 2016, which are incorporated herein by reference.

Interest Rate Risk

Total debt outstanding, including tax equity of $199 million and commercial paper of $150 million, was $5.2 billion at December 31, 2016, of which $212 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 $0.5 million annually. The estimated fair value of our debt excluding the debt associated with capital leases and tax equity at December 31, 2016 was $5.1 billion, in comparison to a book value of $4.7 billion.

There are no interest rate derivative contracts outstanding at December 31, 2016 and 2015.

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 2016, we contributed $44 million to our pension plans. Our contribution to the pension plans in 2017 is expected to be approximately $33 million.

The discount rate used in accounting for pension and other benefit obligations in 2016 ranged from 3.90% to 4.24%. The expected rate of return on plan assets for qualified pension benefits in 2016 ranged from 5.50% to 7.75%. 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 2016 Pension Expense Increase (Decrease)	
	Change in Assumption	Pension Benefits	Post Retirement
		(in millions)	
Increase in discount rate	50 basis points	$ (18)	$ (3)
Decrease in discount rate	50 basis points	18	3
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.

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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.

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Some relevant considerations when assessing the credit risk exposure of the energy management and gas storage operations 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.
- 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, 2016, 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, 2016:

	Credit Exposure Before Cash Collateral	Cash Collateral	Net Credit Exposure
		(in millions)	
A- and Greater	$ 2,201	$ —	$ 2,201
BBB+ and BBB	636	—	636
BBB-	4	—	4
Total Investment Grade(1)	2,841	—	2,841
Non-investment grade(2) (3) (4) (5)	252	12	240
Total	$ 3,093	$ 12	$ 3,081

(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 32.7% 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 5.2% 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 1.7% 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 broader Iberdrola Group and are a party to a notional cash pooling agreement with Bank Mendes Gans, N.V., or BMG, along with other 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 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.

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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, 2016, was $199 million and the balance of leases and project financing was $70 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 June 2016, Renewables recorded a net dividend of $962 million to Avangrid, Inc. to zero out account balances that had principally accumulated prior to November 2013.

Item 8. Financial Statements and Supplementary Data

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Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of Avangrid, Inc. and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, changes in equity and cash flows for each of the three 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 did not audit the consolidated balance sheet of UIL Holdings Corporation, a wholly-owned subsidiary acquired in 2015, which statement reflects total assets of $5,270 million as of December 31, 2015. That balance sheet was audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the balance sheet amounts included for UIL Holdings Corporation, is based solely on the report of other auditors.

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 and the report of other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and, as to the balance sheet at December 31, 2015, the report of other auditors, 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 2015, and the consolidated results of their operations and their cash flows for each of the three 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.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Avangrid, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated March 10, 2017 expressed an adverse opinion thereon.

/s/ Ernst & Young LLP

New York, New York
March 10, 2017

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Report of Independent Registered Public Accounting Firm

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

We have audited Avangrid, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Avangrid, Inc. and subsidiaries' 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 conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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.

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 the company's annual or interim financial statements will not be prevented or detected on a timely basis. The following material weaknesses have been identified and included in management's assessment. Management has identified material weaknesses in controls related to: (a) the accounting for the change in the estimated useful lives of certain components of the wind farms and with deficiencies in the documentation and execution of internal control procedures, specifically management review controls, within Avangrid Renewables, LLC, (b) the preparation of the consolidated financial statements, including disclosures within those consolidated financial statements, and (c) the recognition and measurement of income taxes. These control deficiencies resulted in part from ineffective training and oversight of process owners and the complexities associated with maintaining accounting records for numerous legal entities and jurisdictions. We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Avangrid, Inc. and subsidiaries as of December 31, 2016 and 2015 and the related consolidated statements of income, comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2016. These material weaknesses were considered in determining the nature, timing and extent of audit tests applied in our audit of the 2016 financial statements, and this report does not affect our report dated March 10, 2017, which expressed an unqualified opinion on those financial statements.

In our opinion, because of the effect of the material weaknesses described above on the achievement of the objectives of the control criteria, Avangrid, Inc. and subsidiaries has not maintained effective internal control over financial reporting as of December 31, 2016, based on the COSO criteria.

/s/ Ernst & Young LLP

New York, New York
March 10, 2017

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Independent Auditor's Report

To the Board of Directors of UIL Holdings Corporation.

In our opinion, the consolidated balance sheet (not presented herein) presents fairly, in all material respects, the financial position of UIL Holdings Corporation and its subsidiaries at December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. The balance sheet is the responsibility of the Company's management. Our responsibility is to express an opinion on the balance sheet based on our audit. We conducted our audit of this statement in accordance with the standards of the Public Company Accounting Oversight Board (United States) and in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the balance sheet is free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the balance sheet, assessing the accounting principles used and significant estimates made by management, and evaluating the overall balance sheet presentation. We believe that our audit of the balance sheet provides a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Boston, MA
April 1, 2016

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Avangrid, Inc. and Subsidiaries
Consolidated Statements of Income

Years Ended December 31, (Millions, except for number of shares and per share data)	2016	2015	2014
Operating Revenues	**$ 6,018**	**$ 4,367**	**$ 4,594**
Operating Expenses			
Purchased power, natural gas and fuel used	1,286	972	1,181
Operations and maintenance	2,206	1,808	1,560
Impairment of non-current assets	—	12	25
Depreciation and amortization	804	695	629
Taxes other than income taxes	528	367	314
Total Operating Expenses	**4,824**	**3,854**	**3,709**
Operating Income	**1,194**	**513**	**885**
Other Income and (Expense)			
Other income	76	55	52
Earnings from equity method investments	7	—	12
Interest expense, net of capitalization	(268)	(267)	(243)
Income Before Income Tax	**1,009**	**301**	**706**
Income tax expense	379	34	282
Net Income	**630**	**267**	**424**
Less: Net income attributable to noncontrolling interests	—	—	—
Net Income Attributable to Avangrid, Inc.	**$ 630**	**$ 267**	**$ 424**
Earnings Per Common Share, Basic:	**$ 2.04**	**$ 1.05**	**$ 1.68**
Earnings Per Common Share, Diluted:	**$ 2.04**	**$ 1.05**	**$ 1.68**
Weighted-average Number of Common Shares Outstanding:			
Basic	309,512,553	254,588,212	252,235,232
Diluted	309,817,322	254,605,111	252,235,232
Cash Dividends Declared Per Common Share	**$ 1.728**	**$ —**	**$ —**

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

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Avangrid, Inc. and Subsidiaries
Consolidated Statements of Comprehensive Income

Years Ended December 31,	2016	2015	2014
(Millions)			
Net Income	**$ 630**	**$ 267**	**$ 424**
Other Comprehensive Income			
Amounts arising during the year:			
Gain on defined benefit plans, net of income taxes of $4.3, $2.2 and $0.6, respectively	7	4	1
Amortization of pension cost for nonqualified plans, net of income taxes of $0.4, $1.7 and $(1.9), respectively	1	3	(3)
Unrealized gain (loss) during the year on derivatives qualifying as cash flow hedges, net of income taxes of $(15.8), $20.9 and $(1.4), respectively	(26)	33	(2)
Reclassification to net income of (gains) losses on cash flow hedges, net of income taxes of $(11.0), $4.9 and $4.1, respectively	(16)	7	5
Other Comprehensive (Loss) Income	**(34)**	**47**	**1**
Comprehensive Income	596	314	425
Less: Net income attributable to noncontrolling interests	—	—	—
Comprehensive Income Attributable to Avangrid, Inc.	**$ 596**	**$ 314**	**$ 425**

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Avangrid, Inc. and Subsidiaries
Consolidated Balance Sheets

As of December 31,	2016	2015
(Millions)		
Assets		
Current Assets		
Cash and cash equivalents	$ 91	$ 427
Accounts receivable and unbilled revenues, net	1,119	974
Accounts receivable from affiliates	25	70
Notes receivable from affiliates	—	6
Derivative assets	99	88
Fuel and gas in storage	246	307
Materials and supplies	132	98
Prepayments and other current assets	255	285
Regulatory assets	285	219
Total Current Assets	**2,252**	**2,474**
Property, plant and equipment, at cost	27,063	25,745
Less: accumulated depreciation	(6,986)	(6,372)
Net Property, Plant and Equipment in Service	**20,077**	**19,373**
Construction work in progress	1,471	1,338
Total Property, Plant and Equipment ($1,144 and $1,206 related to VIEs, respectively)	**21,548**	**20,711**
Equity method investments	387	385
Other investments	55	64
Regulatory assets	3,091	3,314
Other Assets		
Goodwill	3,124	3,115
Intangible assets	538	556
Derivative assets	73	89
Other	241	35
Total Other Assets	**3,976**	**3,795**
Total Assets	**$ 31,309**	**$ 30,743**

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Avangrid, Inc. and Subsidiaries
Consolidated Balance Sheets

As of December 31,	2016	2015
(Millions, except share information)		
Liabilities		
Current Liabilities		
Current portion of debt	$ 349	$ 206
Tax equity financing arrangements - VIEs	96	107
Notes payable	151	163
Notes payable to affiliates	10	—
Interest accrued	60	61
Accounts payable and accrued liabilities	1,096	830
Accounts payable to affiliates	218	90
Dividends payable	134	—
Taxes accrued	52	55
Derivative liabilities	75	91
Other current liabilities	279	285
Regulatory liabilities	192	147
Total Current Liabilities	**2,712**	**2,035**
Regulatory liabilities	1,753	1,841
Deferred income taxes regulatory	565	519
Other Non-current Liabilities		
Deferred income taxes	2,976	2,798
Deferred income	1,483	1,553
Pension and other postretirement	1,106	1,202
Tax equity financing arrangements - VIEs	103	185
Derivative liabilities	78	94
Asset retirement obligations	161	184
Environmental remediation costs	398	406
Other	342	330
Total Other Non-current Liabilities	**6,647**	**6,752**
Non-current Debt	4,510	4,530
Total Non-current Liabilities	**13,475**	**13,642**
Total Liabilities	**16,187**	**15,677**
Commitments and Contingencies	—	—
Equity		
Stockholders' Equity:		
Common stock, $.01 par value, 500,000,000 shares authorized, 309,600,439 and 309,491,082 shares issued; 308,993,149 and 308,864,609 shares outstanding, respectively	3	3
Additional paid-in capital	13,653	13,653
Treasury Stock	(5)	—
Retained earnings	1,544	1,449
Accumulated other comprehensive loss	(86)	(52)
Total Stockholders' Equity	**15,109**	**15,053**
Noncontrolling interests	13	13
Total Equity	**15,122**	**15,066**
Total Liabilities and Equity	**$ 31,309**	**$ 30,743**

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Avangrid, Inc. and Subsidiaries
Consolidated Statements of Cash Flows

Years Ended December 31,	2016	2015	2014
(Millions)			
Cash Flow from Operating Activities			
Net income	**$ 630**	**$ 267**	**$ 424**
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	804	695	629
Impairment of non-current assets	—	12	25
Accretion expenses	10	14	14
Regulatory assets/liabilities amortization	49	101	(38)
Regulatory assets/liabilities carrying cost	13	41	35
Pension cost	110	115	74
Stock-based compensation	1	6	5
Earnings from equity method investments	(7)	—	(12)
Amortization of debt (premium) cost	(28)	4	2
Gain on disposal of property and equity method investment	(33)	—	—
Unrealized losses (gains) on marked to market derivative contracts	(4)	10	(116)
Deferred taxes	377	87	261
Other non-cash items	(23)	(5)	(3)
Changes in operating assets and liabilities:			
Accounts receivable and unbilled revenues	(158)	160	(1)
Inventories	46	4	58
Other assets	107	(39)	(100)
Cash distribution from equity method investments	14	—	—
Accounts payable and accrued liabilities	184	(10)	27
Other liabilities	(447)	(194)	(115)
Taxes accrued	(3)	21	(13)
Regulatory assets/liabilities	(81)	74	175
Net Cash Provided by Operating Activities	**1,561**	**1,363**	**1,331**
Cash Flow from Investing Activities			
Capital expenditures	(1,707)	(1,082)	(1,030)
Contributions in aid of construction	69	38	43
Government grants	—	17	4
Acquisition of business, net of $48 million cash acquired	—	(547)	—
Proceeds from sale of equity method and other investment	57	3	31
Proceeds from sale of property, plant and equipment	50	—	—
Receipts from (payments to) affiliates	6	(6)	10
Cash distribution from equity method investments	6	12	19
Other investments and equity method investments, net	(8)	47	35
Net Cash Used in Investing Activities	**(1,527)**	**(1,518)**	**(888)**
Cash Flow from Financing Activities			
Non-current note issuance	493	350	—
Repayments of non-current debt	(355)	(141)	(27)
Proceeds (repayments) of other short-term debt, net	(2)	10	(14)
Repayments of capital leases	(12)	(12)	(21)
Payments on tax equity financing arrangements	(88)	(102)	(119)
Contribution from noncontrolling interests	—	—	4
Dividends to noncontrolling interests	—	(3)	(3)
Repurchase of common stock	(5)	—	—
Issuance of common stock	(2)	—	—
Dividends paid	(401)	—	—
Net Cash (Used in) Provided by Financing Activities	**(372)**	**102**	**(180)**
Net (Decrease) Increase in Cash, Cash Equivalents and Restricted Cash	**(338)**	**(53)**	**263**
Cash, Cash Equivalents and Restricted Cash, Beginning of Year	**434**	**487**	**224**
Cash, Cash Equivalents and Restricted Cash, End of Year	**$ 96**	**$ 434**	**$ 487**
Supplemental Cash Flow Information			
Cash paid for interest, net of amounts capitalized	$ 229	$ 132	$ 133
Cash paid for income taxes	9	7	21

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

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

(Millions, except for number of shares)	Avangrid, Inc. Stockholders								
	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, 2013	**252,235,232**	**$ 3**	**11,375**	**$ —**	**758**	**(100)**	**$ 12,036**	**$ 15**	**$12,051**
Net income	—	—	—	—	424	—	424	—	424
Other comprehensive income, net of tax of $1.4	—	—	—	—	—	1	1	—	1
Comprehensive income									425
Capital contribution from noncontrolling interests	—	—	—	—	—	—	—	4	4
Dividends to noncontrolling interests	—	—	—	—	—	—	—	(3)	(3)
Balances, December 31, 2014	**252,235,232**	**3**	**11,375**	**—**	**1,182**	**(99)**	**12,461**	**16**	**12,477**
Net income	—	—	—	—	267	—	267	—	267
Other comprehensive income, net of tax of $29.7	—	—	—	—	—	47	47	—	47
Comprehensive income									314
Issuance of common stock	57,255,850	—	2,278	—	—	—	2,278	—	2,278
Common stock held in trust	(626,473)	—	—	—	—	—	—	—	—
Dividends to noncontrolling interests	—	—	—	—	—	—	—	(3)	(3)
Balances, December 31, 2015	**308,864,609**	**3**	**13,653**	**—**	**1,449**	**(52)**	**15,053**	**13**	**15,066**
Net income	—	—	—	—	630	—	630	—	630
Other comprehensive income, net of tax of $22.1	—	—	—	—	—	(34)	(34)	—	(34)
Comprehensive income									596
Dividends declared	—	—	—	—	(535)	—	(535)	—	(535)
Release of common stock held in trust	135,014	—	—	—	—	—	—	—	—
Issuance of common stock	109,357	—	(2)	—	—	—	(2)	—	(2)
Repurchase of common stock	(115,831)	—	—	(5)	—	—	(5)	—	(5)
Stock-based compensation	—	—	2	—	—	—	2	—	2
Balances, December 31, 2016	**308,993,149**	**$ 3**	**$ 13,653**	**$ (5)**	**$ 1,544**	**$ (86)**	**$ 15,109**	**$ 13**	**$15,122**

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

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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). Effective as of April 30, 2016, UIL Holdings Corporation and its subsidiaries (UIL) were transferred to a wholly-owned subsidiary of Networks. AVANGRID is also 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.

Reorganization

On November 20, 2013, we completed a series of reorganizations (Reorganization) of entities under common control. The Reorganization included the transfer of ARHI from an affiliate of Iberdrola to AVANGRID, and the transfer of the principal operating utility companies from AVANGRID to Networks.

AVANGRID and ARHI were acquired by Iberdrola in 2008 and 2007, respectively, and they have been under common control of Iberdrola for all periods presented. Networks was formed as part of the Reorganization in November 2013. Networks is a public utility sub-holding company operating under the Public Utility Holding Company Act of 2005 with operations in New York, Maine, Connecticut and Massachusetts. The wholly owned subsidiaries and the operating utility companies of Networks include: CMP Group - Central Maine Power Company (CMP), RGS - New York State Electric & Gas Corporation (NYSEG), Rochester Gas and Electric Corporation (RG&E), Maine Natural Gas Company (MNG), The United Illuminating Company (UI), 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 certain affiliates of NRG Energy, Inc. (NRG affiliates) 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). ARHI is the sub-holding company of the unregulated energy business that includes the renewable energy and the gas trading and storage businesses.

The transfer of a business among entities under common control is accounted for at carrying amount with retrospective adjustment of prior period financial statements similar to the manner in which a pooling-of-interest was accounted for under accounting principles generally accepted in the United States of America (U.S. GAAP).

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. See Note 4, Acquisition of UIL, for further details.

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 SCG, CNG and BGC.

UI is also a party to a joint venture with certain affiliates of NRG Energy, Inc. (NRG affiliates) 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

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LLC, GenConn) operates peaking generation plants in Devon, Connecticut (GenConn Devon) and Middletown, Connecticut (GenConn Middletown).

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 have been retroactively adjusted to reflect the impact of the stock dividend.

Revision of estimated useful lives of wind power station assets at Renewables

Renewables' wind power station assets in service less salvage value, if any, are depreciated using the straight-line method over their estimated useful lives. Renewables' effective depreciation rate, excluding decommissioning, was 4.0% in both 2015 and 2014. Renewables reviews the estimated useful lives of its fixed assets on an ongoing basis. In the first quarter of 2016, this review indicated that the actual lives of certain assets at wind power stations are expected to be longer than the previously estimated useful lives used for depreciation purposes. As a result, effective January 1, 2016, Renewables changed the estimates of the useful lives of certain assets from 25 years to 40 years, capped at the lease term if lower, to better reflect the estimated periods during which these assets are expected to remain in service. The weighted average useful life of our wind farm assets is now approximately 31 years. The effect of this change in estimate was to reduce depreciation and amortization expense by approximately $52 million, reduce asset retirement obligation accretion expense recorded within operations and maintenance by approximately $3 million, increase earnings from equity method investments by approximately $4 million, increase income before income tax and net income by approximately $59 million and approximately $36 million, respectively, and increase basic and diluted earnings per share by approximately $0.12 for the year ended December 31, 2016.

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.

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(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

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.

(e) Equity method investments

Joint ventures that do not meet consolidation criteria are accounted for using the equity method. Earnings (losses) recognized under the equity method are reflected in the consolidated statements of income as "Earnings (losses) from equity method investments." Dividends received from joint ventures are recognized as a reduction in the carrying amount of the investment and are not recognized as dividend income.

(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.

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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

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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
	Hydroelectric power stations	35-90
	Wind power stations	25-40
	Gas storage	25-40
	Transport facilities	40-56
	Distribution facilities	30-54
Equipment	Conventional meters and measuring devices	15-27
	Computer software	3-5
Other	Buildings	50-75
	Operations offices	4-50

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.

(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

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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.

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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.

(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

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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

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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.

(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) Tax equity financing arrangements-VIEs

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.

We evaluate whether an entity is a variable interest entity (VIE) whenever reconsideration events as defined by the accounting guidance occur (See Note 19). 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.

(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, or below market 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 cost and reported on the balance sheets within “Materials and supplies.”

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

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(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 2053.

(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

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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 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), 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 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 not more-likely-than-not that all or a portion of a tax benefit will 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.

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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.

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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.

(w) Stock-based compensation

Stock-based compensation represents costs related to stock-based awards granted to employees. In the third quarter of 2016 we early adopted all the amendments to ASC 718, Compensation - Stock Compensation, issued in March 2016, to account for our stock based awards. 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.

Reclassifications

Certain amounts have been reclassified in the consolidated statements of cash flow to conform to the 2016 presentation as well as in connection with retrospective adoption of amendments in the accounting standard related to presentation of restricted cash in the statement of cash flow.

New Accounting Standards and Interpretations

(a) Revenue from contracts with customers

In May 2014 the Financial Accounting Standards Board (FASB) issued ASC 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. 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 original effective date for public entities was for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. In August 2015 the FASB issued an accounting standards update that defers by one year the original effective date of the revenue standard for all entities. Thus, the standard is now effective for annual reporting periods beginning after December 15, 2017, and interim periods therein, with early adoption as of the original effective date permitted. We do not plan to early adopt. Entities may apply the amendment 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). We will apply the modified retrospective method. We are currently evaluating how our adoption of the amendments will affect our results of operations, financial position, cash flows, and disclosures. We are considering the effects of the amendments on our ability to recognize revenue for certain contracts for our regulated utilities where collectability is in question and our accounting for contributions in aid of construction for our regulated utilities. In addition, the amendments will require us to capitalize, rather than expense, any costs to acquire new contracts. Additionally, classification differences are also expected to result, including recording our tax equity investments as noncontrolling interests. Some revenue arrangements, such as alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on our consolidated financial statements. The FASB has issued various additional accounting standards updates, with the same deferred effective date, as follows: in March 2016 to amend and clarify the implementation guidance on principal versus agent considerations for reporting revenue gross rather than net, in April 2016 to address implementation questions on identifying performance obligations and accounting for licenses of intellectual property. We do not expect significant effects as a result of those updates. In May 2016 the FASB issued a final update concerning narrow-scope improvements and practical expedients. We are currently evaluating the effects of that update.

(b) Fair value measurement disclosures for certain investments

In May 2015 the FASB issued amendments that affect reporting entities that elect to estimate the fair value of certain investments within scope using the net asset value (NAV) per share (or its equivalent) practical expedient, as specified. The amendments remove the requirement to categorize within the fair value hierarchy all investments for which the fair value is measured at NAV using the practical expedient. They also remove certain disclosure requirements for eligible investments and limit the required disclosures to investments for

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which the entity has elected to measure the fair value using the practical expedient. Assets that calculate NAV per share (or its equivalent), but for which the practical expedient is not applied will continue to be included in the fair value hierarchy.

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The amendments are effective for public entities for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. The amendments permit early application, and require retrospective application to all periods presented. Retrospective application requires investments for which fair value is measured at NAV using the practical expedient to be removed from the fair value hierarchy in all periods presented. Our adoption of the amendments in 2016 did not affect our results of operations, financial position, or cash flows.

(c) Simplifying the measurement of inventory

In July 2015 the FASB issued amendments that require entities to measure inventory at the lower of cost and net realizable value, rather than the lower of cost or market. The amendments do not apply to inventory measured using last-in, first-out or the retail inventory method but apply to all other inventory, including inventory measured using first-in, first-out or average cost. Prior to this update, market value could be replacement cost, net realizable value, or net realizable value less an approximately normal profit margin. Net realizable value is the "estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation." The amendments do not change the methods of estimating the cost of inventory under U.S. GAAP. The amendments are effective for public entities for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. The amendments require prospective application and permit earlier application. We expect our adoption of the amendments will not affect our results of operations, financial position, or cash flows.

(d) 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 results of operations, financial position, or cash flows.

(e) Business combinations: simplifying the accounting for measurement-period adjustments

In September 2015 the FASB issued amendments that require an acquirer to 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. As a result, the acquirer is required to record, in the same period's financial statements, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. The entity is required to present separately on the face of the income statement or disclose in the notes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. The amendments are effective for public entities for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years. The amendments require prospective application to provisional amounts that occur after the effective date of the amendment and permit

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earlier application. The effects of our adoption of the amendments on our results of operation, financial position, or cash flows as it relates to the business combination with UIL have been disclosed in Note 4, Acquisition of UIL.

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(f) 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 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 a right-of-use asset.

(g) Derivative contract novations

In March 2016 the FASB issued amendments concerning the effect of derivative contract novations on existing hedge accounting relationships. As it relates to derivative instruments, novation refers to replacing one of the parties to a derivative instrument with a new party, which may occur for a variety of reasons such as: financial institution mergers, intercompany transactions, an entity exiting a particular derivatives business or relationship, or because of laws or regulatory requirements. The amendments clarify that a change in the counterparty to a derivative instrument that has been designated as the hedging instrument under the guidance for Derivatives and Hedging (Topic 815) does not, in and of itself, require dedesignation of that hedge accounting relationship provided that all other hedge accounting criteria continue to be met. The amendments are effective for public entities for financial statements issued for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. The amendments may be applied on either a prospective basis or a modified retrospective basis and early application is permitted. We expect our adoption will not materially affect our results of operations, financial position, and cash flows.

(h) Improvements to employee share-based payment accounting

The FASB issued amendments in March 2016 regarding the simplification of several aspects of accounting for share-based payment transactions, including income tax consequences, classification of awards as either equity or liabilities, policy election on accounting for forfeitures and classification on the statement of cash flows. Some areas of simplification apply only to nonpublic entities. The amendments are effective for public entities for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. Early adoption permitted in any interim or annual period, but must adopt all of the amendments in the same period. For the purpose of accounting for the stock-based compensation plans, in the third quarter of 2016 we early adopted all the above amendments and elected to account for forfeitures when they occur. Our adoption of the amendments did not materially affect our results of operations, financial position, or cash flows.

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(i) 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 collectibility 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 results of operations, financial position, and cash flows.

(j) Certain classifications in the statement of cash flows

The FASB issued the 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.

(k) Presentation of restricted cash in the statement of cash flows

The FASB issued the amendment in November 2016 to address existing diversity in the classification and presentation of changes in restricted cash on the statement of cash flows. The amendment requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. The amendment does not provide a definition of restricted cash or restricted cash equivalents. The amendment is effective for public entities for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years, with early adoption permitted. The amendment should be applied using a retrospective transition method to each period presented. As permitted, we have early adopted the amendment as of the beginning of the fourth quarter of 2016 and have applied it retrospectively to all periods presented. Accordingly, the changes in restricted cash and restricted cash equivalents, presented previously in other assets of operating activities, were included in cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows, which increased by $2 million and had no change in net cash provided by operating activities in the consolidated statements of cash flow, for both of the years ended December 31, 2015 and 2014, respectively.

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

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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

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impairments, including goodwill; (3) depreciable lives of assets; (4) income tax valuation allowances; (5) uncertain tax positions; (6) reserves for professional, workers' compensation, and comprehensive general insurance liability risks; (7) contingency and litigation reserves; (8) fair value measurements; (9) earnings sharing mechanisms; (10) environmental remediation liabilities; and (11) 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 6% of our employees.

Note 4. Acquisition of UIL

On December 16, 2015 (acquisition date), we completed our acquisition of UIL, a diversified energy company with its portfolio of regulated utility companies in Connecticut and Massachusetts that is expected to provide us with a greater flexibility to grow the combined regulated businesses through project development and create an enhanced platform to develop transmission and distribution projects in the Northeastern United States. In connection with the consummation of 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 $595 million in cash. 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. This method requires, among other things, that assets acquired and liabilities assumed in a business combination, with certain exceptions, be recognized at their fair values as of the acquisition date.

As UIL's common stock was publicly traded in an active market until the acquisition date, we determined that UIL's common stock is more reliably measurable than the common stock of AVANGRID to determine the fair value of the consideration transferred in the transaction.

The purchase consideration for UIL under the acquisition method is based on the stock price of UIL on the acquisition date multiplied by the number of shares issued by AVANGRID to the UIL shareowners after applying an equity exchange factor to the shares of vested restricted common stock of UIL (other than those UIL restricted shares that vest by their terms upon the consummation of the acquisition), performance shares and other shares awards under UIL 2008 Stock and Incentive Compensation Plan and the UIL Deferred Compensation Plan. The "equity exchange factor" is the sum of one plus a fraction, (i) the numerator of which is the cash consideration and (ii) the denominator of which is the average of the volume weighted averages of the trading prices of UIL common stock on each of the ten consecutive trading days ending on (and including) the trading day that immediately precedes the closing date of the acquisition minus $10.50. The determination of the purchase price is based on a UIL stock price of $50.10 per share, which represents the closing stock price on the acquisition date.

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The fair value of shares of AVANGRID common stock issued to the UIL shareowners in the business combination represents the purchase consideration in the business combination, which was computed as follows:

	(millions, except share and unit data)
Common shares(1)	56,629,377
Price per share of UIL common stock as of the acquisition date	$ 50.10
Subtotal value of common shares	$ 2,837
Restricted stock units(2)	476,198
Other shares(3)	12,999
Equity exchange factor	1.2806
Total restricted and other shares(3) after applying an equity exchange factor	626,473
Price per share used(5)	$ 39.60
Subtotal value of restricted and other shares	$ 25
Total shares of AVANGRID common stock issued to UIL shareowners (including held in trust as treasury stock)	57,255,850
Performance shares(4)	211,904
Equity exchange factor	1.2806
Total performance shares after applying an equity exchange factor	271,368
Price per share used(5)	$ 39.60
Subtotal value of performance shares	$ 11
Total consideration	$ 2,873

(1) Based on UIL's common shares outstanding on December 16, 2015.
(2) Based on UIL's shares of vested restricted stock.
(3) Based on UIL's restricted shares that vested upon the change in control.
(4) Based on UIL's vested performance shares award.
(5) Based on the closing share price of UIL common stock on December 16, 2015, less the cash component of $10.50, which is not applicable to restricted shares (other than those UIL restricted shares that vest by their terms upon the consummation of the acquisition), performance shares and other awards under the UIL 2008 Stock and Incentive Compensation Plan and the UIL Deferred Compensation Plan.

The following is a summary of the components of the consideration transferred to UIL's shareowners:

	(millions, except share data)
Cash ($10.50 x number of UIL common shares outstanding at the acquisition date - 56,629,377)	$ 595
Equity	2,278
Total consideration	$ 2,873

We also paid $37.5 million for transaction costs incurred in this business combination, which are recorded in "Operations and maintenance" in the consolidated statements of income for the year ended December 31, 2015.

The following unaudited pro forma financial information presents the combined results of operations as if the acquisition had been completed on January 1, 2014, the beginning of the comparable prior annual reporting period. The unaudited pro forma results include: (i) merger credit adjustments to operating revenue (see Merger Settlement Agreement below for further details); (ii) elimination of accrued transaction costs representing non-recurring expenses directly related to the transaction, and (iii) the associated tax impact on these unaudited pro forma adjustments.

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The unaudited pro forma results do not reflect any cost saving synergies from operating efficiencies or the effect of the incremental costs incurred in integrating the two companies. Accordingly, these unaudited pro forma results are presented for informational

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purpose only and are not necessarily indicative of what the actual results of operations of the combined company would have been if the acquisition had occurred at the beginning of the period presented, nor are they indicative of future results of operations:

	Year Ended December 31,	
	2015	2014
	(millions)	
Revenue	$ 5,958	$ 6,226
Net income	$ 468	$ 539

The revenue and net (loss) of UIL since the acquisition date included in the consolidated statements of income for the year ended December 31, 2015 were $36 million and $(36) million, respectively (see Merger Settlement Agreement below for further details).

We finalized the valuation of the assets acquired and liabilities assumed within the measurement period during 2016. For the majority of UIL's assets and liabilities, primarily property, plant and equipment, fair value was determined to be the respective carrying amounts of the predecessor entity. UIL's operations are conducted in a regulated environment where the regulatory authority allows an approved rate of return on the carrying amount of the regulated asset base. Measurement period adjustments that were recognized in the year ended December 31, 2016 relate to the adjustments of the allocation of the purchase price to the following: equity method investments; contracts; debt; contingent liabilities, including those related to certain environmental sites; income taxes; non-regulated property, plant and equipment and goodwill.

The following is a summary of the allocation of the purchase price as of the acquisition date and measurement period adjustments recognized in the year ended December 31, 2016:

	Provisional amounts reported in 2015	Measurement period adjustments	Finalized amounts
		(millions)	
Current assets, including cash of $48 million	$ 500	$ (7)	$ 493
Other investments	114	22	136
Property, plant and equipment	3,552	(5)	3,547
Regulatory assets	966	36	1,002
Other assets	52	—	52
Current liabilities	(493)	—	(493)
Regulatory liabilities	(493)	—	(493)
Non-current debt	(1,878)	(27)	(1,905)
Other liabilities	(1,201)	(30)	(1,231)
Total net assets acquired at fair value	1,119	(11)	1,108
Goodwill – consideration transferred in excess of fair value assigned	1,754	11	1,765
Total consideration	**$ 2,873**		**$ 2,873**

Goodwill generated from the acquisition of UIL increased by $11 million to the total amount of $1,765 million as of the acquisition date as a result of the finalization of the purchase price allocation. Goodwill generated from the acquisition of UIL has been assigned to the reporting units under the Networks reportable segment and is primarily attributable to expected future growth of the combined regulated businesses and enhanced platform to develop transmission and distribution projects in the Northeastern United States. The goodwill generated from this acquisition is not deductible for tax purposes.

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Merger Settlement Agreement

As part of the process of seeking and obtaining regulatory approval for the acquisition in Connecticut and Massachusetts, Iberdrola, S.A., AVANGRID and UIL reached settlement agreements with the Office of Consumer Counsel 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 have been made in Connecticut, recognized in the period subsequent to the acquisition in 2015 unless otherwise noted, each of which is reasonably expected to be at a cost of $500,000 or more:

- 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. These amounts will be recorded by the Company as incurred in future periods.
- 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. These amounts will be recorded by the Company as incurred in future periods.
- 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 consent order that, pursuant to the terms and conditions in the consent order, requires UI to investigate and remediate certain environmental conditions within the perimeter of the English Station site. To the extent that the investigation and remediation is less than $30 million, UI would remit to the State of Connecticut the difference between such costs and $30 million for a public purpose as determined in the discretion of the Governor the Attorney General of Connecticut and the Commissioner of DEEP. Pursuant to the consent order UI is obligated to comply with the consent order, even if the cost of such compliance exceeds $30 million. 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 (See Note 14, Environmental Liabilities – English Station, for further details).

As of December 31, 2016 and 2015 we reserved $28.3 million and $20.5 million, respectively, for this matter and have accrued the remaining $1.7 million and $9.5 million in accordance with the settlement with PURA approving the acquisition. The difference of $7.8 million pre-tax has been reflected as the reversal of an expense in our 2016 results, reversing the amounts recorded in 2015, to adjust the allocation of the purchase price as a measurement period adjustment from the acquisition of UIL. The adjustment to the reserve during 2016 was recorded in the "Operations and maintenance" line of the consolidated statement of income as a measurement period adjustment based on additional information obtained for the site regarding circumstances of the site as of the acquisition date of UIL.

As part of the final allocation of the purchase price we have determined a fair value of contingent liabilities of approximately $46.0 million relating to certain environmental sites.

The following commitments have been made in Massachusetts, recognized in the period subsequent to the acquisition in 2015 unless otherwise noted, each of which is reasonably expected to be at a cost of $500,000 or more:

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- 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, which primarily resulted in the net loss for UIL in the period following the acquisition date in 2015.

Note 5. Industry Regulation

Electricity and Natural Gas Distribution – Maine and New York

The Maine distribution rate stipulation, the Maine transmission Federal Energy Regulatory Commission (FERC) Return on Equity (ROE) case, the New York rate plans, Reforming Energy Vision (REV), and the New York Transmission Company (New York TransCo) filings are some of the most important specific regulatory processes that 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.

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 with its implementation, currently expected in mid-2017.

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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.

Transmission - FERC ROE Proceeding

See Note 13, 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.

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.

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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

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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 (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 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 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 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%. The proposal includes an Earnings sharing mechanism (ESM) applicable to each company. The customer share of earnings would increase at higher ROE levels, with customers receiving 50%, 75% and 90% of earnings over 9.5%, 10.0% and 10.5% of ROE, respectively, in the first rate year. Earnings sharing is based on the lower of actual equity of 50%. Earnings thresholds increase in subsequent rate years.

The 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 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 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 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;

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(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.

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The 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 proposal also includes a downward-only Net Plant reconciliation. In addition, the proposal includes downward-only reconciliations for the costs of: electric distribution and gas vegetation management; pipeline integrity; and incremental maintenance. The 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.

Electric and Gas regulated utilities – Connecticut and Massachusetts

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.

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 GSC charge on their bills.

UI has wholesale power supply agreements in place for its entire standard service load for the first half of 2017, 80% of its standard service load for the second half of 2017 and 20% of its standard service load for the first half of 2018. 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, PURA approved new distribution rate schedules for UI for three years which became effective January 1, 2017 and which, among other things, decreased the UI distribution and CTA allowed ROE from 9.15% to 9.10%, continued UI's existing earnings sharing mechanism by which UI and 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.

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 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 initiate a rate case for new rates effective before at least 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.

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

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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 is expected to begin in the first quarter of 2017.

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 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 expected to begin in the first quarter of 2017.

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. The Joint Proposal provides a term of the RSSA from April 1, 2015 through March 31, 2017. RG&E shall make monthly payments to Ginna in the amount of $15.4 million. RG&E will be entitled to 70% of revenues from Ginna's sales into the NYISO energy and capacity markets, while Ginna will be entitled to 30% of such revenues. The signatory parties recommend that the NYPSC authorize RG&E to implement a rate surcharge effective January 1, 2016, to recover amounts paid to Ginna pursuant to the RSSA. RG&E's payment obligation to Ginna did not begin until the rate surcharge was in effect and FERC issued an order authorizing the FERC Settlement agreement in the Settlement Docket. RG&E will use 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. To the extent that the available credits are insufficient to satisfy the final payment from RG&E to Ginna then the RSSA surcharge would continue past March 31, 2017, to recover up to $2.3 million per month until the final payment has been recovered by RG&E from ratepayers. In the month following the expiration of the term on March 31, 2017, Ginna shall prepare and issue an invoice to RG&E for, and RG&E shall pay to Ginna, a one-time payment in the amount of $11.5 million, which will be recovered from ratepayers. If Ginna continues to deliver energy to the NYISO transmission system or makes available capacity to the NYISO markets after seventy-five days following March 31, 2017, Ginna shall pay RG&E a capital recovery balance in eight quarterly installments as long as Ginna is continuing to deliver energy or making available capacity throughout this period. The estimated capital recovery balance that is expected to be in place on March 31, 2017 is $20.1 million and will accrue interest unless amounts are prepaid

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by Ginna. The capital recovery balance will be refunded to ratepayers, to the extent collected, which is based on the term of the delivery of energy or capacity being made available by Ginna. On February 23, 2016, the

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NYPSC unanimously adopted the Joint Proposal in the Ginna RSSA proceeding as in the public interest. On March 1, 2016, FERC issued an Order approving the contested Settlement agreement, subject to conditions.

New York TransCo

Networks holds an approximately 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.

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 $4,291 million associated with the minimum equity requirements as of December 31, 2016.

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

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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 will develop up to 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 project, which percentage is expected to equate to approximately 25 basis points on a levelized basis over the life of the project. UI expects the cost of this program, a planned 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 to be approximately $47 million.

Pursuant to Section 8 of Public Act 13-303, "An Act Concerning Connecticut's Clean Energy Goals," (PA 13-303), in January 2014, at DEEP's direction, UI entered into three contracts for the purchase of RECs associated with an aggregate of 5.7 MW of energy production from biomass plants in New England. The costs of these agreements will be fully recoverable through electric rates.

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, 2017 through December 31, 2017 of $28.8 million and $35.7 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 6. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations, our utilities capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric and natural gas rates. We base our assessment of whether recovery is probable on the existence of regulatory orders that allow for recovery of certain costs over a specific period, or allow for reconciliation or deferral of certain costs. When costs are not treated in a specific 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. Substantially all assets or liabilities for which funds have been expended or received are either included in the rate base or are accruing a carrying cost until they will be included in the rate base. 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 amount of these items is approximately $2,357 million.

Regulatory assets and other 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 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 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 or will be used to recover costs of the Ginna RSSA. Following the approval of the proposal by the NYPSC, unfunded future income taxes were adjusted for the amount of $126 million to reflect the

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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. The amounts will be collected over a period of fifty years.

Current and non-current regulatory assets as of December 31, 2016 and 2015 consisted of:

As of December 31,	2016	2015
(Millions)		
Current		
Pension and other post-retirement benefits cost deferrals	$ 22	$ 8
Pension and other post-retirement benefits	7	13
Storm costs	40	8
Temporary supplemental assessment surcharge	4	7
Reliability support services	27	—
Revenue decoupling mechanism	15	6
Transmission revenue reconciliation mechanism	12	5
Electric supply reconciliation	13	—
Hedges losses	10	37
Contracts for differences	14	18
Hardship programs	16	13
Deferred property tax	10	—
Plant decommissioning	6	—
Deferred purchased gas	14	12
Deferred transmission expense	13	12
Environmental remediation costs	14	37
Other	48	43
Total Current Regulatory Assets	**285**	**219**
Non-current		
Pension and other post-retirement benefits cost deferrals	134	151
Pension and other post-retirement benefits	1,320	1,509
Storm costs	187	251
Deferred meter replacement costs	32	34
Unamortized losses on reacquired debt	20	23
Environmental remediation costs	287	271
Unfunded future income taxes	542	549
Asset retirement obligations	18	24
Deferred property tax	33	45
Federal tax depreciation normalization adjustment	161	158
Merger capital expense target customer credit	11	15
Debt premium	151	141
Plant decommissioning	14	7
Contracts for differences	61	50
Hardship programs	18	29
Other	102	57
Total Non-current Regulatory Assets	**$ 3,091**	**$ 3,314**

“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.

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"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. The portion of storm costs for the amount of $123 million is being recovered over ten-year period and the remaining portion is being amortized over five years following the approval of the proposal by the NYPSC. CMP's total deferral, including carrying costs, was $2 million and $12 million as of December 31, 2016 and 2015, respectively. 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, 2016.

"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 proposal by the NYPSC, these amounts will be collected over a period of fifty years and the NYPSC Staff will perform an audit 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 New York (NY) amount is being amortized over a five year period following the approval of the 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.

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Current and non-current regulatory liabilities as of December 31, 2016 and 2015 consisted of:

As of December 31,	2016	2015
(Millions)		
Current		
Reliability support services (Cayuga)	$ 3	$ 16
Non by-passable charges	22	7
Energy efficiency portfolio standard	45	33
Gas supply charge and deferred natural gas cost	6	6
Transmission revenue reconciliation mechanism	5	16
Pension and other post-retirement benefits	3	3
Pension and other post-retirement benefits cost deferrals	14	—
Carrying costs on deferred income tax bonus depreciation	15	—
Carrying costs on deferred income tax - Mixed Services 263(a)	5	—
Yankee DOE refund	24	5
Merger-related rate credits	3	20
Revenue decoupling mechanism	9	14
Other	38	27
Total Current Regulatory Liabilities	**192**	**147**
Non-current		
Accrued removal obligations	1,117	1,084
Asset sale gain account	9	8
Carrying costs on deferred income tax bonus depreciation	95	116
Economic development	35	36
Merger capital expense target customer credit account	15	17
Pension and other post-retirement benefits	76	90
Positive benefit adjustment	42	51
New York state tax rate change	9	17
Post term amortization	3	25
Theoretical reserve flow thru impact	24	31
Deferred property tax	19	15
Net plant reconciliation	10	10
Variable rate debt	28	32
Carrying costs on deferred income tax - Mixed Services 263(a)	25	31
Rate refund – FERC ROE proceeding	22	21
Transmission congestion contracts	18	—
Merger-related rate credits	21	24
Accumulated deferred investment tax credits	15	10
Asset retirement obligation	13	13
Earning sharing provisions	12	—
Middletown/Norwalk local transmission network service collections	19	19
Excess generation service charge	—	21
Low income programs	46	42
Unfunded future income taxes	—	27
Non-firm margin sharing credits	7	8
Deferred income taxes regulatory	565	519
Other	73	93
Total Non-current Regulatory Liabilities	**$ 2,318**	**$ 2,360**

“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.

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“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. 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 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 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 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 Energy East by Iberdrola. The amortization period is five years following the approval of the 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 Energy East. This is being used to moderate increases in rates. The amortization period is five years following the approval of the 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 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 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 proposal by the NYPSC.

“Merger-related rate credits” resulted from the acquisition of UIL. This is being used to moderate increases in rates. See Merger Settlement Agreement in Note 4 for further details. In the year ended December 31, 2016, $20 million of rate credits was 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.

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

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"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 7. Goodwill and Intangible assets

Goodwill by reportable segment as of December 31, 2016 and 2015 consisted of:

As of December 31,	2016	2015
(Millions)		
Networks	$ 2,744	$ 2,733
Renewables	380	380
Gas	—	—
Other (a)	—	2
Total	**$ 3,124**	**$ 3,115**

(a) Does not represent a reportable segment. It includes Corporate.

As of December 31, 2016, the gross amounts of goodwill were $2,744 million, for Networks reportable segment, $3,340 million for Renewables and Gas reportable segments and no goodwill for Corporate, (which does not represent a segment), with accumulated impairment losses of $2,960 million for Renewables and Gas reporting segments. As of December 31, 2015, the gross amounts of goodwill were $2,733 million, for Networks reportable segment, $3,340 million for Renewables and $2 million for Corporate, with accumulated impairment losses of $2,960 million for Renewables and Gas reporting segments. During the year ended December 31, 2015 goodwill in Networks reportable segment increased by $1,754 million due to acquisition of UIL based on preliminary allocation of the purchase price. During the year ended December 31, 2016, upon finalization of the valuation of assets acquired and liabilities assumed, goodwill in Networks reportable segment related to the acquisition of UIL increased by $11 million to a total amount of $1,765 million as of December 31, 2016 (See Note 4 – Acquisition of UIL – for further details).

During the year ended December 31, 2016, we reversed $2 million of goodwill in Corporate as a result of the sale of our interest in equity investment (See Note 21).

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 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 as of December 31, 2016, based on the finalized valuation of assets acquired and liabilities assumed.

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.

2016

We had no impairment of goodwill in 2016 as a result of our impairment testing.

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Networks

Provided recent relevant events (acquisition of UIL in December 2015 and approval of the proposal by the NYPSC, see Note 4 and 5, respectively) we conducted a quantitative analysis (step one) in 2016. Based on the results of our step one impairment test the estimated fair value of each of the Networks reporting units was in excess of their respective carrying values.

Renewables

Based on the results of our step one impairment test for the Renewables reporting unit conducted in 2016, its estimated fair value was in excess of the carrying value. The assumptions used to estimate fair value were based on projections incorporated in our current operating plans as well as other available information. The current operating plans included significant assumptions and estimates associated with sales growth, profitability and related cash flows, along with cash flows associated with taxes and capital spending. The discount rate used to estimate fair value was risk adjusted in consideration of the economic conditions of the reporting unit. We also considered other assumptions that market participants may use. By their nature, projections are uncertain. Potential events and circumstances, such as declining wind energy output and prices obtained per MWh, changes in incentives established to promote renewable energies and increases in capital expenditures per MW could have an adverse effect on our assumptions.

2015

We had no impairment of goodwill in 2015 as a result of our impairment testing.

Networks

As a result of our step zero qualitative assessment, it was not more likely than not that the fair value of each of the Networks reporting units was less than its carrying amount and it was not necessary to perform the two-step goodwill impairment test. The step zero qualitative assessment was performed in 2015 considering the substantial excess of fair value over the carrying value that was demonstrated in the 2014 impairment test. The qualitative assessment considered key factors such as the level of interest rates, the regulatory environment including the allowed rate of return, and projections of future sales and capital spending. In 2015 the impairment testing of goodwill for Networks includes Maine and New York reporting units.

Renewables

Based on the results of our step one impairment test for the Renewables reporting unit conducted in 2015, its estimated fair value exceeded carrying value. The assumptions used to estimate fair value were based on projections incorporated in our current operating plans as well as other available information. The current operating plans included significant assumptions and estimates associated with sales growth, profitability and related cash flows, along with cash flows associated with taxes and capital spending. The discount rate used to estimate fair value was risk adjusted in consideration of the economic conditions of the reporting unit. We also considered other assumptions that market participants may use. By their nature, projections are uncertain. Potential events and circumstances, such as declining wind energy output and prices obtained per MWh, changes in incentives established to promote renewable energies and increases in capital expenditures per MW could have an adverse effect on our assumptions.

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, 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

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Total Intangible Assets	**$ 923**	**$ (385)**	**$ 538**

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As of December 31, 2015	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
(Millions)			
Gas Storage rights	$ 324	$ (116)	$ 208
Wind development	584	(243)	341
Other	15	(8)	7
Total Intangible Assets	**$ 923**	**$ (367)**	**$ 556**

Gas Storage rights are being amortized on a straight-line basis over a 40-year estimated life. 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, 2016, 2015 and 2014 amounted to $25 million, $54 million and $66 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, 2016, to be as follows:

Year ending December 31,	
(Millions)	
2017	$ 16
2018	16
2019	18
2020	17
2021	21

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.

Note 8. Property, Plant and Equipment

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	$ 10,343	$ 10,384	$ 20,727
Natural gas transportation, distribution and other	4,803	613	5,416
Other common operating property	877	43	920
Total Property, Plant and Equipment in Service (a)	**16,023**	**11,040**	**27,063**
Total accumulated depreciation (b)	(3,970)	(3,016)	(6,986)
Total Net Property, Plant and Equipment in Service	**12,053**	**8,024**	**20,077**
Construction work in progress	979	492	1,471
Total Property, Plant and Equipment	**$ 13,032**	**$ 8,516**	**$ 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.

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Property, plant and equipment as of December 31, 2015, consisted of:

As of December 31, 2015	Regulated	Nonregulated	Total
(Millions)			
Electric generation, distribution, transmission and other	$ 11,506	$ 10,058	$ 21,564
Natural gas transportation, distribution and other	2,673	651	3,324
Other common operating property	817	40	857
Total Property, Plant and Equipment in Service (a)	**14,996**	**10,749**	**25,745**
Total accumulated depreciation (b)	(3,727)	(2,645)	(6,372)
Total Net Property, Plant and Equipment in Service	**11,269**	**8,104**	**19,373**
Construction work in progress	1,094	244	1,338
Total Property, Plant and Equipment	**$ 12,363**	**$ 8,348**	**$ 20,711**

(a) Includes capitalized leases of $178 million primarily related to electric generation, distribution, transmission and other.
(b) Includes accumulated amortization of capitalized leases of $53 million.

Capitalized interest costs were $20 million, $13 million, and $12 million for the years ended December 31, 2016, 2015 and 2014, respectively.

There was no impairment or write off recorded during the year ended December 31, 2016. We impaired or wrote off amounts of $12 million and $24 million for the years ended December 31, 2015 and 2014, respectively, resulting from reassessment of the economic feasibility of our various Renewables development projects in construction.

Depreciation expense for the years ended December 31, 2016, 2015 and 2014, amounted to $779 million, $641 million and $563 million, respectively.

Note 9. Asset retirement obligations

AROs are intended to meet the costs for dismantling and restoration work that we have committed to carry out at our operational facilities.

The reconciliation of ARO carrying amounts for the years ended December 31, 2016 and 2015 consisted of:

(Millions)	
As of December 31, 2014	**$ 234**
Liabilities settled during the year	(16)
Liabilities incurred during the year	—
Accretion expense	14
Revisions in estimated cash flows	(48)
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**

Several of the wind generation facilities have restricted cash for purposes of settling AROs. Restricted cash related to AROs was $2.0 million and $1.8 million as of December 31, 2016 and 2015, respectively. 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.

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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;

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the removal of property upon termination of an easement, right-of-way or franchise; and costs for abandonment of certain types of gas mains.

As a result of the revision of the estimated useful lives of wind power station assets in 2016 updated weighted average lease terms were used to value AROs. This revision resulted in lower discounted AROs, which we estimate will result in approximately $3 million annual reduction in expense going forward.

Note 10. Debt

Long- term debt as of December 31, 2016 and 2015 consisted of:

As of December 31,		2016		2015	
(Millions)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
First mortgage bonds - fixed (a)	2018-2045	$ 1,752	3.07%-10.60%	$ 1,815	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	1.32%	219	0.195%-1.181%
Other various non-current debt - fixed	2017-2045	2,772	2.89%-10.48%	2,440	2.89%-10.48%
Obligations under capital leases	2017-2023	104	4%-4.44%	87	4%-4.44%
Unamortized debt issuance costs and discount		(31)		(25)	
Total Debt		**4,859**		**4,736**	
Less: debt due within one year, included in current liabilities		349		206	
Total Non-current Debt		**$ 4,510**		**$ 4,530**	

(a) The first mortgage bonds have pledged collateral of substantially all the respective utility's in service properties of approximately $5,886 million.

In November 2016, NYSEG issued $500 million in aggregate principal amount of 3.25% notes maturing in 2026. The proceeds of the offering were used to reduce balances owed to AVANGRID under an intercompany revolving demand note agreement, to refinance $100 million of NYSEG debt that matured on December 15, 2016, and to repurchase, at par value, $96 million of outstanding auction rate securities on December 19, 2016.

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.

On December 27, 2016, UI repurchased, at par value, $64 million of auction rate securities using cash on hand and borrowing under an intercompany demand note agreement with AVANGRID.

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

(Millions)					
2017	2018	2019	2020	2021	Total
$ 349	$ 180	$ 358	$ 723	$ 308	$ 1,918

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

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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, 2016 and 2015.

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Fair Value of Debt

The estimated fair value of debt amounted to $5,204 million and $4,985 million as of December 31, 2016 and 2015, 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 and $204 million as of December 31, 2016 and 2015, respectively, 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 $161 million and $163 million of notes payable as of December 31, 2016 and 2015, respectively. As of December 31, 2015, the balance consisted of $160 million of borrowings under the UIL credit facility and $3 million in other notes payable. As of December 31, 2016 the balance consisted of $150 million of commercial paper, $10 million in notes payable to affiliates 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 a condition of closing on the AVANGRID credit facility, three existing credit facilities were terminated: the AVANGRID revolving credit facility, which provided for maximum borrowings of up to $300M and had a scheduled termination date in May 2019; the joint utility revolving credit facility, to which NYSEG, RG&E and CMP were parties, which provided for borrowings of up to $600 million and which had a scheduled termination date in July 2018; the UIL credit facility, to which UIL, UI, SCG, CNG and BG were parties, which provided for maximum borrowings of $400 million and which had a scheduled termination date in November 2016.

As of December 31, 2016 the AVANGRID credit facility is undrawn, but the capacity to borrow under the facility is reduced by the amount of outstanding commercial paper, leaving available credit of $1,350 million.

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Note 11. 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). RG&E hedges all its electric load obligations using contracts for a NYISO location where an active market exists. The forward market prices used to value RG&E's 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 has a combination of Level 1 and Level 2 fair values for its electric energy derivative contracts. A portion of its electric load obligations are exchange traded contracts in a NYISO location where an active market exists. The forward market prices used to value NYSEG's 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. A portion of NYSEG's electric energy derivative contracts are non-exchange traded contracts that are valued using inputs that are directly observable for the asset or liability, or indirectly observable through corroboration with observable market data and therefore we include the fair value in Level 2.
- 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 12 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, accounts receivable, accounts payable, notes payable and interest accrued approximate their estimated fair values and are considered as Level 1.

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The financial instruments measured at fair value as of December 31, 2016 and 2015 consisted of:

As of December 31, 2016 (Millions)	Level 1	Level 2	Level 3	Netting	Total
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)**

As of December 31, 2015 (Millions)	Level 1	Level 2	Level 3	Netting	Total
Securities portfolio (available for sale)	**$ 39**	**$ —**	**$ —**	**$ —**	**$ 39**
Derivative assets					
Derivative financial instruments - power	10	81	48	(71)	68
Derivative financial instruments - gas	267	25	68	(280)	80
Contracts for differences	—	—	29	—	29
Total	**277**	**106**	**145**	**(351)**	**177**
Derivative liabilities					
Derivative financial instruments - power	(43)	(12)	(14)	55	(14)
Derivative financial instruments - gas	(193)	(40)	(51)	212	(72)
Contracts for differences	—	—	(96)	—	(96)
Derivative financial instruments - other	—	—	(3)	—	(3)
Total	**$ (236)**	**$ (52)**	**$ (164)**	**$ 267**	**$ (185)**

The reconciliations of changes in the fair value of financial instruments based on Level 3 inputs for the years ended December 31, 2016, 2015 and 2014 consisted of:

(Millions)	2016	2015	2014
Fair value as of January 1,	**$ (19)**	**$ 57**	**$ 53**
Gains for the year recognized in operating revenues	67	33	11
Losses for the year recognized in operating revenues	—	(8)	(1)
Total gains or losses for the period recognized in operating revenues	67	25	10
Gains recognized in OCI	1	2	—
Losses recognized in OCI	—	(3)	(3)
Total gains or losses recognized in OCI	1	(1)	(3)
Net change recognized in regulatory assets and liabilities	(8)	—	—
Purchases	3	(73)	14
Settlements	(9)	(14)	(26)
Transfers out of Level 3 (a)	(4)	(13)	9
Fair value as of December 31,	**$ 31**	**$ (19)**	**$ 57**
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	$ 67	$ 25	$ 10

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

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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, 2016

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)	$ 4.27	$ 7.37	$ 1.64
				SP15 ($/MWh)	$ 44.23	$ 80.28	$ 14.25
				Mid C ($/MWh)	$ 35.44	$ 83.93	$ 3.60
				Cinergy ($/MWh)	$ 36.40	$ 77.49	$ 18.53

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.

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The determination of fair value of the CfDs (see Note 12 for further details on CfDs) was based on a probability-based expected cash flow analysis that was discounted at risk-free interest rates, as applicable, and an adjustment for non-performance risk using credit default swap rates. Certain management assumptions were required, including development of pricing that 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, 2016
Risk of non-performance	0.68% - 0.81%
Discount rate	1.47% - 2.45%
Forward pricing ($ per MW)	$3.15 - $9.55

Note 12. Derivative Instruments and Hedging

Our Networks, Renewables and Gas activities are exposed to certain risks, which are managed by using derivative instruments. All derivative instruments are recognized as either assets or liabilities at fair value on 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 for electricity derivatives was a loss of $12.3 million and $34.3 million as of December 31, 2016 and 2015, respectively. The loss reclassified from regulatory assets into income, which is included in electricity purchased, was $66.7 million, $46.9 million, and $21.3 million for the years ended December 31, 2016, 2015 and 2014, 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 gain of $3.5 million and a loss of $3.1 million as of December 31, 2016 and 2015, respectively. The loss reclassified from regulatory assets into income, which is included in natural gas purchased, was $1.9 million, $6.3 million, and $2.2 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Pursuant to PURA, 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). 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, 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

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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. As of December 31, 2015, UI has recorded a gross derivative asset of $29 million ($1 million of which is

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related to UI's portion of the CfD signed by CL&P), a regulatory asset of $68 million, a gross derivative liability of $96 million ($61 million of which is related to UI's portion of the CfD signed by CL&P) and a regulatory liability of $1 million.

The unrealized gains and losses from fair value adjustments to these derivatives, which are recorded in regulatory assets or regulatory liabilities, for the year ended December 31, 2016 and for the period from December 17, 2015 to December 31, 2015, respectively, were as follows:

(Millions)	Year Ended December 31, 2016	Period from December 17, 2015 to December 31, 2015
Regulatory Assets - Derivative liabilities	$ 7	$ 1
Regulatory Liabilities - Derivative assets	$ 1	$ —

The net notional volumes of the outstanding derivative instruments associated with Networks activities as of December 31, 2016 and 2015, respectively, consisted of:

As of December 31, (Millions)	2016	2015
Wholesale electricity purchase contracts (MWh)	5.6	6.7
Natural gas purchase contracts (Dth)	5.8	4.8
Fleet fuel purchase contracts (Gallons)	2.3	3.8

The offsetting of derivatives, location in the consolidated balance sheet and amounts of derivatives associated with Networks activities as of December 31, 2016 and 2015, respectively, consisted of:

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)

As of December 31, 2015 (Millions)	Current Assets	Noncurrent Assets	Current Liabilities	Noncurrent Liabilities
Not designated as hedging instruments				
Derivative assets	$ 11	$ 18	$ —	$ —
Derivative liabilities	—	—	(28)	(68)
	11	18	(28)	(68)
Designated as hedging instruments				
Derivative assets	3	6	3	6
Derivative liabilities	(3)	(6)	(42)	(7)
	—	—	(39)	(1)
Total derivatives before offset of cash collateral	11	18	(67)	(69)

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Cash collateral receivable	—	—	37	—
Total derivatives as presented in the balance sheet	$ 11	$ 18	$ (30)	$ (69)

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The effect of derivatives in cash flow hedging relationships on OCI and income for the years ended December 31, 2016, 2015 and 2014, 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)
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**
2014			
Interest rate contracts	$ —	Interest expense	$ 9
Commodity contracts	(4)	Operating expenses	1
Total	**$ (4)**		**$ 10**

(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 $76.7 million, $84.9 million, and $93.5 million for the years ended December 31, 2016, 2015 and 2014, respectively. We recorded $8.0 million, $8.6 million, and $8.9 million in net derivative losses related to discontinued cash flow hedges for the years ended December 31, 2016, 2015 and 2014, respectively. We will amortize approximately $8.0 million of discontinued cash flow hedges in 2017. During the years ended December 31, 2016, 2015 and 2014, there was no ineffective portion for cash flow hedges.

The unrealized loss of $0.4 million on hedge derivatives is reported in OCI because the forecasted transaction is considered to be probable as of December 31, 2016. We expect that $0.4 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 AECO basis swaps that hedge the fuel requirements

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of its Klamath facility. 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.

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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 net notional volumes of outstanding derivative instruments associated with Renewables and Gas activities as of December 31, 2016 and 2015, respectively, consisted of:

As of December 31,	2016	2015
(MWh/Dth in Millions)		
Wholesale electricity purchase contracts	3	3
Wholesale electricity sales contracts	7	6
Foreign exchange forward purchase contracts	—	4
Natural gas and other fuel purchase contracts	329	332
Financial power contracts	8	7
Basis swaps - purchases	49	67
Basis swaps - sales	45	80

The fair values of derivative contracts associated with Renewables and Gas activities as of December 31, 2016 and 2015, respectively, consisted of:

As of December 31,	2016	2015
(Millions)		
Wholesale electricity purchase contracts	$ (2)	$ (13)
Wholesale electricity sales contracts	6	35
Foreign exchange forward purchase contracts	—	(1)
Natural gas and other fuel purchase contracts	30	10
Financial power contracts	56	32
Basis swaps- purchases	3	1
Basis swaps- sales	(2)	(2)
Total	**$ 91**	**$ 62**

The offsetting of derivatives, location in the consolidated balance sheet and amounts of derivatives associated with Renewables and Gas activities as of December 31, 2016 and 2015, respectively, consisted of:

As of December 31, 2016	Current Assets	Noncurrent Assets	Current Liabilities	Noncurrent Liabilities
(Millions)				
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)

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As of December 31, 2015 (Millions)	Current Assets	Noncurrent Assets	Current Liabilities	Noncurrent Liabilities
Not designated as hedging instruments				
Derivative assets	$ 186	$ 113	$ 117	$ 4
Derivative liabilities	(85)	(14)	(169)	(29)
	101	99	(52)	(25)
Designated as hedging instruments				
Derivative assets	56	13	—	—
Derivative liabilities	—	—	(9)	—
	56	13	(9)	—
Total derivatives before offset of cash collateral	157	112	(61)	(25)
Cash collateral receivable (payable)	(80)	(41)	—	—
Total derivatives as presented in the balance sheet	$ 77	$ 71	$ (61)	$ (25)

The effect of trading and non-trading derivatives, respectively, associated with Renewables and Gas activities for the years ended December 31, 2016, 2015 and 2014 consisted of:

Years Ended December 31, (Millions)	2016	2015	2014
Wholesale electricity purchase contracts	$ 3	$ 6	$ (9)
Wholesale electricity sales contracts	(7)	(5)	9
Financial power contracts	4	—	(2)
Financial and natural gas contracts	(22)	(26)	125
Total (Loss) Gain	**$ (22)**	**$ (25)**	**$ 123**

Years Ended December 31, (Millions)	2016	2015	2014
Wholesale electricity purchase contracts	$ 9	$ (8)	$ (8)
Wholesale electricity sales contracts	(20)	(5)	15
Financial power contracts	(10)	24	30
Natural gas and other fuel purchase contracts	34	18	(1)
Total Gain	**$ 13**	**$ 29**	**$ 36**

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.

In 2015 we began designating those derivatives contracts at Renewables and Gas businesses that qualify as hedges. This designation was made prospectively, and in accordance with all the requirements of hedge accounting. The effect of derivatives in cash flow hedging relationships on OCI and income for the years ended December 31, 2016 and 2015 consisted of:

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

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

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Amounts will be 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 $13.6 million of losses included in accumulated OCI at December 31, 2016 is expected to be reclassified into earnings within the next 12 months. During the years ended December 31, 2016 and 2015, we recorded 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 $0.4 million and $2.3 million in net derivative gain related to discontinued cash flow hedge for the years ended December 31, 2016 and 2015.

(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, 2016, UI would have had to post an aggregate of approximately $12.8 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 $20 million and $11 million as of December 31, 2016 and 2015, 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, 2016 is $12 million, for which we have posted collateral.

Note 13. 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.

MNG Rate Case

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

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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 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 return. In June 2015 the NETOs filed an appeal in the U.S. Court of Appeals for the District of Columbia of the FERC's final order. The appeal is currently pending, and we cannot predict the outcome of this appeal.

On December 26, 2012, a second, ROE complaint (Complaint II) for a subsequent rate period was filed requesting the ROE 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 ROE 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 were held in June 2015 on Complaints II and III before a FERC Administrative Law Judge, relating to the refund periods and going forward period. 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 mid-2017.

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. The CMP and UI total reserve associated with Complaints I, II and III is $21.6 million and $4.4 million, respectively, as of December 31, 2016. 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 base ROE be 8.61% and ROE Cap be 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. 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. Hearings are being held later this year with an expected Initial Decision from the Administrative Law Judge in 2017.

Yankee Nuclear Spent Fuel Disposal Claim

CMP has an ownership interest in Maine Yankee Atomic Power Company, Connecticut Yankee Atomic Power Company, and Yankee Atomic Electric Company, (the Yankee Companies), three New England single-unit decommissioned nuclear reactor sites, and UI has an ownership interest in Connecticut Yankee Atomic Power Company. Every six years, pursuant to the statute of limitations, the Yankee

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Companies file a lawsuit to recover damages from the Department of Energy (DOE or Government) for breach of the Nuclear Spent Fuel Disposal Contract to remove Spent Nuclear Fuel (SNF) and Greater than Class C Waste (GTCC) as required by contract

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and the Nuclear Waste Policy Act beginning in 1998. The damages are the incremental costs for the Government's failure to take the spent nuclear fuel.

In 2012, the U.S. Court of Appeals issued a favorable decision in the Yankee Companies' claim for the first six year period (Phase I). Total damages awarded to the Yankee Companies were nearly $160 million. The Yankee Companies won on all appellate points in the U.S. Court of Appeals for the Federal Circuit's unanimous decision. The Federal Appeals Court affirmed the September 2010 U.S. Court of Federal Claims award of $39.7 million to Connecticut Yankee Atomic Power Company; affirmed the Court of Federal Claims award of $81.7 million to Maine Yankee Atomic Power Company; and increased Yankee Atomic Electric Company's damages award from $21.4 million to $38.3 million. The Phase I damage award became final on December 4, 2012. The Yankee Companies received payment from DOE in January 2013. CMP's share of the award was approximately $36.5 million which was credited back to customers. UI's share of the award was $3.8 million which was credited back to customers.

In November 2013 the U.S. Court of Claims issued its decision in the Phase II case (the second 6 year period). The Trial Court decision awards the Yankee Companies a combined $235.4 million (Connecticut Yankee $126.3 million, Maine Yankee $37.7 million, and Yankee Atomic $73.3 million). The Phase II period covers January 1, 2002 through December 31, 2008 for Connecticut Yankee and Yankee Atomic, and January 1, 2003 through December 31, 2008 for Maine Yankee. Maine Yankee's damage award was lower because it recovered a larger amount in the Phase I case ($82 million) and its decommissioning was both less expensive and completed sooner than the other Yankee Companies. The damage awards flow through the Yankees to shareholders (including CMP and UI) to reduce retail customer charges. In January 2014 the government informed the Yankee Companies it would not appeal the Trial Court decision, as a result the Yankee Companies received full payment in April 2014. CMP's share of the award was approximately $28.2 million which was credited back to customers. UI received approximately $12 million of such award which was applied, in part, against the remaining storm regulatory asset balance. The remaining regulatory liability balance was applied to the GSC "working capital allowance" and will be returned to customers through the non-by-passable federally mandated congestion charge.

In August 2013, the Yankees filed a third round of claims against the government seeking damages for the years 2009-2014 (Phase III). The Phase III trial was completed in July 2015 and the Court has issued its decision on March 25, 2016 awarding the Yankee Companies a combined $76.8 million (Connecticut Yankee $32.6 million, Maine Yankee $24.6 million and Yankee Atomic $19.6 million). The damage awards will potentially flow through the Yankee Companies to shareholders, including CMP and UI, upon FERC approval, and will reduce retail customer charges or otherwise as specified by law. CMP and UI will receive their proportionate share of the awards that flow through based on percentage ownership. On July 18, 2016, the notice of appeal period expired and the Phase III trial award became final. On October 14, 2016, the Yankee Companies received the Government's payment of the damage award of a combined $41.6 million (Connecticut Yankee $18.4 million, Maine Yankee $3.6 million and Yankee Atomic $19.6 million). In December 2016 CMP and UI received their proportionate share of $4.2 million of the Phase III damage awards, based on percentage ownership, and CMP received an additional $21.5 million for SNF trust refund relating to excess funds of Maine Yankee unrelated to Phase III. All amounts will flow through to customers.

NYPSC Staff Review of Earnings Sharing Calculations and Other Regulatory Deferrals

In December 2012, the NYPSC Staff (Staff) informed NYSEG and RG&E that the Staff had conducted an audit of the companies' annual compliance filings (ACF) for 2009 through August 31, 2010, and the first rate year of the current rate plan, September 1, 2010 through August 31, 2011. The Staff's preliminary findings indicated adjustments to deferred balances primarily associated with storm costs and the treatment of certain incentive compensation costs for purposes of the 2011 ACF. The Staff's findings approximate $9.8 million of adjustments to deferral balances and customer earnings sharing accruals. NYSEG and RG&E reviewed the Staff's adjustments and work papers and provided a response in early 2013. NYSEG and RG&E disagreed with certain Staff conclusions and as a result recorded a $3.4 million reserve in December 2012 in anticipation of settling the Staff issues. In the proposal approved by the NYPSC (see Note 5) the parties agreed that in full and final resolution of all years through 2012, and in full and final resolution of storm-related deferrals through 2014, the companies will add $2.4 million to the customer share of earnings sharing. Staff indicated in December 2016 that it had completed its review 2013 and 2014 compliance filings and no issues were identified.

California Energy Crisis Litigation

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

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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 power purchase agreements unjust and unreasonable. However, the proposed ruling did conclude that price of the power purchase agreements imposed an excessive burden on customers in the amount of $259 million. Renewables position, as presented at hearings and agreed by 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.

Leases

Operating lease expense relating to operational facilities, office building leases, and vehicle and equipment leases was $70.6 million, $47.7 million and $48.7 million for the years ended December 31, 2016, 2015 and 2014, respectively. Amounts related to contingent payments predominantly linked to electricity generation at the respective facilities was $22.2 million, $22.2 million and $20.4 million for the years ended December 31, 2016, 2015 and 2014, 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 will operate and maintain the RSS units and manage and comply with scheduling deadlines and requirements for maintaining the Facility and the RSS units as eligible energy and capacity providers and will comply with dispatch instructions. NYSEG will pay Cayuga a monthly fixed price and will also pay for capital expenditures for specified capital projects. NYSEG will be 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 $37.8 million, $25.5 million and $19.8 million for the years ended December 31, 2016, 2015 and 2014, respectively.

On December 31, 2014, we concluded the sale of our ten-percent undivided interest in Unit 1 of the Springerville power plant to Tucson Electric Power for $19.6 million. We had previously accounted for this plant as an operating lease. This transaction was recorded in "Other income and (expense)."

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 through March 2017. RG&E shall make monthly payments to GNPP in the amount of $15.4 million. RG&E will be entitled to 70% of revenues from GNPP's sales into the energy and capacity markets, while GNPP will be entitled to 30% of such revenues. We account for this arrangement as an operating lease. The net expense incurred under this operating lease was $114.9 million and $79.9 million for the years ended December 31, 2016 and 2015, respectively.

Total future minimum lease payments as of December 31, 2016 consisted of:

Year	Operating Leases	Capital Leases	Total
		(Millions)	
2017	$ 106	$ 30	$ 136
2018	28	6	34
2019	28	7	35
2020	26	7	33
2021	28	4	32
2022 and thereafter	487	50	537

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Total	**$ 703**	**$ 104**	**$ 807**

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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.

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 Power Purchase Agreement (PPA) for 12 years (five 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 (two years remaining). Power sales commitments include: (i) a 55MW Biomass off-take agreement for 12 years (five 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.

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Forward purchases and sales commitments under power, gas, and other arrangements as of December 31, 2016 consisted of:

	Purchases				Sales			
Year	Gas	Power	Other	Total	Gas	Power	Other	Total
	(Millions)							
2017	$ 284	$ 168	$ 35	$ 487	$ 23	$ 132	$ 4	$ 159
2018	245	108	23	376	4	76	4	84
2019	205	68	14	287	5	53	1	59
2020	161	65	12	238	5	42	—	47
2021	127	52	12	191	—	33	—	33
Thereafter	520	379	109	1,008	—	26	—	26
Totals	**$ 1,542**	**$ 840**	**$ 205**	**$ 2,587**	**$ 37**	**$ 362**	**$ 9**	**$ 408**

Guarantee Commitments to Third Parties

As of December 31, 2016, we had approximately $2.6 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, 2016, neither we nor our subsidiaries have any liabilities recorded for these instruments.

Property, Plant and Equipment

We have made future commitments to purchase property, plant, and equipment in order to continue to develop and grow our business. The amount of such future commitments was $493 million as of December 31, 2016.

Note 14. 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 $6 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 $22 million as of December 31, 2016. 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.

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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; eleven 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 $221 million to $465 million as of December 31, 2016. 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.

As of December 31, 2016 and 2015, 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 $97 million and $99 million, respectively.

The liability to investigate and perform remediation at the known inactive MGP sites was $388 million and $397 million as of December 31, 2016 and 2015, respectively. We recorded a corresponding regulatory asset, net of insurance recoveries and the amount collected from FirstEnergy, as described below, because we expect to recover the net costs in rates. Our environmental liability accruals are recorded on an undiscounted basis and are expected to be paid through the year 2053.

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, 2016 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.

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. In January 2015, NYSEG sent FirstEnergy a demand for $16 million representing FirstEnergy's share of clean-up expenses incurred by NYSEG at the nine sites from January 2010 to November 2014 while the District Court appeal was pending. Nearly all of this amount has been paid by FirstEnergy. FirstEnergy would also be liable for a share of post 2014 costs, which, based on current projections, would be $26 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.

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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 Idemnity and One Beacon have answered admitting issuance of the excess policies, but contesting coverage and providing documentation proving they received notice of the claims in the 1990s. 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 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 and Asnat filed a subsequent lawsuit in Connecticut state court seeking among other things: (i) remediation of the property; (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 on or before August 1, 2017.

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. A status report was filed with the court in December 2016 and the next status report is due in May 2017.

On August 4, 2016, DEEP issued 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.

In connection with the consent order, on August 4, 2016, DEEP also issued a Consent Order to Evergreen Power, Asnat, and certain related parties that provides UI access to investigate and remediate the English Station site consistent with the consent order. 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, 2016 and 2015 we reserved $28.3 million and $20.5 million, respectively, for this matter and have accrued the remaining $1.7 million and $9.5 million in accordance with the settlement with PURA approving the acquisition. The difference of $7.8 million pre-tax has been reflected as the reversal of an expense in our 2016 results, reversing the amounts recorded in 2015, to adjust the allocation of the purchase price as a measurement period adjustment from the acquisition of UIL. The adjustment to the reserve during 2016 was recorded in the "Operations and maintenance" line of the consolidated statement of income as a measurement period adjustment based on additional information obtained for the site regarding circumstances of the site as of the acquisition date of UIL.

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Note 15. Income Taxes

Current and deferred taxes charged to (benefit) expense for the years ended December 31, 2016, 2015 and 2014 consisted of:

Years Ended December 31, (Millions)	2016	2015	2014
Current			
Federal	$ (6)	$ (20)	$ (10)
State	8	(33)	31
Current taxes charged to (benefit) expense	**2**	**(53)**	**21**
Deferred			
Federal	414	136	218
State	2	(6)	82
Deferred taxes charged to expense	**416**	**130**	**300**
Production tax credits	(38)	(42)	(37)
Investment tax credits	(1)	(1)	(2)
Total Income Tax Expense	**$ 379**	**$ 34**	**$ 282**

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, 2016, 2015 and 2014 consisted of:

Years Ended December 31, (Millions)	2016	2015	2014
Tax expense at federal statutory rate	$ 353	$ 105	$ 247
Depreciation and amortization not normalized	61	15	15
Investment tax credit amortization	(1)	(1)	(2)
Tax return related adjustments	(2)	6	2
Production tax credits	(38)	(42)	(37)
Tax equity financing arrangements	(25)	(36)	(11)
Change in tax reserves	—	—	3
Changes in New York tax law	—	—	41
State tax expense (benefit), net of federal benefit	7	(25)	32
Non-deductible acquisition costs	—	9	—
Other, net	24	3	(8)
Total Income Tax Expense	**$ 379**	**$ 34**	**$ 282**

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Deferred tax assets and liabilities as of December 31, 2016 and 2015 consisted of:

As of December 31, (Millions)	2016	2015
Non-current Deferred Income Tax Liabilities (Assets)		
Property related	$ 5,195	$ 4,763
Unfunded future income taxes	216	211
Federal and state tax credits	(417)	(367)
Accumulated deferred investment tax credits	14	15
Federal and state NOL's	(1,397)	(1,367)
Joint ventures/partnerships	651	655
Nontaxable grant revenue	(581)	(595)
Other	(171)	(17)
Non-current Deferred Income Tax Liabilities	3,510	3,298
Add: Valuation allowance	31	19
Total Non-current Deferred Income Tax Liabilities	3,541	3,317
Less amounts classified as regulatory liabilities		
Non-current deferred income taxes	565	519
Non-current Deferred Income Tax Liabilities	$ 2,976	$ 2,798
Deferred tax assets	$ 2,565	$ 2,346
Deferred tax liabilities	6,106	5,663
Net Accumulated Deferred Income Tax Liabilities	$ 3,541	$ 3,317

Valuation allowances are recorded to reduce deferred tax assets when it is not more-likely-than not that all or a portion of a tax benefit will be realized. A valuation allowance for the entire $9 million (net of federal benefit) carryforward of Maine Research and Development Super credits generated in tax years 2007 through 2012 was established as of December 31, 2012 with no change in this balance as of December 31, 2015. A valuation allowance of $10 million was established on various state NOLs as of December 31, 2015 and 2016, respectively. The $12 million increase in valuation allowances established in 2016 represents a full valuation allowance of $15 million (net of federal benefit) on Connecticut state tax credits, partially offset by a reduction of $3 million related to the Maine Research and Development Super credits.

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2016, 2015 and 2014 consisted of:

Years ended December 31, (Millions)	2016	2015	2014
Beginning Balance	$ 36	$ 38	$ 41
Increases for tax positions related to prior years	8	1	20
Decreases for tax positions related to prior years	(4)	—	—
Reduction for tax position related to settlements with taxing authorities	—	(3)	(23)
Ending Balance	**$ 40**	**$ 36**	**$ 38**

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 $2 million, $2 million, and $3 million for the years ended December 31, 2016, 2015 and 2014, respectively. If recognized, $8 million of the total gross unrecognized tax benefits would affect the effective tax rate.

The total amount of unrecognized tax benefits anticipated to result in a net decrease to unrecognized tax benefits within 12 months of December 31, 2016 is estimated to be $9 million primarily relating to anticipation of additional guidance to be released by the IRS.

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On December 29, 2014, the Joint Committee on Taxation approved the examination of AVANGRID and its subsidiaries, without ARHI, for the tax years 1998 through 2009. The results of these audits, net of reserves already provided, were immaterial. All New York and Maine state returns, which were filed without ARHI, are closed through 2011.

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, 2016, 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, 2016, 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 $394 million, state tax net operating losses of $241 million in several jurisdictions and miscellaneous state tax credits of $32 million available to carry forward and reduce future income tax liabilities. For state purposes, we recognized a valuation allowance of $31 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 16. 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 2011. 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 plan covers the majority of employees of UI and UIL corporate. The plan was closed to newly-hired employees in 2005. UI also has a non-qualified supplemental pension plan for certain employees and a non-qualified retiree-only pension plan for certain early retirement benefits.

The Regulated Gas Companies in Connecticut and Massachusetts have multiple qualified pension plans covering a majority of their union and management employees. These entities also have non-qualified supplemental pension plans for certain employees. 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.

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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, 2016 and 2015 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	2016	2015	2016	2015
(Millions)				
Change in benefit obligation				
Benefit obligation as of January 1,	**$ 3,509**	**$ 2,620**	**$ 525**	**$ 435**
Acquisition of UIL	—	1,019	—	122
Service cost	44	36	5	5
Interest cost	142	99	21	16
Plan participants' contributions	—	—	7	4
Plan amendments	—	—	—	(1)
Actuarial gain	(43)	(105)	(24)	(31)
Special termination benefits	—	2	—	—
Benefits paid	(204)	(162)	(39)	(25)
Benefit Obligation as of December 31,	**3,448**	**3,509**	**495**	**525**
Change in plan assets				
Fair value of plan assets as of January 1,	**2,664**	**2,143**	**162**	**129**
Acquisition of UIL	—	687	—	39
Actual return on plan assets	169	(31)	11	(4)
Employer contributions	43	27	30	21
Plan participants' contributions	—	—	7	4
Benefits paid	(204)	(162)	(39)	(25)
Withdrawals from VEBA	—	—	(11)	(2)
Fair Value of Plan Assets as of December 31,	**2,672**	**2,664**	**160**	**162**
Funded Status as of December 31,	**$ (776)**	**$ (845)**	**$ (335)**	**$ (363)**

Amounts recognized as of December 31, 2016 and 2015 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	2016	2015	2016	2015
(Millions)				
Current liabilities	$ —	$ —	$ (5)	$ (5)
Non-current liabilities	(776)	(845)	(330)	(358)
Total	**$ (776)**	**$ (845)**	**$ (335)**	**$ (363)**

Networks offered retired employees an option to receive their future pension benefit as a lump sum during 2014. Approximately $118.5 million of payments were made in 2014 as a result of retired employees exercising the lump sum option. The lump sum payments did not trigger settlement accounting.

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Amounts recognized in OCI for ARHI for the years ended December 31, 2016, 2015 and 2014, consisted of:

	Pension Benefits			Postretirement Benefits		
Years Ended December 31,	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
(Millions)						
Net (gain) loss	$ 23	$ 25	$ 22	$ (3)	$ (1)	$ 8

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, 2016, 2015 and 2014 for Networks consisted of:

	Pension Benefits			Postretirement Benefits		
Years Ended December 31,	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
(Millions)						
Net loss	$ 860	$ 994	$ 1,045	$ 44	$ 76	$ 96
Prior service cost (credit)	7	9	12	(40)	(49)	(57)

Our accumulated benefit obligation for all defined benefit pension plans of Networks and ARHI was $3,214 million and $3,261 million as of December 31, 2016 and 2015, respectively. CMP's and NYSEG's postretirement benefits were partially funded as of December 31, 2016 and 2015.

The projected benefit obligation and the accumulated benefit obligation exceeded the fair value of pension plan assets for all plans of Networks and ARHI as of December 31, 2016 and 2015.

The aggregate projected and accumulated benefit obligations and the fair value of plan assets for underfunded plans of Networks and ARHI as of December 31, 2016 and 2015 consisted of:

	Projected Benefit Obligation Exceeds Fair Value of Plan Assets		Accumulated Benefit Obligation Exceeds Fair Value of Plan Assets	
As of December 31,	**2016**	**2015**	**2016**	**2015**
(Millions)				
Projected benefit obligation	$ 3,448	$ 3,509	$ 3,448	$ 3,509
Accumulated benefit obligation	3,214	3,261	3,214	3,261
Fair value of plan assets	2,672	2,664	2,672	2,664

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Components of Networks' net periodic benefit cost and other changes in plan assets and benefit obligations recognized in income and regulatory assets and liabilities as of December 31, 2016, 2015 and 2014 consisted of:

(Millions)	Pension Benefits			Postretirement Benefits		
As of December 31,	2016	2015	2014	2016	2015	2014
Net Periodic Benefit Cost:						
Service cost	$ 44	$ 36	$ 30	$ 5	$ 4	$ 4
Interest cost	140	97	107	20	15	17
Expected return on plan assets	(199)	(156)	(161)	(8)	(7)	(7)
Amortization of prior service cost (benefit)	2	3	4	(9)	(9)	(11)
Amortization of net loss	123	130	94	8	7	—
Special termination benefit charge	—	2	—	—	—	—
Settlement charge	—	2	—	—	—	—
Net Periodic Benefit Cost	**110**	**114**	**74**	**16**	**10**	**3**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities:						
Settlements	$ —	$ (2)	$ —	$ —	$ —	$ —
Net loss (gain)	(11)	69	434	(24)	(12)	72
Amortization of net loss	(123)	(130)	(94)	(8)	(7)	—
Current year prior service cost	—	—	—	—	(1)	—
Amortization of prior service (cost) benefit	(2)	(3)	(4)	9	9	11
Total Other Changes	(136)	**(66)**	**336**	(23)	**(11)**	**83**
Total Recognized	**$ (26)**	**$ 48**	**$ 410**	**$ (7)**	**$ (1)**	**$ 86**

Components of ARHI's net periodic benefit cost and other changes in plan assets and benefit obligations recognized in income and OCI as of December 31, 2016, 2015 and 2014 consisted of:

(Millions)	Pension Benefits			Postretirement Benefits		
As of December 31,	2016	2015	2014	2016	2015	2014
Net Periodic Benefit Cost:						
Service cost	$ —	$ —	$ —	$ —	$ 1	$ 1
Interest cost	2	2	2	1	1	1
Expected return on plan assets	(2)	(2)	(3)	—	—	—
Amortization of prior service cost	-	—	—	—	—	1
Amortization of net loss	1	1	—	—	—	1
Settlement charge	1	—	—	—	—	—
Net Periodic Benefit Cost (income)	**2**	**1**	**(1)**	**1**	**2**	**4**
Other Changes in plan assets and benefit obligations recognized in OCI:						
Net loss (gain)	—	4	6	(2)	(8)	(5)
Amortization of net loss	(1)	(1)	—	—	—	(1)
Amortization of prior service (cost)	—	—	—	—	—	(1)
Total Other Changes	**(1)**	**3**	**6**	**(2)**	**(8)**	**(7)**
Total Recognized	**$ 1**	**$ 4**	**$ 5**	**$ (1)**	**$ (6)**	**$ (3)**

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.

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Amounts expected to be amortized from regulatory assets or liabilities into net periodic benefit cost for the year ending December 31, 2017 consists of:

Year Ended December 31, 2017	Pension Benefits	Postretirement Benefits
(Millions)		
Estimated net loss	$ 126	$ 5
Estimated prior service cost (benefit)	2	(9)

Amounts expected to be amortized from OCI into net periodic benefit cost for the year ending December 31, 2017 consists of:

Year Ended December 31, 2017	Pension Benefits	Postretirement Benefits
(Millions)		
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, 2017.

The weighted-average assumptions used to determine benefit obligations for Networks and ARHI as of December 31, 2016 and 2015 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	2016	2015	2016	2015
Discount rate - Networks	4.12% / 4.24%	4.10% / 4.24%	4.12% / 4.24%	4.10% / 4.24%
Discount rate - ARHI	3.81%	3.90%	3.81%	3.90%
Rate of compensation increase - Networks	3.50% - 4.20%	4.00%	—	—

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, 2016, 2015 and 2014 consisted of:

	Pension Benefits			Postretirement Benefits		
Years Ended December 31,	2016	2015	2014	2016	2015	2014
Discount rate - Networks	4.12% / 4.24%	3.80% / 4.24%	4.90%	4.12% / 4.24%	3.80% / 4.24%	4.90%
Discount rate - ARHI	3.90%	3.90%	5.00%	3.90%	3.90%	5.00%
Expected long-term return on plan assets - Networks	7.40% / 7.75%	7.50%	7.50%	7.16%	—	—
Expected long-term return on plan assets - ARHI	5.50%	5.50%	6.90%	5.50%	5.75%	6.50%
Expected long-term return on plan assets - nontaxable trust - Networks	—	—	—	7.00%	7.50%	7.50%
Expected long-term return on plan assets - taxable trust - Networks	—	—	—	4.50%	5.00%	5.00%
Rate of compensation increase - Networks	3.50% - 4.20%	4.10%	4.20%	—	—	—

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations, and the effect of rebalancing of plan assets discussed below. Our analysis considered current capital market conditions and projected conditions. NYSEG, RG&E and UIL amortize unrecognized actuarial gains and losses over ten years from the time they are incurred as required by the NYPSC, PURA and DPU. Our other companies use the standard amortization methodology under which amounts in excess of ten-percent of the greater of the projected benefit obligation or market related value are amortized over the plan participants' average remaining service to retirement.

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Assumed health care cost trend rates used to determine benefit obligations as of December 31, 2016 and 2015 consisted of:

As of December 31,	2016	2015
Health care cost trend rate assumed for next year - Networks	7.00%/9.00%	7.50%/ 7.00%
Health care cost trend rate assumed for next year - ARHI	6.75%/8.50%	7.00%/ 9.00%
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	2027
Year that the rate reaches the ultimate trend rate - ARHI	2026 / 2028	2026

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	$ 14	$ (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 $33 million to the pension benefit plans during 2017.

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, 2016 consisted of:

(Millions)	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
2017	$ 211	$ 34	$ —
2018	212	34	—
2019	216	34	—
2020	219	35	—
2021	224	35	—
2022 - 2026	1,125	169	3

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 Non-current Liabilities, was $57 million and $59 million at December 31, 2016 and 2015, 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

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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'

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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, 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	—
Common collective trusts	1,192	—	371	821
Partnerships/joint venture interests	5	—	—	5
Real estate investments	61	—	—	61
Other, principally annuity, fixed income	589	—	315	274
Total	**$ 2,672**	**$ 414**	**$ 1,097**	**$ 1,161**

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The fair values of pension benefits plan assets, by asset category, as of December 31, 2015 consisted of:

As of December 31, 2015		Fair Value Measurements		
(Millions)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 57	$ 3	$ 54	$ —
U.S. government securities	171	171	—	—
Common stocks	314	314	—	—
Registered investment companies	114	114	—	—
Corporate bonds	324	—	324	—
Preferred stocks	5	—	5	—
Common collective trusts	859	—	369	490
Partnership/joint venture interests	84	—	—	84
Real estate investments	89	—	—	89
Other, principally annuity, fixed income	647	—	329	318
Total	**$ 2,664**	**$ 602**	**$ 1,081**	**$ 981**

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.
- Mutual funds - based upon quoted market prices in active markets, which represent the Net Asset Value (NAV) of the shares held.
- Preferred stocks - at the closing price reported in the active market in which the individual investment is traded.
- Common/collective trusts and Partnership/joint ventures - using the NAV provided by the administrator of the fund. The NAV is based on the value of the underlying assets owned by the fund, minus its liabilities, and then divided by the number of shares outstanding. The NAV is classified as Level 2 if the plan has the ability to redeem the investment with the investee at NAV per share at the measurement date. Redemption restrictions or adjustments to NAV based on unobservable inputs result in the fair value measurement being classified as Level 3 if those inputs are significant to the overall fair value measurement.
- Real estate investments - based on a discounted cash flow approach that includes the projected future rental receipts, expenses and residual values because the highest and best use of the real estate from a market participant view is as rental property.
- 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.

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The reconciliation of changes in fair value of plan assets based on Level 3 inputs for the years ended December 31, 2016 and 2015, consisted of:

(Millions)	Common Collective Trusts	Partnership Joint Venture Interests	Real Estate Investments	Other Investments	Total
As of December 31, 2014	**$ 449**	**$ 79**	**$ 75**	**$ 342**	**$ 945**
Actual return on plan assets:					
Relating to assets sold during the year	(3)	(19)	—	1	(21)
Relating to assets still held at the reporting date	(5)	19	10	(21)	3
Purchases, sales and settlements	49	5	4	(4)	54
As of December 31, 2015	**$ 490**	**$ 84**	**$ 89**	**$ 318**	**$ 981**
Actual return on plan assets:					
Relating to assets sold during the year	6	(19)	—	1	(12)
Relating to assets still held at the reporting date	51	—	2	(8)	45
Purchases, sales and settlements	274	(60)	(30)	(37)	147
As of December 31, 2016	**$ 821**	**$ 5**	**$ 61**	**$ 274**	**$ 1,161**

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 have 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, 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**	**$ —**

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The fair values of other postretirement benefits plan assets, by asset category, as of December 31, 2015 consisted of:

As of December 31, 2015		Fair Value Measurements		
(Millions)	Total	Level 1	Level 2	Level 3
Asset Category				
Money market funds	$ 4	$ 4	$ —	$ —
Mutual funds, fixed	36	36	—	—
Government and corporate bonds	2	—	2	—
Mutual funds, equity	46	46	—	—
Common stocks	24	24	—	—
Mutual funds, other	50	43	7	—
Total	**$ 162**	**$ 153**	**$ 9**	**$ —**

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, which represent the NAV of shares held.
- 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, 2016 and 2015.

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 $34 million, $17 million and $20 million for 2016, 2015, and 2014 respectively.

Note 17. Equity

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 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, 2015, our share capital consisted of 500,000,000 shares of common stock authorized, 309,491,082 shares issued and 308,864,609 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 491,459 and 626,473 shares of common stock held in trust and no convertible preferred shares outstanding as of December 31, 2016 and December 31, 2015, respectively. 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. During the year ended December 31, 2016, we repurchased 115,831 shares of common stock of AVANGRID in the open market. The total cost of repurchase, including commissions, was $5 million.

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 condensed consolidated financial statements have been retroactively adjusted to reflect the impact of the stock dividend.

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Accumulated OCI (Loss)

Accumulated OCI for the years ended December 31, 2016, 2015 and 2014 consisted of:

Accumulated Other Comprehensive Income (Loss) (Millions)	As of December 31, 2013	2014 Change	As of December 31, 2014	2015 Change	As of December 31, 2015	2016 Change	As of December 31, 2016
Loss on revaluation of defined benefit plans, net of income tax expense of $0.6 for 2014, $2.2 for 2015 and $4.3 for 2016	$ (26)	$ 1	$ (25)	$ 4	$ (21)	$ 7	$ (14)
Loss for nonqualified pension plans, net of income tax expense (benefit) of $(1.9) for 2014, $1.7 for 2015 and $0.4 for 2016	(8)	(3)	(11)	3	(8)	1	(7)
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 ($1.4) for 2014, $20.9 for 2015 and $(15.8) for 2016	—	(2)	(2)	33	31	(26)	5
Reclassification adjustment for losses on settled cash flow hedges, net of income tax expense (benefit) of $4.1 for 2014, $4.9 for 2015 and $(11.0) for 2016 (a)	(66)	5	(61)	7	(54)	(16)	(70)
Net unrealized (loss) gain on derivatives qualifying as cash flow hedges	(66)	3	(63)	40	(23)	(42)	(65)
Accumulated Other Comprehensive (Loss) Income	**$ (100)**	**$ 1**	**$ (99)**	**$ 47**	**$ (52)**	**$ (34)**	**$ (86)**

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

Note 18. 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 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, 2016 and 2015. We did not have any potentially-dilutive securities for the year ended December 31, 2014. 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, 2016, 2015 and 2014, consisted of:

Years Ended December 31, (Millions, except for number of shares and per share data)	2016	2015	2014
Numerator:			
Net income attributable to AVANGRID	$ 630	$ 267	$ 424
Denominator:			
Weighted average number of shares outstanding - basic	309,512,553	254,588,212	252,235,232
Weighted average number of shares outstanding - diluted	309,817,322	254,605,111	252,235,232
Earnings per share attributable to AVANGRID			
Earnings Per Common Share, Basic	$ 2.04	$ 1.05	$ 1.68
Earnings Per Common Share, Diluted	$ 2.04	$ 1.05	$ 1.68

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Note 19. Tax equity financing arrangements

The sale of a membership interest in the tax equity financing arrangements (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 TEF's based on being the primary beneficiary for these variable interest entities (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 5.4% and 8.5% as of December 31, 2016 and 2015, 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. This treatment is expected to remain consistent over the terms of the TEFs. The assets and liabilities of these VIEs totaled approximately $1,343 million and $244 million, respectively, at December 31, 2016. As of December 31, 2015 the assets and liabilities of VIEs totaled approximately $1,401 million and $338 million, respectively. At December 31, 2016 and 2015, the assets and liabilities of the VIEs consisted primarily of property, plant and equipment, equity method investments and TEF liabilities. At December 31, 2016 and 2015, equity method investments of VIEs were approximately $161 million and $169 million, respectively.

We consider the following four structures to be TEFs: (1) Aeolus Wind Power II LLC, (2) Aeolus Wind Power III LLC, (3) Aeolus Wind Power IV LLC, and (4) Locust Ridge Wind Farms, LLC, (collectively, Aeolus). 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.

During 2014, the investor returns on the Aeolus I structure successfully met the investor requirements, causing the structure to flip back to us and leaving the investor with a ten-percent noncontrolling interest. In October 2015, AVANGRID purchased this remaining interest from the investor with a gain of $5 million recorded within "Other income and (expense)" of the consolidated statements of income.

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Note 20. Grants, Government Incentives and Deferred Income

The changes in deferred income as of December 31, 2016 and 2015 consisted of:

(Millions)	Government grants	Other deferred income	Total
As of December 31, 2014	$ 1,606	$ 15	$ 1,621
Additions	—	—	—
Recognized in income	(77)	9	(68)
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

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.

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, 2016 and 2015.

Other deferred income relates predominantly to gas storage transactions where revenues are recognized as services are provided.

Government grants related to depreciable assets and contributions in aid of construction treated as credits to property, plant and equipment in accordance with FERC requirements were $459 million and $390 million as of December 31, 2016 and 2015, respectively.

Note 21. 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 $45 million and $41 million as of December 31, 2016 and 2015, respectively.

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 $128 million and $143 million for Flat Rock Wind Power LLC, and $64 million and $69 million for Flat Rock Wind Power II LLC, as of December 31, 2016 and 2015, respectively.

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 $128 million and $110 million as of December 31, 2016 and 2015.

Networks holds an approximately 20% ownership interest in New York TransCo, LLC. New York TransCo, LLC was established by the New York transmission utilities to develop, own, and operate electric transmission in New York. The investment in New York TransCo, LLC is being accounted for as an equity investment, the carrying value of which was $22 million as of December 31, 2016 (See Note 24).

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None of our joint ventures have any contingent liabilities or capital commitments. Distributions received from equity method investments amounted to $20 million, $12 million, and $19 million for the years ended December 31, 2016, 2015, and 2014 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. As of December 31, 2016, 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 as of December 31, 2015.

Note 22. Other Financial Statements Items

Other income and (expense)

Other income and (expense) for the years ended December 31, 2016, 2015 and 2014 consisted of:

Years ended December 31, (Millions)	2016	2015	2014
Allowance for funds used during construction	$ 26	$ 21	$ 17
Carrying costs on regulatory assets	14	28	29
Other	36	6	6
Total Other income and (expense)	**$ 76**	**$ 55**	**$ 52**

Included in “Other” is a gain of $33 million resulted from the sale of our interest in Iroquois in 2016 (See Note 21).

Accounts Receivable

Accounts receivable as of December 31, 2016 and 2015 consisted of:

As of December 31, (Millions)	2016	2015
Trade receivables	$ 1,183	$ 1,036
Allowance for bad debts	(64)	(62)
Total Accounts Receivable	**$ 1,119**	**$ 974**

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, 2016 and 2015 consisted of:

(Millions)	
As of December 31, 2013	**58**
Current period provision	39
Write-off as uncollectible	(48)
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**

DPA receivable balances were $54 million and $62 million as of December 31, 2016 and 2015, respectively.

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Prepayments and Other Current Assets

Prepayments and other current assets as of December 31, 2016 and 2015 consisted of:

As of December 31, (Millions)	2016	2015
Prepaid other taxes	$ 153	$ 130
Broker margin and collateral accounts	32	46
Loans to third parties	3	3
Fixed-term deposits	3	11
Other pledged deposits	8	24
Prepaid expenses	53	53
Other	3	18
Total	**$ 255**	**$ 285**

Other Non-current Assets

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

In addition, included in "Other non-current assets", are $5 million and $7 million, which represent restricted cash as of December 31, 2016 and 2015, respectively.

Other current liabilities

Other current liabilities as of December 31, 2016 and 2015 consisted of:

As of December 31, (Millions)	2016	2015
Advances received	$ 107	$ 96
Accrued salaries	84	68
Short-term environmental provisions	34	35
Collateral deposits received	45	59
Pension and other postretirement	5	5
Other	4	22
Total	**$ 279**	**$ 285**

Note 23. 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

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net income adding back income tax expense, depreciation and amortization, impairment of non-current assets and interest expense net of capitalization, and then subtracting other income and earnings from equity method investments per segment. Segment

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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, 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) from continuing operations	1,086	149	(41)	—	1,194
Adjusted EBITDA	1,552	462	(16)	—	1,998
Earnings (loss) from equity method investments	15	(8)	—	—	7
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 of noncurrent assets	—	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 (loss) from equity method investments	1	(5)	—	4	—
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.

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Segment information as of and for the year ended December 31, 2014 consisted of:

For the year ended December 31, 2014 (Millions)	Networks	Renewables	Gas	Other(a)	AVANGRID Consolidated
Revenue - external	$ 3,396	$ 1,180	$ 12	$ 6	$ 4,594
Revenue - intersegment	1	9	72	(82)	—
Impairment of noncurrent assets	—	24	—	1	25
Depreciation and amortization	275	332	22	—	629
Operating income (loss) from continuing operations	616	257	16	(4)	885
Adjusted EBITDA	891	613	38	(3)	1,539
Earnings from equity method investments	—	2	—	10	12
Capital expenditures	775	250	5	—	1,030
As of December 31, 2014					
Property, plant and equipment	8,389	8,219	525	—	17,133
Equity method investments	—	262	—	—	262
Total assets	$ 12,858	$ 12,328	$ 1,393	$ (2,417)	$ 24,162

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

Included in revenue-external for the year ended December 31, 2014 are: $2,726 million from regulated electric operations, $668 million from regulated gas operations and $2 million from other operations of Networks; $1,180 million from renewable energy generation of Renewables; $8 million from gas storage services and $4 million from gas trading operations of Gas.

Reconciliation of consolidated Adjusted EBITDA to the AVANGRID consolidated Net Income for the years ended December 31, 2016, 2015 and 2014, respectively, is as follows:

Years Ended December 31, (Millions)	2016	2015	2014
Consolidated Adjusted EBITDA	**$ 1,998**	**$ 1,220**	**$ 1,539**
Less:			
Impairment of non-current assets	—	12	25
Depreciation and amortization	804	695	629
Interest expense, net of capitalization	268	267	243
Income tax expense	379	34	282
Add:			
Other income	76	55	52
Earnings from equity method investments	7	—	12
Consolidated Net Income	**$ 630**	**$ 267**	**$ 424**

Note 24. 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, 2016, 2015 and 2014, respectively, consisted of:

Years Ended December 31,	2016		2015		2014	
(Millions)	Sales To	Purchases From	Sales To	Purchases From	Sales To	Purchases From
Iberdrola Financiación, S.A.	$ —	$ (2)	—	$ (1)	—	$ (2)
Iberdrola Renovables Energia, S.L.	—	(8)	—	(9)	—	(10)
Iberdrola Canada Energy Services, Ltd	—	(37)	—	(55)	—	(49)
Iberdrola, S.A.	—	(31)	—	(35)	—	(20)

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Other	21	(1)	3	(2)	12	(10)

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In addition to the statements of income items above we made purchases of turbines for wind farms from Gamesa Corporación Tecnológica, S.A. (Gamesa), in which our ultimate parent Iberdrola has a 20% ownership. The amounts capitalized for these transactions were $269 million and $70 million for the years ended December 31, 2016 and 2015, respectively. In addition, included in "Other non-current assets" are $92 million of safe harbor turbine payments we made to Gamesa as of December 31, 2016 (see Note 22). In June 2016, Siemens AG and Gamesa signed a binding agreement to merge their wind power businesses. After completion of the merger, which is expected in the first quarter of 2017, Iberdrola will have 8.1% ownership of the new combined company.

Related party balances as of December 31, 2016 and 2015, respectively, consisted of:

As of December 31,	2016		2015	
(Millions)	Owed By	Owed To	Owed By	Owed To
Iberdrola Canada Energy Services, Ltd	$ —	$ (14)	$ 7	$ (5)
Gamesa Corporación Tecnológica, S.A.	1	(181)	68	(77)
Iberdrola, S.A.	—	(30)	—	(3)
Iberdrola Energy Projects, Inc.	—	—	1	(3)
Iberdrola Renovables Energía, S.L.	2	—	—	—
Other	22	(3)	—	(2)

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 predominantly relate to the purchase of gas for ARHI's gas-fired generation facility at Klamath.

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 Gamesa, which was recorded in impairment of non-current assets 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, 2016 the amount receivable from New York TransCo was $11 million.

AVANGRID manages its overall liquidity position as part of the broader Iberdrola Group and is a party to a cash pooling agreement with Bank Mendes Gans, N.V., similar to other members of the Iberdrola Group. Cash surpluses remaining after meeting the liquidity requirements of AVANGRID and its subsidiaries may be deposited in the cash pooling account where such funds are available to meet the liquidity needs of other affiliates within the Iberdrola Group. Under the cash pooling agreement, affiliates with credit balances have pledged those balances to cover the debit balances of the other affiliated parties to the agreement.

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Note 25. 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. An additional 11,804 PSUs were granted to officers and employees of AVANGRID in December 2016. 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, 2016, 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 2017 and 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, 2016, 2015 and 2014 was $0.6 million, $6.0 million and $4.8, respectively. The total income tax benefit recognized for stock-based compensation arrangements for the years ended December 31, 2016, 2015 and 2014, was $0.2 million, $2.4 million and $1.9 million, respectively.

The total liability relating to stock-based compensation, which is included in other non-current liabilities, was $9.5 million and $17.5 million as of December 31, 2016 and 2015, respectively. Before 2016 the Company's historical stock-based expense and liabilities were based on shares of Iberdrola and not on shares of the Company. These Iberdrola shares-based awards were early terminated at the end of 2015, and the liability will be settled in two equal installments no later than June 30, 2017 and March 30, 2018.

A summary of the status of the AVANGRID's nonvested PSUs as of December 31, 2016, and changes during the fiscal year ended December 31, 2016, is presented below:

	Number of PSUs		Weighted Average Grant Date Fair Value
Nonvested Balance – December 31, 2015	411,207	$	39.60
Granted	1,335,416	$	31.92
Forfeited	(36,592)	$	32.83
Vested	(186,050)	$	40.84
Nonvested Balance – December 31, 2016	1,523,981	$	33.01

As of December 31, 2016, total unrecognized costs for non-vested PSUs were $22 million. The weighted-average period over which the PSU costs will be recognized is approximately 5 years.

The weighted average grant date fair value of PSUs granted during the year was $31.92 per share for the year ended December 31, 2016.

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Note 26. Quarterly financial data (unaudited)

Selected quarterly financial data for 2016 and 2015 are set forth below:

(Millions, except per share data)	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2016				
Operating revenues	$ 1,670	$ 1,439	$ 1,418	$ 1,491
Operating Income	$ 349	$ 322	$ 217	$ 306
Net Income	$ 212	$ 102	$ 109	$ 207
Net Income attributable to Avangrid, Inc.	$ 212	$ 102	$ 109	$ 207
Earnings Per Common Share, Basic and Diluted: (1)	$ 0.69	$ 0.33	$ 0.35	$ 0.67
2015				
Operating revenues	$ 1,227	$ 939	$ 1,048	$ 1,153
Operating Income	$ 196	$ 73	$ 161	$ 83
Net Income	$ 106	$ 11	$ 54	$ 96
Net Income attributable to Avangrid, Inc.	$ 106	$ 11	$ 54	$ 96
Earnings Per Common Share, Basic and Diluted: (1)	$ 0.42	$ 0.04	$ 0.22	$ 0.37

(1) Based on weighted average number of 309 million shares outstanding each quarter in 2016 and 252 million shares for each quarter of 2015, except for fourth quarter of 2015, which is based on weighted average of 262 million shares as a result of the acquisition of UIL.

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 proposal by the NYPSC, which was recorded as an increase to income tax expense and an offsetting increase to revenue.

The first, second, third and fourth quarters of 2015 include $4 million, $8 million, $7 million and $18.5 million of pre-tax merger related expenses, respectively. Additionally, the fourth quarter of 2015 includes $44 million relating to rate credits, before income taxes, and $63 million tax benefits related to state income tax matters, including the initial impact of the merger on our consolidated tax filings.

Note 27. Subsequent events

In January 2017 we released 5,088 shares of common stock held in trust, each having a par value of $0.01.

On February 16, 2017, 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 3, 2017 to shareholders of record at the close of business on March 10, 2017.

On February 16, 2017, the board of directors of AVANGRID adopted an annual cash incentive plan pursuant to the 2016 Omnibus Incentive Plan approved by the shareholders of AVANGRID.

On March 1, 2017, we issued 70,493 shares of common stock, each having a par value of $0.01, which was approved by the board of directors of AVANGRID on February 16, 2017.

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Schedule I –Financial Statements of Parent

AVANGRID, INC. (PARENT)
CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF INCOME
FOR THE YEARS ENDED DECEMBER 31, 2016, 2015, AND 2014
(Millions)

Years Ended December 31,	2016	2015	2014
Operating Revenues	$ —	$ —	$ —
Operating Expenses			
Operating expense	5	38	2
Taxes other than income taxes	5	5	2
Total Operating Expenses	10	43	4
Operating Loss	(10)	(43)	(4)
Other Income and (expense)			
Other income and (expense)	68	10	(1)
Equity earnings of subsidiaries	565	44	515
Interest expense	(32)	(14)	(34)
Income Before Income Tax	591	(3)	476
Income tax expense (benefit)	(39)	(270)	52
Net Income	**$ 630**	**$ 267**	**$ 424**

See accompanying notes to Schedule I.

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Schedule I –Financial Statements of Parent

AVANGRID, INC. (PARENT)
CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF COMPREHENSIVE INCOME
FOR THE YEARS ENDED DECEMBER 31, 2016, 2015, AND 2014
(Millions)

Years Ended December 31,	2016	2015	2014
Net Income	$ 630	$ 267	$ 424
Other comprehensive (loss) income of subsidiaries	(34)	47	1
Comprehensive Income	**$ 596**	**$ 314**	**$ 425**

See accompanying notes to Schedule I.

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Schedule I –Financial Statements of Parent

AVANGRID, INC. (PARENT)
CONDENSED FINANCIAL INFORMATION OF PARENT
BALANCE SHEETS
AS OF DECEMBER 31, 2016 AND 2015
(Millions)

As of December 31,	2016	2015
Assets		
Current Assets		
Cash and cash equivalents	$ 67	$ 125
Accounts receivable from subsidiaries	66	602
Notes receivable from subsidiaries	1,908	453
Prepayments and other current assets	11	16
Total current assets	2,052	1,196
Investments in subsidiaries	14,097	14,093
Other assets		
Deferred income taxes	220	148
Other	3	4
Total other assets	223	152
Total Assets	**$ 16,372**	**$ 15,441**
Liabilities		
Current Liabilities		
Current portion of debt	$ 8	$ —
Notes payable	150	—
Notes payable to subsidiaries	454	321
Accounts payable and accrued liabilities	4	12
Accounts payable to subsidiaries	3	3
Interest accrued	6	—
Interest accrued subsidiaries	29	1
Dividends payable	134	—
Taxes accrued	2	44
Other current liabilities	3	4
Total current liabilities	793	385
Other non-current liabilities		
Other	—	3
Total other non-current liabilities	—	3
Non-current debt	470	—
Total non-current liabilities	470	3
Total Liabilities	**1,263**	**388**
Equity		
Stockholders' Equity:		
Common stock	3	3
Additional paid-in capital	13,653	13,653
Treasury Stock	(5)	—
Retained earnings	1,544	1,449
Accumulated other comprehensive loss	(86)	(52)
Total Equity	**15,109**	**15,053**
Total Liabilities and Equity	**$ 16,372**	**$ 15,441**

See accompanying notes to Schedule I.

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Schedule I –Financial Statements of Parent

AVANGRID, INC. (PARENT)
CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2016, 2015, AND 2014
(Millions)

Years Ended December 31,	2016	2015	2014
Cash Flow from Operating Activities			
Net Cash provided by (used in) Operating Activities	**$ 324**	**$ (380)**	**$ (32)**
Cash Flow from Investing Activities			
Notes receivable from subsidiaries	(627)	317	(478)
Acquisition of subsidiary	—	(595)	—
Investments in subsidiaries	(533)	—	—
Return of capital from investments in subsidiaries	420	1,111	200
Other investments	—	—	11
Net Cash (used in) provided by Investing Activities	**(740)**	**833**	**(267)**
Cash Flow from Financing Activities			
Proceeds (repayments) of short-term notes payable from subsidiaries, net	133	(331)	302
Proceeds from short-term notes payable	150	—	—
Proceeds of non-current debt	483	—	—
Repurchase of common stock	(5)	—	—
Issuance of common stock	(2)	—	—
Dividends paid	(401)	—	—
Net Cash provided by (used in) Financing Activities	**358**	**(331)**	**302**
Net (Decrease) Increase in Cash and Cash Equivalents	**(58)**	**122**	**3**
Cash and Cash Equivalents, Beginning of Year	**$ 125**	**3**	**$ —**
Cash and Cash Equivalents, End of Year	**$ 67**	**$ 125**	**$ 3**
Supplemental Cash Flow Information			
Cash paid for interest	$ 4	$ 20	$ 25
Cash payment (refund) for income taxes	71	—	(6)

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.

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AVANGRID will file a consolidated federal income tax return that includes the taxable income or loss of all its subsidiaries for the 2016 tax period. Each subsidiary company is treated as a member of the consolidated group and determines its current and deferred

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taxes separately and settles its current tax liability or benefit each year directly with AVANGRID pursuant to a tax sharing agreement between AVANGRID and its members.

Note 2. 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.

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. During the year ended December 31, 2016, AVANGRID repurchased 115,831 shares of its common stock in the open market. The total cost of repurchase, including commissions, was $5 million.

On February 16, 2017, 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 3, 2017 to shareholders of record at the close of business on March 10, 2017.

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.

Note 4. Cash dividends paid by subsidiaries

Cash dividends paid by subsidiaries are as follows:

Years ended December 31,	2016	2015	2014
(In millions)			
AVANGRID Networks	$ 220	$ 59	$ 200
AVANGRID Renewables	200	750	—
Other AVANGRID subsidiaries	—	302	—
	$ 420	$ 1,111	$ 200

In December 2016, AVANGRID made a capital contribution of $50 million to its subsidiary, CMP. During 2016, AVANGRID recorded a net non-cash dividend of $827 million from its subsidiaries to zero out their account balances of notes receivables and payables.

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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, 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.

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, 2016. 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: (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. This material weakness did not result in any restatement of prior-period financial statements.

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.

As a result of the material weakness noted above, management concluded that, as of December 31, 2016, our internal control over financial reporting was not effective. We completed additional substantive procedures prior to filing this Annual Report on Form 10-K. Based on these procedures, 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. In addition, we have developed a remediation plan for this material weakness, which is described below.

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AVANGRID’s independent registered public accounting firm, Ernst & Young LLP, has issued an adverse audit report on the effectiveness of AVANGRID's internal control over financial reporting as of December 31, 2016, which appears in Part II, Item 8,

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"Financial Statements and Supplementary Data – Report of Independent Registered Public Accounting Firm," of this Annual Report on Form 10-K.

Changes in Internal Control

Except for the control deficiencies discussed above that have been assessed as a material weakness as of December 31, 2016, and the remediation as described within "Remediation Plans and Other Information" below, there were no other changes in our internal control over financial reporting identified in management's evaluation pursuant to Rules 13a-15(d) or 15d-15(d) of the Exchange Act during the period covered by this Annual Report on Form 10-K that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Remediation Plans and Other Information

AVANGRID's management, with oversight from its Audit and Compliance Committee of the Board of Directors of AVANGRID, is actively engaged in remediation efforts to address the material weakness identified above. Management has taken and will take a number of actions to remediate the material weakness including the following remediation plans:

- Implementing and enhancing additional management review controls;
- Increasing accounting personnel to devote additional time and internal control resources;
- Implementing enhanced controls to monitor the effectiveness of the underlying business process controls that are dependent on the data and financial reports generated from the relevant information systems;
- Continuing to implement controls newly designed during the third and fourth quarters of 2016 that management has determined through testing are more precise;
- Implementing specific enhanced review procedures in the property, plant and equipment area, including the estimation of useful lives, as well as within income taxes;
- 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
- Enhancing the automation of processes and controls to allow for the more timely completion and enhanced review of internal controls surrounding financial information and disclosures.

These improvements are targeted at strengthening the Company's internal control over financial reporting and remediating the material weakness. 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 plan to have our enhanced review procedures and documentation standards in place and operating in the first quarter of 2017 and expect that the remediation of this material weakness will be completed by December 31, 2017.

Item 9B. ***Other Information.***

None.

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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 2017 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2016.

Item 11. ***Executive Compensation.***

The information required by this item is incorporated by reference to our Proxy Statement for the 2017 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2016.

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 2017 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2016.

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 2017 Annual Meeting of Shareholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2016.

Item 14. ***Principal Accounting Fees and Services.***

The information required by this item is incorporated by reference to our Proxy Statement for the 2017 Annual Meeting of Shareholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2016.

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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.

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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	Bylaws of Avangrid, Inc. (incorporated herein by reference to Exhibit 3.4 to Form 8-K filed with the Securities and Exchange Commission on December 18, 2015).
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.*
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	Second Amended and Restated Five-Year Revolving Credit Agreement, dated as of May 30, 2012, among Avangrid, Inc. (formerly Iberdrola USA, Inc.), as Borrower, The Several Lenders from Time to Time Parties Hereto, Citibank N.A., as Administrative Agent, and Sovereign Bank, N.A. and TD Bank N.A., as Syndication Agents (incorporated herein by reference to Exhibit 10.5 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.4	First Amendment to the Second Amended and Restated Five-Year Revolving Credit Agreement, dated as of May 7, 2013, among Avangrid, Inc. (formerly Iberdrola USA, Inc.), Citibank N.A. and the other parties named therein (incorporated herein by reference to Exhibit 10.6 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.5	Second Amendment to the Second Amended and Restated Five-Year Revolving Credit Agreement, dated as of November 25, 2013, among Avangrid, Inc. (formerly Iberdrola USA, Inc.), Citibank, N.A., and other parties named therein (incorporated herein by reference to Exhibit 10.7 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.6	Third Amendment to the Second Amended and Restated Five-Year Revolving Credit Agreement, dated as of April 1, 2015, among Avangrid, Inc. (formerly Iberdrola USA, Inc.), Citibank, N.A. and the other parties named therein (incorporated herein by reference to Exhibit 10.8 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).

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Exhibit Number	Exhibit Description
10.7	Five-Year Revolving Credit Agreement, dated July 15, 2011, among New York State Electric & Gas Corporation, Central Maine Power Company and Rochester Gas and Electric as Borrowers, the Lenders, JPMorgan Chase Bank N.A., as Administrative Agent, Bank of America, N.A., as Syndication Agent, Banco Bilbao Vizcaya Argentaria S.A., New York Branch, Sovereign Bank, TD Bank, N.A., The Bank of New York Mellon, and Union Bank, N.A. as Co-Documentation Agents, and J.P. Morgan Securities LLC, and Merrill Lynch, Pierce, Fenner & Smith Incorporated as Joint Lead Arrangers and Joint Bookrunners (incorporated herein by reference to Exhibit 10.9 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.8	Amendment to Revolving Credit Agreement, dated July 28, 2011, among New York State Electric & Gas Corporation, Rochester Gas & Electric Corporation, Central Maine Power Company, the Lenders and JPMorgan Chase Bank, N.A. as Administrative Agent (incorporated herein by reference to Exhibit 10.10 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.9	First Amendment and Extension Agreement, dated July 18, 2013, among New York State Electric & Gas Corporation, Rochester Gas and Electric Corporation, Central Maine Power Company, the Lenders, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., as Syndication Agent, and Banco Bilbao Vizcaya Argentaria S.A., New York Branch, Sovereign Bank (Santander Group), TD Bank, N.A., The Bank of New York Mellon and Union Bank, N.A., as Co-Documentation Agents (incorporated herein by reference to Exhibit 10.11 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.10	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).
10.11	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).
10.12	Amendment No. 1 to Guarantee and Support Agreement, dated May 27, 2010, between Iberdrola, S.A. and Iberdrola Renewables Holdings, Inc. (formerly known as ScottishPower Holdings, Inc.) (incorporated herein by reference to Exhibit 10.16 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.13	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).†
10.14	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). †
10.15	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).†
10.16	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). †

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Exhibit Number	Exhibit Description
10.17	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). †
10.18	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). †
10.19	Offer letter dated June 16, 2014 between Pablo Canales Abaitua and Iberdrola USA Management Corporation (incorporated herein by reference to Exhibit 10.25 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015).†
10.20	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).†
10.21	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).
10.22	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).
10.23	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). †
10.24	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).†
10.25	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).†
10.26	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).†
10.27	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).†
10.28	Employment Agreement, dated as of January 23, 2006, between UIL Holdings Corporation and James P. Torgerson (incorporated herein by reference to Exhibit 10.1 of UIL Holdings Corporation's Current Report on Form 8-K filed with the Securities and Exchange Commission on January 11, 2006).†
10.29	First Amendment, dated August 4, 2008, to Employment Agreement, between UIL Holdings Corporation and James P. Torgerson (incorporated herein by reference to Exhibit 10.26a of UIL Holdings Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).†
10.30	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).†
10.31	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).†

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Exhibit Number	Exhibit Description
10.32	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).†
10.33	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).†
10.34	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).†
10.35	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).†
10.36	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).†
10.37	Employment Agreement, dated as of November 24, 2009, among Avangrid, Inc. (formerly Energy East Corporation), Rochester Gas & Electric Corporation, and Mark S. Lynch (incorporated herein by reference to Exhibit 10.5 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016).†
10.38	First Amendment, dated March 31, 2011, to Employment Agreement, dated as of November 24, 2009, among Avangrid, Inc. (formerly Iberdrola USA, Inc.), Rochester Gas & Electric Corporation, and Mark S. Lynch (incorporated herein by reference to Exhibit 10.6 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016).†
10.39	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).
10.40	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).
10.41	Form of Commercial Paper Dealer Agreement among Avangrid, Inc., as Issuer, and various Dealers (incorporated herein by reference to Exhibit 10.1 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
10.42	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). †
10.43	Avangrid, Inc. Omnibus Incentive Plan (incorporated herein by reference to Form S-8 filed with the SEC on July 21, 2016).†
10.44	Uncommitted Line of Credit for Standby Letters of Credit Agreement, dated as of December 2, 2016, between Avangrid, Inc. and Crédit Agricole Corporate. *
10.45	Substitution Agreement, dated as of December 19, 2016, between UIL Holdings Corporation and Avangrid, Inc.*
10.46	Employment Agreement, dated March 30, 2004, between The United Illuminating Company and Anthony Marone III (incorporated herein by reference to Exhibit 10.7 to UIL Holdings Corporation's Annual Report on Form 10-K filed with the SEC for the fiscal year ended December 31, 2013). †
10.47	First Amendment, dated November 8, 2004, to Employment Agreement between The United Illuminating Company and Anthony Marone III (incorporated herein by reference to Exhibit 10.7a to UIL Holdings Corporation's Annual Report on Form 10-K filed with the SEC for the fiscal year ended December 31, 2013). †

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Exhibit Number	Exhibit Description
10.48	Second Amendment, dated August 4, 2008, to Employment Agreement between The United Illuminating Company and Anthony Marone III (incorporated herein by reference to Exhibit 10.7b to UIL Holdings Corporation's Annual Report on Form 10-K filed with the SEC for the fiscal year ended December 31, 2013). †
10.49	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).†
21.1	Significant subsidiaries of the Registrant.*
23.1	Consent of Ernst & Young LLP, independent registered public accounting firm of Avangrid, Inc.*
23.2	Consent of PricewaterhouseCoopers LLP, independent accountants of UIL Holdings Corporation.*
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.

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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 10, 2017

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 10, 2017
/s/ Richard J. Nicholas Richard J. Nicholas	Chief Financial Officer (Principal Financial Officer)	March 10, 2017
/s/ Daniel Alcain Daniel Alcain	Controller (Principal Accounting Officer)	March 10, 2017
/s/ Ignacio Sánchez Galán Ignacio Sánchez Galán	Chairman of the Board	March 10, 2017
/s/ John E. Baldacci John E. Baldacci	Director	March 10, 2017
/s/ Pedro Azagra Blázquez Pedro Azagra Blázquez	Director	March 10, 2017
/s/ Arnold L. Chase Arnold L. Chase	Director	March 10, 2017
/s/ Alfredo Elías Ayub Alfredo Elías Ayub	Director	March 10, 2017
/s/ Carol Lynn Folt Carol Lynn Folt	Director	March 10, 2017
/s/ John L. Lahey John L. Lahey	Director	March 10, 2017
/s/ Santiago Martinez Garrido Santiago Martinez Garrido	Director	March 10, 2017
/s/ Juan Carlos Rebollo Liceaga Juan Carlos Rebollo Liceaga	Director	March 10, 2017
/s/ José Sainz Armada José Sainz Armada	Director	March 10, 2017
/s/ Alan D. Solomont Alan D. Solomont	Director	March 10, 2017
/s/ Elizabeth Timm Elizabeth Timm	Director	March 10, 2017
/s/ Felipe de Jesús Calderón Hinojosa Felipe de Jesús Calderón Hinojosa	Director	March 10, 2017

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EXHIBIT 4.5

THIRD SUPPLEMENTAL INDENTURE

THIRD SUPPLEMENTAL INDENTURE (the "Third Supplemental Indenture"), dated as of December 19, 2016, to the Indenture dated as of October 7, 2010 (the "Base Indenture" and, as amended and supplemented to the date hereof, the "Indenture") by and among UIL HOLDINGS CORPORATION, a Connecticut corporation ("UIL"), AVANGRID, Inc., a corporation duly organized and existing under the laws of the State of New York ("Avangrid"), and THE BANK OF NEW YORK MELLON (formerly known as The Bank of New York), a corporation organized under the laws of the State of New York authorized to conduct a banking business, as Trustee (the "Trustee").

RECITALS

WHEREAS, the predecessor company to UIL, UIL Holdings Corporation ("Predecessor UIL") and the Trustee have heretofore executed and delivered the Base Indenture to provide for the issuance of Predecessor UIL's unsecured senior debt securities to be issued from time to time in one or more series as might be determined by Predecessor UIL under the Indenture;

WHEREAS, Predecessor UIL and the Trustee have heretofore executed and delivered the First Supplemental Indenture, dated as of October 7, 2010, pursuant to which Predecessor UIL issued its 4.625% Notes due 2020, in the aggregate principal amount of $450,000,000 (the "2010 Notes");

WHEREAS, on December 16, 2016, Predecessor UIL merged with and into Green Merger Sub, Inc., a Connecticut corporation (the "Merger");

WHEREAS, in connection with the Merger, the surviving entity, Green Merger Sub, Inc., was renamed UIL;

WHEREAS, Predecessor UIL, Green Merger Sub, Inc. and the Trustee have heretofore entered into a Second Supplemental Indenture, dated as of December 16, 2015, pursuant to which UIL, as the surviving entity of the Merger, assumed all of the obligations of Predecessor UIL under the Indenture and the 2010 Notes;

WHEREAS, UIL is a subsidiary of Avangrid;

WHEREAS, UIL and Avangrid desire to amend the Indenture and the 2010 Notes to provide for the substitution of UIL with Avangrid as the issuer thereunder;

WHEREAS, Section 9.01(f) of the Base Indenture permits the execution of supplemental indentures without notice to or the consent of any Holders to make any change that does not materially adversely affect the rights of any Holder;

WHEREAS, the substitution of UIL with Avangrid as the issuer under the Indenture and the 2010 Notes shall not materially adversely affect the rights of any Holder;

WHEREAS, pursuant to this Third Supplemental Indenture, Avangrid shall be substituted for UIL as issuer of the 2010 Notes and assume all of the obligations and perform every covenant of the issuer in the Indenture (including every Supplemental Indenture) and the 2010 Notes (collectively, the "Obligations");

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WHEREAS, upon assumption of the Obligations by Avangrid, UIL shall be relieved of all obligations and covenants under the Indenture;

WHEREAS, in connection with the execution of this Third Supplemental Indenture, the Trustee has received Officers' Certificates and Opinion of Counsel as contemplated by Sections 9.05 and 10.03 of the Base Indenture; and

WHEREAS, all conditions necessary have been done or performed to make this Third Supplemental Indenture a valid and binding agreement of UIL and Avangrid in accordance with its terms.

NOW, THEREFORE, in consideration of the premises and the covenants and agreements contained herein, and for other good and valuable consideration the receipt of which is hereby acknowledged, UIL, Avangrid and the Trustee hereby agree as follows:

ARTICLE 1

RATIFICATION; DEFINITIONS

Section 1.01. Third Supplemental Indenture. This Third Supplemental Indenture is supplemental to, and is entered into pursuant to Section 9.01(f) of the Base Indenture, and except as expressly modified, amended or supplemented by this Third Supplemental Indenture, all the terms, conditions and provisions of the Indenture are in all respects ratified and confirmed and shall remain in full force and effect.

Section 1.02. Definitions. Unless the context shall otherwise require, all terms which are defined in the Indenture shall have the same meanings, respectively, in this Third Supplemental Indenture as such terms are given in the Indenture.

ARTICLE 2

ASSUMPTION OF OBLIGATIONS

Section 2.01 Assumption of Obligations under Indenture and 2010 Notes. As of the date hereof, Avangrid hereby expressly assumes the due and punctual payment of principal of (and premium, if any) and interest, if any, on all the 2010 Notes and the performance of every covenant of the Indenture on the part of UIL to be performed or observed.

(b) As of the date hereof, Avangrid succeeds to, is substituted for and may exercise every right and power of, UIL under the Indenture and the 2010 Notes with the same effect as if Avangrid had originally been named in the Indenture and the 2010 Notes as the "Company" and UIL shall be relieved of all obligations and covenants under the Indenture and the 2010 Notes.

ARTICLE 3

MISCELLANEOUS

Section 3.01. Effective of Supplemental Indenture. This Third Supplemental Indenture is executed and shall be construed as an indenture supplemental to the Indenture and, as provided in the Indenture, this Third Supplemental Indenture forms a part thereof.

Section 3.02. Counterparts. This Third Supplemental Indenture may be executed in any number of counterparts, each of which shall be an original; but such counterparts shall constitute but one and the same instrument.

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Section 3.03. Acceptance. The Trustee accepts the Indenture, as supplemented by this Third Supplemental Indenture, and agrees to perform the same upon the terms and conditions set forth therein as so supplemented. The Trustee shall not be responsible in any manner whatsoever for or in respect of the validity or sufficiency of this Third Supplemental Indenture or the due execution hereof by UIL or Avangrid or in respect of the recitals contained herein, all of which are made solely by UIL and Avangrid. In entering into this Third Supplemental Indenture, the Trustee shall be entitled to the benefit of every provision of the Indenture and the 2010 Notes relating to the conduct or affecting the liability or affording protection to the Trustee, whether or not elsewhere herein so provided.

Section 3.04. Successors and Assigns. All covenants and agreements in this Third Supplemental Indenture by Avangrid or the Trustee shall bind their respective successors and assigns, whether so expressed or not.

Section 3.05. Severability. In case any one or more of the provisions contained in this Third Supplemental Indenture shall for any reason be held to be invalid, illegal or unenforceable in any respect, such invalidity, illegality or unenforceability shall not affect any other provisions of this Third Supplemental Indenture, but this Third Supplemental Indenture shall be construed as if such invalid or illegal or unenforceable provision had never been contained herein or therein.

Section 3.06. Governing Law. This Third Supplemental Indenture shall be construed in accordance with and governed by the laws of the State of New York.

Section 3.07. Conflict with Trust Indenture Act. If any provision hereof limits, qualifies or conflicts with another provision hereof which is required to be included in this Third Supplemental Indenture by any of the provisions of the Trust Indenture Act of 1939, as amended, such required provision shall control.

Section 3.08. No Benefit. Nothing in this Third Supplemental Indenture, express or implied, shall give to any Person other than the parties hereto and their successors or assigns, and the Holders of the 2010 Notes, any benefit or legal or equitable rights, remedy or claim under this Third Supplemental Indenture, the Indenture or the 2010 Notes.

Section 3.09. References to Supplemental Indenture. Any and all notices, requests, certificates and other instruments executed and delivered after the execution and delivery of this Third Supplemental Indenture may refer to the Indenture without making specific reference to this Third Supplemental Indenture, but nevertheless all such references shall include this Third Supplemental Indenture unless the context requires otherwise.

[*Signature Page Follows*]

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IN WITNESS WHEREOF, the parties hereto have caused this Third Supplemental Indenture to be duly executed, all as of the day and year first above written.

UIL Holdings Corporation

By : /s/ Steven P. Fauzza
Name: Steven P. Fauzza
Title: Vice President, Controller & Treasurer

By : /s/ Leonard Rodriquez
Name: Leonard Rodriquez
Title: General Counsel

Avangrid, Inc.

By : /s/ Howard Coon
Name: Howard Coon
Title: Vice President & Treasurer

By : /s/ Daniel Alcain
Name: Daniel Alcain
Title: Senior Vice President – Controller

The Bank of New York Mellon,
as Trustee

By: /s/ Francine Kincaid
Name: Francine Kincaid
Title: Vice President

[*Signature Page to the Third Supplemental Indenture*]

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EXHIBIT 10.44

December 2, 2106

Avangrid, Inc.
70 Farm View Drive
New Gloucester, ME 04260

Attention: Howard Coon, Vice President, Treasurer

Re: Offer, dated as of December 2, 2016 for a U.S.$50,000,000 Uncommitted Line of Credit for Standby Letters of Credit

Ladies and Gentlemen:

1. Introduction:

Crédit Agricole Corporate and Investment Bank ("Issuing Bank") is pleased to offer to negotiate with Avangrid, Inc., a New York corporation ("Account Party"), for the issuance of standby letters of credit, which shall be comprised of performance and financial letters of credit (the "Letters of Credit") on an uncommitted basis on and subject to the terms and conditions hereof and of the other Credit Documents (as defined below); provided, however, that the aggregate amount of the L/C Obligations (as defined below) outstanding at any time hereunder shall not exceed U.S.$50,000,000 (the "Maximum Amount"); and provided, further, that there shall be a sublimit for performance Letters of Credit with a tenor of more than one (1) year up to five (5) years of U.S.$10,000,000. The Letters of Credit issued hereunder shall be utilized by Account Party for general corporate purposes.

Upon execution hereof by Account Party and the satisfaction of the conditions to effectiveness set forth herein, this Agreement shall become effective and shall remain in effect until the earlier of November 30, 2017 and the date of revocation hereof by Issuing Bank in its sole discretion (such earlier date, the "Expiration Date"). Any obligations of Account Party incurred pursuant to this Agreement shall survive its revocation or expiration.

ACCOUNT PARTY UNDERSTANDS AND AGREES THAT (A) ISSUING BANK MAY REVOKE THIS AGREEMENT AT ANY TIME WITHOUT NOTICE TO ACCOUNT PARTY AND (B) THIS AGREEMENT IS NOT A COMMITMENT BY ISSUING BANK TO ISSUE ANY LETTER OF CREDIT AND NO COMMITMENT FEE IS BEING PAID. NOTWITHSTANDING ANYTHING HEREIN CONTAINED TO THE CONTRARY, IT IS HEREBY AGREED THAT SO LONG AS ANY LETTER OF CREDIT ISSUED PURSUANT TO THE TERMS HEREOF OR ANY APPLICATION (AS DEFINED BELOW) REMAINS OUTSTANDING, THE EVENTS OF DEFAULT SPECIFIED HEREIN SHALL REMAIN EFFECTIVE AND SHALL SURVIVE THE TERMINATION OF THIS AGREEMENT AND ISSUING BANK SHALL BE ENTITLED TO EXERCISE ANY AND ALL REMEDIES IN RESPECT THEREOF.

2. Definitions:

As used herein and in the other Credit Documents (unless otherwise defined therein), the following terms have the following meanings:

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"Account Party": as defined in Section 1.

"Affiliate": means, with respect to any specified Person, any other Person directly or indirectly controlling or controlled by or under direct or indirect common control with such specified Person. For purposes of this definition, "control," when used with respect to any specified Person, means the power to direct the management and policies of such Person, directly or indirectly, whether through the ownership of voting securities, by contract or otherwise. For purposes of this definition, the terms "controlling," "controlled by" and "under common control with" have correlative meanings.

"Agreement": means this Offer for a U.S.$50,000,000 Uncommitted Line of Credit for Standby Letters of Credit, as amended, restated, amended and restated, supplemented, extended or otherwise modified from time to time.

"Anti-Corruption Laws": means any applicable laws, rules, or regulations relating to bribery or corruption, including (a) the United States Foreign Corrupt Practices Act of 1977; (b) the United Kingdom Bribery Act of 2010; and (c) any other similar law, rule or regulation in any applicable jurisdiction currently in force or hereafter enacted.

"Anti-Money Laundering Laws": means any laws or regulations relating to money laundering or terrorist financing in any applicable jurisdiction currently in force or hereafter enacted.

"Application": means an application, in the form attached hereto as Exhibit A or such other form as the Issuing Bank shall from time to time issue, requesting Issuing Bank to open a Letter of Credit. For the avoidance of doubt, to the extent any provision of any Application conflicts with or is otherwise inconsistent with this Agreement, the terms of this Agreement shall supersede any such Application and this Agreement shall govern.

"Base Rate": means as determined by Issuing Bank on a daily basis, the higher of (a) the rate per annum established by Issuing Bank from time to time as the reference rate for short-term commercial loans in U.S. Dollars to domestic corporate borrowers (which Account Party acknowledges is not necessarily Issuing Bank's lowest rate) and (b) the overnight cost of funds of Issuing Bank as determined solely by Issuing Bank plus 1/4 of 1% per annum.

"Board": means the Board of Governors of the Federal Reserve System of the U.S.

"Business Day": means any day, other than a Saturday or Sunday or legal holiday, on which commercial banks generally are open for business in New York, New York .

"Change of Control": means at any time Iberdrola S.A. shall cease to own, directly or indirectly, at least 51 % of the economic and voting interests in Account Party, free and clear of any Lien.

"Code": means the U.S. Internal Revenue Code of 1986, as amended.

"Collateral Account": as defined in Section 9.

"Contingent Obligation": means, as to any Person, any guarantee of payment by such Person of any Indebtedness or other obligation of any other Person, or any agreement to provide financial assurance with respect to the financial condition, or the payment of the obligations of, such other Person which has the effect of assuring or holding harmless any third Person against loss with respect to one or more obligations of such third Person.

"Credit Documents": means this Agreement, and the Applications.

"Currency": means U.S. Dollars and/or any Foreign Currency.

"Default": means any Event of Default or any condition or event which, after the giving of notice, the lapse of time, or both, or any other condition, would become an Event of Default.

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"Dollar Equivalent": means, on any date of determination, with respect to an amount denominated in any Foreign Currency, the amount of U.S. Dollars that would be required to purchase such amount of such Foreign Currency on the date two (2) Business Days prior to such date, based upon the spot selling rate at which Issuing Bank offers to sell such Foreign Currency for U.S. Dollars in the London foreign exchange market at approximately 11:00 a.m., London time, for delivery two (2) Business Days later.

"Event of Default": as defined in Section 9.

"Expiration Date": as defined in Section 1.

"FATCA": means Sections 1471 through 1474 of the Code, as of the date of this Agreement (or any amended or successor version), and any current or future regulations or official interpretations thereof.

"Financial Statements": means the income statement, statement of cash flows and balance sheet of Account Party furnished in accordance with Section 8(a)(i).

"Foreign Currency": means at any time any Currency other than U.S. Dollars.

"GAAP": means generally accepted accounting principles in the U.S. consistent with those utilized in preparing the Financial Statements.

"Indebtedness": means with respect to any Person at any date: (a) all indebtedness of such Person for borrowed money or for the deferred purchase price of property or services (other than current trade liabilities incurred in the ordinary course of business and payable in accordance with customary practices), (b) any other indebtedness which is evidenced by a note, bond, debenture or similar instrument, (c) all capital lease obligations of such Person, (d) all obligations of such Person in respect of outstanding letters of credit, acceptances and similar obligations created for the account of such Person, (e) all liabilities secured by any Lien on any property owned by such Person even though such Person has not assumed or otherwise become liable for the payment thereof, (f) all Contingent Obligations of such Person and (g) net liabilities of such Person under interest rate cap agreements, interest rate swap agreements, foreign currency exchange agreements and other hedging agreements or arrangements (calculated on a basis satisfactory to Issuing Bank and in accordance with accepted industry practice). The Indebtedness of any Person shall include any Indebtedness of any partnership in which such Person is the general partner.

"Indemnified Liabilities": as defined in Section 12(b).

"Indemnitee": as defined in Section 12(b).

"ISP": as defined in Section 18(b).

"Issuing Bank": as defined in Section 1.

"L/C Obligations": means at any time, an amount equal to the sum of (a) the aggregate then undrawn and unexpired amount of the then outstanding Letters of Credit and (b) the aggregate amount of drawings under the Letters of Credit for which Issuing Bank has not then been reimbursed pursuant to Section 4.

"Letters of Credit": as defined in Section 1.

"Lien": means any mortgage, pledge, hypothecation, assignment, deposit arrangement, encumbrance, lien (statutory or other), other charge or security interest; or any preference, priority or other agreement or preferential arrangement of any kind or nature whatsoever (including, without limitation, any conditional sale or other title retention agreement or any capital lease obligation having substantially the same economic effect as any of the foregoing).

"Material Adverse Effect": means a material adverse effect on (a) the business, operations, property, condition (financial or otherwise) or prospects of Account Party, (b) the ability of Account Party to perform

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its obligations under any Credit Document or (c) the validity or enforceability of (i) any of the Credit Documents or (ii) the rights or remedies of Issuing Bank thereunder.

"Maximum Amount": as defined in Section 1.

"OFAC": means the Office of Foreign Assets Control of the U.S. Department of the Treasury.

"Person": means an individual, partnership, corporation, limited liability company, business trust, joint stock company, trust, unincorporated association, joint venture, governmental authority or other entity of whatever nature.

"Reimbursement Amounts": as defined in Section 4(b).

"Requirement of Law": means as to any Person, the certificate of incorporation and by-laws or other comparable organizational or governing documents of such Person, and any law, treaty, rule, restriction or regulation or determination of an arbitrator or a court or other governmental authority (including, without limitation, any federal, state or local environmental and employee benefit laws and regulations), in each case applicable to or binding upon such Person or any of its property or to which such Person or any of its property is subject.

"Sanctioned Jurisdiction" means any country or territory that is the subject of comprehensive Sanctions broadly restricting or prohibiting dealings with, in or involving such country or territory (currently, Iran, Cuba, Syria, Sudan, North Korea and the Crimea region of Ukraine).

"Sanctioned Person" means any individual or entity (a) identified on a Sanctions List, (b) organized, domiciled or resident in a Sanctioned Jurisdiction, or (c) otherwise the subject or target of any Sanctions, including by reason of ownership or control by one or more individuals or entities described in clauses (a) or (b).

"Sanctions" shall mean any economic or financial sanctions or trade embargoes imposed, administered or enforced by (a) the U.S. (including OFAC and U.S. Department of State), (b) the United Nations Security Council, (c) the European Union or any member state, (d) the United Kingdom (including Her Majesty's Treasury), or (e) any other applicable jurisdiction.

"Sanctions List" shall mean any list of designated individuals or entities that are the subject of Sanctions, including (a) the Specially Designated Nationals and Blocked Persons List maintained by OFAC, (b) the Consolidated United Nation Security Council Sanctions List, (c) the consolidated list of persons, groups and entities subject to EU financial sanctions maintained by the European Union or any member state and (d) the Consolidated List of Financial Sanctions Targets in the United Kingdom maintained by Her Majesty's Treasury.

"SEC": means the Securities and Exchange Commission.

"Subsidiary": means as to any Person, a corporation, partnership or other entity of which shares of stock or other ownership interests having ordinary voting power (other than stock or such other ownership interests having such power only by reason of the happening of a contingency) to elect a majority of the board of directors or other managers of such corporation, partnership or other entity are at the time owned, or the management of which is otherwise controlled, directly or indirectly through one or more intermediaries, or both, by such Person. Unless otherwise qualified, all references to a "Subsidiary" or to "Subsidiaries" in this Agreement shall refer to a Subsidiary or Subsidiaries of Account Party.

"Taxes": as defined in Section 5.

"UCP": as defined in Section 18(b).

"U.S.": means the United States of America.

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"U.S. Dollars" or "U.S.$": means the lawful currency of the U.S.

"USA Patriot Act": means the Uniting and Strengthening America by Providing Appropriate Tools Required to Intercept and Obstruct Terrorism Act of 2001 (USA PATRIOT Act, Title III of Pub. L. 107-56 (signed into law October 26, 2001)).

3. Issuance and Terms of Letters of Credit; Fees;

(a) At any time after the date hereof, Account Party may request Issuing Bank to issue a Letter of Credit by issuing a written request to Issuing Bank at its address specified on its signature page hereto, together with an Application therefor, completed to the satisfaction of Issuing Bank (which request and Application must be received by Issuing Bank prior to 10:00 A.M. (New York time) on the proposed date of utilization (which must be a Business Day on or prior to the Expiration Date)). Issuing Bank shall inform Account Party of its decision in its sole discretion to accept or reject such request within three (3) Business Days. If Issuing Bank does not respond within such period of time, the request will be considered to be rejected.

(b) Each Letter of Credit shall (i) be governed by the provisions hereof and of the relevant Application, (ii) be issued in either U.S. Dollars or an Agreed Foreign Currency and in a face amount to be mutually agreed, and (iii) expire on a Business Day (A) no later than twelve (12) months after the date of the issuance in the case of a financial Letter of Credit and (B) no later than five (5) years in the case of a performance Letter of Credit; provided that the aggregate amount of all L/C Obligations outstanding at any time hereunder shall not exceed the Maximum Amount; and provided, further, that the aggregate amount of performance Letters of Credit with a tenor greater than twelve (12) months to be issued hereunder may not exceed U.S.$10,000,000.

(c) Account Party shall pay to Issuing Bank a commission on each individual Letter of Credit at a rate to be agreed upon at issuance of each individual Letter of Credit, quarterly and payable in arrears. In addition, Account Party shall pay to Issuing Bank a non-refundable amendment fee with respect to each amendment to any Letter of Credit in the amount of U.S.$250 payable in advance on the date of such amendment.

(d) With respect to any obligation of Account Party to Issuing Bank under this Agreement payable in any Foreign Currency: (i) Account Party shall indemnify, defend and hold Issuing Bank harmless from all loss arising from any fluctuation in the value of such Foreign Currency from the date such obligation is payable to Issuing Bank by the terms hereof until paid in full; and (ii) upon the failure or inability of Account Party to pay Issuing Bank immediately upon demand the full amount of such obligation in such Foreign Currency, Account Party shall immediately upon Issuing Bank's demand pay to Issuing Bank the Dollar Equivalent of such amount in same day funds which shall be sufficient to fully compensate Issuing Bank for all amounts paid and all changes, costs and expenses incurred by Issuing Bank in acquiring the full amount of such Foreign Currency and Account Party shall pay interest accrued thereon at the highest rate permitted to be charged by Issuing Bank under applicable law, in U.S. Dollars, from the date such obligation is payable to Issuing Bank by the terms hereof until the date of receipt by Issuing Bank of full payment. For purposes of this Agreement the amount of any Letter of Credit denominated in any Foreign Currency shall be deemed to be the Dollar Equivalent of the amount of the Foreign Currency of such Letter of Credit.

4. Reimbursements; Overdue Amounts:

(a) Account Party will reimburse Issuing Bank (in same day funds without set-off, counterclaim or any other deduction of any nature whatsoever and in the Currency of the applicable Letter of Credit), on the date of any drawing under a Letter of Credit, if such drawing is made prior to 11:00 A.M. (New York time), or the next Business Day after the date of such drawing, if such drawing is made on or after 11:00 A.M. (New York time), amounts due in respect of drawings under the Letters of Credit ("Reimbursement Amounts"), and any interest (to the extent permitted by law) and other amounts due hereunder or under any other Credit Document; provided that if the Credit Documents provide for acceptance of a time draft or incurrence of a deferred payment obligation and if Account Party notifies

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Issuing Bank of such acceptance or incurrence at least one (1) Business Day in advance of its maturity, reimbursement shall be due sufficiently in advance of its maturity to enable Issuing Bank, as issuer, to arrange for its cover in same day funds to reach the place where it is payable no later than the date of its maturity.

(b) Any amounts that are not paid on the date when due shall bear interest (before as well as after judgment) payable on demand at 2% over the Base Rate from and including the date when such payment was due to, but excluding, the date of receipt of payment.

5. Calculations; Payments; Taxes:

(a) All payments hereunder, including for Reimbursement Amounts and computations of fees and interest shall be made on the basis of a 360-day year for actual days elapsed. Except as required by law, any and all payments by Account Party under the Credit Documents shall be made free and clear of and without reduction or withholding for any and all present or future taxes, levies, deductions, imposts, charges or withholdings, imposed by any governmental authority (all such taxes, levies, deductions, imposts, charges, and withholdings being hereinafter called "Taxes"), excluding (i) franchise taxes, branch profits taxes or taxes imposed on or measured by the overall net income of Issuing Bank, (ii) any U.S. tax that is imposed on amounts payable to Issuing Bank under the law applicable at the time such Issuing Bank acquires an interest in a Letter of Credit (or designates a new lending office), except to the extent Issuing Bank (or its assignor, if any) was entitled, at the time of the designation of a new lending office (or assignment) to receive additional amounts from Account Party with respect to such withholding tax, (iii) taxes attributable to Issuing Bank's failure or inability to comply with Section 5(b), and (iv) any withholding taxes imposed under FATCA.

(b) (i) If Issuing Bank is entitled to an exemption from or reduction of withholding tax with respect to payments made under any Credit Document, Issuing Bank shall deliver to Account Party, at the time or times prescribed by applicable law and reasonably requested by Account Party, such properly completed and executed documentation reasonably requested by Account Party as will permit such payments to be made without withholding or at a reduced rate of withholding. In addition, Issuing Bank, if requested by Account Party, shall deliver such other documentation prescribed by law or reasonably requested by Account Party as will enable Account Party to determine whether or not Issuing Bank is subject to backup withholding or information reporting requirements.

(ii) If Account Party shall be required by law to deduct any Taxes from or in respect of any sum payable under the Credit Documents to Issuing Bank, (A) Account Party shall forthwith pay to Issuing Bank such additional amounts as may be necessary so that after making all required deductions for Taxes Issuing Bank receives an amount equal to the sum it would have received had no such deductions been made and (B) Account Party shall make such deductions and shall pay the full amount deducted to the relevant taxing authority in accordance with applicable law. Account Party shall, provide appropriate documentation, including receipts, evidencing payment by Account Party of any such Taxes. The obligations of Account Party under this Section 5 shall survive the termination of this Agreement, the repayment or reimbursement of all Reimbursement Amounts and all other amounts payable hereunder and under the other Credit Documents.

(iii) Without limiting the generality of the foregoing, if a payment made to Issuing Bank under any Credit Document would be subject to U.S. federal withholding Tax imposed by FATCA if such Issuing Bank were to fail to comply with the applicable reporting requirements of FATCA (including those contained in Section 1471(b) or 1472(b) of the Code, as applicable), such Issuing Bank shall deliver to Account Party at the time or times prescribed by law and at such time or times as reasonably requested by Account Party such documentation prescribed by applicable law (including as prescribed by Section 1471(b)(3)(C)(i) of the Code) and such additional documentation reasonably requested by Account Party as may be necessary for Account Party to comply with its obligations under FATCA and to determine that Issuing Bank has complied with Issuing Bank's obligations under FATCA or to determine the amount to deduct and withhold from such payment. Solely for purposes of this sub-clause (b)(iii), "FATCA" shall include any amendments made to FATCA after the date of this Agreement.

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(iv) Issuing Bank agrees that if any form or certification it previously delivered pursuant to this Section 5 becomes obsolete or inaccurate in any respect (other than as a result of expiration), it shall update such form or certification or promptly notify Account Party in writing of its legal inability to do so.

6. Increased Costs:

In the event of the introduction of, or any change in, any applicable law, rule, regulation or official directive (whether or not having the force of law), or in the interpretation or application thereof by any governmental authority after the date hereof which results in an increase in the cost to Issuing Bank of making or maintaining, or which reduces the rate of return on capital of Issuing Bank as a consequence of its obligations with respect to, execution or maintenance of this Agreement or the issuance, maintenance or extension or amendment of any Letter of Credit by reason of reserve (including, without limitation, the imposition of any reserves with respect to "Eurocurrency Liabilities" (as defined in Regulation D of the Board)), liquidity, capital adequacy or similar requirements, or which results in a reduction of amounts otherwise receivable by Issuing Bank from Account Party of principal, interest or other fees and charges hereunder and thereunder by reason of tax (other than tax on the overall net income of Issuing Bank), levy, impost, fee, charge, withholding or similar requirements of any kind, Account Party will pay to Issuing Bank upon demand an amount equal to such actual increased cost or reduction. For clarity, the foregoing sentence shall apply to all requests, rules, guidelines or directives concerning capital adequacy issued in connection with the Dodd-Frank Wall Street Reform and Consumer Protection Act and all requests, rules, guidelines or directives concerning capital adequacy promulgated by the Bank for International Settlements, the Basel Committee on Banking Regulations and Supervisory Practices (or any successor or similar authority) or the U.S. financial regulatory authorities, regardless of the date adopted, issued, promulgated or implemented. If Account Party becomes liable for the payment of any additional amounts pursuant to this Section 6, it may avoid further liability for such additional amounts by: as to each outstanding Letter of Credit, seeking and obtaining replacements therefor from other financial institutions which fully cancel all obligations of Issuing Bank under such Letter of Credit (which shall thereupon be returned promptly to Issuing Bank) and the relevant Application and paying to Issuing Bank in full on the date of replacement all interest, fees and other amounts or charges due relating to such obligations. The obligations of Account Party under this Section 6 shall survive the termination of this Agreement the repayment or reimbursement of all principal and all other amounts payable hereunder and under the other Credit Documents.

7. Representations and Warranties:

Account Party represents and warrants as of the date hereof and as of the date of each Letter of Credit issued, renewed, extended or amended that:

(a) (i) it is a corporation duly organized and validly existing under the laws of the State of New York, (ii) it is in good standing therein, (iii) it is duly qualified to transact business in all jurisdictions where its ownership, lease or operation of property, or conduct of its business requires such qualification, (iv) no consent or authorization of, approval by, notice to, filing with or other act by or in respect of, any governmental authority or any other Person is required in connection with the execution, delivery, performance, validity or enforceability of any of the Credit Documents, and (v) it has the legal right and corporate power and authority to own its assets and properties and enter into, execute, deliver and perform the Credit Documents and all documents, instruments and agreements related thereto and perform the transactions and agreements contemplated thereby;

(b) the execution, delivery and performance of the Credit Documents have been duly authorized by all necessary corporate action;

(c) this Agreement has been, and each of the Credit Documents when delivered hereunder, will have been, duly executed and delivered by it, and this Agreement is, and each of the Credit Documents when delivered hereunder will, constitute the legal, valid and binding obligations of Account Party enforceable in accordance with their respective terms except as enforceability may be limited by applicable bankruptcy, insolvency, reorganization, moratorium or similar laws affecting the

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enforcement of creditors' rights generally and by general equitable principles (whether enforcement is sought by proceedings in equity or at law);

(d) it is not in default under any material agreement to which it is a party or by which its businesses, assets or properties are bound, which default would materially adversely affect such Borrower's financial condition and the execution and delivery of, and the performance by it under, the Credit Documents do not and will not, create any Lien on its businesses, properties or assets, contravene, violate or conflict with any material Requirement of Law, nor result in a breach or default under any material agreement to which it is a party or by which its businesses, assets or properties are bound, except for such defaults or breaches that would not have a Material Adverse Effect;

(e) except as disclosed on Schedule 7(e) or in Account Party's annual reports on Form 10-K or quarterly reports on Form 10-Q filed with the SEC, there are no actions, suits or proceedings of any kind pending or threatened against Account Party or its assets or properties which, in any one case or in the aggregate, could reasonably be expected to have a Material Adverse Effect;

(f) it is in compliance with all Requirements of Law except where such non-compliance could not reasonably be expected to have a Material Adverse Effect; provided, however, that where such compliance relates to any Anti-Corruption Laws, Anti-Money Laundering Laws or Sanctions, each of Account Party and its Subsidiaries is in compliance in all respects and subject to no exceptions;

(g) it has filed or caused to be filed all federal, state and local tax returns which are, to its knowledge, required to be filed by it, and has paid or has made provision for the payment of all taxes shown to be due and payable on such returns or on any assessments received by it, other than any taxes or assessments it is contesting in good faith by appropriate proceedings and with respect to which it shall, to the extent required by GAAP, have set aside adequate reserves on its books;

(h) no part of the proceeds of any Letter of Credit will be used for "purchasing" or "carrying" any "margin stock" within the respective meanings of such quoted terms under Regulations T, U and X of the Board or for any purpose, which violates, or which would cause Issuing Bank to violate, the provisions of any such regulations;

(i) it is not subject to regulation under the Investment Company Act of 1940, as amended, or subject to any federal or state statutes or regulations limiting its ability to incur the indebtedness contemplated under, or otherwise affecting the validity or enforceability of, the Credit Documents;

(j) Account Party's obligations hereunder and under any other Credit Document do and, at all times hereafter, shall rank pari passu with all other unsecured and unsubordinated indebtedness of Account Party;

(k) the Financial Statements were prepared in accordance with GAAP consistently applied unless expressly disclosed therein and fairly present the consolidated financial position of the Account Party during the relevant financial year unless expressly disclosed therein to the contrary;

(l) Account Party shall, and shall cause its Subsidiaries to, maintain and enforce policies and procedures designed to promote and achieve compliance by Account Party and its Subsidiaries with applicable Anti-Corruption Laws, Anti-Money Laundering Laws and Sanctions;

(m) none of Account Party or any of its Subsidiaries or, any of their respective directors, officers or, to Account Party's knowledge, any of their respective Affiliates, agents or employees (i) has conducted their respective businesses or taken any action that would constitute or give rise to a violation of any Anti-Corruption Law or Anti-Money Laundering Law or (ii) is or has been subject to any action, proceeding, litigation, claim or, to Account Party's knowledge, investigation with regard to any actual or alleged violation of any Anti-Corruption Laws or Anti-Money Laundering Laws;

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(n) none of Account Party or any of its Subsidiaries or any of their respective directors, officers or, to Account Party's knowledge, any of their respective Affiliates, agents or employees (i) is a Sanctioned Person, (ii) is currently engaging or has engaged in any dealings or transactions with, involving or for the benefit of a Sanctioned Person, or in or involving any Sanctioned Jurisdiction, in each case in violation of applicable Sanctions, or (iii) is subject to any action, proceeding, litigation, claim or, to Account Party's knowledge, investigation with regard to any actual or alleged violation of Sanctions; and

(o) since September 30, 2016, no event, circumstance or change has occurred that has caused, either individually or in the aggregate, a Material Adverse Effect.

8. Covenants:

Until the later of (a) the Expiration Date and (b) the date on which all obligations of Account Party in respect of the Credit Documents are indefeasibly paid in cash in full and all Letters of Credit have expired or been released by the beneficiaries thereof and tendered to Issuing Bank for cancellation, Account Party agrees and covenants with Issuing Bank as follows:

(i) Account Party shall be deemed to have furnished Issuing Bank with its audited annual Financial Statements when its annual report on Form 10-K is filed with the SEC and its quarterly unaudited Financial Statements when its quarterly report on Form 10-Q is filed with the SEC;

(ii) Account Party shall provide prompt written notice of any Default or Event of Default;

(iii) Account Party shall continue to engage in business of the same general type as now conducted by it and preserve, renew and keep in full force and effect its corporate existence and take all reasonable action to maintain all rights, privileges and franchises necessary in the normal conduct of its business and comply with its material contractual obligations;

(iv) Account Party shall not convey, sell, lease, transfer or otherwise dispose of, or create, assume or suffer to exist any Lien on, all or substantially all of its assets (in each case, whether in one transaction or in a series of transactions);

(v) Account Party shall not consolidate with, or merge into, any other Person (unless there is no Change of Control of Account Party and no Default or Event of Default shall have occurred and be continuing or result therefrom);

(vi) Account Party is in compliance, and shall comply with all Requirements of Law (other than those specifically referenced in clauses (vii) through (ix) below) except where the failure to so comply could not reasonably be expected to have a Material Adverse Effect;

(vii) Account Party's obligations hereunder and under the other Credit Documents shall rank pari passu with all other unsecured and unsubordinated indebtedness of Account Party;

(viii) Account Party shall, and shall cause its Subsidiaries to, continue to maintain and enforce policies and procedures designed to promote and achieve compliance by Account Party and its Subsidiaries with applicable Anti-Corruption Laws, Anti-Money Laundering Laws and Sanctions;

(ix) Account Party shall not, directly or indirectly, (A) use any part of the proceeds of the Letters of Credit, or otherwise make available such proceeds to any Person in any manner that would constitute or give rise to a violation of Sanctions by any party hereto or (B) fund all or part of any repayment or reimbursement of the obligations hereunder out of proceeds derived from any transaction or activity involving a Sanctioned Person or Sanctioned Jurisdiction; and

(x) Account Party shall not, directly or indirectly, use any part of the proceeds of the Letters of Credit for any payments to any governmental official or employee, political party, official of a political party, candidate for political office, or anyone else acting in an official capacity, in order to obtain,

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retain or direct business or obtain any improper advantage, in each case in violation of Anti-Corruption Law.

9. Events of Default:

The occurrence of any one or more of the following events shall constitute an "Event of Default" under the Credit Documents:

(a) if Account Party shall (i) fail to reimburse any Reimbursement Amount when due and payable or (ii) fail to pay interest or any other amounts due under the Credit Documents within five (5) days of the date on which such payment of interest or other amount was due and payable;

(b) if Account Party shall fail to perform any of its obligations for the payment of any Indebtedness (i) under its $1,500,000,000 Revolving Credit Agreement dated as of April 5, 2016, as amended, with JPMorgan Chase Bank, N.A., as Administrative Agent, et al., or (ii) in the aggregate amount of more than U.S.$50,000,000 (other than Indebtedness described in subsection 9(a)) when due (whether at scheduled maturity or upon acceleration, demand or otherwise) or if Account Party shall default under any agreement or instrument relating to such Indebtedness or any other event shall occur and continue after any grace period applicable thereto, if the effect of such default or event is to accelerate, or permit the acceleration of, the maturity of such Indebtedness;

(c) if Account Party shall:

(i) commence a voluntary case or other proceeding seeking liquidation, reorganization or other relief with respect to itself or its debts under any bankruptcy, insolvency or other similar law now or hereafter in effect or seeking the appointment of a trustee, receiver, liquidator, custodian or other similar official of it or any material part of its property, or shall consent to any such relief or to the appointment of or taking possession by any such official in an involuntary case or other proceeding commenced against it, or shall make a general assignment for the benefit of creditors, or shall fail generally to pay its debts as they become due, or shall take any action to authorize any of the foregoing; or

(ii) suffer the commencement of an involuntary case or other proceeding seeking liquidation, reorganization or other relief with respect to itself or its debts under any bankruptcy, insolvency or other similar law now or hereafter in effect or seeking the appointment of a trustee, receiver, liquidator, custodian or other similar official of it or any material part of its property, and such involuntary case or other proceeding shall not be controverted by appropriate proceedings within thirty (30) days of the commencement thereof or shall remain undismissed or undischarged for a period of sixty (60) days; or suffer the entry of an order for relief or be adjudicated a bankrupt or insolvent under the bankruptcy, insolvency or similar laws of any competent jurisdiction;

(d) if any representation, warranty or statement made by Account Party in any Credit Document or in any certificate or statement furnished pursuant to, or in connection with, any Credit Document shall prove to have been incorrect, misleading or incomplete in any material respect when made or deemed made;

(e) if Account Party shall fail to perform or observe in any material respect any term, covenant or agreement on its part to be performed or observed pursuant to any Credit Document (other than those covered by subsection 9(a)) and such failure shall continue unremedied for thirty (30) days after the earlier of (i) an officer of Account Party obtaining knowledge thereof and (ii) receipt by Account Party of written notice thereof from Issuing Bank;

(f) if one or more judgments or decrees shall be entered against Account Party or any of its Subsidiaries involving in the aggregate for all such Persons a liability (not paid or fully covered by insurance) of U.S.$50,000,000 or more and all such judgments and decrees shall not have been vacated, discharged, stayed or bonded pending appeal within sixty (60) days from the entry thereof;

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(g) if an event shall occur with respect to Account Party which, in the reasonable judgment of Issuing Bank, has or is likely to have a Material Adverse Effect; or

(h) if a Change of Control or any material alteration of the structure or organization of Account Party, including without limitation, as a result of a leveraged buyout, recapitalization, merger or consolidation shall occur.

Upon the occurrence of any Event of Default (other than any Event of Default specified in subsection 9(c) in respect of Account Party), Issuing Bank may, by written notice to Account Party, declare this Agreement canceled and/or declare all amounts outstanding under this Agreement (including, without limitation, all amounts of L/C Obligations, whether or not the beneficiaries of the then outstanding Letters of Credit shall have presented the documents required thereunder) to be immediately due and payable in full, whereupon this Agreement shall be canceled and/or such amounts shall become immediately due and payable; provided, however, that upon the occurrence of any Event of Default specified in subsection 9(c) in respect of Account Party, this Agreement automatically shall be canceled and all amounts outstanding under this Agreement (including, without limitation, all amounts of L/C Obligations, whether or not the beneficiaries of the then outstanding Letters of Credit shall have presented the documents required thereunder) automatically shall become immediately due and payable in full, in each case without notice, presentment, demand, protest or other action of any kind, all of which are hereby expressly waived by Account Party.

With respect to any Letters of Credit with respect to which presentment for honor shall not have occurred at the time of an acceleration pursuant to the immediately preceding paragraph, Account Party shall at such time deposit in a cash collateral account on Issuing Bank's books, within Issuing Bank's sole dominion and control, designated by Issuing Bank and over which Issuing Bank shall have exclusive right of withdrawal (the "Collateral Account"), an amount (in the Currency of such Letter of Credit; provided that upon the failure or inability of Account Party for any reason to so effect such payment in the required Currency, Account Party shall be obliged to perform in accordance with Section 3(e)) equal to the aggregate then undrawn and unexpired amount of such Letters of Credit. The Collateral Account (and any and all funds and investments held therein) shall be held in the name of, and subject to the sole dominion and control of, Issuing Bank, as cash collateral for the reimbursement obligations of Account Party in the event of any drawing under the Letters of Credit. Any and all amounts held in the Collateral Account shall be applied by Issuing Bank to satisfy Account Party's L/C Obligations for which Issuing Bank has not been reimbursed, and any unused portion of such amounts after the Letters of Credit shall have expired and all L/C Obligations shall have been satisfied, shall be applied to repay other obligations of Account Party under this Agreement and the other Credit Documents. Except as expressly provided in this Section 9, notice, presentment, demand, protest and any other action of any kind are hereby expressly waived by Account Party.

Account Party hereby grants to Issuing Bank a security interest in, and right of set-off against, any and all funds and investments held in the Collateral Account from time to time and any instrument evidencing the foregoing to secure the obligations of Account Party hereunder in respect of the Letters of Credit, any and all reimbursement obligations arising in connection therewith and other obligations under this Agreement and the other Credit Documents.

Issuing Bank shall have the rights, powers and remedies of a secured party under the Uniform Commercial Code as in effect from time to time in the State of New York with respect to the funds and investments held in the Collateral Account from time to time. Account Party shall take such actions from time to time as Issuing Bank may reasonably request to perfect and preserve the security interests provided for in this Agreement.

Issuing Bank shall release all funds and investments held in the Collateral Account to, or upon the order of, Account Party (or as a court of competent jurisdiction may otherwise direct) upon the later to occur of the date that (i) this Agreement and the other Credit Documents terminate and (ii) all obligations of Account Party under the Letters of Credit and all L/C Obligations are satisfied and indefeasibly paid in full and such Letters of Credit have been canceled or expired and all amounts drawn thereunder have been reimbursed in full.

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The rights and remedies of Issuing Bank under this Agreement are in addition to, and not in substitution of, the rights and remedies Issuing Bank is entitled to exercise at law, in equity and under the other Credit Documents.

10. Effectiveness of Agreement; Conditions Precedent:

(a) The effectiveness of this Agreement is subject to receipt by Issuing Bank, in form and substance satisfactory to it, of each of the following:

(i) a copy of this Agreement, duly executed by Issuing Bank and Account Party;

(ii) a customary certificate duly executed by an authorized officer of Account Party, attaching (A) a copy of the articles of incorporation or comparable organizational document duly certified by the Secretary of State of the State of New York as of a recent date; (B) a copy of the by-laws or comparable organizational document of Account Party, duly certified by an authorized officer of Account Party as being in full force and effect; (C) a copy of Account Party's resolutions certified by an authorized officer of Account Party authorizing Account Party to enter into the transactions contemplated by the Credit Documents to which Account Party is a party, including, without limitation, requesting the issuance of Letters of Credit as contemplated hereunder from Issuing Bank in the aggregate amount contemplated hereunder, and evidencing the authority of the officer(s) named therein to sign the Credit Documents and such other documents on behalf of Account Party as Issuing Bank shall require; (D) a certificate of incumbency and specimen signatures of the authorized signers of the Credit Documents issued by the secretary or assistant secretary of Account Party; and (E) a certificate of good standing duly certified by the Secretary of State of the State of New York;

(iii) a customary certificate duly executed by an authorized officer of Account Party, certifying as to (A) the truth in all respects of the representations and warranties contained in this Agreement and the other Credit Documents as though made on and as of the date of the effectiveness of this Agreement and (B) the absence of any Default or Event of Default; and

(iv) such other documents, instruments or agreements as Issuing Bank shall reasonably request.

(b) An additional condition precedent to the issuance of each Letter of Credit is the receipt by Issuing Bank of a duly executed Application in respect of such Letter of Credit.

(c)Each request to issue, renew, amended or extend a Letter of Credit by Account Party hereunder shall constitute a representation and warranty that (i) each of the representations and warranties made by Account Party contained herein or in any other Credit Document shall be true and correct on and as of the date of such issuance, renewal, amendment or extension as if made on and as of such date and (ii) no Default or Event of Default exists (either immediately before or immediately after giving effect to such issuance, renewal, amendment or extension).

11. Authorization to Debit; Right of Set-Off:

With respect to the payment of amounts due hereunder and under any Letter of Credit, Account Party hereby authorizes Issuing Bank to debit any demand deposit account of Account Party maintained with Issuing Bank for such amount when due. In the event Account Party shall default in the payment of any amount due hereunder, under any Letter of Credit, or under the other Credit Documents, Issuing Bank shall have the right to set off and apply any deposit, general or special, time or demand, provisional or final, at any time held or owing by any branch or office of Crédit Agricole S.A. to, or for the credit of, Account Party.

12. Costs and Expenses; Indemnity; Waiver of Special Damages:

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(a) Account Party agrees to pay or reimburse Issuing Bank for all Issuing Bank's charges, costs and expenses (including, without limitation, reasonable fees and disbursements of counsel to Issuing Bank) incurred in connection with (i) the issuance, amendment, renewal or extension of any Letter of Credit or any demand for, or collection of, payment thereunder and (ii) the enforcement, protection or preservation of any rights under this Agreement and the other Credit Documents and any other document prepared in connection therewith.

(b) Account Party agrees to indemnify Issuing Bank and any of its Affiliates and the respective branches, agencies, directors, officers, employees, agents, advisors, partners, trustees and administrators of Issuing Bank and its Affiliates (each such Person being called an "Indemnitee") against, and pay and hold each Indemnitee harmless from, any and all losses, claims, damages and related costs and expenses, including the fees, charges and disbursements of any counsel for any Indemnitee, suffered or incurred by, or asserted against, any Indemnitee however characterized or arising out of, in connection with, or as a result of (i) any delay in paying, stamp, excise and other taxes, if any, which may be payable or determined to be payable in connection with the execution and delivery of, or consummation or administration of, any of the transactions contemplated by, or any amendment, supplement or modification of, or any waiver or consent under or in respect of, any Credit Document and any such other document, (ii) any Letter of Credit or the use of the proceeds therefrom (including any refusal by Issuing Bank to honor a demand for payment under a Letter of Credit if the documents presented in connection with such demand to not strictly comply with the terms of such Letter of Credit) and (iii) any and all other liabilities, obligations, losses, damages, penalties, any actual or prospective actions, claims, litigation, suites, investigation or proceeding (whether sounding in contract, in tort or on any other ground and regardless of whether any Indemnitee is a party thereto), judgments, suits, costs, expenses or disbursements of any kind or nature whatsoever with respect to the execution, delivery, enforcement, performance or administration of, or in any other way arising out of or relating to, any Credit Document or any other documents contemplated by or referred to therein or any action taken or omitted to be taken by any Indemnitee with respect to any of the foregoing (all the foregoing, collectively, the "Indemnified Liabilities"); provided, however, that Account Party shall have no obligation hereunder to any Indemnitee with respect to Indemnified Liabilities arising solely from the gross negligence or willful misconduct of such Indemnitee, as determined by a court of competent jurisdiction in a final, non-appealable judgment.

(c) Neither party hereto shall be liable in any action initiated by one against the other for punitive, special, indirect or consequential damages resulting from or arising out of this Agreement, including, without limitation, loss of profit or business interruptions, however the same may be caused.

All amounts due under this Section 12 shall be payable immediately after demand therefor. Without prejudice to the survival of any other provision hereof, the terms of this Section 12 shall survive the termination of this Agreement and the repayment or reimbursement of all Reimbursement Amounts and all other amounts payable hereunder.

13. Obligations Absolute; Risks:

(a)The obligation of Account Party to reimburse Issuing Bank, its correspondents, any of its branches, agencies or Affiliates for each drawing under each Letter of Credit shall be absolute, unconditional and irrevocable, and shall be paid strictly in accordance with the terms of this Agreement under any and all circumstances and irrespective of, including the following: (i) any form, lack of accuracy, legal effect, validity or enforceability of such Letter of Credit, this Agreement, or any other Credit Document or the authority of any persons signing any Credit Documents; provided such Credit Documents appear on their face to be in order; (ii) the existence of any claim, counterclaim, dispute, set-off, defense or other right that Account Party may have at any time against any beneficiary or any transferee of such Letter of Credit (or any Person for whom any such beneficiary or any such transferee may be acting), Issuing Bank or any other Person, whether in connection with this Agreement, any other Credit Document, the transactions contemplated hereby or by such Letter of Credit or any agreement or instrument relating thereto, or any unrelated transaction; (iii) any draft, demand, certificate or other document presented under such Letter of Credit proving to be forged, fraudulent, invalid or insufficient in any respect or any statement therein being untrue, insufficient or inaccurate in any respect; or any loss, error, interruption,

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omission or delay in the transmission, delivery or otherwise of any document required in order to make a drawing under such Letter of Credit; (iv) any payment by Issuing Bank under such Letter of Credit against presentation of a draft or certificate that does not strictly comply with the terms of such Letter of Credit; or any payment made by Issuing Bank under such Letter of Credit to any Person; (v) any act, omission, insolvency or failure in business of any other Person including any branch of Issuing Bank; or (vi) any other event, act or omission, circumstance or happening whatsoever, whether or not similar to any of the foregoing, including any other circumstance that might otherwise constitute a defense available to, or a discharge of, Account Party. For the avoidance of doubt, the occurrence of any of the above contingencies shall not affect or impair Issuing Bank's rights and powers hereunder or the obligations of payments, indemnity or reimbursement of Account Party to Issuing Bank hereunder.

(b)None of Issuing Bank, nor any of its Affiliates nor the respective branches, agencies, directors, officers, employees, agents, advisors, partners, trustees and administrators of Issuing Bank and its Affiliates, shall have any liability or responsibility by reason of or in connection with the issuance or transfer of any Letter of Credit by Issuing Bank or any payment or failure to make any payment thereunder irrespective of any of the circumstances referred to in Section 13(a) above, or any act, error, omission, interruption, loss or delay in transmission or delivery of any draft, notice or other communication under or relating to any Letter of Credit (including any document required to make a drawing thereunder), any error in interpretation of technical terms or any consequence arising from causes beyond the control of Issuing Bank. The parties hereto expressly agree that:

(i) Issuing Bank may accept documents that appear on their face to be in substantial compliance with the terms of a Letter of Credit without responsibility for further investigation, regardless of any notice or information to the contrary, and may make payment upon presentation of documents that appear on their face to be in substantial compliance with the terms of such Letter of Credit;

(ii) Issuing Bank shall have the right, in its sole discretion, to decline to accept such documents and to make such payment if such documents are not in strict compliance with the terms of such Letter of Credit; and

(iii) This Section 13(b) shall establish the standard of care to be exercised by Issuing Bank when determining whether drafts and other documents presented under a Letter of Credit comply with the terms thereof (and the parties hereto hereby waive, to the extent permitted by applicable law, any standard of care inconsistent with the foregoing).

14. Assignments; Successors and Assigns; Pledges to Federal Reserve Bank:

(a) This Agreement shall be binding upon and inure to the benefit of Account Party, Issuing Bank and their respective successors and assigns, except that Account Party may not assign, transfer or delegate any of its rights or obligations under this Agreement without the prior written consent of Issuing Bank (such consent not to be unreasonably withheld or delayed). Issuing Bank may, at any time and from time to time, assign all or any part of its rights and obligations under the Credit Documents subject to the prior written consent of Account Party (such consent not to be unreasonably withheld or delayed); provided that no such consent shall be required (i) during the occurrence and continuance of a Default or an Event of Default or (ii) for any assignment to an Affiliate of Issuing Bank.

(b) Nothing herein shall prohibit Issuing Bank from pledging or assigning this Agreement to any Federal Reserve Bank in accordance with applicable law.

15. Notices:

(a) All notices and other communications provided for herein shall be in writing and shall be delivered by hand or overnight courier service, mailed by certified or registered mail or sent by telecopier or electronic communications (including delivery of a "pdf" by email). Notices and other communications sent by hand or overnight courier service, or mailed by certified or registered mail, shall be deemed to have been given when received; notices and other communications sent by fax or email (or

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similar electronic communications) shall be deemed to have been given when sent (except that, if not given during normal business hours for the recipient, shall be deemed to have been given at the opening of business on the next Business Day for the recipient).

(b) Account Party hereby authorized Issuing Bank to accept and process any amendments, transfers, assignments of proceeds, instructions, consents, waivers and all documents relating to any Letter of Credit which are sent to Issuing Bank by electronic transmission, including SWIFT, electronic mail, telex, telecopy, telefax, courier, mail or other computer- generated telecommunications and such electronic communications shall have the same legal effect as if written and shall be binding upon and enforceable against Account Party. Issuing Bank may, but shall not be obligated to, require (a) authentication of such electronic transmission or (b) provision of original documents to Issuing Bank prior to acting on such electronic transmission. Account Party acknowledges and agrees that the privacy and integrity of electronic transmissions cannot be guaranteed to be secure or error free due to the possibility that third parties could intercept, view or alter such electronic transmissions. To the extent that any documents, information or data relating to any Letter of Credit, any Application or any other Credit Document are transmitted electronically, Account Party hereby irrevocably releases Issuing Bank from any loss or liability incurred in connection with the electronic transmission of any such documents, data and information, including any unauthorized interception, alteration or fraudulent generation and transmission of electronic transmissions by third parties.

16. Amendments and Waivers; Execution in Counterparts; Electronic Execution:

(a)Neither this Agreement nor any provision hereof may be waived, amended or modified except pursuant to an agreement or agreements in writing entered into by parties hereto.

(b)This Agreement may be executed in any number of counterparts and by different parties hereto in separate counterparts, each of which when so executed and delivered shall be deemed to be an original and all of which taken together shall constitute but one and the same agreement.

(c)Delivery of an executed counterpart of a signature page to this Agreement by telecopier or electronic communications (inducing delivery of a “pdf” by email) shall be effective as delivery of a manually executed counterpart of this Agreement.

17. No Waiver; Severability; Integration:

The failure or delay by Issuing Bank to exercise any right, power or remedy under this Agreement or any other Credit Document or with respect to the indebtedness evidenced hereby or thereby shall not operate as a waiver thereof, nor shall the exercise of any single or partial right, power or remedy preclude any other or further exercise of the same or any other right, power or remedy. Any provision of this Agreement which is illegal, prohibited or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such illegality, prohibition or unenforceability without invalidating the remaining provisions hereof, and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction. This Agreement and the other Credit Documents constitute the entire agreement and understanding among the parties hereto and supersede any and all prior agreements and understandings, oral or written, relating to the subject matter hereof.

18. Governing Law:

(a) THIS AGREEMENT SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE INTERNAL LAWS OF THE STATE OF NEW YORK.

(b) Each Letter of Credit, each Application and all transactions thereunder shall be subject to and governed by either (a) the Uniform Customs and Practice for Documentary Credits (2007 Revision), International Chamber of Commerce, Publication No. 600 (as the same may be modified or amended, the “UCP”) or (b) the International Standby Practices (ISP98), International Chamber of Commerce, Publication No. 590 (as the same may be modified or amended, the “ISP”) as Issuing Bank shall select in its sole discretion. To the extent not inconsistent with the UCP or the ISP, as the case may

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be, each Letter of Credit, each Application and all transactions thereunder shall be governed by and construed in accordance with, the internal laws of the State of New York.

19. Jurisdiction; Venue; Waiver of Jury Trial:

(a) Each of the parties hereto hereby irrevocably and unconditionally submits, for itself and its property, to the exclusive jurisdiction of any New York State or federal court of the U.S. sitting in New York City, whether trial or appellate, in any action or proceeding arising out of, or relating to, this Agreement or any of the other Credit Documents, or for recognition or enforcement of any judgment in respect thereof, and each of the parties hereto hereby irrevocably and unconditionally agrees that all claims in respect of any such action or proceeding may be heard and determined in any such New York State court or, to the extent permitted by law, in such federal court and consents that any such action or proceeding may be brought in such courts and waives to the fullest extent permitted by law any objection that it may now or hereafter have to the venue of any such action or proceeding in any such court or that such action or proceeding was brought in an inconvenient court and agrees not to plead or claim the same. Each of the parties hereto agrees that a final judgment in any such action or proceeding shall be conclusive and may be enforced in other jurisdictions by suit on the judgment or in any other manner provided by law. Nothing in this Agreement shall affect any right that Issuing Bank may otherwise have to bring any action or proceeding relating to this Agreement or any of the other Credit Documents in the courts of any jurisdiction.

(b) **EACH OF THE PARTIES HERETO HEREBY IRREVOCABLY WAIVES ALL RIGHT TO TRIAL BY JURY IN ANY ACTION, PROCEEDING OR COUNTERCLAIM ARISING OUT OF, OR RELATING TO, ANY CREDIT DOCUMENT OR THE ACTIONS OF ISSUING BANK OR ACCOUNT PARTY IN THE NEGOTIATION, ADMINISTRATION, PERFORMANCE OR ENFORCEMENT THEREOF.**

20. USA Patriot Act Notification:

Issuing Bank hereby notifies Account Party that pursuant to the USA Patriot Act, it is required to obtain, verify and record information that identifies Account Party, including without limitation the name and address of Account Party.

* *

If the foregoing is acceptable, kindly acknowledge your agreement with the terms and conditions hereof by having one original copy of this Agreement signed by a duly authorized representative of Account Party (pursuant to its resolutions) and returned to Issuing Bank as soon as possible.

[Signature pages follow]

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Yours truly,

CRÉDIT AGRICOLE CORPORATE AND INVESTMENT BANK

By: /s/ Ghislain Descamps

Name: Ghislain Descamps
Title: Managing Director

By: /s Louis-Marie Dubois

Name: Louis-Marie Dubois
Title: Vice President

Address for notices:

1301 Avenue of the Americas
New York, New York 10019
Attention: Louis-Marie Dubois, Export and Trade Finance, 18th Floor
Email: etf-us@ca-cib.com

Accepted and Agreed:

AVANGRID, INC.

By: /s/ Howard Coon
Name: Howard Coon
Title: Vice President & Treasurer

By: /s/ Daniel Alcain
Name: Daniel Alcain
Title: Senior Vice President – Controller

Address for notices:

70 Farm View Drive
New Gloucester, Maine 04260
Attention: Howard Coon, Vice President, Treasurer
Email: howard.coon@avangrid.com

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EXHIBIT A

APPLICATION AND AGREEMENT FOR
IRREVOCABLE STANDBY LETTER OF CREDIT

To: Crédit Agricole Corporate and Investment Bank ("Crédit Agricole CIB" or "you")
Issuing Office: _____ Date: _____

Application and Agreement for Irrevocable Standby Letter of Credit (this "Application") is hereby made for the issuance by you of your irrevocable standby letter of credit (the "Credit") in conformity with your practices and procedures and, to the extent not inconsistent therewith, in accordance with the following instructions:

(Complete Each Section Fully or Indicate "Not Applicable")

Please send the Credit to the Beneficiary by your customary means as follows:

_____ Directly to the Beneficiary.
_____ Through the Advising Bank specified below.
_____ Through your Correspondent.

Name and address of the "Beneficiary": _____

Name and address of the Advising Bank: _____

Name and address of each "Applicant" to be named as an Account Party: _____

Amount of the Credit: _____

Currency: _____

The Credit shall expire at your counters on: _____

The Credit shall provide for an extension of the expiry date: _____Yes _____No

Automatic Renewal Clause: _____Yes _____No

Cancellation Period (check one): ___30 Days ___90 Days ___120 Days; Other: _____

Amounts under the Credit shall be available as follows: _____

Partial Drawings under the Credit: _____Are permitted. _____Are not permitted.

Special Instructions:

In order to induce you to issue the Credit as provided herein, each Applicant (if more than one) hereby expressly agrees to be bound by this Application and the Offer, dated as of December 2, 2016 for a U.S.$50,000,000 Uncommitted Line of Credit for Standby Letters of Credit, as amended, restated, amended and restated, supplemented, extended or otherwise modified from time to time (the "Offer"). Any capitalized term not defined herein shall have the definition set forth in the Offer.

[Applicant]	[Applicant]
_____	_____
By: _____	By: _____
Name:_____	Name:_____
Title: _____	Title: _____
Address:	Address:

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_____

For Office Use Only

No. of Credit: _____ Approved by: _____

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EXHIBIT 10.45

SUBSTITUTION AGREEMENT

This SUBSTITUTION AGREEMENT, dated as of December 19, 2016 (the "Agreement"), is entered into by and between UIL HOLDINGS CORPORATION, a corporation duly organized and existing under the laws of the State of Connecticut ("UIL") and AVANGRID, INC., a corporation duly organized and existing under the laws of the State of New York ("Avangrid").

RECITALS

WHEREAS, the predecessor company to UIL, UIL Holdings Corporation ("predecessor UIL") and The Bank of New York Mellon, a corporation organized under the laws of the State of New York authorized to conduct a banking business, as Trustee ("Trustee"), entered into an Indenture dated as of October 7, 2010 (the "Base Indenture" and, as amended and supplemented to the date hereof, the "Indenture") to provide for the issuance of predecessor UIL's unsecured senior debt securities to be issued from time to time in one or more series as might be determined by predecessor UIL under the Indenture;

WHEREAS, predecessor UIL and the Trustee have heretofore executed and delivered the First Supplemental Indenture, dated as of October 7, 2010, pursuant to which predecessor UIL issued its 4.625% Notes due 2020, in the aggregate principal amount of $450,000,000 (the "2010 Notes");

WHEREAS, on December 15, 2015, predecessor UIL merged with and into UIL, a wholly-owned subsidiary of Avangrid.

WHEREAS, UIL, predecessor UIL and the Trustee have heretofore entered into a Second Supplemental Indenture, pursuant to which UIL assumed all of the obligations of predecessor UIL under the Indenture and the 2010 Notes;

WHEREAS, UIL, Avangrid and the Trustee intend to execute a Third Supplemental Indenture (the "Third Supplemental Indenture") pursuant to which Avangrid will be substituted for UIL as issuer of the 2010 Notes and assume all of the obligations and perform every covenant in the Indenture (including every supplemental indenture) (collectively, the "Obligations"); and

WHEREAS, upon assumption of the Obligations by Avangrid, UIL shall be relieved of all obligations and covenants under the Indenture;

NOW THEREFORE: in consideration of the premises and the covenants and agreements provided for herein, and for other good and valuable consideration the receipt of which is hereby acknowledged, UIL and Avangrid mutually covenant and agree as follows:

SECTION I. *Payments by UIL*

UIL shall transfer, on December 19, 2016 (the "Transfer Date"), (i) to such account as shall be designated by Avangrid to UIL, an amount equal to $ in respect of the market value of the aggregate outstanding principal amount of the 2010 Notes (the "Principal Payment") plus (ii) $ in respect of the aggregate interest accrued under the 2010 Notes from and including the relevant last interest payment date up to but excluding the Transfer Date ("Interest Payment").

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SECTION 2. Assumption of Obligations by Avangrid

Upon receipt of the Principal Payment and the Interest Payment on the Transfer Date, Avangrid shall assume all of the Obligations arising out of the execution of the Third Supplemental Indenture, and UIL shall be simultaneously discharged from such obligations.

SECTION 3. *Effect of Headings.*

The Article and Section headings herein are for convenience only and shall not affect the construction hereof.

SECTION 4. *Successors and Assigns.*

All covenants and agreements in this Agreement by Avangrid shall bind its successors and assigns, whether so expressed or not.

SECTION 5. *Counterparts.*

This Agreement may be executed in any number of counterparts, each of which shall be deemed to be an original, but all such counterparts shall together constitute but one and the same instrument.

SECTION 6. *Governing Law.*

This Agreement shall be governed by and construed in accordance with the laws of New York.

IN WITNESS WHEREOF, the parties hereto have caused this Substitution Agreement to be duly executed as of the day and year first written above.

UIL Holdings Corporation

By: /s/ Steven P Fauzza
Name: Steven P Fauzza
Title: Vice President, Controller & Treasurer

By: /s/ Leonard Rodriquez
Name: Leonard Rodriquez
Title: General Counsel

Avangrid, Inc.

By:/s/ Howard Coon
Name: Howard Coon
Title: Vice President & Treasurer

By: /s/ Daniel Alcain
Name: Daniel Alcain
Title: Senior Vice President – Controller

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EXHIBIT 21.1

LIST OF SUBSIDIARIES OF Avangrid, Inc.

Name of Subsidiary	State or Jurisdiction of Incorporation Or Organization
Avangrid Networks, Inc.(1)*	Maine
New York State Electric & Gas Corporation(2)	New York
Rochester Gas and Electric Corporation (2)	New York
Central Maine Power Company(2)	Maine
Maine Natural Gas Corporation(2)	Maine
UIL Holdings Corporation.(2)	Connecticut
The United Illuminating Company(5)	Connecticut
The Southern Connecticut Gas Company(5)	Connecticut
Connecticut Natural Gas Corporation(5)	Connecticut
The Berkshire Gas Company(5)	Massachusetts
Avangrid Renewables Holdings, Inc.(1)*	Delaware
Avangrid Renewables, LLC(3)	Oregon
Enstor Gas, LLC(3)*	Delaware
Enstor Energy Services, LLC(4)	Delaware
Enstor, Inc.(4)	Oregon

(1) Subsidiary of Avangrid, Inc.
(2) Subsidiary of Avangrid Networks, Inc.
(3) Subsidiary of Avangrid Renewables Holdings, Inc.
(4) Subsidiary of Enstor Gas, LLC
(5) Subsidiary of UIL Holdings Corporation

* Holding Company

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EXHIBIT 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-8 No. 333-212616) pertaining to Avangrid, Inc.'s common stock to be available for issuance under the Avangrid, Inc. Omnibus Incentive Plan, and

(2) Registration Statement (Form S-8 No. 333-208571) pertaining to Avangrid, Inc.'s common stock to be available for issuance under the UIL Holdings Corporation 2008 Stock and Incentive Compensation Plan and the UIL Holdings Corporation Deferred Compensation Plan;

of our reports dated March 10, 2017, with respect to the consolidated financial statements and schedule and the effectiveness of internal control over financial reporting of Avangrid, Inc. included in this Annual Report (Form 10-K) for the year ended December 31, 2016.

/s/ Ernst & Young LLP

New York, New York
March 10, 2017

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EXHIBIT 23.2

Consent of Independent Accountants

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (333-208571) of Avangrid, Inc. of our report dated April 1, 2016 relating to the consolidated balance sheet of UIL Holdings Corporation, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Boston, MA
March 10, 2017

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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)) 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) 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

c) 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 10, 2017

/s/ James P. Torgerson
James P. Torgerson
Director and Chief Executive Officer

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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)) 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) 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

c) 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 10, 2017

/s/ Richard J. Nicholas
Richard J. Nicholas
Chief Financial Officer

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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 10, 2017

/s/ Richard J. Nicholas
Richard J. Nicholas
Chief Financial Officer
Avangrid, Inc.
March 10, 2017

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Document and Entity Information - USD ($) $ in Millions	12 Months Ended		
	Dec. 31, 2016	Mar. 09, 2017	Jun. 30, 2016
Document And Entity Information [Abstract]			
Document Type	10-K		
Amendment Flag	false		
Document Period End Date	Dec. 31, 2016		
Document Fiscal Year Focus	2016		
Document Fiscal Period Focus	FY		
Trading Symbol	AGR		
Entity Registrant Name	Avangrid, Inc.		
Entity Central Index Key	0001634997		
Current Fiscal Year End Date	--12-31		
Entity Well-known Seasoned Issuer	Yes		
Entity Voluntary Filers	No		
Entity Current Reporting Status	Yes		
Entity Filer Category	Large Accelerated Filer		
Entity Common Stock, Shares Outstanding		309,068,730	
Entity Public Float			$ 2,576

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Consolidated Statements of Income - USD ($) $ in Millions	12 Months Ended		
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Operating Revenues	$ 6,018	$ 4,367	$ 4,594
Operating Expenses			
Purchased power, natural gas and fuel used	1,286	972	1,181
Operations and maintenance	2,206	1,808	1,560
Impairment of non-current assets		12	25
Depreciation and amortization	804	695	629
Taxes other than income taxes	528	367	314
Total Operating Expenses	4,824	3,854	3,709
Operating Income	1,194	513	885
Other Income and (Expense)			
Other income and (expense)	76	55	52
Earnings from equity method investments	7		12
Interest expense, net of capitalization	(268)	(267)	(243)
Income (Loss) Before Income Tax	1,009	301	706
Income tax expense (benefit)	379	34	282
Net Income	630	267	424
Net Income Attributable to Avangrid, Inc.	$ 630	$ 267	$ 424
Earnings Per Common Share, Basic:	$ 2.04	$ 1.05	$ 1.68
Earnings Per Common Share, Diluted:	$ 2.04	$ 1.05	$ 1.68
Weighted-average Number of Common Shares Outstanding:			
Basic	309,512,553	254,588,212	252,235,232
Diluted	309,817,322	254,605,111	252,235,232
Cash Dividends Declared Per Common Share	$ 1.728		
Avangrid, Inc [Member]			
Operating Expenses			
Operating expense	$ 5	$ 38	$ 2
Taxes other than income taxes	5	5	2
Total Operating Expenses	10	43	4
Operating Income	(10)	(43)	(4)
Other Income and (Expense)			
Other income and (expense)	68	10	(1)
Earnings from equity method investments	565	44	515
Interest expense, net of capitalization	(32)	(14)	(34)
Income (Loss) Before Income Tax	591	(3)	476
Income tax expense (benefit)	(39)	(270)	52
Net Income	630	267	424
Net Income Attributable to Avangrid, Inc.	$ 630	$ 267	$ 424

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Consolidated Statements of Comprehensive Income - USD ($) $ in Millions	12 Months Ended		
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Net Income	$ 630	$ 267	$ 424
Other Comprehensive Income, Amounts arising during the year:			
Gain on defined benefit plans, net of income taxes	7	4	1
Amortization of pension cost for nonqualified plans, net of income taxes	1	3	(3)
Unrealized gain (loss) during the year on derivatives qualifying as cash flow hedges, net of income taxes	(26)	33	(2)
Reclassification to net income of (gains) losses on cash flow hedges, net of income taxes [1]	(16)	7	5
Other Comprehensive (Loss) Income	(34)	47	1
Comprehensive Income	596	314	425
Comprehensive Income Attributable to Avangrid, Inc.	596	314	425
Avangrid, Inc [Member]			
Net Income	630	267	424
Other Comprehensive Income, Amounts arising during the year:			
Other Comprehensive (Loss) Income	(34)	47	1
Comprehensive Income	$ 596	$ 314	$ 425

[1] Reclassification is reflected in the operating expenses line item in the consolidated statements of income.

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Consolidated Statements of Comprehensive Income (Parenthetical) - USD ($) $ in Millions	12 Months Ended		
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Unrealized gain (loss) during period on derivatives qualified as cash flow hedges, income tax (expense) benefit	$ (15.8)	$ 20.9	$ (1.4)
Reclassification to net income of losses on cash flow hedges, income tax expense	11.0	4.9	4.1
Qualified Pension Plan [Member]			
Gain (loss) on defined benefit plans, income tax expense (benefit)	4.3	2.2	0.6
Non-Qualified Pension Plans [Member]			
Gain (loss) on defined benefit plans, income tax expense (benefit)	$ 0.4	$ 1.7	$ (1.9)

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Consolidated Balance Sheets - USD ($) $ in Millions	Dec. 31, 2016		Dec. 31, 2015	
Current Assets				
Cash and cash equivalents	$ 91		$ 427	
Accounts receivable and unbilled revenues, net	1,119		974	
Accounts receivable from affiliates	25		70	
Notes receivable from affiliates			6	
Derivative assets	99		88	
Fuel and gas in storage	246		307	
Materials and supplies	132		98	
Prepayments and other current assets	255		285	
Regulatory assets	285		219	
Total Current Assets	2,252		2,474	
Property, plant and equipment, at cost	27,063	[1]	25,745	[2]
Less: accumulated depreciation	(6,986)	[3]	(6,372)	[4]
Net Property, Plant and Equipment in Service	20,077		19,373	
Construction work in progress	1,471		1,338	
Total Property, Plant and Equipment ($1,144 and $1,206 related to VIEs, respectively)	21,548		20,711	
Equity method investments	387		385	
Other investments	55		64	
Regulatory assets	3,091		3,314	
Other Assets				
Goodwill	3,124		3,115	
Intangible assets	538		556	
Derivative assets	73		89	
Other	241		35	
Total Other Assets	3,976		3,795	
Total Assets	31,309		30,743	
Current Liabilities				
Current portion of debt	349		206	
Tax equity financing arrangements - VIEs	96		107	
Notes payable	151		163	
Notes payable to affiliates	10			
Interest accrued	60		61	
Accounts payable and accrued liabilities	1,096		830	
Accounts payable to affiliates	218		90	
Dividends payable	134			
Taxes accrued	52		55	
Derivative liabilities	75		91	
Other current liabilities	279		285	
Regulatory liabilities	192		147	

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Total Current Liabilities	2,712	2,035
Regulatory liabilities	1,753	1,841
Deferred income taxes regulatory	565	519
Other Non-current Liabilities		
Deferred income taxes	2,976	2,798
Deferred income	1,483	1,553
Pension and other postretirement	1,106	1,202
Tax equity financing arrangements - VIEs	103	185
Derivative liabilities	78	94
Asset retirement obligations	161	184
Environmental remediation costs	398	406
Other	342	330
Total Other Non-current Liabilities	6,647	6,752
Non-current Debt	4,510	4,530
Total Non-current Liabilities	13,475	13,642
Total Liabilities	16,187	15,677
Commitments and Contingencies		
Stockholders' Equity:		
Common stock	3	3
Additional paid-in capital	13,653	13,653
Treasury Stock	(5)	
Retained earnings	1,544	1,449
Accumulated other comprehensive loss	(86)	(52)
Total Stockholders’ Equity	15,109	15,053
Noncontrolling interests	13	13
Total Equity	15,122	15,066
Total Liabilities and Equity	31,309	30,743
Avangrid, Inc [Member]		
Current Assets		
Cash and cash equivalents	67	125
Accounts receivable from affiliates	66	602
Notes receivable from affiliates	1,908	453
Prepayments and other current assets	11	16
Total Current Assets	2,052	1,196
Other investments	14,097	14,093
Other Assets		
Deferred income taxes	220	148
Other	3	4
Total other assets	223	152
Total Assets	16,372	15,441
Current Liabilities		
Current portion of debt	8	
Notes payable	150	
Notes payable to subsidiaries	454	321

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Interest accrued	6	
Accounts payable and accrued liabilities	4	12
Accounts payable to subsidiaries	3	3
Interest accrued subsidiaries	29	1
Dividends payable	134	
Taxes accrued	2	44
Other current liabilities	3	4
Total Current Liabilities	793	385
Other Non-current Liabilities		
Other		3
Total Other Non-current Liabilities		3
Non-current Debt	470	
Total Non-current Liabilities	470	3
Total Liabilities	1,263	388
Stockholders' Equity:		
Common stock	3	3
Additional paid-in capital	13,653	13,653
Treasury Stock	(5)	
Retained earnings	1,544	1,449
Accumulated other comprehensive loss	(86)	(52)
Total Stockholders’ Equity	15,109	15,053
Total Liabilities and Equity	$ 16,372	$ 15,441

[1] Includes capitalized leases of $208 million primarily related to electric generation, distribution, transmission and other.

[2] Includes capitalized leases of $178 million primarily related to electric generation, distribution, transmission and other.

[3] Includes accumulated amortization of capitalized leases of $60 million.

[4] Includes accumulated amortization of capitalized leases of $53 million.

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Consolidated Balance Sheets (Parenthetical) - USD ($) $ in Millions		Dec. 31, 2016	Dec. 31, 2015
Property, Plant and Equipment, VIEs		$ 21,548	$ 20,711
Common stock, par value		$ 0.01	$ 0.01
Common stock, authorized		500,000,000	500,000,000
Common stock, issued		309,600,439	309,491,082
Common stock, outstanding	[1]	308,993,149	308,864,609
Variable Interest Entity, Primary Beneficiary [Member]			
Property, Plant and Equipment, VIEs		$ 1,144	$ 1,206

[1] Par value of share amounts is $.01

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Consolidated Statements of Cash Flows - USD ($) $ in Millions	12 Months Ended		
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Cash Flow from Operating Activities			
Net Income	$ 630	$ 267	$ 424
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation and amortization	804	695	629
Impairment of non-current assets		12	25
Accretion expenses	10	14	14
Regulatory assets/liabilities amortization	49	101	(38)
Regulatory assets/liabilities carrying cost	13	41	35
Pension cost	110	115	74
Stock-based compensation	1	6	5
Earnings from equity method investments	(7)		(12)
Amortization of debt (premium) cost	(28)	4	2
Gain on disposal of property and equity method investment	(33)		
Unrealized losses (gains) on marked to market derivative contracts	(4)	10	(116)
Deferred taxes	377	87	261
Other non-cash items	(23)	(5)	(3)
Changes in operating assets and liabilities:			
Accounts receivable and unbilled revenues	(158)	160	(1)
Inventories	46	4	58
Other assets	107	(39)	(100)
Cash distribution from equity method investments	14		
Accounts payable and accrued liabilities	184	(10)	27
Other liabilities	(447)	(194)	(115)
Taxes accrued	(3)	21	(13)
Regulatory assets/liabilities	(81)	74	175
Net Cash Provided by Operating Activities	1,561	1,363	1,331
Cash Flow from Investing Activities			
Capital expenditures	(1,707)	(1,082)	(1,030)
Contributions in aid of construction	69	38	43
Government grants		17	4
Acquisition of business, net of $48 million cash acquired		(547)	
Proceeds from sale of equity method and other investment	57	3	31
Proceeds from sale of property, plant and equipment	50		
Receipts from (payments to) affiliates	6	(6)	10
Cash distribution from equity method investments	6	12	19
Other investments and equity method investments, net	(8)	47	35
Net Cash Used in Investing Activities	(1,527)	(1,518)	(888)
Cash Flow from Financing Activities			
Non-current note issuance	493	350	

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Repayments of non-current debt	(355)	(141)	(27)
Proceeds (repayments) of other short-term debt, net	(2)	10	(14)
Repayments of capital leases	(12)	(12)	(21)
Payments on tax equity financing arrangements	(88)	(102)	(119)
Contribution from noncontrolling interests			4
Dividends to noncontrolling interests		(3)	(3)
Repurchase of common stock	(5)		
Issuance of common stock	(2)		
Dividends paid	(401)		
Net Cash (Used in) Provided by Financing Activities	(372)	102	(180)
Net (Decrease) Increase in Cash, Cash Equivalents and Restricted Cash	(338)	(53)	263
Cash, Cash Equivalents and Restricted Cash, Beginning of Year	434	487	224
Cash, Cash Equivalents and Restricted Cash, End of Year	96	434	487
Cash and Cash Equivalents, Beginning of Year	427		
Cash and Cash Equivalents, End of Year	91	427	
Supplemental Cash Flow Information			
Cash paid for interest, net of amounts capitalized	229	132	133
Cash paid (refund) for income taxes	9	7	21
Avangrid, Inc [Member]			
Cash Flow from Operating Activities			
Net Income	630	267	424
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Earnings from equity method investments	(565)	(44)	(515)
Changes in operating assets and liabilities:			
Net Cash Provided by Operating Activities	324	(380)	(32)
Cash Flow from Investing Activities			
Notes receivable from subsidiaries	(627)	317	(478)
Acquisition of subsidiary		(595)	
Investments in subsidiaries	(533)		
Return of capital from investments in subsidiaries	420	1,111	200
Other investments and equity method investments, net			11
Net Cash Used in Investing Activities	(740)	833	(267)
Cash Flow from Financing Activities			
Proceeds (repayments) of short-term notes payable from subsidiaries, net	133	(331)	302
Proceeds from short-term notes payable	150		
Non-current note issuance	483		
Repurchase of common stock	(5)		
Issuance of common stock	(2)		
Dividends paid	(401)		
Net Cash (Used in) Provided by Financing Activities	358	(331)	302
Net (Decrease) Increase in Cash, Cash Equivalents and Restricted Cash	(58)	122	3
Cash and Cash Equivalents, Beginning of Year	125	3	
Cash and Cash Equivalents, End of Year	67	125	3

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Supplemental Cash Flow Information			
Cash paid for interest, net of amounts capitalized	4	$ 20	25
Cash paid (refund) for income taxes	$ 71		$ (6)

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Consolidated Statements of Cash Flows (Parenthetical) $ in Millions	12 Months Ended Dec. 31, 2015 USD ($)
Statement Of Cash Flows [Abstract]	
Cash acquired from acquisition of business	$ 48

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Consolidated Statements of Changes in Equity - USD ($) $ in Millions	Total	Common stock	Additional paid-in capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Non controlling Interests
Balance at Dec. 31, 2013	$ 12,051	$ 3	$ 11,375		$ 758	$ (100)	$ 12,036	$ 15
Balance, shares at Dec. 31, 2013	[1] 252,235,232							
Net Income	$ 424				424		424	
Other comprehensive income, net of tax	1					1	1	
Comprehensive Income Attributable to Avangrid, Inc.	425							
Capital contribution from noncontrolling interests	4							4
Dividends to noncontrolling interests	(3)							(3)
Balance at Dec. 31, 2014	$ 12,477	3	11,375		1,182	(99)	12,461	16
Balance, shares at Dec. 31, 2014	[1] 252,235,232							
Net Income	$ 267				267		267	
Other comprehensive income, net of tax	47					47	47	
Comprehensive Income Attributable to Avangrid, Inc.	314							
Issuance of common stock	$ 2,278		2,278				2,278	
Issuance of common stock, shares	[1] 57,255,850							
Common stock held in trust	[1] (626,473)							
Dividends to noncontrolling interests	$ (3)							(3)
Balance at Dec. 31, 2015	$ 15,066	3	13,653		1,449	(52)	15,053	13
Balance, shares at Dec. 31, 2015	[1] 308,864,609							
Net Income	$ 630				630		630	
Other comprehensive income, net of tax	(34)					(34)	(34)	
Comprehensive Income Attributable to Avangrid, Inc.	596							
Dividends declared	$ (535)				(535)		(535)	
Release of common stock held in trust	[1] 135,014							
Issuance of common stock, issuance costs	$ (2)		(2)				(2)	
Issuance of common stock, shares	[1] 109,357							
Repurchase of common stock	$ (5)			$ (5)			(5)	
Repurchase of common stock, shares	[1] (115,831)							
Stock-based compensation	$ 2		2				2	
Balance at Dec. 31, 2016	$ 15,122	$ 3	$ 13,653	$ (5)	$ 1,544	$ (86)	$ 15,109	$ 13

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Balance, shares at Dec. 31, 2016	[1]	308,993,149

[1] Par value of share amounts is $.01

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Consolidated Statements of Changes in Equity (Parenthetical) - USD ($) $ in Millions	12 Months Ended		
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Statement Of Stockholders Equity [Abstract]			
Common Stock, Par or Value Per Share	$ 0.01	$ 0.01	
Other Comprehensive Income (Loss) Taxes	$ 22.1	$ 29.7	$ 1.4

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Background and Nature of Operations

Organization Consolidation And Presentation Of Financial Statements [Abstract]

Background and Nature of Operations

12 Months Ended Dec. 31, 2016

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). Effective as of April 30, 2016, UIL Holdings Corporation and its subsidiaries (UIL) were transferred to a wholly-owned subsidiary of Networks. AVANGRID is also 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.

Reorganization

On November 20, 2013, we completed a series of reorganizations (Reorganization) of entities under common control. The Reorganization included the transfer of ARHI from an affiliate of Iberdrola to AVANGRID, and the transfer of the principal operating utility companies from AVANGRID to Networks.

AVANGRID and ARHI were acquired by Iberdrola in 2008 and 2007, respectively, and they have been under common control of Iberdrola for all periods presented. Networks was formed as part of the Reorganization in November 2013. Networks is a public utility sub-holding company operating under the Public Utility Holding Company Act of 2005 with operations in New York, Maine, Connecticut and Massachusetts. The wholly owned subsidiaries and the operating utility companies of Networks include: CMP Group - Central Maine Power Company (CMP), RGS - New York State Electric & Gas Corporation (NYSEG), Rochester Gas and Electric Corporation (RG&E), Maine Natural Gas Company (MNG), The United Illuminating Company (UI), 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 certain affiliates of NRG Energy, Inc. (NRG affiliates) 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). ARHI is the sub-holding company of the unregulated energy business that includes the renewable energy and the gas trading and storage businesses.

The transfer of a business among entities under common control is accounted for at carrying amount with retrospective adjustment of prior period financial statements similar to the manner in which a pooling-of-interest was accounted for under accounting principles generally accepted in the United States of America (U.S. GAAP).

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

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(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. See Note 4, Acquisition of UIL, for further details.

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 SCG, CNG and BGC.

UI is also a party to a joint venture with certain affiliates of NRG Energy, Inc. (NRG affiliates) 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).

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Basis of Presentation

12 Months Ended
Dec. 31, 2016

Basis of Presentation

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 have been retroactively adjusted to reflect the impact of the stock dividend.

Revision of estimated useful lives of wind power station assets at Renewables

Renewables' wind power station assets in service less salvage value, if any, are depreciated using the straight-line method over their estimated useful lives. Renewables' effective depreciation rate, excluding decommissioning, was 4.0% in both 2015 and 2014. Renewables reviews the estimated useful lives of its fixed assets on an ongoing basis. In the first quarter of 2016, this review indicated that the actual lives of certain assets at wind power stations are expected to be longer than the previously estimated useful lives used for depreciation purposes. As a result, effective January 1, 2016, Renewables changed the estimates of the useful lives of certain assets from 25 years to 40 years, capped at the lease term if lower, to better reflect the estimated periods during which these assets are expected to remain in service. The weighted average useful life of our wind farm assets is now approximately 31 years. The effect of this change in estimate was to reduce depreciation and amortization expense by approximately $52 million, reduce asset retirement obligation accretion expense recorded within operations and maintenance by approximately $3 million, increase earnings from equity method investments by approximately $4 million, increase income before income tax and net income by approximately $59 million and approximately $36 million, respectively, and increase basic and diluted earnings per share by approximately $0.12 for the year ended December 31, 2016.

Avangrid, Inc [Member]
Basis of Presentation

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 2016 tax period. Each subsidiary company is treated as a member of the consolidated group and determines its current and deferred taxes separately and

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settles its current tax liability or benefit each year directly with AVANGRID pursuant to a tax sharing agreement between AVANGRID and its members.

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Summary of Significant Accounting Policies, New Accounting Pronouncements, and Use of Estimates	12 Months Ended
	Dec. 31, 2016
Accounting Policies [Abstract]	
Summary of Significant Accounting Policies, New Accounting Pronouncements, and Use of Estimates	

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.

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(d) Business combinations

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.

(e) Equity method investments

Joint ventures that do not meet consolidation criteria are accounted for using the equity method. Earnings (losses) recognized under the equity method are reflected in the consolidated statements of income as "Earnings (losses) from equity method investments." Dividends received from joint ventures are recognized as a reduction in the carrying amount of the investment and are not recognized as dividend income.

(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.

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(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
	Hydroelectric power stations	35-90
	Wind power stations	25-40
	Gas storage	25-40
	Transport facilities	40-56
	Distribution facilities	30-54
Equipment	Conventional meters and measuring devices	15-27
	Computer software	3-5
Other	Buildings	50-75
	Operations offices	4-50

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.

(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.

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(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.

(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

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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.

(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) Tax equity financing arrangements-VIEs

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

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sheets. Subsequently, this liability is amortized based on the cash and tax benefits provided to the tax equity investors.

We evaluate whether an entity is a variable interest entity (VIE) whenever reconsideration events as defined by the accounting guidance occur (See Note 19). 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.

(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, or below market 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 cost 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

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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 2053.

(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

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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 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), 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 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 not more-likely-than-not that all or a portion of a tax benefit will 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.

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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.

(w) Stock-based compensation

Stock-based compensation represents costs related to stock-based awards granted to employees. In the third quarter of 2016 we early adopted all the amendments to ASC 718, Compensation - Stock Compensation, issued in March 2016, to account for our stock based awards. 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.

Reclassifications

Certain amounts have been reclassified in the consolidated statements of cash flow to conform to the 2016 presentation as well as in connection with retrospective adoption of amendments in the accounting standard related to presentation of restricted cash in the statement of cash flow.

New Accounting Standards and Interpretations

(a) Revenue from contracts with customers

In May 2014 the Financial Accounting Standards Board (FASB) issued ASC 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. 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 original effective date for public entities was for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. In August 2015 the FASB issued an accounting standards update that defers by one year the original effective date of the revenue standard for all entities. Thus, the standard is now effective for annual reporting periods beginning after December 15, 2017, and interim periods therein, with early adoption as of the original effective date permitted. We do not plan to early adopt. Entities may apply the amendment 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). We will apply the modified retrospective method. We are currently evaluating how our adoption of the amendments will affect our results of operations, financial position, cash flows, and disclosures. We are considering the effects of the amendments on our ability to recognize revenue for certain contracts for our regulated utilities where collectability is in question and our accounting for contributions in aid of construction for our regulated utilities. In addition, the amendments will require us to capitalize, rather than expense, any costs to acquire new contracts. Additionally, classification differences are also expected to result, including recording our tax equity investments as noncontrolling interests. Some revenue arrangements, such as alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on our consolidated financial statements. The FASB has issued various additional accounting standards updates, with the same deferred effective

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date, as follows: in March 2016 to amend and clarify the implementation guidance on principal versus agent considerations for reporting revenue gross rather than net, in April 2016 to address implementation questions on identifying performance obligations and accounting for licenses of intellectual property. We do not expect significant effects as a result of those updates. In May 2016 the FASB issued a final update concerning narrow-scope improvements and practical expedients. We are currently evaluating the effects of that update.

(b) Fair value measurement disclosures for certain investments

In May 2015 the FASB issued amendments that affect reporting entities that elect to estimate the fair value of certain investments within scope using the net asset value (NAV) per share (or its equivalent) practical expedient, as specified. The amendments remove the requirement to categorize within the fair value hierarchy all investments for which the fair value is measured at NAV using the practical expedient. They also remove certain disclosure requirements for eligible investments and limit the required disclosures to investments for which the entity has elected to measure the fair value using the practical expedient. Assets that calculate NAV per share (or its equivalent), but for which the practical expedient is not applied will continue to be included in the fair value hierarchy. The amendments are effective for public entities for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. The amendments permit early application, and require retrospective application to all periods presented. Retrospective application requires investments for which fair value is measured at NAV using the practical expedient to be removed from the fair value hierarchy in all periods presented. Our adoption of the amendments in 2016 did not affect our results of operations, financial position, or cash flows.

(c) Simplifying the measurement of inventory

In July 2015 the FASB issued amendments that require entities to measure inventory at the lower of cost and net realizable value, rather than the lower of cost or market. The amendments do not apply to inventory measured using last-in, first-out or the retail inventory method but apply to all other inventory, including inventory measured using first-in, first-out or average cost. Prior to this update, market value could be replacement cost, net realizable value, or net realizable value less an approximately normal profit margin. Net realizable value is the "estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation." The amendments do not change the methods of estimating the cost of inventory under U.S. GAAP. The amendments are effective for public entities for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. The amendments require prospective application and permit earlier application. We expect our adoption of the amendments will not affect our results of operations, financial position, or cash flows.

(d) 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

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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 results of operations, financial position, or cash flows.

(e) Business combinations: simplifying the accounting for measurement-period adjustments

In September 2015 the FASB issued amendments that require an acquirer to 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. As a result, the acquirer is required to record, in the same period's financial statements, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. The entity is required to present separately on the face of the income statement or disclose in the notes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. The amendments are effective for public entities for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years. The amendments require prospective application to provisional amounts that occur after the effective date of the amendment and permit earlier application. The effects of our adoption of the amendments on our results of operation, financial position, or cash flows as it relates to the business combination with UIL have been disclosed in Note 4, Acquisition of UIL.

(f) 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 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 a right-of-use asset.

(g) Derivative contract novations

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In March 2016 the FASB issued amendments concerning the effect of derivative contract novations on existing hedge accounting relationships. As it relates to derivative instruments, novation refers to replacing one of the parties to a derivative instrument with a new party, which may occur for a variety of reasons such as: financial institution mergers, intercompany transactions, an entity exiting a particular derivatives business or relationship, or because of laws or regulatory requirements. The amendments clarify that a change in the counterparty to a derivative instrument that has been designated as the hedging instrument under the guidance for Derivatives and Hedging (Topic 815) does not, in and of itself, require dedesignation of that hedge accounting relationship provided that all other hedge accounting criteria continue to be met. The amendments are effective for public entities for financial statements issued for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. The amendments may be applied on either a prospective basis or a modified retrospective basis and early application is permitted. We expect our adoption will not materially affect our results of operations, financial position, and cash flows.

(h) Improvements to employee share-based payment accounting

The FASB issued amendments in March 2016 regarding the simplification of several aspects of accounting for share-based payment transactions, including income tax consequences, classification of awards as either equity or liabilities, policy election on accounting for forfeitures and classification on the statement of cash flows. Some areas of simplification apply only to nonpublic entities. The amendments are effective for public entities for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. Early adoption permitted in any interim or annual period, but must adopt all of the amendments in the same period. For the purpose of accounting for the stock-based compensation plans, in the third quarter of 2016 we early adopted all the above amendments and elected to account for forfeitures when they occur. Our adoption of the amendments did not materially affect our results of operations, financial position, or cash flows.

(i) 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 collectibility 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 results of operations, financial position, and cash flows.

(j) Certain classifications in the statement of cash flows

The FASB issued the 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

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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.

(k) Presentation of restricted cash in the statement of cash flows

The FASB issued the amendment in November 2016 to address existing diversity in the classification and presentation of changes in restricted cash on the statement of cash flows. The amendment requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. The amendment does not provide a definition of restricted cash or restricted cash equivalents. The amendment is effective for public entities for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years, with early adoption permitted. The amendment should be applied using a retrospective transition method to each period presented. As permitted, we have early adopted the amendment as of the beginning of the fourth quarter of 2016 and have applied it retrospectively to all periods presented. Accordingly, the changes in restricted cash and restricted cash equivalents, presented previously in other assets of operating activities, were included in cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows, which increased by $2 million and had no change in net cash provided by operating activities in the consolidated statements of cash flow, for both of the years ended December 31, 2015 and 2014, respectively.

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) depreciable lives of assets; (4) income tax valuation allowances; (5) uncertain tax positions; (6) reserves for professional, workers' compensation, and comprehensive general insurance liability risks; (7) contingency and litigation reserves; (8) fair value measurements; (9) earnings sharing mechanisms; (10) environmental remediation liabilities; and (11) 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

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We have approximately 48% of the employees covered by a collective bargaining agreement. Agreements which will expire within the coming year apply to approximately 6% of our employees.

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Acquisition of UIL

12 Months Ended
Dec. 31, 2016

Business Combinations [Abstract]
Acquisition of UIL

Note 4. Acquisition of UIL

On December 16, 2015 (acquisition date), we completed our acquisition of UIL, a diversified energy company with its portf of regulated utility companies in Connecticut and Massachusetts that is expected to provide us with a greater flexibilit grow the combined regulated businesses through project development and create an enhanced platform to develop transmis and distribution projects in the Northeastern United States. In connection with the consummation of the acquisition we iss 309,490,839 shares of common stock of AVANGRID, out of which 252,234,989 shares were issued to Iberdrola throug 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, shares (including those held in trust as treasury stock) were issued to UIL shareowners in addition to payment of $595 mil in cash. Following the completion of the acquisition, former UIL shareowners owned 18.5% of the outstanding share common stock of AVANGRID, and Iberdrola owned the remaining shares.

The acquisition was accounted for as a business combination. This method requires, among other things, that assets acqu and liabilities assumed in a business combination, with certain exceptions, be recognized at their fair values as of acquisition date.

As UIL's common stock was publicly traded in an active market until the acquisition date, we determined that UIL's comm stock is more reliably measurable than the common stock of AVANGRID to determine the fair value of the considera transferred in the transaction.

The purchase consideration for UIL under the acquisition method is based on the stock price of UIL on the acquisition multiplied by the number of shares issued by AVANGRID to the UIL shareowners after applying an equity exchange fa to the shares of vested restricted common stock of UIL (other than those UIL restricted shares that vest by their terms u the consummation of the acquisition), performance shares and other shares awards under UIL 2008 Stock and Incen Compensation Plan and the UIL Deferred Compensation Plan. The "equity exchange factor" is the sum of one plus a fract (i) the numerator of which is the cash consideration and (ii) the denominator of which is the average of the volume weigh averages of the trading prices of UIL common stock on each of the ten consecutive trading days ending on (and includ the trading day that immediately precedes the closing date of the acquisition minus $10.50. The determination of the purch price is based on a UIL stock price of $50.10 per share, which represents the closing stock price on the acquisition date.

The fair value of shares of AVANGRID common stock issued to the UIL shareowners in the business combination repres the purchase consideration in the business combination, which was computed as follows:

		(millions, except share and unit data)
Common shares(1)		56,629,377
Price per share of UIL common stock as of the acquisition date	$	50.10
Subtotal value of common shares	$	2,837
Restricted stock units(2)		476,198
Other shares(3)		12,999
Equity exchange factor		1.2806
Total restricted and other shares(3) after applying an equity exchange factor		626,473
Price per share used(5)	$	39.60
Subtotal value of restricted and other shares	$	25
Total shares of AVANGRID common stock issued to UIL shareowners (including held in trust as treasury stock)		57,255,850
Performance shares(4)		211,904
Equity exchange factor		1.2806
Total performance shares after applying an equity exchange factor		271,368
Price per share used(5)	$	39.60
Subtotal value of performance shares	$	11
Total consideration	$	2,873

(1) Based on UIL's common shares outstanding on December 16, 2015.
(2) Based on UIL's shares of vested restricted stock.

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(3) Based on UIL's restricted shares that vested upon the change in control.
(4) Based on UIL's vested performance shares award.
(5) Based on the closing share price of UIL common stock on December 16, 2015, less the cash component of $10 which is not applicable to restricted shares (other than those UIL restricted shares that vest by their terms upon consummation of the acquisition), performance shares and other awards under the UIL 2008 Stock and Incen Compensation Plan and the UIL Deferred Compensation Plan.

The following is a summary of the components of the consideration transferred to UIL's shareowners:

	(millions, except share data)
Cash ($10.50 x number of UIL common shares outstanding at the acquisition date - 56,629,377)	$ 595
Equity	2,278
Total consideration	$ 2,873

We also paid $37.5 million for transaction costs incurred in this business combination, which are recorded in "Operations maintenance" in the consolidated statements of income for the year ended December 31, 2015.

The following unaudited pro forma financial information presents the combined results of operations as if the acquisi had been completed on January 1, 2014, the beginning of the comparable prior annual reporting period. The unaudited forma results include: (i) merger credit adjustments to operating revenue (see Merger Settlement Agreement below for fur details); (ii) elimination of accrued transaction costs representing non-recurring expenses directly related to the transact and (iii) the associated tax impact on these unaudited pro forma adjustments.

The unaudited pro forma results do not reflect any cost saving synergies from operating efficiencies or the effect of incremental costs incurred in integrating the two companies. Accordingly, these unaudited pro forma results are presented informational purpose only and are not necessarily indicative of what the actual results of operations of the combined comp would have been if the acquisition had occurred at the beginning of the period presented, nor are they indicative of fu results of operations:

	Year Ended December 31,	
	2015	2014
	(millions)	
Revenue	$ 5,958	$ 6,226
Net income	$ 468	$ 539

The revenue and net (loss) of UIL since the acquisition date included in the consolidated statements of income for the y ended December 31, 2015 were $36 million and $(36) million, respectively (see Merger Settlement Agreement below further details).

We finalized the valuation of the assets acquired and liabilities assumed within the measurement period during 2016. the majority of UIL's assets and liabilities, primarily property, plant and equipment, fair value was determined to be respective carrying amounts of the predecessor entity. UIL's operations are conducted in a regulated environment where regulatory authority allows an approved rate of return on the carrying amount of the regulated asset base. Measurement pe adjustments that were recognized in the year ended December 31, 2016 relate to the adjustments of the allocation of purchase price to the following: equity method investments; contracts; debt; contingent liabilities, including those relate certain environmental sites; income taxes; non-regulated property, plant and equipment and goodwill.

The following is a summary of the allocation of the purchase price as of the acquisition date and measurement pe adjustments recognized in the year ended December 31, 2016:

	Provisional amounts reported in 2015	Measurement period adjustments	Finalized amounts
		(millions)	
Current assets, including cash of $48 million	$ 500	$ (7)	$ 493
Other investments	114	22	136
Property, plant and equipment	3,552	(5)	3,547
Regulatory assets	966	36	1,002
Other assets	52	—	52
Current liabilities	(493)	—	(493)
Regulatory liabilities	(493)	—	(493)
Non-current debt	(1,878)	(27)	(1,905)
Other liabilities	(1,201)	(30)	(1,231)

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Total net assets acquired at fair value	1,119	(11)	1,108
Goodwill – consideration transferred in excess of fair value assigned	1,754	11	1,765
Total consideration	**$ 2,873**		**$ 2,873**

Goodwill generated from the acquisition of UIL increased by $11 million to the total amount of $1,765 million as of acquisition date as a result of the finalization of the purchase price allocation. Goodwill generated from the acquisition of has been assigned to the reporting units under the Networks reportable segment and is primarily attributable to expected fu growth of the combined regulated businesses and enhanced platform to develop transmission and distribution projects in Northeastern United States. The goodwill generated from this acquisition is not deductible for tax purposes.

Merger Settlement Agreement

As part of the process of seeking and obtaining regulatory approval for the acquisition in Connecticut and Massachus Iberdrola, S.A., AVANGRID and UIL reached settlement agreements with the Office of Consumer Counsel in Connecticut with the Attorney General of the Commonwealth of Massachusetts and the Department of Energy Resources in Massachus which settlement agreements included commitments of actions to be taken after the transaction closed.

As a result, the following commitments have been made in Connecticut, recognized in the period subsequent to the acquisi in 2015 unless otherwise noted, each of which is reasonably expected to be at a cost of $500,000 or more:

- A one-time, $20 million rate credit to customers in 2016, allocated among UI, SCG and CNG customers based 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 cap investments over a three-year period without seeking recovery until the next SCG rate case. These amounts wil recorded by the Company as incurred in future periods.
- Agreement not to seek to increase UI distribution base rates effective before January 1, 2017, and agreement no 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 c energy technologies.
- $5 million in benefits to customers resulting from UI recovering only the debt rate rather than the equity return two years, on an increased $50 million of investment in storm resiliency programs. These amounts will be recor by the Company as incurred in future periods.
- Contribution of $1 million for disaster relief entities.
- Maintaining charitable contribution at historical contribution levels (between $500,000 and $800,000) for at l four years.
- Upon the resolution of all appeals of the PURA decision approving the acquisition, UI will withdraw its app of two PURA dockets relating to PURA's disallowance of certain reconciliation amounts. The appeals w withdrawn by UI in June 2016.

In connection with the acquisition proceeding, UI signed the consent order that, pursuant to the terms and conditions in consent order, requires UI to investigate and remediate certain environmental conditions within the perimeter of the Eng Station site. To the extent that the investigation and remediation is less than $30 million, UI would remit to the Stat Connecticut the difference between such costs and $30 million for a public purpose as determined in the discretion of Governor the Attorney General of Connecticut and the Commissioner of DEEP. Pursuant to the consent order UI is oblig to comply with the consent order, even if the cost of such compliance exceeds $30 million. The state will discuss options w UI on recovering or funding any cost above $30 million such as through public funding or recovery from third parties, howe it is not bound to agree to or support any means of recovery or funding (See Note 14, Environmental Liabilities – Eng Station, for further details).

As of December 31, 2016 and 2015 we reserved $28.3 million and $20.5 million, respectively, for this matter and have accr the remaining $1.7 million and $9.5 million in accordance with the settlement with PURA approving the acquisition. difference of $7.8 million pre-tax has been reflected as the reversal of an expense in our 2016 results, reversing the amo recorded in 2015, to adjust the allocation of the purchase price as a measurement period adjustment from the acquisitio UIL. The adjustment to the reserve during 2016 was recorded in the "Operations and maintenance" line of the consolid statement of income as a measurement period adjustment based on additional information obtained for the site regard circumstances of the site as of the acquisition date of UIL.

As part of the final allocation of the purchase price we have determined a fair value of contingent liabilities of approxima $46.0 million relating to certain environmental sites.

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The following commitments have been made in Massachusetts, recognized in the period subsequent to the acquisition in 2
unless otherwise noted, each of which is reasonably expected to be at a cost of $500,000 or more:

- Customers of BGC will receive a total of $4.0 million in rate credits, to be spread over the months of Noven
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 cre
and an additional $19.8 million as liabilities, which primarily resulted in the net loss for UIL in the period following
acquisition date in 2015.

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Industry Regulation

12 Months Ended
Dec. 31, 2016

Regulated Operations [Abstract]

Industry Regulation

Note 5. Industry Regulation

Electricity and Natural Gas Distribution – Maine and New York

The Maine distribution rate stipulation, the Maine transmission Federal Energy Regulatory Commission (FERC) Return on Equity (ROE) case, the New York rate plans, Reforming Energy Vision (REV), and the New York Transmission Company (New York TransCo) filings are some of the most important specific regulatory processes that 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.

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

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customer billing system investment. The approved stipulation allows CMP to recover the system costs effective with its implementation, currently expected in mid-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.

Transmission - FERC ROE Proceeding

See Note 13, 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.

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

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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 (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 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 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 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%. The proposal includes an Earnings sharing mechanism (ESM) applicable to each company. The customer share of earnings would increase at higher ROE levels, with customers receiving 50%, 75% and 90% of earnings over 9.5%, 10.0% and 10.5% of ROE, respectively, in the first rate year. Earnings sharing is based on the lower of actual equity of 50%. Earnings thresholds increase in subsequent rate years.

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The 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 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 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 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 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 proposal also includes a downward-only Net Plant reconciliation. In addition, the proposal includes downward-only reconciliations for the costs of: electric distribution and gas vegetation management; pipeline integrity; and incremental maintenance. The 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.

Electric and Gas regulated utilities – Connecticut and Massachusetts

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.

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 GSC charge on their bills.

UI has wholesale power supply agreements in place for its entire standard service load for the first half of 2017, 80% of its standard service load for the second half of 2017 and 20% of its standard service load for the first half of 2018. 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.

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In December 2016, PURA approved new distribution rate schedules for UI for three years which became effective January 1, 2017 and which, among other things, decreased the UI distribution and CTA allowed ROE from 9.15% to 9.10%, continued UI's existing earnings sharing mechanism by which UI and 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.

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 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 initiate a rate case for new rates effective before at least 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.

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 is expected to begin in the first quarter of 2017.

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 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

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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 expected to begin in the first quarter of 2017.

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. The Joint Proposal provides a term of the RSSA from April 1, 2015 through March 31, 2017. RG&E shall make monthly payments to Ginna in the amount of $15.4 million. RG&E will be entitled to 70% of revenues from Ginna's sales into the NYISO energy and capacity markets, while Ginna will be entitled to 30% of such revenues. The signatory parties recommend that the NYPSC authorize RG&E to implement a rate surcharge effective January 1, 2016, to recover amounts paid to Ginna pursuant to the RSSA. RG&E's payment obligation to Ginna did not begin until the rate surcharge was in effect and FERC issued an order authorizing the FERC Settlement agreement in the Settlement Docket. RG&E will use 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. To the extent that the available credits are insufficient to satisfy the final payment from RG&E to Ginna then the RSSA surcharge would continue past March 31, 2017, to recover up to $2.3 million per month until the final payment has been recovered by RG&E from ratepayers. In the month following the expiration of the term on March 31, 2017, Ginna shall prepare and issue an invoice to RG&E for, and RG&E shall pay to Ginna, a one-time payment in the amount of $11.5 million, which will be recovered from ratepayers. If Ginna continues to deliver energy to the NYISO transmission system or makes available capacity to the NYISO markets after seventy-five days following March 31, 2017, Ginna shall pay RG&E a capital recovery balance in eight quarterly installments as long as Ginna is continuing to deliver energy or making available capacity throughout this period. The estimated capital recovery balance that is expected to be in place on March 31, 2017 is $20.1 million and will accrue interest unless amounts are prepaid by Ginna. The capital recovery balance will be refunded to ratepayers, to the extent collected, which is based on the term of the delivery of energy or capacity being made available by Ginna. On February 23, 2016, the NYPSC unanimously adopted the Joint Proposal in the Ginna RSSA proceeding as in the public interest. On March 1, 2016, FERC issued an Order approving the contested Settlement agreement, subject to conditions.

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New York TransCo

Networks holds an approximately 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.

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.

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We had restricted net assets of approximately $4,291 million associated with the minimum equity requirements as of December 31, 2016.

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 will develop up to 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 project, which percentage is expected to equate to approximately 25 basis points on a levelized basis over the life of the project. UI expects the cost of this program, a planned 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 to be approximately $47 million.

Pursuant to Section 8 of Public Act 13-303, "An Act Concerning Connecticut's Clean Energy Goals," (PA 13-303), in January 2014, at DEEP's direction, UI entered into three contracts for the purchase of RECs associated with an aggregate of 5.7 MW of energy production from biomass plants in New England. The costs of these agreements will be fully recoverable through electric rates.

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, 2017 through December 31, 2017 of $28.8 million and $35.7 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.

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Regulatory Assets and Liabilities

Regulated Operations [Abstract]

Regulatory Assets and Liabilities

12 Months Ended Dec. 31, 2016

Note 6. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations, our utilities capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric and natural gas rates. We base our assessment of whether recovery is probable on the existence of regulatory orders that allow for recovery of certain costs over a specific period, or allow for reconciliation or deferral of certain costs. When costs are not treated in a specific 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. Substantially all assets or liabilities for which funds have been expended or received are either included in the rate base or are accruing a carrying cost until they will be included in the rate base. 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 amount of these items is approximately $2,357 million.

Regulatory assets and other 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 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 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 or will be used to recover costs of the Ginna RSSA. Following the approval of the 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. The amounts will be collected over a period of fifty years.

Current and non-current regulatory assets as of December 31, 2016 and 2015 consisted of:

As of December 31,	2016	2015
(Millions)		
Current		
Pension and other post-retirement benefits cost deferrals	$ 22	$ 8
Pension and other post-retirement benefits	7	13
Storm costs	40	8
Temporary supplemental assessment surcharge	4	7
Reliability support services	27	—
Revenue decoupling mechanism	15	6

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Transmission revenue reconciliation mechanism	12	5
Electric supply reconciliation	13	—
Hedges losses	10	37
Contracts for differences	14	18
Hardship programs	16	13
Deferred property tax	10	—
Plant decommissioning	6	—
Deferred purchased gas	14	12
Deferred transmission expense	13	12
Environmental remediation costs	14	37
Other	48	43
Total Current Regulatory Assets	**285**	**219**
Non-current		
Pension and other post-retirement benefits cost deferrals	134	151
Pension and other post-retirement benefits	1,320	1,509
Storm costs	187	251
Deferred meter replacement costs	32	34
Unamortized losses on reacquired debt	20	23
Environmental remediation costs	287	271
Unfunded future income taxes	542	549
Asset retirement obligations	18	24
Deferred property tax	33	45
Federal tax depreciation normalization adjustment	161	158
Merger capital expense target customer credit	11	15
Debt premium	151	141
Plant decommissioning	14	7
Contracts for differences	61	50
Hardship programs	18	29
Other	102	57
Total Non-current Regulatory Assets	**$ 3,091**	**$ 3,314**

“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. The portion of storm costs for the amount of $123 million is being recovered over ten-year period and the remaining portion is being amortized over five years following the approval of the proposal by the NYPSC. CMP’s total deferral, including carrying costs, was $2 million and $12 million as of December 31, 2016 and 2015, respectively. 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, 2016.

“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.

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“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 proposal by the NYPSC, these amounts will be collected over a period of fifty years and the NYPSC Staff will perform an audit 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 New York (NY) amount is being amortized over a five year period following the approval of the 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.

Current and non-current regulatory liabilities as of December 31, 2016 and 2015 consisted of:

As of December 31,	2016	2015

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(Millions)		
Current		
Reliability support services (Cayuga)	$ 3	$ 16
Non by-passable charges	22	7
Energy efficiency portfolio standard	45	33
Gas supply charge and deferred natural gas cost	6	6
Transmission revenue reconciliation mechanism	5	16
Pension and other post-retirement benefits	3	3
Pension and other post-retirement benefits cost deferrals	14	—
Carrying costs on deferred income tax bonus depreciation	15	—
Carrying costs on deferred income tax - Mixed Services 263(a)	5	—
Yankee DOE refund	24	5
Merger-related rate credits	3	20
Revenue decoupling mechanism	9	14
Other	38	27
Total Current Regulatory Liabilities	**192**	**147**
Non-current		
Accrued removal obligations	1,117	1,084
Asset sale gain account	9	8
Carrying costs on deferred income tax bonus depreciation	95	116
Economic development	35	36
Merger capital expense target customer credit account	15	17
Pension and other post-retirement benefits	76	90
Positive benefit adjustment	42	51
New York state tax rate change	9	17
Post term amortization	3	25
Theoretical reserve flow thru impact	24	31
Deferred property tax	19	15
Net plant reconciliation	10	10
Variable rate debt	28	32
Carrying costs on deferred income tax - Mixed Services 263(a)	25	31
Rate refund – FERC ROE proceeding	22	21
Transmission congestion contracts	18	—
Merger-related rate credits	21	24
Accumulated deferred investment tax credits	15	10
Asset retirement obligation	13	13
Earning sharing provisions	12	—
Middletown/Norwalk local transmission network service collections	19	19
Excess generation service charge	—	21
Low income programs	46	42
Unfunded future income taxes	—	27
Non-firm margin sharing credits	7	8
Deferred income taxes regulatory	565	519
Other	73	93
Total Non-current Regulatory Liabilities	**$ 2,318**	**$ 2,360**

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“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. 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 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 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 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 Energy East by Iberdrola. The amortization period is five years following the approval of the 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 Energy East. This is being used to moderate increases in rates. The amortization period is five years following the approval of the 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 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 proposal by the NYPSC.

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“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 proposal by the NYPSC.

“Merger-related rate credits” resulted from the acquisition of UIL. This is being used to moderate increases in rates. See Merger Settlement Agreement in Note 4 for further details. In the year ended December 31, 2016, $20 million of rate credits was 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.

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Goodwill and Intangible Assets

12 Months Ended Dec. 31, 2016

Goodwill And Intangible Assets Disclosure [Abstract]

Goodwill and Intangible Assets

Note 7. Goodwill and Intangible assets

Goodwill by reportable segment as of December 31, 2016 and 2015 consisted of:

As of December 31,	2016	2015
(Millions)		
Networks	$ 2,744	$ 2,733
Renewables	380	380
Gas	—	—
Other (a)	—	2
Total	**$ 3,124**	**$ 3,115**

(a) Does not represent a reportable segment. It includes Corporate.

As of December 31, 2016, the gross amounts of goodwill were $2,744 million, for Networks reportable segment, $3,340 million for Renewables and Gas reportable segments and no goodwill for Corporate, (which does not represent a segment), with accumulated impairment losses of $2,960 million for Renewables and Gas reporting segments. As of December 31, 2015, the gross amounts of goodwill were $2,733 million, for Networks reportable segment, $3,340 million for Renewables and $2 million for Corporate, with accumulated impairment losses of $2,960 million for Renewables and Gas reporting segments. During the year ended December 31, 2015 goodwill in Networks reportable segment increased by $1,754 million due to acquisition of UIL based on preliminary allocation of the purchase price. During the year ended December 31, 2016, upon finalization of the valuation of assets acquired and liabilities assumed, goodwill in Networks reportable segment related to the acquisition of UIL increased by $11 million to a total amount of $1,765 million as of December 31, 2016 (See Note 4 – Acquisition of UIL – for further details).

During the year ended December 31, 2016, we reversed $2 million of goodwill in Corporate as a result of the sale of our interest in equity investment (See Note 21).

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 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 as of December 31, 2016, based on the finalized valuation of assets acquired and liabilities assumed.

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.

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2016

We had no impairment of goodwill in 2016 as a result of our impairment testing.

Networks

Provided recent relevant events (acquisition of UIL in December 2015 and approval of the proposal by the NYPSC, see Note 4 and 5, respectively) we conducted a quantitative analysis (step one) in 2016. Based on the results of our step one impairment test the estimated fair value of each of the Networks reporting units was in excess of their respective carrying values.

Renewables

Based on the results of our step one impairment test for the Renewables reporting unit conducted in 2016, its estimated fair value was in excess of the carrying value. The assumptions used to estimate fair value were based on projections incorporated in our current operating plans as well as other available information. The current operating plans included significant assumptions and estimates associated with sales growth, profitability and related cash flows, along with cash flows associated with taxes and capital spending. The discount rate used to estimate fair value was risk adjusted in consideration of the economic conditions of the reporting unit. We also considered other assumptions that market participants may use. By their nature, projections are uncertain. Potential events and circumstances, such as declining wind energy output and prices obtained per MWh, changes in incentives established to promote renewable energies and increases in capital expenditures per MW could have an adverse effect on our assumptions.

2015

We had no impairment of goodwill in 2015 as a result of our impairment testing.

Networks

As a result of our step zero qualitative assessment, it was not more likely than not that the fair value of each of the Networks reporting units was less than its carrying amount and it was not necessary to perform the two-step goodwill impairment test. The step zero qualitative assessment was performed in 2015 considering the substantial excess of fair value over the carrying value that was demonstrated in the 2014 impairment test. The qualitative assessment considered key factors such as the level of interest rates, the regulatory environment including the allowed rate of return, and projections of future sales and capital spending. In 2015 the impairment testing of goodwill for Networks includes Maine and New York reporting units.

Renewables

Based on the results of our step one impairment test for the Renewables reporting unit conducted in 2015, its estimated fair value exceeded carrying value. The assumptions used to estimate fair value were based on projections incorporated in our current operating plans as well as other available information. The current operating plans included significant assumptions and estimates associated with sales growth, profitability and related cash flows, along with cash flows associated with taxes and capital spending. The discount rate used to estimate fair value was risk adjusted in consideration of the economic conditions of the reporting unit. We also considered other assumptions that market participants may use. By their nature, projections are uncertain. Potential events and circumstances, such as declining wind energy output and prices obtained per MWh, changes in incentives established to promote renewable energies and increases in capital expenditures per MW could have an adverse effect on our assumptions.

Intangible assets

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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, 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**

As of December 31, 2015	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
(Millions)			
Gas Storage rights	$ 324	$ (116)	$ 208
Wind development	584	(243)	341
Other	15	(8)	7
Total Intangible Assets	**$ 923**	**$ (367)**	**$ 556**

Gas Storage rights are being amortized on a straight-line basis over a 40-year estimated life. 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, 2016, 2015 and 2014 amounted to $25 million, $54 million and $66 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, 2016, to be as follows:

Year ending December 31,	
(Millions)	
2017	$ 16
2018	16
2019	18
2020	17
2021	21

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.

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Property, Plant and Equipment	12 Months Ended Dec. 31, 2016
Property Plant And Equipment [Abstract]	

Property, Plant and Equipment

Note 8. Property, Plant and Equipment

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	$ 10,343	$ 10,384	$ 20,727
Natural gas transportation, distribution and other	4,803	613	5,416
Other common operating property	877	43	920
Total Property, Plant and Equipment in Service (a)	**16,023**	**11,040**	**27,063**
Total accumulated depreciation (b)	(3,970)	(3,016)	(6,986)
Total Net Property, Plant and Equipment in Service	**12,053**	**8,024**	**20,077**
Construction work in progress	979	492	1,471
Total Property, Plant and Equipment	**$ 13,032**	**$ 8,516**	**$ 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.

Property, plant and equipment as of December 31, 2015, consisted of:

As of December 31, 2015	Regulated	Nonregulated	Total
(Millions)			
Electric generation, distribution, transmission and other	$ 11,506	$ 10,058	$ 21,564
Natural gas transportation, distribution and other	2,673	651	3,324
Other common operating property	817	40	857
Total Property, Plant and Equipment in Service (a)	**14,996**	**10,749**	**25,745**
Total accumulated depreciation (b)	(3,727)	(2,645)	(6,372)
Total Net Property, Plant and Equipment in Service	**11,269**	**8,104**	**19,373**
Construction work in progress	1,094	244	1,338
Total Property, Plant and Equipment	**$ 12,363**	**$ 8,348**	**$ 20,711**

(a) Includes capitalized leases of $178 million primarily related to electric generation, distribution, transmission and other.
(b) Includes accumulated amortization of capitalized leases of $53 million.

Capitalized interest costs were $20 million, $13 million, and $12 million for the years ended December 31, 2016, 2015 and 2014, respectively.

There was no impairment or write off recorded during the year ended December 31, 2016. We impaired or wrote off amounts of $12 million and $24 million for the years ended December 31,

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2015 and 2014, respectively, resulting from reassessment of the economic feasibility of our various Renewables development projects in construction.

Depreciation expense for the years ended December 31, 2016, 2015 and 2014, amounted to $779 million, $641 million and $563 million, respectively.

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Asset Retirement Obligations	12 Months Ended Dec. 31, 2016
Asset Retirement Obligation Disclosure [Abstract]	
Asset Retirement Obligations	

Note 9. Asset retirement obligations

AROs are intended to meet the costs for dismantling and restoration work that we have committed to carry out at our operational facilities.

The reconciliation of ARO carrying amounts for the years ended December 31, 2016 and 2015 consisted of:

(Millions)		
As of December 31, 2014	**$**	**234**
Liabilities settled during the year		(16)
Liabilities incurred during the year		—
Accretion expense		14
Revisions in estimated cash flows		(48)
As of December 31, 2015	**$**	**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**

Several of the wind generation facilities have restricted cash for purposes of settling AROs. Restricted cash related to AROs was $2.0 million and $1.8 million as of December 31, 2016 and 2015, respectively. 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.

As a result of the revision of the estimated useful lives of wind power station assets in 2016 updated weighted average lease terms were used to value AROs. This revision resulted in lower discounted AROs, which we estimate will result in approximately $3 million annual reduction in expense going forward.

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Debt

12 Months Ended
Dec. 31, 2016

Debt Disclosure [Abstract]

Debt

Note 10. Debt

Long- term debt as of December 31, 2016 and 2015 consisted of:

As of December 31,		2016		2015	
(Millions)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
First mortgage bonds - fixed (a)	2018-2045	$ 1,752	3.07%-10.60%	$ 1,815	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	1.32%	219	0.195%-1.181%
Other various non-current debt - fixed	2017-2045	2,772	2.89%-10.48%	2,440	2.89%-10.48%
Obligations under capital leases	2017-2023	104	4%-4.44%	87	4%-4.44%
Unamortized debt issuance costs and discount		(31)		(25)	
Total Debt		**4,859**		**4,736**	
Less: debt due within one year, included in current liabilities		349		206	
Total Non-current Debt		**$ 4,510**		**$ 4,530**	

(a) The first mortgage bonds have pledged collateral of substantially all the respective utility's in service properties of approximately $5,886 million.

In November 2016, NYSEG issued $500 million in aggregate principal amount of 3.25% notes maturing in 2026. The proceeds of the offering were used to reduce balances owed to AVANGRID under an intercompany revolving demand note agreement, to refinance $100 million of NYSEG debt that matured on December 15, 2016, and to repurchase, at par value, $96 million of outstanding auction rate securities on December 19, 2016.

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.

On December 27, 2016, UI repurchased, at par value, $64 million of auction rate securities using cash on hand and borrowing under an intercompany demand note agreement with AVANGRID.

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

(Millions) 2017	2018	2019	2020	2021	Total
$ 349	$ 180	$ 358	$ 723	$ 308	$ 1,918

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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, 2016 and 2015.

Fair Value of Debt

The estimated fair value of debt amounted to $5,204 million and $4,985 million as of December 31, 2016 and 2015, 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 and $204 million as of December 31, 2016 and 2015, respectively, 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 $161 million and $163 million of notes payable as of December 31, 2016 and 2015, respectively. As of December 31, 2015, the balance consisted of $160 million of borrowings under the UIL credit facility and $3 million in other notes payable. As of December 31, 2016 the balance consisted of $150 million of commercial paper, $10 million in notes payable to affiliates 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 a condition of closing on the AVANGRID credit facility, three existing credit facilities were terminated: the AVANGRID revolving credit facility, which provided for maximum borrowings of up to $300M and had a scheduled termination date in May 2019; the joint utility revolving credit facility, to which NYSEG, RG&E and CMP were parties, which provided for borrowings of up to $600 million and which had a scheduled termination date in July 2018; the UIL credit facility, to which UIL, UI, SCG, CNG and BG were parties, which provided for maximum borrowings of $400 million and which had a scheduled termination date in November 2016.

As of December 31, 2016 the AVANGRID credit facility is undrawn, but the capacity to borrow under the facility is reduced by the amount of outstanding commercial paper, leaving available credit of $1,350 million.

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Fair Value of Financial Instruments and Fair Value Measurements	12 Months Ended
	Dec. 31, 2016
Fair Value Disclosures [Abstract]	
Fair Value of Financial Instruments and Fair Value Measurements	

Note 11. 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). RG&E hedges all its electric load obligations using contracts for a NYISO location where an active market exists. The forward market prices used to value RG&E's 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 has a combination of Level 1 and Level 2 fair values for its electric energy derivative contracts. A portion of its electric load obligations are exchange traded contracts in a NYISO location where an active market exists. The forward market prices used to value NYSEG's 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. A portion of NYSEG's electric energy derivative contracts are non-exchange traded contracts that are valued using inputs that are directly observable for the asset or liability, or indirectly observable through corroboration with observable market data and therefore we include the fair value in Level 2.
- 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 12 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, accounts receivable, accounts payable, notes payable and interest accrued approximate their estimated fair values and are considered as Level 1.

The financial instruments measured at fair value as of December 31, 2016 and 2015 consisted of:

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As of December 31, 2016 (Millions)	Level 1	Level 2	Level 3	Netting	Total
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)**

As of December 31, 2015 (Millions)	Level 1	Level 2	Level 3	Netting	Total
Securities portfolio (available for sale)	**$ 39**	**$ —**	**$ —**	**$ —**	**$ 39**
Derivative assets					
Derivative financial instruments - power	10	81	48	(71)	68
Derivative financial instruments - gas	267	25	68	(280)	80
Contracts for differences	—	—	29	—	29
Total	**277**	**106**	**145**	**(351)**	**177**
Derivative liabilities					
Derivative financial instruments - power	(43)	(12)	(14)	55	(14)
Derivative financial instruments - gas	(193)	(40)	(51)	212	(72)
Contracts for differences	—	—	(96)	—	(96)
Derivative financial instruments - other	—	—	(3)	—	(3)
Total	**$ (236)**	**$ (52)**	**$ (164)**	**$ 267**	**$ (185)**

The reconciliations of changes in the fair value of financial instruments based on Level 3 inputs for the years ended December 31, 2016, 2015 and 2014 consisted of:

(Millions)	2016	2015	2014
Fair value as of January 1,	**$ (19)**	**$ 57**	**$ 53**
Gains for the year recognized in operating revenues	67	33	11
Losses for the year recognized in operating revenues	—	(8)	(1)
Total gains or losses for the period recognized in operating revenues	67	25	10
Gains recognized in OCI	1	2	—
Losses recognized in OCI	—	(3)	(3)
Total gains or losses recognized in OCI	1	(1)	(3)
Net change recognized in regulatory assets and liabilities	(8)	—	—
Purchases	3	(73)	14
Settlements	(9)	(14)	(26)
Transfers out of Level 3 (a)	(4)	(13)	9
Fair value as of December 31,	**$ 31**	**$ (19)**	**$ 57**
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	$ 67	$ 25	$ 10

(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-

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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, 2016							
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)	$ 4.27	$ 7.37	$ 1.64
				SP15 ($/MWh)	$44.23	$80.28	$14.25
				Mid C ($/MWh)	$35.44	$83.93	$ 3.60
				Cinergy ($/MWh)	$36.40	$77.49	$18.53

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 12 for further details on CfDs) was based on a probability-based expected cash flow analysis that was discounted at risk-free interest rates, as applicable, and an adjustment for non-performance risk using credit default swap rates. Certain management assumptions were required, including development of pricing that 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

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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, 2016
Risk of non-performance	0.68% - 0.81%
Discount rate	1.47% - 2.45%
Forward pricing ($ per MW)	$3.15 - $9.55

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Derivative Instruments and Hedging

12 Months Ended Dec. 31, 2016

Derivative Instruments And Hedging Activities Disclosure [Abstract]

Derivative Instruments and Hedging

Note 12. Derivative Instruments and Hedging

Our Networks, Renewables and Gas activities are exposed to certain risks, which are managed by using derivative instruments. instruments are recognized as either assets or liabilities at fair value on the consolidated balance sheets in accordance with the accountir 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 elec contracts, both physical and financial, to manage fluctuations in electricity commodity prices in order to provide price stability to custo include the cost or benefit of those contracts in the amount expensed for electricity purchased when the related electricity is sold. We r in the fair value of electric hedge contracts to derivative assets and / or liabilities with an offset to regulatory assets and / or regulatory accordance with the accounting requirements concerning regulated operations.

The amount recognized in regulatory assets for electricity derivatives was a loss of $12.3 million and $34.3 million as of December 31, respectively. The loss reclassified from regulatory assets into income, which is included in electricity purchased, was $66.7 million, $4 $21.3 million for the years ended December 31, 2016, 2015 and 2014, respectively.

NYSEG and RG&E have purchased gas adjustment clauses that allow them to recover through rates any changes in the market pric natural gas, substantially eliminating their exposure to natural gas price risk. NYSEG and RG&E use natural gas futures and forw fluctuations in natural gas commodity prices to provide price stability to customers. We include the cost or benefit of natural gas futures the commodity cost that is passed on to customers when the related sales commitments are fulfilled. We record changes in the fair valu hedge contracts to derivative assets and or liabilities with an offset to regulatory assets and or regulatory liabilities in accordance with requirements for regulated operations.

The amount recognized in regulatory assets for natural gas hedges was a gain of $3.5 million and a loss of $3.1 million as of Decembe 2015, respectively. The loss reclassified from regulatory assets into income, which is included in natural gas purchased, was $1.9 millio and $2.2 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Pursuant to PURA, UI and Connecticut's other electric utility, CL&P, each executed two long-term CfDs with certain incremental capa each of which specifies a capacity quantity and a monthly settlement that reflects the difference between a forward market price and the The costs or benefits of each contract will be paid by or allocated to customers and will be subject to a cost-sharing agreement betwee pursuant to which approximately 20% of the cost or benefit is borne by or allocated to UI customers and approximately 80% is borne 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 U recognition of costs (a regulatory asset) or obligations (a regulatory liability). For those CfDs signed by CL&P, UI records its approxima pursuant to the cost-sharing agreement noted above. As of December 31, 2016, UI has recorded a gross derivative asset of $19 million 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 m is related to UI's portion of the CfD signed by CL&P) and a regulatory liability of $0. As of December 31, 2015, UI has recorded a g asset of $29 million ($1 million of which is related to UI's portion of the CfD signed by CL&P), a regulatory asset of $68 million, a g liability of $96 million ($61 million of which is related to UI's portion of the CfD signed by CL&P) and a regulatory liability of $1 mi

The unrealized gains and losses from fair value adjustments to these derivatives, which are recorded in regulatory assets or regulator the year ended December 31, 2016 and for the period from December 17, 2015 to December 31, 2015, respectively, were as follows:

	Year Ended December 31, 2016	Period from December 17, 2015 to December 31, 2015
(Millions)		
Regulatory Assets - Derivative liabilities	$ 7	$ 1
Regulatory Liabilities - Derivative assets	$ 1	$ —

The net notional volumes of the outstanding derivative instruments associated with Networks activities as of December 31, 2 respectively, consisted of:

As of December 31,	2016	2015
(Millions)		
Wholesale electricity purchase contracts (MWh)	5.6	6.7
Natural gas purchase contracts (Dth)	5.8	4.8
Fleet fuel purchase contracts (Gallons)	2.3	3.8

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The offsetting of derivatives, location in the consolidated balance sheet and amounts of derivatives associated with Networks activities a
31, 2016 and 2015, respectively, consisted of:

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

As of December 31, 2015 (Millions)	Current Assets	Noncurrent Assets	Current Liabilities	Noncu Liabi
Not designated as hedging instruments				
Derivative assets	$ 11	$ 18	$ —	$
Derivative liabilities	—	—	(28)	
	11	18	(28)	
Designated as hedging instruments				
Derivative assets	3	6	3	
Derivative liabilities	(3)	(6)	(42)	
	—	—	(39)	
Total derivatives before offset of cash collateral	11	18	(67)	
Cash collateral receivable	—	—	37	
Total derivatives as presented in the balance sheet	$ 11	$ 18	$ (30)	$

The effect of derivatives in cash flow hedging relationships on OCI and income for the years ended December 31, 2016, 2015 and 201
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)
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**
2014			
Interest rate contracts	$ —	Interest expense	$ 9
Commodity contracts	(4)	Operating expenses	1
Total	**$ (4)**		**$ 10**

(a) Changes in OCI are reported in pre-tax dollars, the reclassified amounts of commodity contracts are included within "Purchase
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 $76.7 million,
and $93.5 million for the years ended December 31, 2016, 2015 and 2014, respectively. We recorded $8.0 million, $8.6 million, ar
in net derivative losses related to discontinued cash flow hedges for the years ended December 31, 2016, 2015 and 2014, respec
amortize approximately $8.0 million of discontinued cash flow hedges in 2017. During the years ended December 31, 2016, 2015 a
was no ineffective portion for cash flow hedges.

The unrealized loss of $0.4 million on hedge derivatives is reported in OCI because the forecasted transaction is considered to be
December 31, 2016. We expect that $0.4 million of those losses will be reclassified into earnings within the next twelve months. The m
of time over which we are hedging our exposure to the variability in future cash flows for forecasted fleet fuel transactions is twelve m

(b) Renewables and Gas activities

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We sell fixed-price gas and power forwards to hedge our merchant wind assets from declining commodity prices for our Renewables b 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 o 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 inten 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 value of our contracted transport positions. The intent of buying and selling these basis swaps is to fix the location differential betweer 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 sw 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 derivative contracts are effective in offsetting the variability of cash flows associated with future power sales and gas purchases, the fa changes are recorded in OCI. Any hedge ineffectiveness is recorded in current period earnings. For thermal operations, Renewables wi designate both fixed price NYMEX gas contracts and AECO basis swaps that hedge the fuel requirements of its Klamath facility. Rene also designate fixed price power swaps at various locations in the U.S. market to hedge future power sales from its Klamath facility an farms.

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

The net notional volumes of outstanding derivative instruments associated with Renewables and Gas activities as of December 31, 2 respectively, consisted of:

As of December 31,	2016	2015
(MWh/Dth in Millions)		
Wholesale electricity purchase contracts	3	3
Wholesale electricity sales contracts	7	6
Foreign exchange forward purchase contracts	—	4
Natural gas and other fuel purchase contracts	329	332
Financial power contracts	8	7
Basis swaps - purchases	49	67
Basis swaps - sales	45	80

The fair values of derivative contracts associated with Renewables and Gas activities as of December 31, 2016 and 2015, respectively,

As of December 31,	2016	2015
(Millions)		
Wholesale electricity purchase contracts	$ (2)	$ (13)
Wholesale electricity sales contracts	6	35
Foreign exchange forward purchase contracts	—	(1)
Natural gas and other fuel purchase contracts	30	10
Financial power contracts	56	32
Basis swaps- purchases	3	1
Basis swaps- sales	(2)	(2)
Total	**$ 91**	**$ 62**

The offsetting of derivatives, location in the consolidated balance sheet and amounts of derivatives associated with Renewables and G of December 31, 2016 and 2015, respectively, consisted of:

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

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As of December 31, 2015 (Millions)	Current Assets	Noncurrent Assets	Current Liabilities	
Not designated as hedging instruments				
Derivative assets	$ 186	$ 113	$ 117	$
Derivative liabilities	(85)	(14)	(169)	
	101	99	(52)	
Designated as hedging instruments				
Derivative assets	56	13	—	
Derivative liabilities	—	—	(9)	
	56	13	(9)	
Total derivatives before offset of cash collateral	157	112	(61)	
Cash collateral receivable (payable)	(80)	(41)	—	
Total derivatives as presented in the balance sheet	$ 77	$ 71	$ (61)	$

The effect of trading and non-trading derivatives, respectively, associated with Renewables and Gas activities for the years ended Dece 2015 and 2014 consisted of:

Years Ended December 31, (Millions)	2016	2015	2014
Wholesale electricity purchase contracts	$ 3	$ 6	$ (9)
Wholesale electricity sales contracts	(7)	(5)	9
Financial power contracts	4	—	(2)
Financial and natural gas contracts	(22)	(26)	125
Total (Loss) Gain	**$ (22)**	**$ (25)**	**$ 123**

Years Ended December 31, (Millions)	2016	2015	2014
Wholesale electricity purchase contracts	$ 9	$ (8)	$ (8)
Wholesale electricity sales contracts	(20)	(5)	15
Financial power contracts	(10)	24	30
Natural gas and other fuel purchase contracts	34	18	(1)
Total Gain	**$ 13**	**$ 29**	**$ 36**

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

In 2015 we began designating those derivatives contracts at Renewables and Gas businesses that qualify as hedges. This designa prospectively, and in accordance with all the requirements of hedge accounting. The effect of derivatives in cash flow hedging relatio and income for the years ended December 31, 2016 and 2015 consisted of:

Year Ended December 31, (Millions)	(Loss) Gain Recognized in OCI on Derivatives Effective Portion (a)	Location of Gain Reclassified from Accumulated OCI into Income	(Gain) Reclassified from Accumulated OCI into Income Effective Portion (a)
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 will be reclassified from accumulated OCI into income in the period during which the transaction being hedged affects earn becomes probable that a forecasted transaction being hedged would not occur. Notwithstanding future changes in prices, approximatel of losses included in accumulated OCI at December 31, 2016 is expected to be reclassified into earnings within the next 12 mon years ended December 31, 2016 and 2015, we recorded a net loss of $6.8 million and a net gain $4.8 million, respectively, in earnin ineffectiveness from cash flow hedges. We recorded $0.4 million and $2.3 million in net derivative gain related to discontinued cash the years ended December 31, 2016 and 2015.

(c) Counterparty credit risk management

NYSEG and RG&E face risks related to counterparty performance on hedging contracts due to counterparty credit default. We ha matrix of unsecured credit thresholds that are dependent on the counterparty’s or the counterparty’s guarantor’s applicable credit r

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Moody's or Standard & Poor's. When our exposure to risk for a counterparty exceeds the unsecured credit threshold, the counterpart post additional collateral or we will no longer transact with the counterparty until the exposure drops below the unsecured credit thresh

The wholesale power supply agreements of UI contain default provisions that include required performance assurance, including ce 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 o 2016, UI would have had to post an aggregate of approximately $12.8 million in collateral.

We have various master netting arrangements in the form of multiple contracts with various single counterparties that are subject agreements that provide for the net settlement of all contracts through a single payment. Those arrangements reduce our exposure to in the event of default on or termination of any single contract. For financial statement presentation purposes, we offset fair recognized for derivative instruments and fair value amounts recognized for the right to reclaim or the obligation to return cash co from derivative instruments executed with the same counterparty under a master netting arrangement. The amounts of cash collatera netting arrangements that have not been offset against net derivative positions were $20 million and $11 million as of December 31, respectively. Derivative instruments settlements and collateral payments are included in "Other assets" and "Other liabilities" of operat 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 fr major credit rating agencies. If our debt were to fall below investment grade, we would be in violation of those provisions and the coun derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivat in net liability positions. The aggregate fair value of all derivative instruments with credit risk related contingent features that are in a li as of December 31, 2016 is $12 million, for which we have posted collateral.

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Commitments and Contingent Liabilities	12 Months Ended Dec. 31, 2016
Commitments And Contingencies Disclosure [Abstract]	
Commitments and Contingent Liabilities	

Note 13. 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.

MNG Rate Case

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

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 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 return. In June 2015 the NETOs filed an appeal in the U.S. Court of Appeals for the District of Columbia of the FERC's final order. The appeal is currently pending, and we cannot predict the outcome of this appeal.

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On December 26, 2012, a second, ROE complaint (Complaint II) for a subsequent rate period was filed requesting the ROE 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 ROE 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 were held in June 2015 on Complaints II and III before a FERC Administrative Law Judge, relating to the refund periods and going forward period. 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 mid-2017.

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. The CMP and UI total reserve associated with Complaints I, II and III is $21.6 million and $4.4 million, respectively, as of December 31, 2016. 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 base ROE be 8.61% and ROE Cap be 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. 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. Hearings are being held later this year with an expected Initial Decision from the Administrative Law Judge in 2017.

Yankee Nuclear Spent Fuel Disposal Claim

CMP has an ownership interest in Maine Yankee Atomic Power Company, Connecticut Yankee Atomic Power Company, and Yankee Atomic Electric Company, (the Yankee Companies), three New England single-unit decommissioned nuclear reactor sites, and UI has an ownership interest in Connecticut Yankee Atomic Power Company. Every six years, pursuant to the statute of limitations, the Yankee Companies file a lawsuit to recover damages from the Department of Energy (DOE or Government) for breach of the Nuclear Spent Fuel Disposal Contract to remove Spent Nuclear Fuel (SNF) and Greater than Class C Waste (GTCC) as required by contract and the Nuclear Waste Policy Act beginning in 1998. The damages are the incremental costs for the Government's failure to take the spent nuclear fuel.

In 2012, the U.S. Court of Appeals issued a favorable decision in the Yankee Companies' claim for the first six year period (Phase I). Total damages awarded to the Yankee Companies were nearly $160 million. The Yankee Companies won on all appellate points in the U.S. Court of Appeals for the Federal Circuit's unanimous decision. The Federal Appeals Court affirmed the September 2010 U.S. Court of Federal Claims award of $39.7 million to Connecticut Yankee Atomic Power Company; affirmed the Court of Federal Claims award of $81.7 million to Maine Yankee Atomic Power Company; and increased Yankee Atomic Electric Company's damages award from $21.4 million to $38.3 million. The Phase I damage award became final on December 4, 2012. The

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Yankee Companies received payment from DOE in January 2013. CMP's share of the award was approximately $36.5 million which was credited back to customers. UI's share of the award was $3.8 million which was credited back to customers.

In November 2013 the U.S. Court of Claims issued its decision in the Phase II case (the second 6 year period). The Trial Court decision awards the Yankee Companies a combined $235.4 million (Connecticut Yankee $126.3 million, Maine Yankee $37.7 million, and Yankee Atomic $73.3 million). The Phase II period covers January 1, 2002 through December 31, 2008 for Connecticut Yankee and Yankee Atomic, and January 1, 2003 through December 31, 2008 for Maine Yankee. Maine Yankee's damage award was lower because it recovered a larger amount in the Phase I case ($82 million) and its decommissioning was both less expensive and completed sooner than the other Yankee Companies. The damage awards flow through the Yankees to shareholders (including CMP and UI) to reduce retail customer charges. In January 2014 the government informed the Yankee Companies it would not appeal the Trial Court decision, as a result the Yankee Companies received full payment in April 2014. CMP's share of the award was approximately $28.2 million which was credited back to customers. UI received approximately $12 million of such award which was applied, in part, against the remaining storm regulatory asset balance. The remaining regulatory liability balance was applied to the GSC "working capital allowance" and will be returned to customers through the non-by-passable federally mandated congestion charge.

In August 2013, the Yankees filed a third round of claims against the government seeking damages for the years 2009-2014 (Phase III). The Phase III trial was completed in July 2015 and the Court has issued its decision on March 25, 2016 awarding the Yankee Companies a combined $76.8 million (Connecticut Yankee $32.6 million, Maine Yankee $24.6 million and Yankee Atomic $19.6 million). The damage awards will potentially flow through the Yankee Companies to shareholders, including CMP and UI, upon FERC approval, and will reduce retail customer charges or otherwise as specified by law. CMP and UI will receive their proportionate share of the awards that flow through based on percentage ownership. On July 18, 2016, the notice of appeal period expired and the Phase III trial award became final. On October 14, 2016, the Yankee Companies received the Government's payment of the damage award of a combined $41.6 million (Connecticut Yankee $18.4 million, Maine Yankee $3.6 million and Yankee Atomic $19.6 million). In December 2016 CMP and UI received their proportionate share of $4.2 million of the Phase III damage awards, based on percentage ownership, and CMP received an additional $21.5 million for SNF trust refund relating to excess funds of Maine Yankee unrelated to Phase III. All amounts will flow through to customers.

NYPSC Staff Review of Earnings Sharing Calculations and Other Regulatory Deferrals

In December 2012, the NYPSC Staff (Staff) informed NYSEG and RG&E that the Staff had conducted an audit of the companies' annual compliance filings (ACF) for 2009 through August 31, 2010, and the first rate year of the current rate plan, September 1, 2010 through August 31, 2011. The Staff's preliminary findings indicated adjustments to deferred balances primarily associated with storm costs and the treatment of certain incentive compensation costs for purposes of the 2011 ACF. The Staff's findings approximate $9.8 million of adjustments to deferral balances and customer earnings sharing accruals. NYSEG and RG&E reviewed the Staff's adjustments and work papers and provided a response in early 2013. NYSEG and RG&E disagreed with certain Staff conclusions and as a result recorded a $3.4 million reserve in December 2012 in anticipation of settling the Staff issues. In the proposal approved by the NYPSC (see Note 5) the parties agreed that in full and final resolution of all years through 2012, and in full and final resolution of storm-related deferrals through 2014, the companies will add $2.4 million to the customer share of earnings sharing. Staff indicated in December 2016 that it had completed its review 2013 and 2014 compliance filings and no issues were identified.

California Energy Crisis Litigation

Two California agencies brought a complaint in 2001 against a long-term power purchase agreement entered into by Renewables, as seller, to the California Department of Water Resources, as purchaser, alleging that the terms and conditions of the power purchase agreement

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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 power purchase agreements unjust and unreasonable. However, the proposed ruling did conclude that price of the power purchase agreements imposed an excessive burden on customers in the amount of $259 million. Renewables position, as presented at hearings and agreed by 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.

Leases

Operating lease expense relating to operational facilities, office building leases, and vehicle and equipment leases was $70.6 million, $47.7 million and $48.7 million for the years ended December 31, 2016, 2015 and 2014, respectively. Amounts related to contingent payments predominantly linked to electricity generation at the respective facilities was $22.2 million, $22.2 million and $20.4 million for the years ended December 31, 2016, 2015 and 2014, 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 will operate and maintain the RSS units and manage and comply with scheduling deadlines and requirements for maintaining the Facility and the RSS units as eligible energy and capacity providers and will comply with dispatch instructions. NYSEG will pay Cayuga a monthly fixed price and will also pay for capital expenditures for specified capital projects. NYSEG will be 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 $37.8 million, $25.5 million and $19.8 million for the years ended December 31, 2016, 2015 and 2014, respectively.

On December 31, 2014, we concluded the sale of our ten-percent undivided interest in Unit 1 of the Springerville power plant to Tucson Electric Power for $19.6 million. We had previously accounted for this plant as an operating lease. This transaction was recorded in "Other income and (expense)."

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 through March 2017. RG&E shall make monthly payments to GNPP in the amount of $15.4 million. RG&E will be entitled to 70% of revenues from GNPP's sales into the energy and capacity markets, while GNPP will be entitled to 30% of such revenues. We account for this arrangement as an operating lease. The net expense incurred under this operating lease was $114.9 million and $79.9 million for the years ended December 31, 2016 and 2015, respectively.

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Total future minimum lease payments as of December 31, 2016 consisted of:

Year	Operating Leases	Capital Leases	Total
		(Millions)	
2017	$ 106	$ 30	$ 136
2018	28	6	34
2019	28	7	35
2020	26	7	33
2021	28	4	32
2022 and thereafter	487	50	537
Total	**$ 703**	**$ 104**	**$ 807**

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.

Power, Gas, and Other Arrangements – Renewables and Gas

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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 Power Purchase Agreement (PPA) for 12 years (five 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 (two years remaining). Power sales commitments include: (i) a 55MW Biomass off-take agreement for 12 years (five 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, 2016 consisted of:

	Purchases				Sales			
Year	Gas	Power	Other	Total	Gas	Power	Other	Total
				(Millions)				
2017	$ 284	$ 168	$ 35	$ 487	$ 23	$ 132	$ 4	$ 159
2018	245	108	23	376	4	76	4	84
2019	205	68	14	287	5	53	1	59
2020	161	65	12	238	5	42	—	47
2021	127	52	12	191	—	33	—	33
Thereafter	520	379	109	1,008	—	26	—	26
Totals	**$1,542**	**$ 840**	**$ 205**	**$2,587**	**$ 37**	**$ 362**	**$ 9**	**$ 408**

Guarantee Commitments to Third Parties

As of December 31, 2016, we had approximately $2.6 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, 2016, neither we nor our subsidiaries have any liabilities recorded for these instruments.

Property, Plant and Equipment

We have made future commitments to purchase property, plant, and equipment in order to continue to develop and grow our business. The amount of such future commitments was $493 million as of December 31, 2016.

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Environmental Liabilities	12 Months Ended Dec. 31, 2016
Environmental Remediation Obligations [Abstract]	
Environmental Liabilities	

Note 14. 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 $6 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 $22 million as of December 31, 2016. 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; eleven 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 $221 million to $465 million as of December 31, 2016. 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.

As of December 31, 2016 and 2015, 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 $97 million and $99 million, respectively.

The liability to investigate and perform remediation at the known inactive MGP sites was $388 million and $397 million as of December 31, 2016 and 2015, respectively. We recorded a corresponding regulatory asset, net of insurance recoveries and the amount collected from

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FirstEnergy, as described below, because we expect to recover the net costs in rates. Our environmental liability accruals are recorded on an undiscounted basis and are expected to be paid through the year 2053.

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, 2016 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.

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. In January 2015, NYSEG sent FirstEnergy a demand for $16 million representing FirstEnergy's share of clean-up expenses incurred by NYSEG at the nine sites from January 2010 to November 2014 while the District Court appeal was pending. Nearly all of this amount has been paid by FirstEnergy. FirstEnergy would also be liable for a share of post 2014 costs, which, based on current projections, would be $26 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 Idemnity and One Beacon have answered admitting issuance of the excess policies, but contesting coverage and providing documentation proving they received notice of the claims in

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the 1990s. 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 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 and Asnat filed a subsequent lawsuit in Connecticut state court seeking among other things: (i) remediation of the property; (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 on or before August 1, 2017.

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. A status report was filed with the court in December 2016 and the next status report is due in May 2017.

On August 4, 2016, DEEP issued 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.

In connection with the consent order, on August 4, 2016, DEEP also issued a Consent Order to Evergreen Power, Asnat, and certain related parties that provides UI access to investigate and remediate the English Station site consistent with the consent order. 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, 2016 and 2015 we reserved $28.3 million and $20.5 million, respectively, for this matter and have accrued the remaining $1.7 million and $9.5 million in accordance with the settlement with PURA approving the acquisition. The difference of $7.8 million pre-tax has been reflected as the reversal of an expense in our 2016 results, reversing the amounts recorded in 2015, to adjust the allocation of the purchase price as a measurement period adjustment from the acquisition of UIL. The adjustment to the reserve during 2016 was recorded in the "Operations and maintenance" line of the consolidated statement of income as a measurement period adjustment based on additional information obtained for the site regarding circumstances of the site as of the acquisition date of UIL.

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Income Taxes

Income Tax Disclosure [Abstract]

Income Taxes

12 Months Ended Dec. 31, 2016

Note 15. Income Taxes

Current and deferred taxes charged to (benefit) expense for the years ended December 31, 2016, 2015 and 2014 consisted of:

Years Ended December 31, (Millions)	2016	2015	2014
Current			
Federal	$ (6)	$ (20)	$ (10)
State	8	(33)	31
Current taxes charged to (benefit) expense	**2**	**(53)**	**21**
Deferred			
Federal	414	136	218
State	2	(6)	82
Deferred taxes charged to expense	**416**	**130**	**300**
Production tax credits	(38)	(42)	(37)
Investment tax credits	(1)	(1)	(2)
Total Income Tax Expense	**$ 379**	**$ 34**	**$ 282**

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, 2016, 2015 and 2014 consisted of:

Years Ended December 31, (Millions)	2016	2015	2014
Tax expense at federal statutory rate	$ 353	$ 105	$ 247
Depreciation and amortization not normalized	61	15	15
Investment tax credit amortization	(1)	(1)	(2)
Tax return related adjustments	(2)	6	2
Production tax credits	(38)	(42)	(37)
Tax equity financing arrangements	(25)	(36)	(11)
Change in tax reserves	—	—	3
Changes in New York tax law	—	—	41
State tax expense (benefit), net of federal benefit	7	(25)	32
Non-deductible acquisition costs	—	9	—
Other, net	24	3	(8)
Total Income Tax Expense	**$ 379**	**$ 34**	**$ 282**

Deferred tax assets and liabilities as of December 31, 2016 and 2015 consisted of:

As of December 31, (Millions)	2016	2015
Non-current Deferred Income Tax Liabilities (Assets)		
Property related	$ 5,195	$ 4,763
Unfunded future income taxes	216	211
Federal and state tax credits	(417)	(367)
Accumulated deferred investment tax credits	14	15

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Federal and state NOL's	(1,397)	(1,367)
Joint ventures/partnerships	651	655
Nontaxable grant revenue	(581)	(595)
Other	(171)	(17)
Non-current Deferred Income Tax Liabilities	3,510	3,298
Add: Valuation allowance	31	19
Total Non-current Deferred Income Tax Liabilities	3,541	3,317
Less amounts classified as regulatory liabilities		
Non-current deferred income taxes	565	519
Non-current Deferred Income Tax Liabilities	$ 2,976	$ 2,798
Deferred tax assets	$ 2,565	$ 2,346
Deferred tax liabilities	6,106	5,663
Net Accumulated Deferred Income Tax Liabilities	$ 3,541	$ 3,317

Valuation allowances are recorded to reduce deferred tax assets when it is not more-likely-than not that all or a portion of a tax benefit will be realized. A valuation allowance for the entire $9 million (net of federal benefit) carryforward of Maine Research and Development Super credits generated in tax years 2007 through 2012 was established as of December 31, 2012 with no change in this balance as of December 31, 2015. A valuation allowance of $10 million was established on various state NOLs as of December 31, 2015 and 2016, respectively. The $12 million increase in valuation allowances established in 2016 represents a full valuation allowance of $15 million (net of federal benefit) on Connecticut state tax credits, partially offset by a reduction of $3 million related to the Maine Research and Development Super credits.

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2016, 2015 and 2014 consisted of:

Years ended December 31, (Millions)	2016	2015	2014
Beginning Balance	$ 36	$ 38	$ 41
Increases for tax positions related to prior years	8	1	20
Decreases for tax positions related to prior years	(4)	—	—
Reduction for tax position related to settlements with taxing authorities	—	(3)	(23)
Ending Balance	**$ 40**	**$ 36**	**$ 38**

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 $2 million, $2 million, and $3 million for the years ended December 31, 2016, 2015 and 2014, respectively. If recognized, $8 million of the total gross unrecognized tax benefits would affect the effective tax rate.

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The total amount of unrecognized tax benefits anticipated to result in a net decrease to unrecognized tax benefits within 12 months of December 31, 2016 is estimated to be $9 million primarily relating to anticipation of additional guidance to be released by the IRS.

On December 29, 2014, the Joint Committee on Taxation approved the examination of AVANGRID and its subsidiaries, without ARHI, for the tax years 1998 through 2009. The results of these audits, net of reserves already provided, were immaterial. All New York and Maine state returns, which were filed without ARHI, are closed through 2011.

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, 2016, 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, 2016, 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 $394 million, state tax net operating losses of $241 million in several jurisdictions and miscellaneous state tax credits of $32 million available to carry forward and reduce future income tax liabilities. For state purposes, we recognized a valuation allowance of $31 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.

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Post-retirement and Similar Obligations	12 Months Ended Dec. 31, 2016
Compensation And Retirement Disclosure [Abstract]	
Post-retirement and Similar Obligations	

Note 16. 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 2011. 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 plan covers the majority of employees of UI and UIL corporate. The plan was closed to newly-hired employees in 2005. UI also has a non-qualified supplemental pension plan for certain employees and a non-qualified retiree-only pension plan for certain early retirement benefits.

The Regulated Gas Companies in Connecticut and Massachusetts have multiple qualified pension plans covering a majority of their union and management employees. These entities also have non-qualified supplemental pension plans for certain employees. 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.

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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, 2016 and 2015 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	2016	2015	2016	2015
(Millions)				
Change in benefit obligation				
Benefit obligation as of January 1,	**$ 3,509**	**$ 2,620**	**$ 525**	**$ 435**
Acquisition of UIL	—	1,019	—	122
Service cost	44	36	5	5
Interest cost	142	99	21	16
Plan participants' contributions	—	—	7	4
Plan amendments	—	—	—	(1)
Actuarial gain	(43)	(105)	(24)	(31)
Special termination benefits	—	2	—	—
Benefits paid	(204)	(162)	(39)	(25)
Benefit Obligation as of December 31,	**3,448**	**3,509**	**495**	**525**
Change in plan assets				
Fair value of plan assets as of January 1,	**2,664**	**2,143**	**162**	**129**
Acquisition of UIL	—	687	—	39
Actual return on plan assets	169	(31)	11	(4)
Employer contributions	43	27	30	21
Plan participants' contributions	—	—	7	4
Benefits paid	(204)	(162)	(39)	(25)
Withdrawals from VEBA	—	—	(11)	(2)
Fair Value of Plan Assets as of December 31,	**2,672**	**2,664**	**160**	**162**
Funded Status as of December 31,	**$ (776)**	**$ (845)**	**$ (335)**	**$ (363)**

Amounts recognized as of December 31, 2016 and 2015 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	2016	2015	2016	2015
(Millions)				
Current liabilities	$ —	$ —	$ (5)	$ (5)
Non-current liabilities	(776)	(845)	(330)	(358)
Total	**$ (776)**	**$ (845)**	**$ (335)**	**$ (363)**

Networks offered retired employees an option to receive their future pension benefit as a lump sum during 2014. Approximately $118.5 million of payments were made in 2014 as a result of retired employees exercising the lump sum option. The lump sum payments did not trigger settlement accounting.

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Amounts recognized in OCI for ARHI for the years ended December 31, 2016, 2015 and 2014, consisted of:

	Pension Benefits			Postretirement Benefits		
Years Ended December 31,	2016	2015	2014	2016	2015	2014
(Millions)						
Net (gain) loss	$ 23	$ 25	$ 22	$ (3)	$ (1)	$ 8

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, 2016, 2015 and 2014 for Networks consisted of:

	Pension Benefits			Postretirement Benefits		
Years Ended December 31,	2016	2015	2014	2016	2015	2014
(Millions)						
Net loss	$ 860	$ 994	$ 1,045	$ 44	$ 76	$ 96
Prior service cost (credit)	7	9	12	(40)	(49)	(57)

Our accumulated benefit obligation for all defined benefit pension plans of Networks and ARHI was $3,214 million and $3,261 million as of December 31, 2016 and 2015, respectively. CMP's and NYSEG's postretirement benefits were partially funded as of December 31, 2016 and 2015.

The projected benefit obligation and the accumulated benefit obligation exceeded the fair value of pension plan assets for all plans of Networks and ARHI as of December 31, 2016 and 2015.

The aggregate projected and accumulated benefit obligations and the fair value of plan assets for underfunded plans of Networks and ARHI as of December 31, 2016 and 2015 consisted of:

	Projected Benefit Obligation Exceeds Fair Value of Plan Assets		Accumulated Benefit Obligation Exceeds Fair Value of Plan Assets	
As of December 31,	2016	2015	2016	2015
(Millions)				
Projected benefit obligation	$ 3,448	$ 3,509	$ 3,448	$ 3,509
Accumulated benefit obligation	3,214	3,261	3,214	3,261
Fair value of plan assets	2,672	2,664	2,672	2,664

Components of Networks' net periodic benefit cost and other changes in plan assets and benefit obligations recognized in income and regulatory assets and liabilities as of December 31, 2016, 2015 and 2014 consisted of:

(Millions)	Pension Benefits			Postretirement Benefits		
As of December 31,	2016	2015	2014	2016	2015	2014
Net Periodic Benefit Cost:						
Service cost	$ 44	$ 36	$ 30	$ 5	$ 4	$ 4
Interest cost	140	97	107	20	15	17
Expected return on plan assets	(199)	(156)	(161)	(8)	(7)	(7)
Amortization of prior service cost (benefit)	2	3	4	(9)	(9)	(11)
Amortization of net loss	123	130	94	8	7	—
Special termination benefit charge	—	2	—	—	—	—
Settlement charge	—	2	—	—	—	—

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Net Periodic Benefit Cost	**110**	**114**	**74**	**16**	**10**	**3**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities:						
Settlements	$ —	$ (2)	$ —	$ —	$ —	$ —
Net loss (gain)	(11)	69	434	(24)	(12)	72
Amortization of net loss	(123)	(130)	(94)	(8)	(7)	—
Current year prior service cost	—	—	—	—	(1)	—
Amortization of prior service (cost) benefit	(2)	(3)	(4)	9	9	11
Total Other Changes	(136)	**(66)**	**336**	(23)	**(11)**	**83**
Total Recognized	**$ (26)**	**$ 48**	**$ 410**	**$ (7)**	**$ (1)**	**$ 86**

Components of ARHI's net periodic benefit cost and other changes in plan assets and benefit obligations recognized in income and OCI as of December 31, 2016, 2015 and 2014 consisted of:

(Millions)	Pension Benefits			Postretirement Benefits		
As of December 31,	2016	2015	2014	2016	2015	2014
Net Periodic Benefit Cost:						
Service cost	$ —	$ —	$ —	$ —	$ 1	$ 1
Interest cost	2	2	2	1	1	1
Expected return on plan assets	(2)	(2)	(3)	—	—	—
Amortization of prior service cost	-	—	—	—	—	1
Amortization of net loss	1	1	—	—	—	1
Settlement charge	1	—	—	—	—	—
Net Periodic Benefit Cost (income)	**2**	**1**	**(1)**	**1**	**2**	**4**
Other Changes in plan assets and benefit obligations recognized in OCI:						
Net loss (gain)	—	4	6	(2)	(8)	(5)
Amortization of net loss	(1)	(1)	—	—	—	(1)
Amortization of prior service (cost)	—	—	—	—	—	(1)
Total Other Changes	**(1)**	**3**	**6**	**(2)**	**(8)**	**(7)**
Total Recognized	**$ 1**	**$ 4**	**$ 5**	**$ (1)**	**$ (6)**	**$ (3)**

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, 2017 consists of:

Year Ended December 31, 2017 (Millions)	Pension Benefits	Postretirement Benefits
Estimated net loss	$ 126	$ 5
Estimated prior service cost (benefit)	2	(9)

Amounts expected to be amortized from OCI into net periodic benefit cost for the year ending December 31, 2017 consists of:

Year Ended December 31, 2017 (Millions)	Pension Benefits	Postretirement Benefits

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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, 2017.

The weighted-average assumptions used to determine benefit obligations for Networks and ARHI as of December 31, 2016 and 2015 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	2016	2015	2016	2015
Discount rate - Networks	4.12% / 4.24%	4.10% / 4.24%	4.12% / 4.24%	4.10% / 4.24%
Discount rate - ARHI	3.81%	3.90%	3.81%	3.90%
Rate of compensation increase - Networks	3.50% - 4.20%	4.00%	—	—

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, 2016, 2015 and 2014 consisted of:

	Pension Benefits			Postretirement Benefits		
Years Ended December 31,	2016	2015	2014	2016	2015	2014
Discount rate - Networks	4.12% / 4.24%	3.80% / 4.24%	4.90%	4.12% / 4.24%	3.80% / 4.24%	4.90%
Discount rate - ARHI	3.90%	3.90%	5.00%	3.90%	3.90%	5.00%
Expected long-term return on plan assets - Networks	7.40% / 7.75%	7.50%	7.50%	7.16%	—	—
Expected long-term return on plan assets - ARHI	5.50%	5.50%	6.90%	5.50%	5.75%	6.50%
Expected long-term return on plan assets - nontaxable trust - Networks	—	—	—	7.00%	7.50%	7.50%
Expected long-term return on plan assets - taxable trust - Networks	—	—	—	4.50%	5.00%	5.00%
Rate of compensation increase - Networks	3.50% - 4.20%	4.10%	4.20%	—	—	—

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations, and the effect of rebalancing of plan assets discussed below. Our analysis considered current capital market conditions and projected conditions. NYSEG, RG&E and UIL amortize unrecognized actuarial gains and losses over ten years from the time they are incurred as required by the NYPSC, PURA and DPU. Our other companies use the standard amortization methodology under which amounts in excess of ten-percent of the greater of the projected benefit obligation or market related value are amortized over the plan participants' average remaining service to retirement.

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Assumed health care cost trend rates used to determine benefit obligations as of December 31, 2016 and 2015 consisted of:

As of December 31,	2016	2015
Health care cost trend rate assumed for next year - Networks	7.00%/ 9.00%	7.50%/ 7.00%
Health care cost trend rate assumed for next year - ARHI	6.75%/ 8.50%	7.00%/ 9.00%
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	2027
Year that the rate reaches the ultimate trend rate - ARHI	2026 / 2028	2026

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	$ 14	$ (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 $33 million to the pension benefit plans during 2017.

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, 2016 consisted of:

(Millions)	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
2017	$ 211	$ 34	$ —
2018	212	34	—
2019	216	34	—
2020	219	35	—
2021	224	35	—
2022 - 2026	1,125	169	3

Non-Qualified Pension Plans

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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 Non-current Liabilities, was $57 million and $59 million at December 31, 2016 and 2015, 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, 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	—
Common collective trusts	1,192	—	371	821

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Partnerships/joint venture interests	5	—	—	5
Real estate investments	61	—	—	61
Other, principally annuity, fixed income	589	—	315	274
Total	**$ 2,672**	**$ 414**	**$ 1,097**	**$ 1,161**

The fair values of pension benefits plan assets, by asset category, as of December 31, 2015 consisted of:

As of December 31, 2015		Fair Value Measurements		
(Millions)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 57	$ 3	$ 54	$ —
U.S. government securities	171	171	—	—
Common stocks	314	314	—	—
Registered investment companies	114	114	—	—
Corporate bonds	324	—	324	—
Preferred stocks	5	—	5	—
Common collective trusts	859	—	369	490
Partnership/joint venture interests	84	—	—	84
Real estate investments	89	—	—	89
Other, principally annuity, fixed income	647	—	329	318
Total	**$ 2,664**	**$ 602**	**$ 1,081**	**$ 981**

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.
- Mutual funds - based upon quoted market prices in active markets, which represent the Net Asset Value (NAV) of the shares held.
- Preferred stocks - at the closing price reported in the active market in which the individual investment is traded.
- Common/collective trusts and Partnership/joint ventures - using the NAV provided by the administrator of the fund. The NAV is based on the value of the underlying assets owned by the fund, minus its liabilities, and then divided by the number of shares outstanding. The NAV is classified as Level 2 if the plan has the ability to redeem the investment with the investee at NAV per share at the measurement date. Redemption restrictions or adjustments to NAV based on unobservable inputs result in the fair value measurement being classified as Level 3 if those inputs are significant to the overall fair value measurement.
- Real estate investments - based on a discounted cash flow approach that includes the projected future rental receipts, expenses and residual values because the highest and best use of the real estate from a market participant view is as rental property.
- 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

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similar instruments but includes adjustments for certain risks that may not be observable such as credit and liquidity risks.

The reconciliation of changes in fair value of plan assets based on Level 3 inputs for the years ended December 31, 2016 and 2015, consisted of:

(Millions)	Common Collective Trusts	Partnership Joint Venture Interests	Real Estate Investments	Other Investments	Total
As of December 31, 2014	**$ 449**	**$ 79**	**$ 75**	**$ 342**	**$ 945**
Actual return on plan assets:					
Relating to assets sold during the year	(3)	(19)	—	1	(21)
Relating to assets still held at the reporting date	(5)	19	10	(21)	3
Purchases, sales and settlements	49	5	4	(4)	54
As of December 31, 2015	**$ 490**	**$ 84**	**$ 89**	**$ 318**	**$ 981**
Actual return on plan assets:					
Relating to assets sold during the year	6	(19)	—	1	(12)
Relating to assets still held at the reporting date	51	—	2	(8)	45
Purchases, sales and settlements	274	(60)	(30)	(37)	147
As of December 31, 2016	**$ 821**	**$ 5**	**$ 61**	**$ 274**	**$ 1,161**

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 have 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, 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	—

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Common stocks	23	23	—	—
Mutual funds, other	16	9	7	—
Total	**$ 160**	**$ 118**	**$ 42**	**$ —**

The fair values of other postretirement benefits plan assets, by asset category, as of December 31, 2015 consisted of:

As of December 31, 2015		Fair Value Measurements		
(Millions)	Total	Level 1	Level 2	Level 3
Asset Category				
Money market funds	$ 4	$ 4	$ —	$ —
Mutual funds, fixed	36	36	—	—
Government and corporate bonds	2	—	2	—
Mutual funds, equity	46	46	—	—
Common stocks	24	24	—	—
Mutual funds, other	50	43	7	—
Total	**$ 162**	**$ 153**	**$ 9**	**$ —**

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, which represent the NAV of shares held.
- 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, 2016 and 2015.

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 $34 million, $17 million and $20 million for 2016, 2015, and 2014 respectively.

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Equity

12 Months Ended
Dec. 31, 2016

Equity [Abstract]
Equity

Note 17. Equity

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 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, 2015, our share capital consisted of 500,000,000 shares of common stock authorized, 309,491,082 shares issued and 308,864,609 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 491,459 and 626,473 shares of common stock held in trust and no convertible preferred shares outstanding as of December 31, 2016 and December 31, 2015, respectively. 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. During the year ended December 31, 2016, we repurchased 115,831 shares of common stock of AVANGRID in the open market. The total cost of repurchase, including commissions, was $5 million.

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 condensed consolidated financial statements have been retroactively adjusted to reflect the impact of the stock dividend.

Accumulated OCI (Loss)

Accumulated OCI for the years ended December 31, 2016, 2015 and 2014 consisted of:

Accumulated Other Comprehensive Income (Loss) (Millions)	As of December 31, 2013	2014 Change	As of December 31, 2014	2015 Change	As of December 31, 2015	2016 Change	As of December 31, 2016
Loss on revaluation of defined benefit plans, net of income tax expense of $0.6 for 2014, $2.2 for 2015 and $4.3 for 2016	$ (26)	$ 1	$ (25)	$ 4	$ (21)	$ 7	$ (14)
Loss for nonqualified pension plans, net of income tax expense (benefit) of $(1.9) for 2014, $1.7 for 2015 and $0.4 for 2016	(8)	(3)	(11)	3	(8)	1	(7)
Unrealized (loss) gain on derivatives qualifying as cash flow hedges:							

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Unrealized (loss) gain during period on derivatives qualifying as cash flow hedges, net of income tax expense (benefit) of ($1.4) for 2014, $20.9 for 2015 and $(15.8) for 2016	—	(2)	(2)	33	31	(26)	5
Reclassification adjustment for losses on settled cash flow hedges, net of income tax expense (benefit) of $4.1 for 2014, $4.9 for 2015 and $(11.0) for 2016 (a)	(66)	5	(61)	7	(54)	(16)	(70)
Net unrealized (loss) gain on derivatives qualifying as cash flow hedges	(66)	3	(63)	40	(23)	(42)	(65)
Accumulated Other Comprehensive (Loss) Income	**$ (100)**	**$ 1**	**$ (99)**	**$ 47**	**$ (52)**	**$ (34)**	**$ (86)**

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

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Earnings Per Share

12 Months Ended
Dec. 31, 2016

Earnings Per Share [Abstract]

Net Income Per Share

Note 18. 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 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, 2016 and 2015. We did not have any potentially-dilutive securities for the year ended December 31, 2014. 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, 2016, 2015 and 2014, consisted of:

Years Ended December 31,	**2016**	**2015**	**2014**
(Millions, except for number of shares and per share data)			
Numerator:			
Net income attributable to AVANGRID	$ 630	$ 267	$ 424
Denominator:			
Weighted average number of shares outstanding - basic	309,512,553	254,588,212	252,235,232
Weighted average number of shares outstanding - diluted	309,817,322	254,605,111	252,235,232
Earnings per share attributable to AVANGRID			
Earnings Per Common Share, Basic	$ 2.04	$ 1.05	$ 1.68
Earnings Per Common Share, Diluted	$ 2.04	$ 1.05	$ 1.68

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Tax Equity Financing Arrangements	12 Months Ended Dec. 31, 2016
Tax Equity Financing Arrangements [Abstract]	
Tax Equity Financing Arrangements	

Note 19. Tax equity financing arrangements

The sale of a membership interest in the tax equity financing arrangements (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 TEF's based on being the primary beneficiary for these variable interest entities (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 5.4% and 8.5% as of December 31, 2016 and 2015, 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. This treatment is expected to remain consistent over the terms of the TEFs. The assets and liabilities of these VIEs totaled approximately $1,343 million and $244 million, respectively, at December 31, 2016. As of December 31, 2015 the assets and liabilities of VIEs totaled approximately $1,401 million and $338 million, respectively. At December 31, 2016 and 2015, the assets and liabilities of the VIEs consisted primarily of property, plant and equipment, equity method investments and TEF liabilities. At December 31, 2016 and 2015, equity method investments of VIEs were approximately $161 million and $169 million, respectively.

We consider the following four structures to be TEFs: (1) Aeolus Wind Power II LLC, (2) Aeolus Wind Power III LLC, (3) Aeolus Wind Power IV LLC, and (4) Locust Ridge Wind Farms, LLC, (collectively, Aeolus). 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.

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During 2014, the investor returns on the Aeolus I structure successfully met the investor requirements, causing the structure to flip back to us and leaving the investor with a ten-percent noncontrolling interest. In October 2015, AVANGRID purchased this remaining interest from the investor with a gain of $5 million recorded within “Other income and (expense)” of the consolidated statements of income.

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Grants, Government Incentives and Deferred Income

12 Months Ended

Dec. 31, 2016

Deferred Revenue Disclosure [Abstract]

Grants, Government Incentives and Deferred Income

Note 20. Grants, Government Incentives and Deferred Income

The changes in deferred income as of December 31, 2016 and 2015 consisted of:

(Millions)	Government grants	Other deferred income	Total
As of December 31, 2014	$ 1,606	$ 15	$ 1,621
Additions	—	—	—
Recognized in income	(77)	9	(68)
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

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.

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, 2016 and 2015.

Other deferred income relates predominantly to gas storage transactions where revenues are recognized as services are provided.

Government grants related to depreciable assets and contributions in aid of construction treated as credits to property, plant and equipment in accordance with FERC requirements were $459 million and $390 million as of December 31, 2016 and 2015, respectively.

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Equity Method Investments

12 Months Ended
Dec. 31, 2016

Equity Method Investments And Joint Ventures [Abstract]

Equity Method Investments

Note 21. 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 $45 million and $41 million as of December 31, 2016 and 2015, respectively.

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 $128 million and $143 million for Flat Rock Wind Power LLC, and $64 million and $69 million for Flat Rock Wind Power II LLC, as of December 31, 2016 and 2015, respectively.

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 $128 million and $110 million as of December 31, 2016 and 2015.

Networks holds an approximately 20% ownership interest in New York TransCo, LLC. New York TransCo, LLC was established by the New York transmission utilities to develop, own, and operate electric transmission in New York. The investment in New York TransCo, LLC is being accounted for as an equity investment, the carrying value of which was $22 million as of December 31, 2016 (See Note 24).

None of our joint ventures have any contingent liabilities or capital commitments. Distributions received from equity method investments amounted to $20 million, $12 million, and $19 million for the years ended December 31, 2016, 2015, and 2014 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. As of December 31, 2016, 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 as of December 31, 2015.

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Other Financial Statements Items	12 Months Ended Dec. 31, 2016
Receivables [Abstract]	
Other Financial Statements Items	

Note 22. Other Financial Statements Items

Other income and (expense)

Other income and (expense) for the years ended December 31, 2016, 2015 and 2014 consisted of:

Years ended December 31, (Millions)	2016	2015	2014
Allowance for funds used during construction	$ 26	$ 21	$ 17
Carrying costs on regulatory assets	14	28	29
Other	36	6	6
Total Other income and (expense)	**$ 76**	**$ 55**	**$ 52**

Included in "Other" is a gain of $33 million resulted from the sale of our interest in Iroquois in 2016 (See Note 21).

Accounts Receivable

Accounts receivable as of December 31, 2016 and 2015 consisted of:

As of December 31, (Millions)	2016	2015
Trade receivables	$ 1,183	$ 1,036
Allowance for bad debts	(64)	(62)
Total Accounts Receivable	**$ 1,119**	**$ 974**

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, 2016 and 2015 consisted of:

(Millions)	
As of December 31, 2013	**58**
Current period provision	39
Write-off as uncollectible	(48)
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**

DPA receivable balances were $54 million and $62 million as of December 31, 2016 and 2015, respectively.

Prepayments and Other Current Assets

Prepayments and other current assets as of December 31, 2016 and 2015 consisted of:

As of December 31, (Millions)	2016	2015
Prepaid other taxes	$ 153	$ 130

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Broker margin and collateral accounts	32	46
Loans to third parties	3	3
Fixed-term deposits	3	11
Other pledged deposits	8	24
Prepaid expenses	53	53
Other	3	18
Total	**$ 255**	**$ 285**

Other Non-current Assets

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

In addition, included in "Other non-current assets", are $5 million and $7 million, which represent restricted cash as of December 31, 2016 and 2015, respectively.

Other current liabilities

Other current liabilities as of December 31, 2016 and 2015 consisted of:

As of December 31, (Millions)	2016	2015
Advances received	$ 107	$ 96
Accrued salaries	84	68
Short-term environmental provisions	34	35
Collateral deposits received	45	59
Pension and other postretirement	5	5
Other	4	22
Total	**$ 279**	**$ 285**

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Segment Information

12 Months Ended
Dec. 31, 2016

Segment Reporting [Abstract]
Segment Information

Note 23. 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 income tax expense, depreciation and amortization, impairment of non-current assets and interest expense net of capitalization, and then subtracting other income 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, 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) from continuing operations	1,086	149	(41)	—	1,194
Adjusted EBITDA	1,552	462	(16)	—	1,998
Earnings (loss) from equity method investments	15	(8)	—	—	7
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.

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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 of noncurrent assets	—	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 (loss) from equity method investments	1	(5)	—	4	—
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.

Segment information as of and for the year ended December 31, 2014 consisted of:

For the year ended December 31, 2014 (Millions)	Networks	Renewables	Gas	Other(a)	AVANGRID Consolidated
Revenue - external	$ 3,396	$ 1,180	$ 12	$ 6	$ 4,594
Revenue - intersegment	1	9	72	(82)	—
Impairment of noncurrent assets	—	24	—	1	25
Depreciation and amortization	275	332	22	—	629
Operating income (loss) from continuing operations	616	257	16	(4)	885
Adjusted EBITDA	891	613	38	(3)	1,539
Earnings from equity method investments	—	2	—	10	12
Capital expenditures	775	250	5	—	1,030
As of December 31, 2014					
Property, plant and equipment	8,389	8,219	525	—	17,133
Equity method investments	—	262	—	—	262
Total assets	$ 12,858	$ 12,328	$ 1,393	$ (2,417)	$ 24,162

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

Included in revenue-external for the year ended December 31, 2014 are: $2,726 million from regulated electric operations, $668 million from regulated gas operations and $2 million from other operations of Networks; $1,180 million from renewable energy generation of Renewables; $8 million from gas storage services and $4 million from gas trading operations of Gas.

Reconciliation of consolidated Adjusted EBITDA to the AVANGRID consolidated Net Income for the years ended December 31, 2016, 2015 and 2014, respectively, is as follows:

Years Ended December 31,	2016	2015	2014

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(Millions)			
Consolidated Adjusted EBITDA	**$ 1,998**	**$ 1,220**	**$ 1,539**
Less:			
Impairment of non-current assets	—	12	25
Depreciation and amortization	804	695	629
Interest expense, net of capitalization	268	267	243
Income tax expense	379	34	282
Add:			
Other income	76	55	52
Earnings from equity method investments	7	—	12
Consolidated Net Income	**$ 630**	**$ 267**	**$ 424**

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Related Party Transactions

12 Months Ended
Dec. 31, 2016

Related Party Transactions [Abstract]

Related Party Transactions

Note 24. 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, 2016, 2015 and 2014, respectively, consisted of:

Years Ended December 31,	2016		2015		2014	
(Millions)	Sales To	Purchases From	Sales To	Purchases From	Sales To	Purchases From
Iberdrola Financiación, S.A.	$ —	$ (2)	—	$ (1)	—	$ (2)
Iberdrola Renovables Energia, S.L.	—	(8)	—	(9)	—	(10)
Iberdrola Canada Energy Services, Ltd	—	(37)	—	(55)	—	(49)
Iberdrola, S.A.	—	(31)	—	(35)	—	(20)
Other	21	(1)	3	(2)	12	(10)

In addition to the statements of income items above we made purchases of turbines for wind farms from Gamesa Corporación Tecnológica, S.A. (Gamesa), in which our ultimate parent Iberdrola has a 20% ownership. The amounts capitalized for these transactions were $269 million and $70 million for the years ended December 31, 2016 and 2015, respectively. In addition, included in "Other non-current assets" are $92 million of safe harbor turbine payments we made to Gamesa as of December 31, 2016 (see Note 22). In June 2016, Siemens AG and Gamesa signed a binding agreement to merge their wind power businesses. After completion of the merger, which is expected in the first quarter of 2017, Iberdrola will have 8.1% ownership of the new combined company.

Related party balances as of December 31, 2016 and 2015, respectively, consisted of:

As of December 31,	2016		2015	
(Millions)	Owed By	Owed To	Owed By	Owed To
Iberdrola Canada Energy Services, Ltd	$ —	$ (14)	$ 7	$ (5)
Gamesa Corporación Tecnológica, S.A.	1	(181)	68	(77)
Iberdrola, S.A.	—	(30)	—	(3)
Iberdrola Energy Projects, Inc.	—	—	1	(3)
Iberdrola Renovables Energía, S.L.	2	—	—	—
Other	22	(3)	—	(2)

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 predominantly relate to the purchase of gas for ARHI's gas-fired generation facility at Klamath.

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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 Gamesa, which was recorded in impairment of non-current assets 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, 2016 the amount receivable from New York TransCo was $11 million.

AVANGRID manages its overall liquidity position as part of the broader Iberdrola Group and is a party to a cash pooling agreement with Bank Mendes Gans, N.V., similar to other members of the Iberdrola Group. Cash surpluses remaining after meeting the liquidity requirements of AVANGRID and its subsidiaries may be deposited in the cash pooling account where such funds are available to meet the liquidity needs of other affiliates within the Iberdrola Group. Under the cash pooling agreement, affiliates with credit balances have pledged those balances to cover the debit balances of the other affiliated parties to the agreement.

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Stock-Based Compensation

Disclosure Of Compensation Related Costs Sharebased Payments [Abstract]

Stock-Based Compensation

12 Months Ended
Dec. 31, 2016

Note 25. 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. An additional 11,804 PSUs were granted to officers and employees of AVANGRID in December 2016. 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, 2016, 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 2017 and 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, 2016, 2015 and 2014 was $0.6 million, $6.0 million and $4.8, respectively. The total income tax benefit recognized for stock-based compensation arrangements for the years ended December 31, 2016, 2015 and 2014, was $0.2 million, $2.4 million and $1.9 million, respectively.

The total liability relating to stock-based compensation, which is included in other non-current liabilities, was $9.5 million and $17.5 million as of December 31, 2016 and 2015, respectively. Before 2016 the Company's historical stock-based expense and liabilities were based on shares of Iberdrola and not on shares of the Company. These Iberdrola shares-based awards were early terminated at the end of 2015, and the liability will be settled in two equal installments no later than June 30, 2017 and March 30, 2018.

A summary of the status of the AVANGRID's nonvested PSUs as of December 31, 2016, and changes during the fiscal year ended December 31, 2016, is presented below:

	Number of PSUs	Weighted Average Grant Date Fair Value
Nonvested Balance – December 31, 2015	411,207	$ 39.60
Granted	1,335,416	$ 31.92
Forfeited	(36,592)	$ 32.83
Vested	(186,050)	$ 40.84
Nonvested Balance – December 31, 2016	1,523,981	$ 33.01

As of December 31, 2016, total unrecognized costs for non-vested PSUs were $22 million. The weighted-average period over which the PSU costs will be recognized is approximately 5 years.

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The weighted average grant date fair value of PSUs granted during the year was $31.92 per share for the year ended December 31, 2016.

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Quarterly Financial Data (unaudited)

12 Months Ended Dec. 31, 2016

Selected Quarterly Financial Information [Abstract]

Quarterly Financial Data (unaudited)

Note 26. Quarterly financial data (unaudited)

Selected quarterly financial data for 2016 and 2015 are set forth below:

(Millions, except per share data)	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2016				
Operating revenues	$ 1,670	$ 1,439	$ 1,418	$ 1,491
Operating Income	$ 349	$ 322	$ 217	$ 306
Net Income	$ 212	$ 102	$ 109	$ 207
Net Income attributable to Avangrid, Inc.	$ 212	$ 102	$ 109	$ 207
Earnings Per Common Share, Basic and Diluted: (1)	$ 0.69	$ 0.33	$ 0.35	$ 0.67
2015				
Operating revenues	$ 1,227	$ 939	$ 1,048	$ 1,153
Operating Income	$ 196	$ 73	$ 161	$ 83
Net Income	$ 106	$ 11	$ 54	$ 96
Net Income attributable to Avangrid, Inc.	$ 106	$ 11	$ 54	$ 96
Earnings Per Common Share, Basic and Diluted: (1)	$ 0.42	$ 0.04	$ 0.22	$ 0.37

(1) Based on weighted average number of 309 million shares outstanding each quarter in 2016 and 252 million shares for each quarter of 2015, except for fourth quarter of 2015, which is based on weighted average of 262 million shares as a result of the acquisition of UIL.

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 proposal by the NYPSC, which was recorded as an increase to income tax expense and an offsetting increase to revenue.

The first, second, third and fourth quarters of 2015 include $4 million, $8 million, $7 million and $18.5 million of pre-tax merger related expenses, respectively. Additionally, the fourth quarter of 2015 includes $44 million relating to rate credits, before income taxes, and $63 million tax benefits related to state income tax matters, including the initial impact of the merger on our consolidated tax filings.

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Subsequent Events	12 Months Ended Dec. 31, 2016
Subsequent Events [Abstract]	
Subsequent Events	**Note 27. Subsequent events** In January 2017 we released 5,088 shares of common stock held in trust, each having a par value of $0.01. On February 16, 2017, 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 3, 2017 to shareholders of record at the close of business on March 10, 2017. On February 16, 2017, the board of directors of AVANGRID adopted an annual cash incentive plan pursuant to the 2016 Omnibus Incentive Plan approved by the shareholders of AVANGRID. On March 1, 2017, we issued 70,493 shares of common stock, each having a par value of $0.01, which was approved by the board of directors of AVANGRID on February 16, 2017.

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Acquisition of UIL and Issuance of Common Stock

12 Months Ended Dec. 31, 2016

Acquisition of UIL

Note 4. Acquisition of UIL

On December 16, 2015 (acquisition date), we completed our acquisition of UIL, a diversified energy company with its portf of regulated utility companies in Connecticut and Massachusetts that is expected to provide us with a greater flexibilit grow the combined regulated businesses through project development and create an enhanced platform to develop transmis and distribution projects in the Northeastern United States. In connection with the consummation of the acquisition we iss 309,490,839 shares of common stock of AVANGRID, out of which 252,234,989 shares were issued to Iberdrola throug 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, shares (including those held in trust as treasury stock) were issued to UIL shareowners in addition to payment of $595 mil in cash. Following the completion of the acquisition, former UIL shareowners owned 18.5% of the outstanding share common stock of AVANGRID, and Iberdrola owned the remaining shares.

The acquisition was accounted for as a business combination. This method requires, among other things, that assets acqu and liabilities assumed in a business combination, with certain exceptions, be recognized at their fair values as of acquisition date.

As UIL's common stock was publicly traded in an active market until the acquisition date, we determined that UIL's comm stock is more reliably measurable than the common stock of AVANGRID to determine the fair value of the considera transferred in the transaction.

The purchase consideration for UIL under the acquisition method is based on the stock price of UIL on the acquisition multiplied by the number of shares issued by AVANGRID to the UIL shareowners after applying an equity exchange fa to the shares of vested restricted common stock of UIL (other than those UIL restricted shares that vest by their terms u the consummation of the acquisition), performance shares and other shares awards under UIL 2008 Stock and Incen Compensation Plan and the UIL Deferred Compensation Plan. The "equity exchange factor" is the sum of one plus a fract (i) the numerator of which is the cash consideration and (ii) the denominator of which is the average of the volume weigh averages of the trading prices of UIL common stock on each of the ten consecutive trading days ending on (and includ the trading day that immediately precedes the closing date of the acquisition minus $10.50. The determination of the purch price is based on a UIL stock price of $50.10 per share, which represents the closing stock price on the acquisition date.

The fair value of shares of AVANGRID common stock issued to the UIL shareowners in the business combination repres the purchase consideration in the business combination, which was computed as follows:

	(millions, except share and unit data)
Common shares(1)	56,629,377
Price per share of UIL common stock as of the acquisition date	$ 50.10
Subtotal value of common shares	$ 2,837
Restricted stock units(2)	476,198
Other shares(3)	12,999
Equity exchange factor	1.2806
Total restricted and other shares(3) after applying an equity exchange factor	626,473
Price per share used(5)	$ 39.60
Subtotal value of restricted and other shares	$ 25
Total shares of AVANGRID common stock issued to UIL shareowners (including held in trust as treasury stock)	57,255,850
Performance shares(4)	211,904
Equity exchange factor	1.2806
Total performance shares after applying an equity exchange factor	271,368
Price per share used(5)	$ 39.60
Subtotal value of performance shares	$ 11
Total consideration	$ 2,873

(1) Based on UIL's common shares outstanding on December 16, 2015.
(2) Based on UIL's shares of vested restricted stock.
(3) Based on UIL's restricted shares that vested upon the change in control.
(4) Based on UIL's vested performance shares award.

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(5) Based on the closing share price of UIL common stock on December 16, 2015, less the cash component of $10 which is not applicable to restricted shares (other than those UIL restricted shares that vest by their terms upon consummation of the acquisition), performance shares and other awards under the UIL 2008 Stock and Incen Compensation Plan and the UIL Deferred Compensation Plan.

The following is a summary of the components of the consideration transferred to UIL's shareowners:

	(millions, except share data)
Cash ($10.50 x number of UIL common shares outstanding at the acquisition date - 56,629,377)	$ 595
Equity	2,278
Total consideration	$ 2,873

We also paid $37.5 million for transaction costs incurred in this business combination, which are recorded in "Operations maintenance" in the consolidated statements of income for the year ended December 31, 2015.

The following unaudited pro forma financial information presents the combined results of operations as if the acquisi had been completed on January 1, 2014, the beginning of the comparable prior annual reporting period. The unaudited forma results include: (i) merger credit adjustments to operating revenue (see Merger Settlement Agreement below for fur details); (ii) elimination of accrued transaction costs representing non-recurring expenses directly related to the transact and (iii) the associated tax impact on these unaudited pro forma adjustments.

The unaudited pro forma results do not reflect any cost saving synergies from operating efficiencies or the effect of incremental costs incurred in integrating the two companies. Accordingly, these unaudited pro forma results are presented informational purpose only and are not necessarily indicative of what the actual results of operations of the combined comp would have been if the acquisition had occurred at the beginning of the period presented, nor are they indicative of fu results of operations:

	Year Ended December 31,	
	2015	2014
	(millions)	
Revenue	$ 5,958	$ 6,226
Net income	$ 468	$ 539

The revenue and net (loss) of UIL since the acquisition date included in the consolidated statements of income for the y ended December 31, 2015 were $36 million and $(36) million, respectively (see Merger Settlement Agreement below further details).

We finalized the valuation of the assets acquired and liabilities assumed within the measurement period during 2016. the majority of UIL's assets and liabilities, primarily property, plant and equipment, fair value was determined to be respective carrying amounts of the predecessor entity. UIL's operations are conducted in a regulated environment where regulatory authority allows an approved rate of return on the carrying amount of the regulated asset base. Measurement pe adjustments that were recognized in the year ended December 31, 2016 relate to the adjustments of the allocation of purchase price to the following: equity method investments; contracts; debt; contingent liabilities, including those relate certain environmental sites; income taxes; non-regulated property, plant and equipment and goodwill.

The following is a summary of the allocation of the purchase price as of the acquisition date and measurement pe adjustments recognized in the year ended December 31, 2016:

	Provisional amounts reported in 2015	Measurement period adjustments	Finalized amounts
		(millions)	
Current assets, including cash of $48 million	$ 500	$ (7)	$ 493
Other investments	114	22	136
Property, plant and equipment	3,552	(5)	3,547
Regulatory assets	966	36	1,002
Other assets	52	—	52
Current liabilities	(493)	—	(493)
Regulatory liabilities	(493)	—	(493)
Non-current debt	(1,878)	(27)	(1,905)
Other liabilities	(1,201)	(30)	(1,231)
Total net assets acquired at fair value	1,119	(11)	1,108

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Goodwill – consideration transferred in excess of fair value assigned	1,754	11	1,765
Total consideration	**$ 2,873**		**$ 2,873**

Goodwill generated from the acquisition of UIL increased by $11 million to the total amount of $1,765 million as of acquisition date as a result of the finalization of the purchase price allocation. Goodwill generated from the acquisition of has been assigned to the reporting units under the Networks reportable segment and is primarily attributable to expected fu growth of the combined regulated businesses and enhanced platform to develop transmission and distribution projects in Northeastern United States. The goodwill generated from this acquisition is not deductible for tax purposes.

Merger Settlement Agreement

As part of the process of seeking and obtaining regulatory approval for the acquisition in Connecticut and Massachus Iberdrola, S.A., AVANGRID and UIL reached settlement agreements with the Office of Consumer Counsel in Connecticut with the Attorney General of the Commonwealth of Massachusetts and the Department of Energy Resources in Massachus which settlement agreements included commitments of actions to be taken after the transaction closed.

As a result, the following commitments have been made in Connecticut, recognized in the period subsequent to the acquisi in 2015 unless otherwise noted, each of which is reasonably expected to be at a cost of $500,000 or more:

- A one-time, $20 million rate credit to customers in 2016, allocated among UI, SCG and CNG customers based 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 cap investments over a three-year period without seeking recovery until the next SCG rate case. These amounts wil recorded by the Company as incurred in future periods.
- Agreement not to seek to increase UI distribution base rates effective before January 1, 2017, and agreement no 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 c energy technologies.
- $5 million in benefits to customers resulting from UI recovering only the debt rate rather than the equity return two years, on an increased $50 million of investment in storm resiliency programs. These amounts will be recor by the Company as incurred in future periods.
- Contribution of $1 million for disaster relief entities.
- Maintaining charitable contribution at historical contribution levels (between $500,000 and $800,000) for at l four years.
- Upon the resolution of all appeals of the PURA decision approving the acquisition, UI will withdraw its app of two PURA dockets relating to PURA's disallowance of certain reconciliation amounts. The appeals w withdrawn by UI in June 2016.

In connection with the acquisition proceeding, UI signed the consent order that, pursuant to the terms and conditions in consent order, requires UI to investigate and remediate certain environmental conditions within the perimeter of the Eng Station site. To the extent that the investigation and remediation is less than $30 million, UI would remit to the Stat Connecticut the difference between such costs and $30 million for a public purpose as determined in the discretion of Governor the Attorney General of Connecticut and the Commissioner of DEEP. Pursuant to the consent order UI is oblig to comply with the consent order, even if the cost of such compliance exceeds $30 million. The state will discuss options w UI on recovering or funding any cost above $30 million such as through public funding or recovery from third parties, howe it is not bound to agree to or support any means of recovery or funding (See Note 14, Environmental Liabilities – Eng Station, for further details).

As of December 31, 2016 and 2015 we reserved $28.3 million and $20.5 million, respectively, for this matter and have accr the remaining $1.7 million and $9.5 million in accordance with the settlement with PURA approving the acquisition. difference of $7.8 million pre-tax has been reflected as the reversal of an expense in our 2016 results, reversing the amo recorded in 2015, to adjust the allocation of the purchase price as a measurement period adjustment from the acquisitio UIL. The adjustment to the reserve during 2016 was recorded in the "Operations and maintenance" line of the consolid statement of income as a measurement period adjustment based on additional information obtained for the site regard circumstances of the site as of the acquisition date of UIL.

As part of the final allocation of the purchase price we have determined a fair value of contingent liabilities of approxima $46.0 million relating to certain environmental sites.

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The following commitments have been made in Massachusetts, recognized in the period subsequent to the acquisition in 2
unless otherwise noted, each of which is reasonably expected to be at a cost of $500,000 or more:

- Customers of BGC will receive a total of $4.0 million in rate credits, to be spread over the months of Noven
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 cre
and an additional $19.8 million as liabilities, which primarily resulted in the net loss for UIL in the period following
acquisition date in 2015.

Avangrid, Inc [Member]
Acquisition of UIL

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 who
owned subsidiary of AVANGRID as a result of the merger of Green Merger Sub, Inc., a Connecticut corporation an
wholly-owned subsidiary of AVANGRID (Merger Sub), with UIL, with Merger Sub surviving as a wholly-owned subsid
of AVANGRID (the acquisition). The acquisition was effected pursuant to the Agreement and Plan of Merger, dated a
February 25, 2015, by and among AVANGRID, Merger Sub, and UIL. Following the completion of the acquisition, Me
Sub was renamed "UIL Holdings Corporation." In connection with the acquisition, AVANGRID issued 309,490,839 share
its common stock, out of which 252,234,989 shares were issued to Iberdrola through a stock dividend, accounted for as a st
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 treas
stock) were issued to UIL shareowners in addition to payment of $10.50 in cash per each share of the common stock of
issued and outstanding at the acquisition date. Following the completion of the acquisition, former UIL shareowners ow
18.5% of the outstanding shares of common stock of AVANGRID and Iberdrola owned the remaining shares.

On April 28, 2016, AVANGRID entered into a repurchase agreement with J.P. Morgan Securities, LLC. (JPM), pursuan
which JPM will, from time to time, acquire, on behalf of AVANGRID, shares of common stock of AVANGRID. The purp
of the stock repurchase program is to allow AVANGRID to maintain the relative ownership percentage of Iberdrola at 81.
The stock repurchase program may be suspended or discontinued at any time upon notice. During the year ended December
2016, AVANGRID repurchased 115,831 shares of its common stock in the open market. The total cost of repurchase, inclu
commissions, was $5 million.

On February 16, 2017, the board of directors of AVANGRID declared a quarterly dividend of $0.432 per share on its comm
stock. This dividend is payable on April 3, 2017 to shareholders of record at the close of business on March 10, 2017.

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Non-current Debt	12 Months Ended Dec. 31, 2016
Debt Disclosure [Abstract]	
Non-current Debt	**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.

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Cash Dividends Paid by Subsidiaries	12 Months Ended Dec. 31, 2016
Cash Dividend [Abstract]	
Cash Dividends Paid by Subsidiaries	

Note 4. Cash dividends paid by subsidiaries

Cash dividends paid by subsidiaries are as follows:

Years ended December 31, (In millions)	2016	2015	2014
AVANGRID Networks	$ 220	$ 59	$ 200
AVANGRID Renewables	200	750	—
Other AVANGRID subsidiaries	—	302	—
	$ 420	$ 1,111	$ 200

In December 2016, AVANGRID made a capital contribution of $50 million to its subsidiary, CMP. During 2016, AVANGRID recorded a net non-cash dividend of $827 million from its subsidiaries to zero out their account balances of notes receivables and payables.

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Summary of Significant Accounting Policies, New Accounting Pronouncements, and Use of Estimates (Policies)	12 Months Ended Dec. 31, 2016
Accounting Policies [Abstract]	
Principles of Consolidation	**(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.
Revenue Recognition	**(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.
Regulatory Accounting	**(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.
Business Combinations	**(d) Business combinations** 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

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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.

Equity Method Investments

(e) Equity method investments

Joint ventures that do not meet consolidation criteria are accounted for using the equity method. Earnings (losses) recognized under the equity method are reflected in the consolidated statements of income as "Earnings (losses) from equity method investments." Dividends received from joint ventures are recognized as a reduction in the carrying amount of the investment and are not recognized as dividend income.

Goodwill and Other Intangible Assets

(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.

Property, Plant and Equipment

(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

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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
	Hydroelectric power stations	35-90
	Wind power stations	25-40
	Gas storage	25-40
	Transport facilities	40-56
	Distribution facilities	30-54
Equipment	Conventional meters and measuring devices	15-27
	Computer software	3-5
Other	Buildings	50-75
	Operations offices	4-50

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.

Impairment of Long-lived Assets

(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.

Fair Value Measurement

(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

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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.

Available for Sale Securities

(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.

Derivatives and Hedge Accounting

(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

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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.

Cash and Cash Equivalents

(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.

Accounts Receivable and Unbilled Revenue, Net

(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.

Tax Equity Financing Arrangements-VIEs

(n) Tax equity financing arrangements-VIEs

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.

We evaluate whether an entity is a variable interest entity (VIE) whenever reconsideration events as defined by the accounting guidance occur (See Note 19). An entity is considered to be a

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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.

Debentures, Bonds and Bank borrowings

(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.

Inventory

(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, or below market 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 cost and reported on the balance sheets within “Materials and supplies.”

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

Government Grants

(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.

Deferred Income

(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.

Asset Retirement 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

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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.

Environmental Remediation Liability

(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 2053.

Post Employment and Other Employee Benefits

(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.

Income Tax

(v) Income tax

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AVANGRID will file a consolidated federal income tax return that includes the taxable income or loss of all its subsidiaries for 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), 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 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 not more-likely-than-not that all or a portion of a tax benefit will 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.

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Significant judgments and estimates are required in determining the consolidated income tax components of the financial statements.

Stock-based Compensation

(w) Stock-based compensation

Stock-based compensation represents costs related to stock-based awards granted to employees. In the third quarter of 2016 we early adopted all the amendments to ASC 718, Compensation - Stock Compensation, issued in March 2016, to account for our stock based awards. 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.

Reclassifications

Reclassifications

Certain amounts have been reclassified in the consolidated statements of cash flow to conform to the 2016 presentation as well as in connection with retrospective adoption of amendments in the accounting standard related to presentation of restricted cash in the statement of cash flow.

New Accounting Standards and Interpretations

New Accounting Standards and Interpretations

(a) Revenue from contracts with customers

In May 2014 the Financial Accounting Standards Board (FASB) issued ASC 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. 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 original effective date for public entities was for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. In August 2015 the FASB issued an accounting standards update that defers by one year the original effective date of the revenue standard for all entities. Thus, the standard is now effective for annual reporting periods beginning after December 15, 2017, and interim periods therein, with early adoption as of the original effective date permitted. We do not plan to early adopt. Entities may apply the amendment 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). We will apply the modified retrospective method. We are currently evaluating how our adoption of the amendments will affect our results of operations, financial position, cash flows, and disclosures. We are considering the effects of the amendments on our ability to recognize revenue for certain contracts for our regulated utilities where collectability is in question and our accounting for contributions in aid of construction for our regulated utilities. In addition, the amendments will require us to capitalize, rather than expense, any costs to acquire new contracts. Additionally, classification differences are also expected to result, including recording our tax equity investments as noncontrolling interests. Some revenue arrangements, such as alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on our consolidated financial statements. The FASB has issued various additional accounting standards updates, with the same deferred effective date, as follows: in March 2016 to amend and clarify the implementation guidance on principal versus agent considerations for reporting revenue gross rather than net, in April 2016 to address implementation questions on identifying performance obligations and accounting for licenses of intellectual property. We do not expect significant effects as a result of those updates. In May 2016 the FASB issued a final update concerning narrow-scope improvements and practical expedients. We are currently evaluating the effects of that update.

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(b) Fair value measurement disclosures for certain investments

In May 2015 the FASB issued amendments that affect reporting entities that elect to estimate the fair value of certain investments within scope using the net asset value (NAV) per share (or its equivalent) practical expedient, as specified. The amendments remove the requirement to categorize within the fair value hierarchy all investments for which the fair value is measured at NAV using the practical expedient. They also remove certain disclosure requirements for eligible investments and limit the required disclosures to investments for which the entity has elected to measure the fair value using the practical expedient. Assets that calculate NAV per share (or its equivalent), but for which the practical expedient is not applied will continue to be included in the fair value hierarchy. The amendments are effective for public entities for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. The amendments permit early application, and require retrospective application to all periods presented. Retrospective application requires investments for which fair value is measured at NAV using the practical expedient to be removed from the fair value hierarchy in all periods presented. Our adoption of the amendments in 2016 did not affect our results of operations, financial position, or cash flows.

(c) Simplifying the measurement of inventory

In July 2015 the FASB issued amendments that require entities to measure inventory at the lower of cost and net realizable value, rather than the lower of cost or market. The amendments do not apply to inventory measured using last-in, first-out or the retail inventory method but apply to all other inventory, including inventory measured using first-in, first-out or average cost. Prior to this update, market value could be replacement cost, net realizable value, or net realizable value less an approximately normal profit margin. Net realizable value is the "estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation." The amendments do not change the methods of estimating the cost of inventory under U.S. GAAP. The amendments are effective for public entities for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. The amendments require prospective application and permit earlier application. We expect our adoption of the amendments will not affect our results of operations, financial position, or cash flows.

(d) 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

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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 results of operations, financial position, or cash flows.

(e) Business combinations: simplifying the accounting for measurement-period adjustments

In September 2015 the FASB issued amendments that require an acquirer to 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. As a result, the acquirer is required to record, in the same period's financial statements, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. The entity is required to present separately on the face of the income statement or disclose in the notes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. The amendments are effective for public entities for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years. The amendments require prospective application to provisional amounts that occur after the effective date of the amendment and permit earlier application. The effects of our adoption of the amendments on our results of operation, financial position, or cash flows as it relates to the business combination with UIL have been disclosed in Note 4, Acquisition of UIL.

(f) 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 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 a right-of-use asset.

(g) Derivative contract novations

In March 2016 the FASB issued amendments concerning the effect of derivative contract novations on existing hedge accounting relationships. As it relates to derivative instruments, novation refers to replacing one of the parties to a derivative instrument with a new party, which may occur for a variety of reasons such as: financial institution mergers, intercompany transactions, an entity exiting a particular derivatives business or relationship, or because of laws or regulatory requirements. The amendments clarify that a change in the counterparty to a derivative instrument that has been designated as the hedging instrument under the guidance for Derivatives and Hedging

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(Topic 815) does not, in and of itself, require dedesignation of that hedge accounting relationship provided that all other hedge accounting criteria continue to be met. The amendments are effective for public entities for financial statements issued for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. The amendments may be applied on either a prospective basis or a modified retrospective basis and early application is permitted. We expect our adoption will not materially affect our results of operations, financial position, and cash flows.

(h) Improvements to employee share-based payment accounting

The FASB issued amendments in March 2016 regarding the simplification of several aspects of accounting for share-based payment transactions, including income tax consequences, classification of awards as either equity or liabilities, policy election on accounting for forfeitures and classification on the statement of cash flows. Some areas of simplification apply only to nonpublic entities. The amendments are effective for public entities for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. Early adoption permitted in any interim or annual period, but must adopt all of the amendments in the same period. For the purpose of accounting for the stock-based compensation plans, in the third quarter of 2016 we early adopted all the above amendments and elected to account for forfeitures when they occur. Our adoption of the amendments did not materially affect our results of operations, financial position, or cash flows.

(i) 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 collectibility 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 results of operations, financial position, and cash flows.

(j) Certain classifications in the statement of cash flows

The FASB issued the 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

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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.

(k) Presentation of restricted cash in the statement of cash flows

The FASB issued the amendment in November 2016 to address existing diversity in the classification and presentation of changes in restricted cash on the statement of cash flows. The amendment requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. The amendment does not provide a definition of restricted cash or restricted cash equivalents. The amendment is effective for public entities for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years, with early adoption permitted. The amendment should be applied using a retrospective transition method to each period presented. As permitted, we have early adopted the amendment as of the beginning of the fourth quarter of 2016 and have applied it retrospectively to all periods presented. Accordingly, the changes in restricted cash and restricted cash equivalents, presented previously in other assets of operating activities, were included in cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows, which increased by $2 million and had no change in net cash provided by operating activities in the consolidated statements of cash flow, for both of the years ended December 31, 2015 and 2014, respectively.

Use of Estimates and Assumptions

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) depreciable lives of assets; (4) income tax valuation allowances; (5) uncertain tax positions; (6) reserves for professional, workers' compensation, and comprehensive general insurance liability risks; (7) contingency and litigation reserves; (8) fair value measurements; (9) earnings sharing mechanisms; (10) environmental remediation liabilities; and (11) 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

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 6% of our employees.

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Summary of Significant Accounting Policies, New Accounting Pronouncements, and Use of Estimates (Tables)

12 Months Ended

Dec. 31, 2016

Accounting Policies [Abstract]

Summary of Main Asset Categories Depreciated Over the Following Estimated Useful Lives

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
	Hydroelectric power stations	35-90
	Wind power stations	25-40
	Gas storage	25-40
	Transport facilities	40-56
	Distribution facilities	30-54
Equipment	Conventional meters and measuring devices	15-27
	Computer software	3-5
Other	Buildings	50-75
	Operations offices	4-50

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Acquisition of UIL (Tables)

12 Months Ended
Dec. 31, 2016

Business Combinations [Abstract]

Summary of Fair Value of Purchase Consideration

The fair value of shares of AVANGRID common stock issued to the UIL shareowners in the business combination repres the purchase consideration in the business combination, which was computed as follows:

	(millions, except share and unit data)
Common shares(1)	56,629,377
Price per share of UIL common stock as of the acquisition date	$ 50.10
Subtotal value of common shares	$ 2,837
Restricted stock units(2)	476,198
Other shares(3)	12,999
Equity exchange factor	1.2806
Total restricted and other shares(3) after applying an equity exchange factor	626,473
Price per share used(5)	$ 39.60
Subtotal value of restricted and other shares	$ 25
Total shares of AVANGRID common stock issued to UIL shareowners (including held in trust as treasury stock)	57,255,850
Performance shares(4)	211,904
Equity exchange factor	1.2806
Total performance shares after applying an equity exchange factor	271,368
Price per share used(5)	$ 39.60
Subtotal value of performance shares	$ 11
Total consideration	$ 2,873

(1) Based on UIL's common shares outstanding on December 16, 2015.
(2) Based on UIL's shares of vested restricted stock.
(3) Based on UIL's restricted shares that vested upon the change in control.
(4) Based on UIL's vested performance shares award.
(5) Based on the closing share price of UIL common stock on December 16, 2015, less the cash component of $10 which is not applicable to restricted shares (other than those UIL restricted shares that vest by their terms upon consummation of the acquisition), performance shares and other awards under the UIL 2008 Stock and Incen Compensation Plan and the UIL Deferred Compensation Plan.

Summary of Components of Estimated Consideration Transferred

The following is a summary of the components of the consideration transferred to UIL's shareowners:

	(millions, except share data)
Cash ($10.50 x number of UIL common shares outstanding at the acquisition date - 56,629,377)	$ 595
Equity	2,278
Total consideration	$ 2,873

Schedule of Unaudited Pro Forma Results

Accordingly, these unaudited pro forma results are presented for informational purpose only and are not necessarily indica of what the actual results of operations of the combined company would have been if the acquisition had occurred at beginning of the period presented, nor are they indicative of future results of operations:

	Year Ended December 31,	
	2015	2014
	(millions)	
Revenue	$ 5,958	$ 6,226
Net income	$ 468	$ 539

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Summary of Allocation of Purchase Price

The following is a summary of the allocation of the purchase price as of the acquisition date and measurement pe adjustments recognized in the year ended December 31, 2016:

	Provisional amounts reported in 2015	Measurement period adjustments	Finalized amounts
		(millions)	
Current assets, including cash of $48 million	$ 500	$ (7)	$ 493
Other investments	114	22	136
Property, plant and equipment	3,552	(5)	3,547
Regulatory assets	966	36	1,002
Other assets	52	—	52
Current liabilities	(493)	—	(493)
Regulatory liabilities	(493)	—	(493)
Non-current debt	(1,878)	(27)	(1,905)
Other liabilities	(1,201)	(30)	(1,231)
Total net assets acquired at fair value	1,119	(11)	1,108
Goodwill – consideration transferred in excess of fair value assigned	1,754	11	1,765
Total consideration	**$ 2,873**		**$ 2,873**

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Industry Regulation (Tables)

12 Months Ended
Dec. 31, 2016

Regulated Operations [Abstract]

Electric and Gas Delivery Rate Increase

The delivery rate increase in the 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%

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Regulatory Assets and Liabilities (Tables)

Regulated Operations [Abstract]

Schedule of Current and Non-Current Regulatory Assets

12 Months Ended Dec. 31, 2016

Current and non-current regulatory assets as of December 31, 2016 and 2015 consisted of:

As of December 31,	2016	2015
(Millions)		
Current		
Pension and other post-retirement benefits cost deferrals	$ 22	$ 8
Pension and other post-retirement benefits	7	13
Storm costs	40	8
Temporary supplemental assessment surcharge	4	7
Reliability support services	27	—
Revenue decoupling mechanism	15	6
Transmission revenue reconciliation mechanism	12	5
Electric supply reconciliation	13	—
Hedges losses	10	37
Contracts for differences	14	18
Hardship programs	16	13
Deferred property tax	10	—
Plant decommissioning	6	—
Deferred purchased gas	14	12
Deferred transmission expense	13	12
Environmental remediation costs	14	37
Other	48	43
Total Current Regulatory Assets	**285**	**219**
Non-current		
Pension and other post-retirement benefits cost deferrals	134	151
Pension and other post-retirement benefits	1,320	1,509
Storm costs	187	251
Deferred meter replacement costs	32	34
Unamortized losses on reacquired debt	20	23
Environmental remediation costs	287	271
Unfunded future income taxes	542	549
Asset retirement obligations	18	24
Deferred property tax	33	45
Federal tax depreciation normalization adjustment	161	158
Merger capital expense target customer credit	11	15
Debt premium	151	141
Plant decommissioning	14	7
Contracts for differences	61	50
Hardship programs	18	29
Other	102	57

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Total Non-current Regulatory Assets	**$ 3,091**	**$ 3,314**

Schedule of Current and Non-Current Regulatory Liabilities

Current and non-current regulatory liabilities as of December 31, 2016 and 2015 consisted of:

As of December 31,	2016	2015
(Millions)		
Current		
Reliability support services (Cayuga)	$ 3	$ 16
Non by-passable charges	22	7
Energy efficiency portfolio standard	45	33
Gas supply charge and deferred natural gas cost	6	6
Transmission revenue reconciliation mechanism	5	16
Pension and other post-retirement benefits	3	3
Pension and other post-retirement benefits cost deferrals	14	—
Carrying costs on deferred income tax bonus depreciation	15	—
Carrying costs on deferred income tax - Mixed Services 263(a)	5	—
Yankee DOE refund	24	5
Merger-related rate credits	3	20
Revenue decoupling mechanism	9	14
Other	38	27
Total Current Regulatory Liabilities	**192**	**147**
Non-current		
Accrued removal obligations	1,117	1,084
Asset sale gain account	9	8
Carrying costs on deferred income tax bonus depreciation	95	116
Economic development	35	36
Merger capital expense target customer credit account	15	17
Pension and other post-retirement benefits	76	90
Positive benefit adjustment	42	51
New York state tax rate change	9	17
Post term amortization	3	25
Theoretical reserve flow thru impact	24	31
Deferred property tax	19	15
Net plant reconciliation	10	10
Variable rate debt	28	32
Carrying costs on deferred income tax - Mixed Services 263(a)	25	31
Rate refund – FERC ROE proceeding	22	21
Transmission congestion contracts	18	—
Merger-related rate credits	21	24

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Accumulated deferred investment tax credits	15	10
Asset retirement obligation	13	13
Earning sharing provisions	12	—
Middletown/Norwalk local transmission network service collections	19	19
Excess generation service charge	—	21
Low income programs	46	42
Unfunded future income taxes	—	27
Non-firm margin sharing credits	7	8
Deferred income taxes regulatory	565	519
Other	73	93
Total Non-current Regulatory Liabilities	**$ 2,318**	**$ 2,360**

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Goodwill and Intangible Assets (Tables)

12 Months Ended Dec. 31, 2016

Goodwill And Intangible Assets Disclosure [Abstract]

Schedule of Goodwill by Reportable Segment

Goodwill by reportable segment as of December 31, 2016 and 2015 consisted of:

As of December 31,	2016	2015
(Millions)		
Networks	$ 2,744	$ 2,733
Renewables	380	380
Gas	—	—
Other (a)	—	2
Total	**$ 3,124**	**$ 3,115**

(a) Does not represent a reportable segment. It includes Corporate.

Schedule of Intangible Assets Acquired and Developed

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, 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**

As of December 31, 2015	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
(Millions)			
Gas Storage rights	$ 324	$ (116)	$ 208
Wind development	584	(243)	341
Other	15	(8)	7
Total Intangible Assets	**$ 923**	**$ (367)**	**$ 556**

Schedule of Expect Amortization Expense

We expect amortization expense for the five years subsequent to December 31, 2016, to be as follows:

Year ending December 31,	
(Millions)	
2017	$ 16
2018	16
2019	18
2020	17
2021	21

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Property, Plant and Equipment (Tables)

[Summary of Main Asset Categories Depreciated Over the Following Estimated Useful Lives]

12 Months Ended Dec. 31, 2016

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
	Hydroelectric power stations	35-90
	Wind power stations	25-40
	Gas storage	25-40
	Transport facilities	40-56
	Distribution facilities	30-54
Equipment	Conventional meters and measuring devices	15-27
	Computer software	3-5
Other	Buildings	50-75
	Operations offices	4-50

[Regulated and Unregulated [Member]]
[Summary of Main Asset Categories Depreciated Over the Following Estimated Useful Lives]

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	$ 10,343	$ 10,384	$20,727
Natural gas transportation, distribution and other	4,803	613	5,416
Other common operating property	877	43	920
Total Property, Plant and Equipment in Service (a)	**16,023**	**11,040**	**27,063**
Total accumulated depreciation (b)	(3,970)	(3,016)	(6,986)
Total Net Property, Plant and Equipment in Service	**12,053**	**8,024**	**20,077**
Construction work in progress	979	492	1,471
Total Property, Plant and Equipment	**$ 13,032**	**$ 8,516**	**$21,548**

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(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.

Property, plant and equipment as of December 31, 2015, consisted of:

As of December 31, 2015	Regulated	Nonregulated	Total
(Millions)			
Electric generation, distribution, transmission and other	$ 11,506	$ 10,058	$21,564
Natural gas transportation, distribution and other	2,673	651	3,324
Other common operating property	817	40	857
Total Property, Plant and Equipment in Service (a)	**14,996**	**10,749**	**25,745**
Total accumulated depreciation (b)	(3,727)	(2,645)	(6,372)
Total Net Property, Plant and Equipment in Service	**11,269**	**8,104**	**19,373**
Construction work in progress	1,094	244	1,338
Total Property, Plant and Equipment	**$ 12,363**	**$ 8,348**	**$20,711**

(a) Includes capitalized leases of $178 million primarily related to electric generation, distribution, transmission and other.
(b) Includes accumulated amortization of capitalized leases of $53 million.

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Asset Retirement Obligations (Tables)

Table Text Block Supplement [Abstract]

Schedule of Asset Retirement Obligations

12 Months Ended Dec. 31, 2016

The reconciliation of ARO carrying amounts for the years ended December 31, 2016 and 2015 consisted of:

(Millions)		
As of December 31, 2014	**$**	**234**
Liabilities settled during the year		(16)
Liabilities incurred during the year		—
Accretion expense		14
Revisions in estimated cash flows		(48)
As of December 31, 2015	**$**	**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**

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Debt (Tables)

Debt Disclosure [Abstract]

Schedule of Long-term Debt

12 Months Ended
Dec. 31, 2016

Long- term debt as of December 31, 2016 and 2015 consisted of:

As of December 31,		2016		2015	
(Millions)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
First mortgage bonds - fixed (a)	2018-2045	$ 1,752	3.07%-10.60%	$ 1,815	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	1.32%	219	0.195%-1.181%
Other various non-current debt - fixed	2017-2045	2,772	2.89%-10.48%	2,440	2.89%-10.48%
Obligations under capital leases	2017-2023	104	4%-4.44%	87	4%-4.44%
Unamortized debt issuance costs and discount		(31)		(25)	
Total Debt		**4,859**		**4,736**	
Less: debt due within one year, included in current liabilities		349		206	
Total Non-current Debt		**$ 4,510**		**$ 4,530**	

(a) The first mortgage bonds have pledged collateral of substantially all the respective utility's in service properties of approximately $5,886 million.

Schedule of Maturities and Repayments of Long-term Debt

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

(Millions) 2017	2018	2019	2020	2021	Total
$ 349	$ 180	$ 358	$ 723	$ 308	$ 1,918

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Fair Value of Financial Instruments and Fair Value Measurements (Tables)

12 Months Ended

Dec. 31, 2016

Fair Value Disclosures [Abstract]

Schedule of Fair Value Measurements

The financial instruments measured at fair value as of December 31, 2016 and 2015 consisted of:

As of December 31, 2016 (Millions)	Level 1	Level 2	Level 3	Netting	Total
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)**

As of December 31, 2015 (Millions)	Level 1	Level 2	Level 3	Netting	Total
Securities portfolio (available for sale)	**$ 39**	**$ —**	**$ —**	**$ —**	**$ 39**
Derivative assets					
Derivative financial instruments - power	10	81	48	(71)	68
Derivative financial instruments - gas	267	25	68	(280)	80
Contracts for differences	—	—	29	—	29
Total	**277**	**106**	**145**	**(351)**	**177**
Derivative liabilities					
Derivative financial instruments - power	(43)	(12)	(14)	55	(14)
Derivative financial instruments - gas	(193)	(40)	(51)	212	(72)
Contracts for differences	—	—	(96)	—	(96)
Derivative financial instruments - other	—	—	(3)	—	(3)
Total	**$ (236)**	**$ (52)**	**$ (164)**	**$ 267**	**$ (185)**

Fair Value, Financial instrument Based on Level 3 Reconciliation

The reconciliations of changes in the fair value of financial instruments based on Level 3 inputs for the years ended December 31, 2016, 2015 and 2014 consisted of:

(Millions)	2016	2015	2014
Fair value as of January 1,	**$ (19)**	**$ 57**	**$ 53**
Gains for the year recognized in operating revenues	67	33	11
Losses for the year recognized in operating revenues	—	(8)	(1)
Total gains or losses for the period recognized in operating revenues	67	25	10
Gains recognized in OCI	1	2	—
Losses recognized in OCI	—	(3)	(3)
Total gains or losses recognized in OCI	1	(1)	(3)
Net change recognized in regulatory assets and liabilities	(8)	—	—
Purchases	3	(73)	14
Settlements	(9)	(14)	(26)
Transfers out of Level 3 (a)	(4)	(13)	9
Fair value as of December 31,	**$ 31**	**$ (19)**	**$ 57**

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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	$ 67	$ 25	$ 10

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

Additional quantitative information about Level 3 fair value measurements of the CfDs is as follows:

Unobservable Input	Range at December 31, 2016
Risk of non-performance	0.68% - 0.81%
Discount rate	1.47% - 2.45%
Forward pricing ($ per MW)	$3.15 - $9.55

Fair Value, Assets and Liabilities Level 3 Measurement, Valuation Techniques

As of December 31, 2016 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)	$ 4.27	$ 7.37	$ 1.64
				SP15 ($/MWh)	$44.23	$80.28	$14.25
				Mid C ($/MWh)	$35.44	$83.93	$ 3.60
				Cinergy ($/MWh)	$36.40	$77.49	$18.53

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Derivative Instruments and Hedging (Tables)

12 Months Ended Dec. 31, 2016

Derivative Instruments And Hedging Activities Disclosure [Abstract]

Summary of Unrealized Gains and Losses from Fair Value Adjustments

The unrealized gains and losses from fair value adjustments to these derivatives, which are recorded in regulatory assets or regulator the year ended December 31, 2016 and for the period from December 17, 2015 to December 31, 2015, respectively, were as follows:

(Millions)	Year Ended December 31, 2016	Period from December 17, 2015 to December 31, 2015
Regulatory Assets - Derivative liabilities	$ 7	$ 1
Regulatory Liabilities - Derivative assets	$ 1	$ —

Schedule of Notional Volumes of Outstanding Derivative Positions

The net notional volumes of the outstanding derivative instruments associated with Networks activities as of December 31, 2 respectively, consisted of:

As of December 31, (Millions)	2016	2015
Wholesale electricity purchase contracts (MWh)	5.6	6.7
Natural gas purchase contracts (Dth)	5.8	4.8
Fleet fuel purchase contracts (Gallons)	2.3	3.8

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

As of December 31, (MWh/Dth in Millions)	2016	2015
Wholesale electricity purchase contracts	3	3
Wholesale electricity sales contracts	7	6
Foreign exchange forward purchase contracts	—	4
Natural gas and other fuel purchase contracts	329	332
Financial power contracts	8	7
Basis swaps - purchases	49	67
Basis swaps - sales	45	80

Schedule of Derivatives Instruments Statements of Financial Performance and Financial Position, Location in Consolidated Balance Sheet and Amounts

The offsetting of derivatives, location in the consolidated balance sheet and amounts of derivatives associated with Networks activities 31, 2016 and 2015, respectively, consisted of:

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

As of December 31, 2015 (Millions)	Current Assets	Noncurrent Assets	Current Liabilities	Noncu Liabi
Not designated as hedging instruments				
Derivative assets	$ 11	$ 18	$ —	$
Derivative liabilities	—	—	(28)	
	11	18	(28)	
Designated as hedging instruments				
Derivative assets	3	6	3	
Derivative liabilities	(3)	(6)	(42)	
	—	—	(39)	

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Total derivatives before offset of cash collateral	11	18	(67)	
Cash collateral receivable	—	—	37	
Total derivatives as presented in the balance sheet	$ 11	$ 18	$ (30)	$

The offsetting of derivatives, location in the consolidated balance sheet and amounts of derivatives associated with Renewables and C of December 31, 2016 and 2015, respectively, consisted of:

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

As of December 31, 2015 (Millions)	Current Assets	Noncurrent Assets	Current Liabilities	
Not designated as hedging instruments				
Derivative assets	$ 186	$ 113	$ 117	$
Derivative liabilities	(85)	(14)	(169)	
	101	99	(52)	
Designated as hedging instruments				
Derivative assets	56	13	—	
Derivative liabilities	—	—	(9)	
	56	13	(9)	
Total derivatives before offset of cash collateral	157	112	(61)	
Cash collateral receivable (payable)	(80)	(41)	—	
Total derivatives as presented in the balance sheet	$ 77	$ 71	$ (61)	$

Schedule of Derivative Instruments, Effect of Cash flow Hedging on Other Comprehensive Income and Income

The effect of derivatives in cash flow hedging relationships on OCI and income for the years ended December 31, 2016, 2015 and 201 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)
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**
2014			
Interest rate contracts	$ —	Interest expense	$ 9
Commodity contracts	(4)	Operating expenses	1
Total	**$ (4)**		**$ 10**

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

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

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

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	$	**(42)**		**$**	**(43)**
2015					
Commodity contracts	$	57	Revenues	$	(2)
Total	**$**	**57**		**$**	**(2)**

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

Schedule of Fair Value, Net Derivative Contracts

The fair values of derivative contracts associated with Renewables and Gas activities as of December 31, 2016 and 2015, respectively,

As of December 31,	2016	2015
(Millions)		
Wholesale electricity purchase contracts	$ (2)	$ (13)
Wholesale electricity sales contracts	6	35
Foreign exchange forward purchase contracts	—	(1)
Natural gas and other fuel purchase contracts	30	10
Financial power contracts	56	32
Basis swaps- purchases	3	1
Basis swaps- sales	(2)	(2)
Total	**$ 91**	**$ 62**

Effect of Trading and Non-trading Derivatives Associated with Renewables and Gas Activities

The effect of trading and non-trading derivatives, respectively, associated with Renewables and Gas activities for the years ended Dece 2015 and 2014 consisted of:

Years Ended December 31,	2016	2015	2014
(Millions)			
Wholesale electricity purchase contracts	$ 3	$ 6	$ (9)
Wholesale electricity sales contracts	(7)	(5)	9
Financial power contracts	4	—	(2)
Financial and natural gas contracts	(22)	(26)	125
Total (Loss) Gain	**$ (22)**	**$ (25)**	**$ 123**

Years Ended December 31,	2016	2015	2014
(Millions)			
Wholesale electricity purchase contracts	$ 9	$ (8)	$ (8)
Wholesale electricity sales contracts	(20)	(5)	15
Financial power contracts	(10)	24	30
Natural gas and other fuel purchase contracts	34	18	(1)
Total Gain	**$ 13**	**$ 29**	**$ 36**

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Commitments and Contingent Liabilities (Tables)

12 Months Ended

Dec. 31, 2016

Commitments And Contingencies Disclosure [Abstract]

Future Minimum Lease Payments

Total future minimum lease payments as of December 31, 2016 consisted of:

Year	Operating Leases	Capital Leases	Total
	(Millions)		
2017	$ 106	$ 30	$ 136
2018	28	6	34
2019	28	7	35
2020	26	7	33
2021	28	4	32
2022 and thereafter	487	50	537
Total	**$ 703**	**$ 104**	**$ 807**

Forward Purchase and Sales Commitment Arrangement

Forward purchases and sales commitments under power, gas, and other arrangements as of December 31, 2016 consisted of:

	Purchases				Sales			
Year	Gas	Power	Other	Total	Gas	Power	Other	Total
	(Millions)							
2017	$ 284	$ 168	$ 35	$ 487	$ 23	$ 132	$ 4	$ 159
2018	245	108	23	376	4	76	4	84
2019	205	68	14	287	5	53	1	59
2020	161	65	12	238	5	42	—	47
2021	127	52	12	191	—	33	—	33
Thereafter	520	379	109	1,008	—	26	—	26
Totals	**$1,542**	**$ 840**	**$ 205**	**$2,587**	**$ 37**	**$ 362**	**$ 9**	**$ 408**

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Income Taxes (Tables)

12 Months Ended
Dec. 31, 2016

Income Tax Disclosure [Abstract]

Schedule of Current and Deferred Taxes Charged to (Benefit) Expense

Current and deferred taxes charged to (benefit) expense for the years ended December 31, 2016, 2015 and 2014 consisted of:

Years Ended December 31, (Millions)	2016	2015	2014
Current			
Federal	$ (6)	$ (20)	$ (10)
State	8	(33)	31
Current taxes charged to (benefit) expense	**2**	**(53)**	**21**
Deferred			
Federal	414	136	218
State	2	(6)	82
Deferred taxes charged to expense	**416**	**130**	**300**
Production tax credits	(38)	(42)	(37)
Investment tax credits	(1)	(1)	(2)
Total Income Tax Expense	**$ 379**	**$ 34**	**$ 282**

Schedule of Differences between Tax Expense Per Statements of Income and Tax Expense at Statutory Federal Tax Rate

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, 2016, 2015 and 2014 consisted of:

Years Ended December 31, (Millions)	2016	2015	2014
Tax expense at federal statutory rate	$ 353	$ 105	$ 247
Depreciation and amortization not normalized	61	15	15
Investment tax credit amortization	(1)	(1)	(2)
Tax return related adjustments	(2)	6	2
Production tax credits	(38)	(42)	(37)
Tax equity financing arrangements	(25)	(36)	(11)
Change in tax reserves	—	—	3
Changes in New York tax law	—	—	41
State tax expense (benefit), net of federal benefit	7	(25)	32
Non-deductible acquisition costs	—	9	—
Other, net	24	3	(8)
Total Income Tax Expense	**$ 379**	**$ 34**	**$ 282**

Schedule of Deferred Tax Assets and Liabilities

Deferred tax assets and liabilities as of December 31, 2016 and 2015 consisted of:

As of December 31, (Millions)	2016	2015
Non-current Deferred Income Tax Liabilities (Assets)		
Property related	$ 5,195	$ 4,763

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Unfunded future income taxes	216	211
Federal and state tax credits	(417)	(367)
Accumulated deferred investment tax credits	14	15
Federal and state NOL's	(1,397)	(1,367)
Joint ventures/partnerships	651	655
Nontaxable grant revenue	(581)	(595)
Other	(171)	(17)
Non-current Deferred Income Tax Liabilities	3,510	3,298
Add: Valuation allowance	31	19
Total Non-current Deferred Income Tax Liabilities	3,541	3,317
Less amounts classified as regulatory liabilities		
Non-current deferred income taxes	565	519
Non-current Deferred Income Tax Liabilities	$ 2,976	$ 2,798
Deferred tax assets	$ 2,565	$ 2,346
Deferred tax liabilities	6,106	5,663
Net Accumulated Deferred Income Tax Liabilities	$ 3,541	$ 3,317

Schedule of Reconciliation of Unrecognized Income Tax Benefits

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2016, 2015 and 2014 consisted of:

Years ended December 31, (Millions)	2016	2015	2014
Beginning Balance	$ 36	$ 38	$ 41
Increases for tax positions related to prior years	8	1	20
Decreases for tax positions related to prior years	(4)	—	—
Reduction for tax position related to settlements with taxing authorities	—	(3)	(23)
Ending Balance	**$ 40**	**$ 36**	**$ 38**

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Post-retirement and Similar Obligations (Tables)

12 Months Ended Dec. 31, 2016

Schedule of Amounts Recognized in Balance Sheet

Amounts recognized as of December 31, 2016 and 2015 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	2016	2015	2016	2015
(Millions)				
Current liabilities	$ —	$ —	$ (5)	$ (5)
Non-current liabilities	(776)	(845)	(330)	(358)
Total	**$ (776)**	**$ (845)**	**$ (335)**	**$ (363)**

Summary of Amounts Recognized in OCI

Amounts recognized in OCI for ARHI for the years ended December 31, 2016, 2015 and 2014, consisted of:

	Pension Benefits			Postretirement Benefits		
Years Ended December 31,	2016	2015	2014	2016	2015	2014
(Millions)						
Net (gain) loss	$ 23	$ 25	$ 22	$ (3)	$ (1)	$ 8

Regulatory Assets and Liabilities

Note 6. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations, our utilities capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric and natural gas rates. We base our assessment of whether recovery is probable on the existence of regulatory orders that allow for recovery of certain costs over a specific period, or allow for reconciliation or deferral of certain costs. When costs are not treated in a specific 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. Substantially all assets or liabilities for which funds have been expended or received are either included in the rate base or are accruing a carrying cost until they will be included in the rate base. 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 amount of these items is approximately $2,357 million.

Regulatory assets and other 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 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 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 or will be used to recover costs of the Ginna RSSA. Following the approval of the 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

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tax expense and an offsetting increase to revenue, during the year ended December 31, 2016. The amounts will be collected over a period of fifty years.

Current and non-current regulatory assets as of December 31, 2016 and 2015 consisted of:

As of December 31,	2016	2015
(Millions)		
Current		
Pension and other post-retirement benefits cost deferrals	$ 22	$ 8
Pension and other post-retirement benefits	7	13
Storm costs	40	8
Temporary supplemental assessment surcharge	4	7
Reliability support services	27	—
Revenue decoupling mechanism	15	6
Transmission revenue reconciliation mechanism	12	5
Electric supply reconciliation	13	—
Hedges losses	10	37
Contracts for differences	14	18
Hardship programs	16	13
Deferred property tax	10	—
Plant decommissioning	6	—
Deferred purchased gas	14	12
Deferred transmission expense	13	12
Environmental remediation costs	14	37
Other	48	43
Total Current Regulatory Assets	**285**	**219**
Non-current		
Pension and other post-retirement benefits cost deferrals	134	151
Pension and other post-retirement benefits	1,320	1,509
Storm costs	187	251
Deferred meter replacement costs	32	34
Unamortized losses on reacquired debt	20	23
Environmental remediation costs	287	271
Unfunded future income taxes	542	549
Asset retirement obligations	18	24
Deferred property tax	33	45
Federal tax depreciation normalization adjustment	161	158
Merger capital expense target customer credit	11	15
Debt premium	151	141
Plant decommissioning	14	7
Contracts for differences	61	50
Hardship programs	18	29
Other	102	57
Total Non-current Regulatory Assets	**$ 3,091**	**$ 3,314**

“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.

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"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. The portion of storm costs for the amount of $123 million is being recovered over ten-year period and the remaining portion is being amortized over five years following the approval of the proposal by the NYPSC. CMP's total deferral, including carrying costs, was $2 million and $12 million as of December 31, 2016 and 2015, respectively. 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, 2016.

"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 proposal by the NYPSC, these amounts will be collected over a period of fifty years and the NYPSC Staff will perform an audit 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 New York (NY) amount is being amortized over a five year period following the approval of the 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.

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"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.

Current and non-current regulatory liabilities as of December 31, 2016 and 2015 consisted of:

As of December 31,	2016	2015
(Millions)		
Current		
Reliability support services (Cayuga)	$ 3	$ 16
Non by-passable charges	22	7
Energy efficiency portfolio standard	45	33
Gas supply charge and deferred natural gas cost	6	6
Transmission revenue reconciliation mechanism	5	16
Pension and other post-retirement benefits	3	3
Pension and other post-retirement benefits cost deferrals	14	—
Carrying costs on deferred income tax bonus depreciation	15	—
Carrying costs on deferred income tax - Mixed Services 263(a)	5	—
Yankee DOE refund	24	5
Merger-related rate credits	3	20
Revenue decoupling mechanism	9	14
Other	38	27
Total Current Regulatory Liabilities	**192**	**147**
Non-current		
Accrued removal obligations	1,117	1,084
Asset sale gain account	9	8
Carrying costs on deferred income tax bonus depreciation	95	116
Economic development	35	36
Merger capital expense target customer credit account	15	17
Pension and other post-retirement benefits	76	90
Positive benefit adjustment	42	51
New York state tax rate change	9	17
Post term amortization	3	25
Theoretical reserve flow thru impact	24	31
Deferred property tax	19	15
Net plant reconciliation	10	10
Variable rate debt	28	32
Carrying costs on deferred income tax - Mixed Services 263(a)	25	31
Rate refund – FERC ROE proceeding	22	21
Transmission congestion contracts	18	—
Merger-related rate credits	21	24
Accumulated deferred investment tax credits	15	10

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Asset retirement obligation	13	13
Earning sharing provisions	12	—
Middletown/Norwalk local transmission network service collections	19	19
Excess generation service charge	—	21
Low income programs	46	42
Unfunded future income taxes	—	27
Non-firm margin sharing credits	7	8
Deferred income taxes regulatory	565	519
Other	73	93
Total Non-current Regulatory Liabilities	**$ 2,318**	**$ 2,360**

"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. 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 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 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 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 Energy East by Iberdrola. The amortization period is five years following the approval of the 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.

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"Positive benefit adjustment" resulted from Iberdrola's 2008 acquisition of Energy East. This is being used to moderate increases in rates. The amortization period is five years following the approval of the 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 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 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 proposal by the NYPSC.

"Merger-related rate credits" resulted from the acquisition of UIL. This is being used to moderate increases in rates. See Merger Settlement Agreement in Note 4 for further details. In the year ended December 31, 2016, $20 million of rate credits was 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.

Amounts Expected to be Amortized for Net Periodic Benefit Cost

Amounts expected to be amortized from regulatory assets or liabilities into net periodic benefit cost for the year ending December 31, 2017 consists of:

Year Ended December 31, 2017 (Millions)	Pension Benefits	Postretirement Benefits
Estimated net loss	$ 126	$ 5
Estimated prior service cost (benefit)	2	(9)

Amounts expected to be amortized from OCI into net periodic benefit cost for the year ending December 31, 2017 consists of:

Year Ended December 31, 2017 (Millions)	Pension Benefits	Postretirement Benefits
Estimated net loss	$ 1	$ —
Estimated prior service cost (benefit)	—	—

Assumed Health Care Cost Trend Rates Used to Determine Benefit Obligations

Assumed health care cost trend rates used to determine benefit obligations as of December 31, 2016 and 2015 consisted of:

As of December 31,	2016	2015
Health care cost trend rate assumed for next year -	7.00%/ 9.00%	7.50%/ 7.00%

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Networks		
Health care cost trend rate assumed for next year - ARHI	6.75%/ 8.50%	7.00%/ 9.00%
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	2027
Year that the rate reaches the ultimate trend rate - ARHI	2026 / 2028	2026

One Percent Change in Assumed Health Care Cost Trend Rates

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	$ 14	$ (12)

Fair Values of Pension Benefits Plan Assets, by Asset Category

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	—
Common collective trusts	1,192	—	371	821
Partnerships/joint venture interests	5	—	—	5
Real estate investments	61	—	—	61
Other, principally annuity, fixed income	589	—	315	274
Total	**$ 2,672**	**$ 414**	**$ 1,097**	**$ 1,161**

The fair values of pension benefits plan assets, by asset category, as of December 31, 2015 consisted of:

As of December 31, 2015		Fair Value Measurements		
(Millions)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 57	$ 3	$ 54	$ —
U.S. government securities	171	171	—	—
Common stocks	314	314	—	—
Registered investment companies	114	114	—	—
Corporate bonds	324	—	324	—
Preferred stocks	5	—	5	—

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Common collective trusts	859	—	369	490
Partnership/joint venture interests	84	—	—	84
Real estate investments	89	—	—	89
Other, principally annuity, fixed income	647	—	329	318
Total	**$ 2,664**	**$ 602**	**$ 1,081**	**$ 981**

Fair Value, Financial instrument Based on Level 3 Reconciliation

The reconciliations of changes in the fair value of financial instruments based on Level 3 inputs for the years ended December 31, 2016, 2015 and 2014 consisted of:

(Millions)	2016	2015	2014
Fair value as of January 1,	**$ (19)**	**$ 57**	**$ 53**
Gains for the year recognized in operating revenues	67	33	11
Losses for the year recognized in operating revenues	—	(8)	(1)
Total gains or losses for the period recognized in operating revenues	67	25	10
Gains recognized in OCI	1	2	—
Losses recognized in OCI	—	(3)	(3)
Total gains or losses recognized in OCI	1	(1)	(3)
Net change recognized in regulatory assets and liabilities	(8)	—	—
Purchases	3	(73)	14
Settlements	(9)	(14)	(26)
Transfers out of Level 3 (a)	(4)	(13)	9
Fair value as of December 31,	**$ 31**	**$ (19)**	**$ 57**
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	$ 67	$ 25	$ 10

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

Additional quantitative information about Level 3 fair value measurements of the CfDs is as follows:

Unobservable Input	Range at December 31, 2016
Risk of non-performance	0.68% - 0.81%
Discount rate	1.47% - 2.45%
Forward pricing ($ per MW)	$3.15 - $9.55

Fair Value of Other Postretirement Benefits Plan Assets, by Asset Category

The fair value 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	—	—

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Mutual funds, other	16	9	7	—
Total	**$ 160**	**$ 118**	**$ 42**	**$ —**

The fair values of other postretirement benefits plan assets, by asset category, as of December 31, 2015 consisted of:

As of December 31, 2015		Fair Value Measurements		
(Millions)	Total	Level 1	Level 2	Level 3
Asset Category				
Money market funds	$ 4	$ 4	$ —	$ —
Mutual funds, fixed	36	36	—	—
Government and corporate bonds	2	—	2	—
Mutual funds, equity	46	46	—	—
Common stocks	24	24	—	—
Mutual funds, other	50	43	7	—
Total	**$ 162**	**$ 153**	**$ 9**	**$ —**

Level 3 [Member]

Fair Value, Financial instrument Based on Level 3 Reconciliation

The reconciliation of changes in fair value of plan assets based on Level 3 inputs for the years ended December 31, 2016 and 2015, consisted of:

(Millions)	Common Collective Trusts	Partnership Joint Venture Interests	Real Estate Investments	Other Investments	Total
As of December 31, 2014	**$ 449**	**$ 79**	**$ 75**	**$ 342**	**$ 945**
Actual return on plan assets:					
Relating to assets sold during the year	(3)	(19)	—	1	(21)
Relating to assets still held at the reporting date	(5)	19	10	(21)	3
Purchases, sales and settlements	49	5	4	(4)	54
As of December 31, 2015	**$ 490**	**$ 84**	**$ 89**	**$ 318**	**$ 981**
Actual return on plan assets:					
Relating to assets sold during the year	6	(19)	—	1	(12)
Relating to assets still held at the reporting date	51	—	2	(8)	45
Purchases, sales and settlements	274	(60)	(30)	(37)	147
As of December 31, 2016	**$ 821**	**$ 5**	**$ 61**	**$ 274**	**$ 1,161**

Networks and ARHI [Member]

Obligations and Funded Status

Obligations and funded status of Networks and ARHI as of December 31, 2016 and 2015 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	2016	2015	2016	2015
(Millions)				
Change in benefit obligation				
Benefit obligation as of January 1,	**$ 3,509**	**$ 2,620**	**$ 525**	**$ 435**
Acquisition of UIL	—	1,019	—	122
Service cost	44	36	5	5
Interest cost	142	99	21	16
Plan participants' contributions	—	—	7	4

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Plan amendments	—	—	—	(1)
Actuarial gain	(43)	(105)	(24)	(31)
Special termination benefits	—	2	—	—
Benefits paid	(204)	(162)	(39)	(25)
Benefit Obligation as of December 31,	**3,448**	**3,509**	**495**	**525**
Change in plan assets				
Fair value of plan assets as of January 1,	**2,664**	**2,143**	**162**	**129**
Acquisition of UIL	—	687	—	39
Actual return on plan assets	169	(31)	11	(4)
Employer contributions	43	27	30	21
Plan participants' contributions	—	—	7	4
Benefits paid	(204)	(162)	(39)	(25)
Withdrawals from VEBA	—	—	(11)	(2)
Fair Value of Plan Assets as of December 31,	**2,672**	**2,664**	**160**	**162**
Funded Status as of December 31,	**$ (776)**	**$ (845)**	**$ (335)**	**$ (363)**

Aggregate Projected and Accumulated Benefit Obligations and Fair Value of Plan Assets for Underfunded Plans

The aggregate projected and accumulated benefit obligations and the fair value of plan assets for underfunded plans of Networks and ARHI as of December 31, 2016 and 2015 consisted of:

	Projected Benefit Obligation Exceeds Fair Value of Plan Assets		Accumulated Benefit Obligation Exceeds Fair Value of Plan Assets	
As of December 31,	**2016**	**2015**	**2016**	**2015**
(Millions)				
Projected benefit obligation	$ 3,448	$ 3,509	$ 3,448	$ 3,509
Accumulated benefit obligation	3,214	3,261	3,214	3,261
Fair value of plan assets	2,672	2,664	2,672	2,664

Weighted Average Assumptions Used to Determine Benefit Obligations and Net periodic Benefit Cost

The weighted-average assumptions used to determine benefit obligations for Networks and ARHI as of December 31, 2016 and 2015 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	**2016**	**2015**	**2016**	**2015**
Discount rate - Networks	4.12% / 4.24%	4.10% / 4.24%	4.12% / 4.24%	4.10% / 4.24%
Discount rate - ARHI	3.81%	3.90%	3.81%	3.90%
Rate of compensation increase - Networks	3.50% - 4.20%	4.00%	—	—

The weighted-average assumptions used to determine net periodic benefit cost for Networks and ARHI for the years ended December 31, 2016, 2015 and 2014 consisted of:

	Pension Benefits			Postretirement Benefits		
Years Ended December 31,	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Discount rate - Networks	4.12% / 4.24%	3.80% / 4.24%	4.90%	4.12% / 4.24%	3.80% / 4.24%	4.90%
Discount rate - ARHI	3.90%	3.90%	5.00%	3.90%	3.90%	5.00%
Expected long-term return on plan assets - Networks	7.40% / 7.75%	7.50%	7.50%	7.16%	—	—
Expected long-term return on plan assets - ARHI	5.50%	5.50%	6.90%	5.50%	5.75%	6.50%

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Expected long-term return on plan assets - nontaxable trust - Networks	—	—	—	7.00%	7.50%	7.50%
Expected long-term return on plan assets - taxable trust - Networks	—	—	—	4.50%	5.00%	5.00%
Rate of compensation increase - Networks	3.50% - 4.20%	4.10%	4.20%	—	—	—

Networks and ARHI [Member] | Improvement and Modernization Act of 2003 [Member]

Expected Future Benefits 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, 2016 consisted of:

(Millions)	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
2017	$ 211	$ 34	$ —
2018	212	34	—
2019	216	34	—
2020	219	35	—
2021	224	35	—
2022 - 2026	1,125	169	3

Iberdrola Renewables Holding, Inc. (IRHI) [Member]

Regulatory Assets and Liabilities

Amounts recognized as regulatory assets or regulatory liabilities for Networks for the years ended December 31, 2016, 2015 and 2014 for Networks consisted of:

	Pension Benefits			Postretirement Benefits		
Years Ended December 31,	2016	2015	2014	2016	2015	2014
(Millions)						
Net loss	$ 860	$ 994	$ 1,045	$ 44	$ 76	$ 96
Prior service cost (credit)	7	9	12	(40)	(49)	(57)

Net Periodic Benefit Cost and Other Changes in Plan Assets and Benefit Obligations

Components of Networks' net periodic benefit cost and other changes in plan assets and benefit obligations recognized in income and regulatory assets and liabilities as of December 31, 2016, 2015 and 2014 consisted of:

(Millions)	Pension Benefits			Postretirement Benefits		
As of December 31,	2016	2015	2014	2016	2015	2014
Net Periodic Benefit Cost:						
Service cost	$ 44	$ 36	$ 30	$ 5	$ 4	$ 4
Interest cost	140	97	107	20	15	17
Expected return on plan assets	(199)	(156)	(161)	(8)	(7)	(7)
Amortization of prior service cost (benefit)	2	3	4	(9)	(9)	(11)
Amortization of net loss	123	130	94	8	7	—

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Special termination benefit charge	—	2	—	—	—	—
Settlement charge	—	2	—	—	—	—
Net Periodic Benefit Cost	**110**	**114**	**74**	**16**	**10**	**3**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities:						
Settlements	$ —	$ (2)	$ —	$ —	$ —	$ —
Net loss (gain)	(11)	69	434	(24)	(12)	72
Amortization of net loss	(123)	(130)	(94)	(8)	(7)	—
Current year prior service cost	—	—	—	—	(1)	—
Amortization of prior service (cost) benefit	(2)	(3)	(4)	9	9	11
Total Other Changes	(136)	**(66)**	**336**	(23)	**(11)**	**83**
Total Recognized	**$ (26)**	**$ 48**	**$ 410**	**$ (7)**	**$ (1)**	**$ 86**

Iberdrola Renewables Holding, Inc [Member]

Net Periodic Benefit Cost and Other Changes in Plan Assets and Benefit Obligations

Components of ARHI's net periodic benefit cost and other changes in plan assets and benefit obligations recognized in income and OCI as of December 31, 2016, 2015 and 2014 consisted of:

(Millions)	Pension Benefits			Postretirement Benefits		
As of December 31,	2016	2015	2014	2016	2015	2014
Net Periodic Benefit Cost:						
Service cost	$ —	$ —	$ —	$ —	$ 1	$ 1
Interest cost	2	2	2	1	1	1
Expected return on plan assets	(2)	(2)	(3)	—	—	—
Amortization of prior service cost	-	—	—	—	—	1
Amortization of net loss	1	1	—	—	—	1
Settlement charge	1	—	—	—	—	—
Net Periodic Benefit Cost (income)	**2**	**1**	**(1)**	**1**	**2**	**4**
Other Changes in plan assets and benefit obligations recognized in OCI:						
Net loss (gain)	—	4	6	(2)	(8)	(5)
Amortization of net loss	(1)	(1)	—	—	—	(1)
Amortization of prior service (cost)	—	—	—	—	—	(1)
Total Other Changes	**(1)**	**3**	**6**	**(2)**	**(8)**	**(7)**
Total Recognized	**$ 1**	**$ 4**	**$ 5**	**$ (1)**	**$ (6)**	**$ (3)**

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Equity (Tables)

Equity [Abstract]

Accumulated Other Comprehensive Income (Loss)

12 Months Ended Dec. 31, 2016

Accumulated OCI (Loss)

Accumulated OCI for the years ended December 31, 2016, 2015 and 2014 consisted of:

Accumulated Other Comprehensive Income (Loss)	As of December 31, 2013	2014 Change	As of December 31, 2014	2015 Change	As of December 31, 2015	2016 Change	As of December 31, 2016
(Millions)							
Loss on revaluation of defined benefit plans, net of income tax expense of $0.6 for 2014, $2.2 for 2015 and $4.3 for 2016	$ (26)	$ 1	$ (25)	$ 4	$ (21)	$ 7	$ (14)
Loss for nonqualified pension plans, net of income tax expense (benefit) of $(1.9) for 2014, $1.7 for 2015 and $0.4 for 2016	(8)	(3)	(11)	3	(8)	1	(7)
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 ($1.4) for 2014, $20.9 for 2015 and $(15.8) for 2016	—	(2)	(2)	33	31	(26)	5
Reclassification adjustment for losses on settled cash flow hedges, net of income	(66)	5	(61)	7	(54)	(16)	(70)

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tax expense (benefit) of $4.1 for 2014, $4.9 for 2015 and $(11.0) for 2016 (a)							
Net unrealized (loss) gain on derivatives qualifying as cash flow hedges	(66)	3	(63)	40	(23)	(42)	(65)
Accumulated Other Comprehensive (Loss) Income	**$ (100)**	**$ 1**	**$ (99)**	**$ 47**	**$ (52)**	**$ (34)**	**$ (86)**

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

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Earnings Per Share (Tables)

12 Months Ended
Dec. 31, 2016

Earnings Per Share [Abstract]

Schedule of Earnings Per Share, Basic and Diluted

The calculations of basic and diluted earnings per share attributable to AVANGRID for the years ended December 31, 2016, 2015 and 2014, consisted of:

Years Ended December 31, (Millions, except for number of shares and per share data)	2016	2015	2014
Numerator:			
Net income attributable to AVANGRID	$ 630	$ 267	$ 424
Denominator:			
Weighted average number of shares outstanding - basic	309,512,553	254,588,212	252,235,232
Weighted average number of shares outstanding - diluted	309,817,322	254,605,111	252,235,232
Earnings per share attributable to AVANGRID			
Earnings Per Common Share, Basic	$ 2.04	$ 1.05	$ 1.68
Earnings Per Common Share, Diluted	$ 2.04	$ 1.05	$ 1.68

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Grants, Government Incentives and Deferred Income (Tables)

12 Months Ended

Dec. 31, 2016

Deferred Revenue Disclosure [Abstract]

Schedule of Changes in Deferred Income

The changes in deferred income as of December 31, 2016 and 2015 consisted of:

(Millions)	Government grants	Other deferred income	Total
As of December 31, 2014	$ 1,606	$ 15	$ 1,621
Additions	—	—	—
Recognized in income	(77)	9	(68)
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

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Other Financial Statements Items (Tables)	12 Months Ended Dec. 31, 2016

Receivables [Abstract]

Schedule of Other Income and (Expense)

Other income and (expense) for the years ended December 31, 2016, 2015 and 2014 consisted of:

Years ended December 31, (Millions)	2016	2015	2014
Allowance for funds used during construction	$ 26	$ 21	$ 17
Carrying costs on regulatory assets	14	28	29
Other	36	6	6
Total Other income and (expense)	**$ 76**	**$ 55**	**$ 52**

Schedule of Accounts Receivable

Accounts receivable as of December 31, 2016 and 2015 consisted of:

As of December 31, (Millions)	2016	2015
Trade receivables	$ 1,183	$ 1,036
Allowance for bad debts	(64)	(62)
Total Accounts Receivable	**$ 1,119**	**$ 974**

Schedule of Change in Allowance For Bad Debts

The change in the allowance for bad debts as of December 31, 2016 and 2015 consisted of:

(Millions)	
As of December 31, 2013	**58**
Current period provision	39
Write-off as uncollectible	(48)
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**

Schedule of Prepayments and Other Current Assets

Prepayments and other current assets as of December 31, 2016 and 2015 consisted of:

As of December 31, (Millions)	2016	2015
Prepaid other taxes	$ 153	$ 130
Broker margin and collateral accounts	32	46
Loans to third parties	3	3
Fixed-term deposits	3	11
Other pledged deposits	8	24
Prepaid expenses	53	53
Other	3	18
Total	**$ 255**	**$ 285**

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Schedule of Other Current Liabilities

Other current liabilities as of December 31, 2016 and 2015 consisted of:

As of December 31, (Millions)	2016	2015
Advances received	$ 107	$ 96
Accrued salaries	84	68
Short-term environmental provisions	34	35
Collateral deposits received	45	59
Pension and other postretirement	5	5
Other	4	22
Total	**$ 279**	**$ 285**

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Segment Information (Tables)

Segment Reporting [Abstract]

Schedule of Segment Information

12 Months Ended Dec. 31, 2016

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) from continuing operations	1,086	149	(41)	—	1,194
Adjusted EBITDA	1,552	462	(16)	—	1,998
Earnings (loss) from equity method investments	15	(8)	—	—	7
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.

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 of noncurrent assets	—	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 (loss) from equity method investments	1	(5)	—	4	—
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.

Segment information as of and for the year ended December 31, 2014 consisted of:

For the year ended December 31, 2014 (Millions)	Networks	Renewables	Gas	Other(a)	AVANGRID Consolidated

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Revenue - external	$ 3,396	$ 1,180	$ 12	$ 6	$ 4,594
Revenue - intersegment	1	9	72	(82)	—
Impairment of noncurrent assets	—	24	—	1	25
Depreciation and amortization	275	332	22	—	629
Operating income (loss) from continuing operations	616	257	16	(4)	885
Adjusted EBITDA	891	613	38	(3)	1,539
Earnings from equity method investments	—	2	—	10	12
Capital expenditures	775	250	5	—	1,030
As of December 31, 2014					
Property, plant and equipment	8,389	8,219	525	—	17,133
Equity method investments	—	262	—	—	262
Total assets	$ 12,858	$ 12,328	$1,393	$(2,417)	$ 24,162

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

Schedule of Reconciliation of Consolidated EBITDA to Consolidated Net Income

Reconciliation of consolidated Adjusted EBITDA to the AVANGRID consolidated Net Income for the years ended December 31, 2016, 2015 and 2014, respectively, is as follows:

Years Ended December 31, (Millions)	2016	2015	2014
Consolidated Adjusted EBITDA	**$ 1,998**	**$ 1,220**	**$ 1,539**
Less:			
Impairment of non-current assets	—	12	25
Depreciation and amortization	804	695	629
Interest expense, net of capitalization	268	267	243
Income tax expense	379	34	282
Add:			
Other income	76	55	52
Earnings from equity method investments	7	—	12
Consolidated Net Income	**$ 630**	**$ 267**	**$ 424**

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Related Party Transactions (Tables)

12 Months Ended Dec. 31, 2016

Related Party Transactions [Abstract]

Schedule of Related Party Transactions

Related party transactions for the years ended December 31, 2016, 2015 and 2014, respectively, consisted of:

Years Ended December 31,	2016		2015		2014	
(Millions)	Sales To	Purchases From	Sales To	Purchases From	Sales To	Purchases From
Iberdrola Financiación, S.A.	$ —	$ (2)	—	$ (1)	—	$ (2)
Iberdrola Renovables Energia, S.L.	—	(8)	—	(9)	—	(10)
Iberdrola Canada Energy Services, Ltd	—	(37)	—	(55)	—	(49)
Iberdrola, S.A.	—	(31)	—	(35)	—	(20)
Other	21	(1)	3	(2)	12	(10)

Schedule of Related Party Balances

Related party balances as of December 31, 2016 and 2015, respectively, consisted of:

As of December 31,	2016		2015	
(Millions)	Owed By	Owed To	Owed By	Owed To
Iberdrola Canada Energy Services, Ltd	$ —	$ (14)	$ 7	$ (5)
Gamesa Corporación Tecnológica, S.A.	1	(181)	68	(77)
Iberdrola, S.A.	—	(30)	—	(3)
Iberdrola Energy Projects, Inc.	—	—	1	(3)
Iberdrola Renovables Energía, S.L.	2	—	—	—
Other	22	(3)	—	(2)

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Stock-Based Compensation (Tables)

12 Months Ended Dec. 31, 2016

Disclosure Of Compensation Related Costs Sharebased Payments [Abstract]

Summary of Nonvested PSUs

A summary of the status of the AVANGRID's nonvested PSUs as of December 31, 2016, and changes during the fiscal year ended December 31, 2016, is presented below:

	Number of PSUs	Weighted Average Grant Date Fair Value
Nonvested Balance – December 31, 2015	411,207	$ 39.60
Granted	1,335,416	$ 31.92
Forfeited	(36,592)	$ 32.83
Vested	(186,050)	$ 40.84
Nonvested Balance – December 31, 2016	1,523,981	$ 33.01

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Quarterly Financial Data (unaudited) (Tables)

12 Months Ended Dec. 31, 2016

Selected Quarterly Financial Information [Abstract]

Schedule of Quarterly Financial Data

Selected quarterly financial data for 2016 and 2015 are set forth below:

(Millions, except per share data)	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2016				
Operating revenues	$ 1,670	$ 1,439	$ 1,418	$ 1,491
Operating Income	$ 349	$ 322	$ 217	$ 306
Net Income	$ 212	$ 102	$ 109	$ 207
Net Income attributable to Avangrid, Inc.	$ 212	$ 102	$ 109	$ 207
Earnings Per Common Share, Basic and Diluted: (1)	$ 0.69	$ 0.33	$ 0.35	$ 0.67
2015				
Operating revenues	$ 1,227	$ 939	$ 1,048	$ 1,153
Operating Income	$ 196	$ 73	$ 161	$ 83
Net Income	$ 106	$ 11	$ 54	$ 96
Net Income attributable to Avangrid, Inc.	$ 106	$ 11	$ 54	$ 96
Earnings Per Common Share, Basic and Diluted: (1)	$ 0.42	$ 0.04	$ 0.22	$ 0.37

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Cash Dividends Paid by Subsidiaries (Tables)

12 Months Ended Dec. 31, 2016

Avangrid, Inc [Member]

Schedule of Cash Dividends Paid by Subsidiaries

Cash dividends paid by subsidiaries are as follows:

Years ended December 31, (In millions)	2016	2015	2014
AVANGRID Networks	$ 220	$ 59	$ 200
AVANGRID Renewables	200	750	—
Other AVANGRID subsidiaries	—	302	—
	$ 420	$1,111	$ 200

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Background and Nature Of Operations - Additional Information (Detail)	12 Months Ended Dec. 31, 2016 $ / shares shares
Nature Of Business [Line Items]	
Owned Subsidiaries	81.50%
Effective date of business acquisition of UIL Holdings	Feb. 25, 2015
Shares issued in connection with acquisition	309,490,839
Shares issued in connection with the acquisition at par value | $ / shares	$ 10.50
Membership interest	50.00%
Iberdrola, S.A. [Member]	
Nature Of Business [Line Items]	
Shares issued in connection with acquisition	252,234,989
UIL Holdings [Member]	
Nature Of Business [Line Items]	
Shares issued in connection with acquisition	57,255,850
Shares issued in connection with the acquisition at par value | $ / shares	$ 0.01
Percentage of ownership	18.50%
Issuance of share in connection of acquisition	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.
NEW YORK	
Nature Of Business [Line Items]	
Incorporation date of organization	Jan. 01, 1997

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Basis of Presentation - Additional Information (Detail) - USD ($) $ / shares in Units, $ in Millions	12 Months Ended		
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Service Life [Member]			
Change In Accounting Estimate [Line Items]			
Decrease in depreciation and amortization expense	$ 52		
Decrease in asset retirement obligation accretion expense	3		
Increase in earnings from equity method investments	4		
Estimated increase in net income	$ 36		
Increase in earnings per share, basic	$ 0.12		
Increase in earnings per share, diluted	$ 0.12		
Estimated increase in income before income tax	$ 59		
Wind Power Stations [Member]			
Change In Accounting Estimate [Line Items]			
Depreciation rate		4.00%	4.00%
Estimated useful life	40 years		
Wind Power Stations [Member] | Wind Farm Assets [Member]			
Change In Accounting Estimate [Line Items]			
Estimated useful life	31 years		
Wind Power Stations [Member] | Scenario, Previously Reported [Member]			
Change In Accounting Estimate [Line Items]			
Estimated useful life		25 years	

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Summary of Significant Accounting Policies, New Accounting Pronouncements, and Use of Estimates - Additional Information (Detail) - USD ($)		12 Months Ended	
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Accounting Polices [Line Items]			
Percentage of tax returns included in taxable income	80.00%		
Increase (decrease) in restricted cash and cash equivalents		$ 2,000,000	$ 0
Percentage of employees covered by collective bargaining agreement	48.00%		
Percentage of expiry	6.00%		
Minimum [Member]			
Accounting Polices [Line Items]			
Finite lived intangible assets useful economic life	4 years		
Maximum [Member]			
Accounting Polices [Line Items]			
Finite lived intangible assets useful economic life	40 years		

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Summary of Significant Accounting Policies, New Accounting Pronouncements, and Use of Estimates - Summary of Main Asset Categories Depreciated Over the Following Estimated Useful Lives (Detail)	12 Months Ended Dec. 31, 2016
Wind Power Stations [Member]	
Property Plant And Equipment [Line Items]	
Estimated Useful Life (years)	40 years
Plant [Member] | Combined Cycle Plants [Member]	
Property Plant And Equipment [Line Items]	
Estimated Useful Life (years)	35 years
Minimum [Member] | Plant [Member] | Hydroelectric Power Stations [Member]	
Property Plant And Equipment [Line Items]	
Estimated Useful Life (years)	35 years
Minimum [Member] | Plant [Member] | Wind Power Stations [Member]	
Property Plant And Equipment [Line Items]	
Estimated Useful Life (years)	25 years
Minimum [Member] | Plant [Member] | Gas Storage [Member]	
Property Plant And Equipment [Line Items]	
Estimated Useful Life (years)	25 years
Minimum [Member] | Plant [Member] | Transport Facilities [Member]	
Property Plant And Equipment [Line Items]	
Estimated Useful Life (years)	40 years
Minimum [Member] | Plant [Member] | Distribution Facilities [Member]	
Property Plant And Equipment [Line Items]	
Estimated Useful Life (years)	30 years
Minimum [Member] | Equipment [Member] | Conventional Meters And Measuring Devices [Member]	
Property Plant And Equipment [Line Items]	
Estimated Useful Life (years)	15 years
Minimum [Member] | Other [Member] | Buildings [Member]	
Property Plant And Equipment [Line Items]	
Estimated Useful Life (years)	50 years
Minimum [Member] | Other [Member] | Operations Offices [Member]	
Property Plant And Equipment [Line Items]	
Estimated Useful Life (years)	4 years
Minimum [Member] | Other [Member] | Computer Software[Member]	
Property Plant And Equipment [Line Items]	
Estimated Useful Life (years)	3 years
Maximum [Member] | Plant [Member] | Hydroelectric Power Stations [Member]	

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Property Plant And Equipment [Line Items]	
Estimated Useful Life (years)	90 years
Maximum [Member] | Plant [Member] | Wind Power Stations [Member]	
Property Plant And Equipment [Line Items]	
Estimated Useful Life (years)	40 years
Maximum [Member] | Plant [Member] | Gas Storage [Member]	
Property Plant And Equipment [Line Items]	
Estimated Useful Life (years)	40 years
Maximum [Member] | Plant [Member] | Transport Facilities [Member]	
Property Plant And Equipment [Line Items]	
Estimated Useful Life (years)	56 years
Maximum [Member] | Plant [Member] | Distribution Facilities [Member]	
Property Plant And Equipment [Line Items]	
Estimated Useful Life (years)	54 years
Maximum [Member] | Equipment [Member] | Conventional Meters And Measuring Devices [Member]	
Property Plant And Equipment [Line Items]	
Estimated Useful Life (years)	27 years
Maximum [Member] | Other [Member] | Buildings [Member]	
Property Plant And Equipment [Line Items]	
Estimated Useful Life (years)	75 years
Maximum [Member] | Other [Member] | Operations Offices [Member]	
Property Plant And Equipment [Line Items]	
Estimated Useful Life (years)	50 years
Maximum [Member] | Other [Member] | Computer Software[Member]	
Property Plant And Equipment [Line Items]	
Estimated Useful Life (years)	5 years

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Acquisition of UIL - Additional Information (Detail) - USD ($)	Dec. 16, 2015	12 Months Ended			Aug. 04, 2016
		Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014	
Business Acquisition [Line Items]					
Shares issued in connection with acquisition		309,490,839			
Common stock, par value		$ 0.01	$ 0.01		
Payments to acquire business, cash paid	$ 595,000,000				
Business acquisition, share price		$ 10.50			
Revenue			$ 5,958,000,000	$ 6,226,000,000	
Business acquisition, Net income (loss)			468,000,000	$ 539,000,000	
Goodwill		$ 3,124,000,000	3,115,000,000		
Costs related to investigation and remediation		388,000,000	397,000,000		
Fair value of contingent liability		46,000,000			
Regulatory liabilities		19,800,000			
Merger Related Rate Credits [Member]					
Business Acquisition [Line Items]					
Regulatory liabilities		44,000,000			
DEEP [Member]					
Business Acquisition [Line Items]					
Business combination contribution to stimulate investment		$ 2,000,000			
Contribution term to stimulate investment		3 years			
Connecticut [Member]					
Business Acquisition [Line Items]					
Contribution for disaster relief entities		$ 1,000,000			
Minimum year of charitable contribution at historical contribution levels		4 years			
Connecticut [Member] | Minimum [Member]					
Business Acquisition [Line Items]					
Business combination expected merger related costs		$ 500,000			
Charitable contribution at historical contribution levels		500,000			
Connecticut [Member] | Maximum [Member]					
Business Acquisition [Line Items]					
Charitable contribution at historical contribution levels		800,000			
Massachusetts [Member] | Minimum [Member]					

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Business Acquisition [Line Items]			
Business combination expected merger related costs	500,000		
AVANGRID [Member]			
Business Acquisition [Line Items]			
Payments to acquire business, cash paid		595,000,000	
Southern Connecticut Gas Company (SCG) [Member]			
Business Acquisition [Line Items]			
Business combination additional rate credits	$ 750,000		
Business combination rate credit allocation period	10 years		
Savings to SCG customers	$ 1,600,000		
UI [Member]			
Business Acquisition [Line Items]			
Regulatory liabilities	0	1,000,000	
UI [Member] | Connecticut [Member]			
Business Acquisition [Line Items]			
Benefits to customers	5,000,000		
Investment in storm resiliency programs	50,000,000		
United Illuminating Company (UI)			
Business Acquisition [Line Items]			
Costs related to investigation and remediation	28,300,000	20,500,000	$ 30,000,000
Estimated environmental liability	1,700,000	9,500,000	
Difference in pretax reflected as reversal of expense	7,800,000		
United Illuminating Company (UI) | Maximum [Member]			
Business Acquisition [Line Items]			
Cost of investigation and remediation	30,000,000		
The Berkshire Gas Company [Member] | Massachusetts [Member]			
Business Acquisition [Line Items]			
Customers receivable rate credits	4,000,000		
Contribution to alternative heating programs	1,000,000		
Connecticut Natural Gas Corporation (CNG) [Member]			
Business Acquisition [Line Items]			
Business combination additional rate credits	$ 1,250,000		
Business combination rate credit allocation period	10 years		
UIL Holdings [Member]			
Business Acquisition [Line Items]			
Shares issued in connection with acquisition	57,255,850		

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Payments to acquire business, cash paid	$ 595,000,000		
Business combination, date of acquisition		Dec. 16, 2015	
Number of Consecutive Trading Days	10 days		
Business acquisition, share price	$ 50.10	$ 10.50	
Business combination, transaction costs			37,500,000
Revenue			36,000,000
Business acquisition, Net income (loss)			$ (36,000,000)
Goodwill		$ 1,765,000,000	
UIL Holdings [Member] | Restatement Adjustment			
Business Acquisition [Line Items]			
Goodwill		11,000,000	
UIL Holdings [Member] | AVANGRID [Member]			
Business Acquisition [Line Items]			
Shares issued in connection with acquisition	309,490,839		
Common stock, par value	$ 0.01		
Percentage of ownership	18.50%		
Business acquisition, share price	$ 10.50		
UIL Holdings [Member] | AVANGRID [Member] | Iberdrola, S.A. [Member]			
Business Acquisition [Line Items]			
Shares issued in connection with acquisition	252,234,989		
UIL Holdings [Member] | AVANGRID [Member] | UIL shareowners [Member]			
Business Acquisition [Line Items]			
Shares issued in connection with acquisition	57,255,850		
Connecticut [Member]			
Business Acquisition [Line Items]			
Business combination amount allocated for rate credits to customers		$ 20,000,000	

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Acquisition of UIL - Summary of Fair Value of Purchase Consideration (Detail) - USD ($) $ / shares in Units, $ in Millions	Dec. 16, 2015	12 Months Ended Dec. 31, 2016	Dec. 31, 2015 [1]	Dec. 15, 2015	Dec. 31, 2014 [1]	Dec. 31, 2013 [1]
Business Acquisition Equity Interests Issued Or Issuable [Line Items]						
Common shares		308,993,149 [1]	308,864,609	252,235,232	252,235,232	252,235,232
Business acquisition, share price		$ 10.50				
Shares issued in connection with acquisition		309,490,839				
Total consideration	$ 2,873					
Performance Shares [Member]						
Business Acquisition Equity Interests Issued Or Issuable [Line Items]						
Vesting shares		186,050				
UIL Holdings [Member]						
Business Acquisition Equity Interests Issued Or Issuable [Line Items]						
Common shares	[2] 56,629,377					
Business acquisition, share price	$ 50.10	$ 10.50				
Subtotal value of common shares	$ 2,837					
Other shares	[3] 12,999					
Shares issued in connection with acquisition	57,255,850					
UIL Holdings [Member] | Restricted Stock Units [Member]						
Business Acquisition Equity Interests Issued Or Issuable [Line Items]						
Vesting shares	[4] 476,198					
Equity exchange factor	1.2806%					
UIL Holdings [Member] | Restricted Stock Units and Other [Member]						

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Business Acquisition Equity Interests Issued Or Issuable [Line Items]		
Total shares after applying an equity exchange factor	[3]	626,473
Price per share used	[5]	$ 39.60
Subtotal value of shares		$ 25
UIL Holdings [Member] | Performance Shares [Member]		
Business Acquisition Equity Interests Issued Or Issuable [Line Items]		
Vesting shares	[6]	211,904
Equity exchange factor		1.2806%
Total shares after applying an equity exchange factor		271,368
Price per share used	[5]	$ 39.60
Subtotal value of shares		$ 11
Total consideration		$ 2,873

[1] Par value of share amounts is $.01

[2] Based on UIL's common shares outstanding on December 16, 2015.

[3] Based on UIL's restricted shares that vested upon the change in control.

[4] Based on UIL's shares of vested restricted stock.

[5] Based on the closing share price of UIL common stock on December 16, 2015, less the cash component of $10.50, which is not applicable to restricted shares (other than those UIL restricted shares that vest by their terms upon the consummation of the acquisition), performance shares and other awards under the UIL 2008 Stock and Incentive Compensation Plan and the UIL Deferred Compensation Plan.

[6] Based on UIL's vested performance shares award.

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Acquisition of UIL - Summary of Fair Value of Purchase Consideration (Detail) (Parenthetical)	Dec. 16, 2015 $ / shares
UIL Holdings [Member]	
Business Acquisition Equity Interests Issued Or Issuable [Line Items]	
Cash paid per common share	$ 10.50

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Acquisition of UIL - Summary of Components of Estimated Consideration Transferred (Detail) $ in Millions	Dec. 16, 2015 USD ($)
Business Combination Consideration Transferred [Abstract]	
Payments to acquire business, cash paid	$ 595
Equity	2,278
Total consideration	$ 2,873

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Acquisition of UIL - Summary of Components of Estimated Consideration Transferred (Parenthetical) (Detail) - $ / shares	Dec. 31, 2016 [1]	Dec. 31, 2015 [1]	Dec. 16, 2015	Dec. 15, 2015	Dec. 31, 2014 [1]	Dec. 31, 2013 [1]
Business Combination Consideration Transferred [Line Items]						
Common shares outstanding	308,993,149	308,864,609		252,235,232	252,235,232	252,235,232
UIL Holdings [Member]						
Business Combination Consideration Transferred [Line Items]						
Cash paid per common share			$ 10.50			
Common shares outstanding	[2]		56,629,377			

[1] Par value of share amounts is $.01

[2] Based on UIL's common shares outstanding on December 16, 2015.

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Acquisition of UIL - Schedule of Unaudited Pro Forma Results (Detail) - USD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2015	Dec. 31, 2014
Business Acquisition Pro Forma Information [Abstract]		
Revenue	$ 5,958	$ 6,226
Net income	$ 468	$ 539

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Acquisition of UIL - Summary of Allocation of Purchase Price (Detail) - USD ($) $ in Millions	Dec. 31, 2016	Dec. 31, 2015	Dec. 16, 2015
Business Acquisition [Line Items]			
Goodwill – consideration transferred in excess of fair value assigned	$ 3,124	$ 3,115	
UIL Holdings [Member]			
Business Acquisition [Line Items]			
Current assets, including cash of $48 million	493		
Other investments	136		
Property, plant and equipment	3,547		
Regulatory assets	1,002		
Other assets	52		
Current liabilities	(493)		
Regulatory liabilities	(493)		
Non-current debt	(1,905)		
Other liabilities	(1,231)		
Total net assets acquired at fair value	1,108		
Goodwill – consideration transferred in excess of fair value assigned	1,765		
Total consideration	2,873		
UIL Holdings [Member] | Scenario, Previously Reported [Member]			
Business Acquisition [Line Items]			
Current assets, including cash of $48 million			$ 500
Other investments			114
Property, plant and equipment			3,552
Regulatory assets			966
Other assets			52
Current liabilities			(493)
Regulatory liabilities			(493)
Non-current debt			(1,878)
Other liabilities			(1,201)
Total net assets acquired at fair value			1,119
Goodwill – consideration transferred in excess of fair value assigned			1,754
Total consideration			$ 2,873
UIL Holdings [Member] | Restatement Adjustment			
Business Acquisition [Line Items]			
Current assets, including cash of $48 million	(7)		
Other investments	22		
Property, plant and equipment	(5)		
Regulatory assets	36		
Non-current debt	(27)		
Other liabilities	(30)		
Total net assets acquired at fair value	(11)		

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Goodwill – consideration transferred in excess of fair value assigned	$ 11

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Acquisition of UIL - Summary of Allocation of Purchase Price (Parenthetical) (Detail) $ in Millions	Dec. 16, 2015 USD ($)
Business Combinations [Abstract]	
Purchase price allocation, cash	$ 48

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Industry Regulation - Additional Information (Detail)	Mar. 31, 2017 USD ($)	May 03, 2016	Nov. 05, 2015	Oct. 21, 2015 USD ($)	Apr. 02, 2015	Jul. 03, 2014	Jan. 22, 2014	Oct. 23, 2013 USD ($) MWh	Sep. 01, 2012 USD ($)	1 Months Ended Dec. 31, 2016 USD ($) Plant	Dec. 31, 2014	Jan. 31, 2014 Contract MW	Aug. 31, 2010 USD ($)	Dec. 31, 2017 USD ($)	12 Months Ended Dec. 31, 2016 USD ($) Company Installment Plant	Dec. 31, 2015 USD ($)	Dec. 31, 2014 USD ($)	Sep. 30, 2012 USD ($)	Mar. 31, 2010 USD ($) MW
Industry Regulation [Line Items]																			
Number of networks supply companies | Company															4				
Purchase obligation per year										$ 2,587,000,000					$ 2,587,000,000				
Depreciation and amortization															$ 804,000,000	$ 695,000,000	$ 629,000,000		
Approved return on equity							9.18%								10.50%				
Customer receiving percentage		50.00%																	
Percentage of earnings sharing lower of actual equity										50.00%					50.00%				
Purchase power, description															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				
Percentage of standard service customers with wholesale power supply agreements in place for the second half of 2017															80.00%				
Percentage of standard service customers with wholesale power supply agreements in place for the first half of 2018															20.00%				
Public utilities regulatory authority distribution rate										9.15%									
Increase (decrease) in distribution rates										9.10%									
Modified agreement monthly payment amount				$ 15,400,000															
Minimum deferred cost required for offset per month										$ 2,300,000					$ 2,300,000				
Number of installments for payment of capital recovery balance | Installment															8				
Ownership interest										50.00%					50.00%				
Requested return on equity base percentage		9.55%													9.20%				
Basis point added to return on equity								0.25%											
Common equity ratio maximum dividend restriction threshold to set rates															3.00%				
Number of average months used to set rate															13 months				
Restricted net assets										$ 4,291,000,000					$ 4,291,000,000				
Number of megawatts of grid connected renewable energy allowed to be developed by UI (in MW) | MWh								10											
Current authorized distribution ROE for CL&P								9.17%											
Cost of renewable connections program								$ 47,000,000											
Number of megawatts energy to be produced by existing biomass facilities | MW												5.7							
Number of long term contracts to purchase RECs from existing biomass facilities | Contract												3							
Ratio of equity investment in peaking generation for joint venture															50.00%				
Number of peaking generation plants | Plant										2					2				
New York Transco [Member]																			
Industry Regulation [Line Items]																			
Customer receiving percentage			53.00%																
Return on equity			9.50%																
Ownership interest											20.00%						20.00%		
Requested return on equity base percentage											10.60%								
Requested return on equity basis points incentive											1.50%								

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Applicants requested			0.50%						
Basis point added to return on equity		0.50%							
Scenario, Forecast [Member]									
Industry Regulation [Line Items]									
Capital recovery payments period	75 days								
Estimated capital recovery balance	$ 20,100,000								
Minimum [Member]									
Industry Regulation [Line Items]									
Requested return on equity base percentage		14.55%							
Maximum [Member]									
Industry Regulation [Line Items]									
Approved return on equity							11.74%		
CMP Distribution [Member]									
Industry Regulation [Line Items]									
Distribution rate review process							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.		
Distribution rate review process period			14 months						
Annual distribution tariff increase percentage							10.70%		
Annual distribution tariff increase							$ 24,300,000		
Distribution tariff rate increased based on ROE							9.45%		
Distribution tariff rate increased based on equity capital							50.00%		
Recovery mechanism when storm cost exceed					$ 3,500,000		$ 3,500,000		
Sharing basis of storm cost							fifty-fifty		
Business combination, date of acquisition							Mar. 31, 2010		
Period of purchase commitment							20 years		
Number of megawatts energy to be purchased from evergreen Rollins wind | MW								60	
Purchase obligation per year								$ 7,000,000	
Recovery Of Deferred Cost							$ 123,000,000		
CMP Distribution [Member] | Minimum [Member]									
Industry Regulation [Line Items]									
Exposure limit of storm cost							$ 3,000,000		
NYSEG [Member]									
Industry Regulation [Line Items]									
Depreciation and amortization				$ 15,200,000					

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Excess depreciation reserve			$ 303,900,000		
Depreciation amortization period			20 years		
RG&E [Member]					
Industry Regulation [Line Items]					
Depreciation and amortization		$ 5,300,000			
Excess depreciation reserve					$ 105,000,000
Depreciation amortization period		20 years			
NYSEG Gas [Member]					
Industry Regulation [Line Items]					
Approved return on equity			9.00%		
Equity Ratio		48.00%	48.00%		
Customer receiving percentage			50.00%		
Return on equity			9.50%		
RG&E Electric [Member]					
Industry Regulation [Line Items]					
Approved return on equity			9.00%		
Equity Ratio		48.00%	48.00%		
Customer receiving percentage			75.00%		
Return on equity			10.00%		
Percentage of revenue entitled	70.00%		70.00%		
Maximum amount of investment under credit agreement		$ 110,000,000	$ 110,000,000		
RG&E Electric [Member] | Deferred Storm Cost Amortization 1 Year [Member]					
Industry Regulation [Line Items]					
Amortization Of Deferred Storm Cost			2,500,000		
RG&E Electric [Member] | Maximum [Member]					
Industry Regulation [Line Items]					
Reliability support service agreement final payment		$ 2,300,000	$ 2,300,000		
RG&E Gas [Member]					
Industry Regulation [Line Items]					
Approved return on equity			9.00%		
Equity Ratio		48.00%	48.00%		
Customer receiving percentage			90.00%		
Return on equity			10.50%		
NYSEG Electric [Member]					
Industry Regulation [Line Items]					
Recovery Of Deferred Cost			$ 262,000,000		
NYSEG Electric [Member] | Deferred Storm Cost Amortization 10 Year's [Member]					
Industry Regulation [Line Items]					
Amortization Of Deferred Storm Cost			123,000,000		
NYSEG Electric [Member] | Deferred Storm Cost Amortization 5 Year's [Member]					
Industry Regulation [Line Items]					
Amortization Of Deferred Storm Cost			139,000,000		
NYSEG Electric [Member] | Deferred Storm Cost Amortization 1 Year [Member]					
Industry Regulation [Line Items]					
Amortization Of Deferred Storm Cost			$ 21,400,000		
United Illuminating Company (UI)					
Industry Regulation [Line Items]					
Period of purchase commitment			21 years		
Public utilities nature of allowance for earnings on equity, description			UI and customers share on a 50/50 basis all distribution earnings above the allowed ROE in a calendar year		
Maximum amount of commitment to purchase		$ 200,000,000	$ 200,000,000		

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Renewable Energy Credits (RECs) from new facilities behind distribution customer meters					
Solicitation period obligations will phase-in					6 years
Maximum annual commitment level obligation after year six			$ 13,600,000		$ 13,600,000
Connecticut Natural Gas Corporation (CNG) [Member]					
Industry Regulation [Line Items]					
Public utilities nature of allowance for earnings on equity, description					CNG and customers share on a 50/ 50 basis all earnings above the allowed ROE in a calendar year.
RG&E & GNPP [Member]					
Industry Regulation [Line Items]					
Modified agreement monthly payment amount					$ 15,400,000
Ginna Nuclear Power Plant LLC [Member]					
Industry Regulation [Line Items]					
Percentage of revenue entitled	30.00%				30.00%
One time payment					$ 11,500,000
New Haven Harbor Station Site [Member]					
Industry Regulation [Line Items]					
Number of Megawatts of project planned | MWh		2.8			
Bridgeport [Member]					
Industry Regulation [Line Items]					
Number of Megawatts of project planned | MWh		5			
Woodbridge [Member]					
Industry Regulation [Line Items]					
Number of Megawatts of project planned | MWh		2.2			
GenConn Devon [Member] | Scenario, Forecast [Member] | Electric Transmission and Distribution [Member]					
Industry Regulation [Line Items]					
Revenue requirements for equity investment in peaking generation				$ 28,800,000	
GenConn Middletown [Member] | Scenario, Forecast [Member] | Electric Transmission and Distribution [Member]					
Industry Regulation [Line Items]					
Revenue requirements for equity investment in peaking generation				$ 35,700,000	

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Industry Regulation - Electric and Gas Delivery Rate Increase (Detail) - USD ($) $ in Millions	12 Months Ended		
	May 01, 2018	May 01, 2017	May 01, 2016
NYSEG Electric [Member]			
Industry Regulation [Line Items]			
Rate Increase			$ 29.6
Delivery Rate Increase			4.10%
NYSEG Electric [Member] | Scenario, Forecast [Member]			
Industry Regulation [Line Items]			
Rate Increase	$ 30.3	$ 29.9	
Delivery Rate Increase	4.10%	4.10%	
NYSEG Gas [Member]			
Industry Regulation [Line Items]			
Rate Increase			$ 13.1
Delivery Rate Increase			7.30%
NYSEG Gas [Member] | Scenario, Forecast [Member]			
Industry Regulation [Line Items]			
Rate Increase	$ 14.8	$ 13.9	
Delivery Rate Increase	7.30%	7.30%	
RG&E Electric [Member]			
Industry Regulation [Line Items]			
Rate Increase			$ 3.0
Delivery Rate Increase			0.70%
RG&E Electric [Member] | Scenario, Forecast [Member]			
Industry Regulation [Line Items]			
Rate Increase	$ 25.9	$ 21.6	
Delivery Rate Increase	5.70%	5.00%	
RG&E Gas [Member]			
Industry Regulation [Line Items]			
Rate Increase			$ 8.8
Delivery Rate Increase			5.20%
RG&E Gas [Member] | Scenario, Forecast [Member]			
Industry Regulation [Line Items]			
Rate Increase	$ 9.5	$ 7.7	
Delivery Rate Increase	5.20%	4.40%	

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Regulatory Assets and Liabilities - Additional Information (Detail) $ in Millions	3 Months Ended Jun. 30, 2016 USD ($)	12 Months Ended Dec. 31, 2016 USD ($) Station	Dec. 31, 2015 USD ($)
Regulatory Assets And Liabilities [Line Items]			
Unrecorded Regulatory Assets		$ 2,357.0	
Unfunded future income tax expense	$ 126.0	$ 126.0	
Unfunded future Income tax expense collection period		50 years	
Deferred costs		$ 2.3	
Number of nuclear generating stations | Station		2	
UIL Holdings [Member]			
Regulatory Assets And Liabilities [Line Items]			
Business combination merger related rate credits		$ 20.0	
NEW YORK			
Regulatory Assets And Liabilities [Line Items]			
Regulatory items amortization period		5 years	
NEW YORK | Prior Tax Rate [Member]			
Regulatory Assets And Liabilities [Line Items]			
Statutory income tax rate, state		7.10%	
NEW YORK | Revised Tax Rate [Member]			
Regulatory Assets And Liabilities [Line Items]			
Statutory income tax rate, state		6.50%	
NEW YORK | Minimum [Member]			
Regulatory Assets And Liabilities [Line Items]			
Deferred income tax recovery period		27 years	
NEW YORK | Maximum [Member]			
Regulatory Assets And Liabilities [Line Items]			
Deferred income tax recovery period		39 years	
Deferred Property Tax [Member] | NEW YORK			
Regulatory Assets And Liabilities [Line Items]			
Regulatory items amortization period		5 years	
Asset Sale Gain Account [Member]			
Regulatory Assets And Liabilities [Line Items]			
Regulatory items amortization period		5 years	
Carrying Costs On Deferred Income Tax Bonus Depreciation [Member]			
Regulatory Assets And Liabilities [Line Items]			
Regulatory items amortization period		5 years	
Economic Development [Member]			
Regulatory Assets And Liabilities [Line Items]			
Regulatory items amortization period		5 years	
Merger Capital Expense [Member]			
Regulatory Assets And Liabilities [Line Items]			
Regulatory items amortization period		5 years	

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Positive Benefit Adjustment [Member]		
Regulatory Assets And Liabilities [Line Items]		
Regulatory items amortization period	5 years	
Post Term Amortization [Member]		
Regulatory Assets And Liabilities [Line Items]		
Regulatory items amortization period	5 years	
Theoretical Reserve Flow Thru Impact [Member]		
Regulatory Assets And Liabilities [Line Items]		
Regulatory items amortization period	5 years	
NYSEG [Member]		
Regulatory Assets And Liabilities [Line Items]		
Annual amortization of regulatory items	$ 16.5	
Regulatory items amortization period	3 years	
NYSEG [Member] | Storm Costs		
Regulatory Assets And Liabilities [Line Items]		
Regulatory items amortization period	5 years	
NYSEG [Member] | Regulatory Items Other Than Storm Costs [Member]		
Regulatory Assets And Liabilities [Line Items]		
Regulatory items amortization period	10 years	
NYSEG [Member] | Deferred Income Tax Charge		
Regulatory Assets And Liabilities [Line Items]		
Regulatory items amortization period	50 years	
Central Maine Power Company [Member]		
Regulatory Assets And Liabilities [Line Items]		
Recovery of deferred storm costs	$ 123.0	
Central Maine Power Company [Member] | Storm Costs		
Regulatory Assets And Liabilities [Line Items]		
Regulatory items amortization period	10 years	
Regulatory assets	$ 2.0	$ 12.0
Central Maine Power Company [Member] | Regulatory Items Other Than Storm Costs [Member]		
Regulatory Assets And Liabilities [Line Items]		
Regulatory items amortization period	5 years	
UI [Member]		
Regulatory Assets And Liabilities [Line Items]		
Regulatory assets	$ 75.0	$ 68.0
UI [Member] | Storm Costs		
Regulatory Assets And Liabilities [Line Items]		
Regulatory assets	0.0	
Deferred costs	$ 1.0	

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Regulatory Assets and Liabilities - Current and Non-Current Assets (Detail) - USD ($) $ in Millions	Dec. 31, 2016	Dec. 31, 2015
Regulatory Asset [Line Items]		
Regulatory Assets, current	$ 285	$ 219
Regulatory Assets, noncurrent	3,091	3,314
Pension And Other Post-Retirement Benefits Deferrals [Member]		
Regulatory Asset [Line Items]		
Regulatory Assets, current	22	8
Regulatory Assets, noncurrent	134	151
Pension And Other Post-Retirement Benefits [Member]		
Regulatory Asset [Line Items]		
Regulatory Assets, current	7	13
Regulatory Assets, noncurrent	1,320	1,509
Storm Costs		
Regulatory Asset [Line Items]		
Regulatory Assets, current	40	8
Regulatory Assets, noncurrent	187	251
Temporary Supplemental Assessment Surcharge [Member]		
Regulatory Asset [Line Items]		
Regulatory Assets, current	4	7
Support Services [Member]		
Regulatory Asset [Line Items]		
Regulatory Assets, current	27	
Revenue Decoupling Mechanism [Member]		
Regulatory Asset [Line Items]		
Regulatory Assets, current	15	6
Transmission Revenue Reconciliation Mechanism [Member]		
Regulatory Asset [Line Items]		
Regulatory Assets, current	12	5
Electric Supply Reconciliation [Member]		
Regulatory Asset [Line Items]		
Regulatory Assets, current	13	
Hedges Loss [Member]		
Regulatory Asset [Line Items]		
Regulatory Assets, current	10	37
Contracts For Differences [Member]		
Regulatory Asset [Line Items]		
Regulatory Assets, current	14	18
Regulatory Assets, noncurrent	61	50
Hardship Programs [Member]		
Regulatory Asset [Line Items]		

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Regulatory Assets, current	16	13
Regulatory Assets, noncurrent	18	29
Deferred Property Tax [Member]		
Regulatory Asset [Line Items]		
Regulatory Assets, current	10	
Regulatory Assets, noncurrent	33	45
Plant Decommissioning [Member]		
Regulatory Asset [Line Items]		
Regulatory Assets, current	6	
Regulatory Assets, noncurrent	14	7
Deferred Purchased Gas [Member]		
Regulatory Asset [Line Items]		
Regulatory Assets, current	14	12
Deferred Transmission Expense [Member]		
Regulatory Asset [Line Items]		
Regulatory Assets, current	13	12
Environmental Restoration Costs [Member]		
Regulatory Asset [Line Items]		
Regulatory Assets, current	14	37
Regulatory Assets, noncurrent	287	271
Other [Member]		
Regulatory Asset [Line Items]		
Regulatory Assets, current	48	43
Regulatory Assets, noncurrent	102	57
Deferred Meter Replacement Costs [Member]		
Regulatory Asset [Line Items]		
Regulatory Assets, noncurrent	32	34
Unamortized Loss On Reacquired Debt [Member]		
Regulatory Asset [Line Items]		
Regulatory Assets, noncurrent	20	23
Future Income Tax [Member]		
Regulatory Asset [Line Items]		
Regulatory Assets, noncurrent	542	549
Asset Retirement Obligation Costs [Member]		
Regulatory Asset [Line Items]		
Regulatory Assets, noncurrent	18	24
Federal Tax Depreciation Normalization Adjustment [Member]		
Regulatory Asset [Line Items]		
Regulatory Assets, noncurrent	161	158
Merger Capital Expense [Member]		
Regulatory Asset [Line Items]		
Regulatory Assets, noncurrent	11	15
Debt Premium [Member]		
Regulatory Asset [Line Items]		

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Regulatory Assets, noncurrent	$ 151	$ 141

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Regulatory Assets and Liabilities - Current and Non-Current Liabilities (Detail) - USD ($) $ in Millions	Dec. 31, 2016	Dec. 31, 2015
Regulatory Liabilities [Line Items]		
Regulatory liabilities	$ 192	$ 147
Regulatory liabilities including deferred income taxes, noncurrent	1,753	1,841
Deferred income taxes regulatory	565	519
Regulatory liabilities including deferred income taxes, noncurrent	2,318	2,360
Support Services [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities	3	16
Non By Passable Charge [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities	22	7
Energy Efficiency Services [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities	45	33
Gas Supply Charge And Deferred Natural Gas Cost [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities	6	6
Transmission Revenue Reconciliation Mechanism [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities	5	16
Pension And Other Post-Retirement Benefits [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities	3	3
Regulatory liabilities including deferred income taxes, noncurrent	76	90
Pension And Other Post-Retirement Benefits Deferrals [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities	14	
Carrying Costs On Deferred Income Tax Bonus Depreciation [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities	15	
Regulatory liabilities including deferred income taxes, noncurrent	95	116
Yankee DOE Refund [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities	24	5
Merger Related Rate Credits [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities	3	20
Regulatory liabilities including deferred income taxes, noncurrent	21	24
Carrying Costs On Deferred Income Tax [Member]		

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Regulatory Liabilities [Line Items]		
Regulatory liabilities	5	
Regulatory liabilities including deferred income taxes, noncurrent	25	31
Revenue Decoupling Mechanism [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities	9	14
Other [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities	38	27
Regulatory liabilities including deferred income taxes, noncurrent	73	93
Accrued Removal Obligations [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities including deferred income taxes, noncurrent	1,117	1,084
Asset Sale Gain Account [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities including deferred income taxes, noncurrent	9	8
Economic Development [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities including deferred income taxes, noncurrent	35	36
Merger Capital Expense [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities including deferred income taxes, noncurrent	15	17
Positive Benefit Adjustment [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities including deferred income taxes, noncurrent	42	51
New York State Tax Rate Change [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities including deferred income taxes, noncurrent	9	17
Post Term Amortization [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities including deferred income taxes, noncurrent	3	25
Theoretical Reserve Flow Thru Impact [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities including deferred income taxes, noncurrent	24	31
Deferred Property Tax [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities including deferred income taxes, noncurrent	19	15
Net Plant Reconciliation [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities including deferred income taxes, noncurrent	10	10
Variable Rate Debt [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities including deferred income taxes, noncurrent	28	32
Rate Refund [Member]		

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Regulatory Liabilities [Line Items]		
Regulatory liabilities including deferred income taxes, noncurrent	22	21
Accumulated Deferred Investment Tax Credits [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities including deferred income taxes, noncurrent	15	10
Asset Retirement Obligation Costs [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities including deferred income taxes, noncurrent	13	13
Transmission Congestion Contracts [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities including deferred income taxes, noncurrent	18	
Middletown/Norwalk Local Transmission Network Service Collections [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities including deferred income taxes, noncurrent	19	19
Excess Generation Service Charge [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities including deferred income taxes, noncurrent		21
Low Income Programs [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities including deferred income taxes, noncurrent	46	42
Unfunded Future Income Taxes [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities including deferred income taxes, noncurrent		27
Earning sharing provisions [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities including deferred income taxes, noncurrent	12	
Non-Firm Margin Sharing Credits [Member]		
Regulatory Liabilities [Line Items]		
Regulatory liabilities including deferred income taxes, noncurrent	$ 7	$ 8

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Goodwill and Intangible assets - Schedule of Goodwill by Reportable Segment (Detail) - USD ($) $ in Millions		Dec. 31, 2016	Dec. 31, 2015
Goodwill [Line Items]			
Goodwill		$ 3,124	$ 3,115
Network [Member]			
Goodwill [Line Items]			
Goodwill		2,744	2,733
Renewables [Member]			
Goodwill [Line Items]			
Goodwill		$ 380	380
Other [Member]			
Goodwill [Line Items]			
Goodwill	[1]		$ 2

[1] Does not represent a reportable segment. It includes Corporate.

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Goodwill and Intangible assets - Additional Information (Detail)	12 Months Ended				
	Dec. 31, 2016 USD ($) Segment	Dec. 31, 2015 USD ($)	Dec. 31, 2014 USD ($)	Dec. 31, 2002 USD ($)	Dec. 31, 2000 USD ($)
Goodwill [Line Items]					
Number of reporting units | Segment	3				
Impairment of goodwill	$ 0	$ 0			
Amortization expense	$ 25,000,000	54,000,000	$ 66,000,000		
Gas Storage Rights [Member]					
Goodwill [Line Items]					
Finite lived intangible assets useful economic life	40 years				
Impairment of intangible assets	$ 4,100,000	6,500,000			
UIL Holdings [Member]					
Goodwill [Line Items]					
Goodwill	1,765,000,000				
Other [Member]					
Goodwill [Line Items]					
Goodwill, gross	0	2,000,000			
Goodwill reversed related to sale of business unit	2,000,000				
Network [Member]					
Goodwill [Line Items]					
Goodwill, gross	2,744,000,000	2,733,000,000			
Goodwill, period increase (decrease)	11,000,000	1,754,000,000			
Renewables And Gas Segments					
Goodwill [Line Items]					
Goodwill, gross	3,340,000,000	3,340,000,000			
Goodwill, accumulated impairment loss	$ 2,960,000,000	$ 2,960,000,000			
Maine Reporting Unit [Member]					
Goodwill [Line Items]					
Goodwill					$ 325,000,000
New York Reporting Unit [Member]					
Goodwill [Line Items]					
Goodwill				$ 654,000,000	

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Goodwill and Intangible assets - Summary of Intangible Assets (Detail) - USD ($) $ in Millions	Dec. 31, 2016	Dec. 31, 2015
Finite Lived Intangible Assets [Line Items]		
Gross Carrying Amount	$ 923	$ 923
Accumulated Amortization	(385)	(367)
Net Carrying Amount	538	556
Gas Storage Rights [Member]		
Finite Lived Intangible Assets [Line Items]		
Gross Carrying Amount	319	324
Accumulated Amortization	(120)	(116)
Net Carrying Amount	199	208
Wind Development [Member]		
Finite Lived Intangible Assets [Line Items]		
Gross Carrying Amount	587	584
Accumulated Amortization	(254)	(243)
Net Carrying Amount	333	341
Other [Member]		
Finite Lived Intangible Assets [Line Items]		
Gross Carrying Amount	17	15
Accumulated Amortization	(11)	(8)
Net Carrying Amount	$ 6	$ 7

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Goodwill and Intangible assets - Schedule of Amortization Expense (Detail) $ in Millions	Dec. 31, 2016 USD ($)
Goodwill And Intangible Assets Disclosure [Abstract]	
2017	$ 16
2018	16
2019	18
2020	17
2021	$ 21

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Property, Plant and Equipment (Detail) - USD ($) $ in Millions	Dec. 31, 2016		Dec. 31, 2015		Dec. 31, 2014
Property Plant And Equipment [Line Items]					
Property, plant and equipment, at cost	$ 27,063	[1]	$ 25,745	[2]	
Less: accumulated depreciation	(6,986)	[3]	(6,372)	[4]	
Total Net Property, Plant and Equipment in Service	20,077		19,373		
Construction work in progress	1,471		1,338		
Total Property, Plant and Equipment ($1,144 and $1,206 related to VIEs, respectively)	21,548		20,711		$ 17,133
Regulated [Member]					
Property Plant And Equipment [Line Items]					
Property, plant and equipment, at cost	16,023	[1]	14,996	[2]	
Less: accumulated depreciation	(3,970)	[3]	(3,727)	[4]	
Total Net Property, Plant and Equipment in Service	12,053		11,269		
Construction work in progress	979		1,094		
Total Property, Plant and Equipment ($1,144 and $1,206 related to VIEs, respectively)	13,032		12,363		
Unregulated [Member]					
Property Plant And Equipment [Line Items]					
Property, plant and equipment, at cost	11,040	[1]	10,749	[2]	
Less: accumulated depreciation	(3,016)	[3]	(2,645)	[4]	
Total Net Property, Plant and Equipment in Service	8,024		8,104		
Construction work in progress	492		244		
Total Property, Plant and Equipment ($1,144 and $1,206 related to VIEs, respectively)	8,516		8,348		
Electric Generation, Distribution and Transmission Equipment [Member]					
Property Plant And Equipment [Line Items]					
Property, plant and equipment, at cost	20,727		21,564		
Electric Generation, Distribution and Transmission Equipment [Member] | Regulated [Member]					
Property Plant And Equipment [Line Items]					
Property, plant and equipment, at cost	10,343		11,506		
Electric Generation, Distribution and Transmission Equipment [Member] | Unregulated [Member]					
Property Plant And Equipment [Line Items]					
Property, plant and equipment, at cost	10,384		10,058		
Natural Gas, Transportation and Distribution Equipment [Member]					
Property Plant And Equipment [Line Items]					
Property, plant and equipment, at cost	5,416		3,324		
Natural Gas, Transportation and Distribution Equipment [Member] | Regulated [Member]					

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Property Plant And Equipment [Line Items]		
Property, plant and equipment, at cost	4,803	2,673
Natural Gas, Transportation and Distribution Equipment [Member] | Unregulated [Member]		
Property Plant And Equipment [Line Items]		
Property, plant and equipment, at cost	613	651
Other Common Operating Property [Member]		
Property Plant And Equipment [Line Items]		
Property, plant and equipment, at cost	920	857
Other Common Operating Property [Member] | Regulated [Member]		
Property Plant And Equipment [Line Items]		
Property, plant and equipment, at cost	877	817
Other Common Operating Property [Member] | Unregulated [Member]		
Property Plant And Equipment [Line Items]		
Property, plant and equipment, at cost	$ 43	$ 40

[1] Includes capitalized leases of $208 million primarily related to electric generation, distribution, transmission and other.

[2] Includes capitalized leases of $178 million primarily related to electric generation, distribution, transmission and other.

[3] Includes accumulated amortization of capitalized leases of $60 million.

[4] Includes accumulated amortization of capitalized leases of $53 million.

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Property, Plant and Equipment - (Parenthetical) (Detail) - USD ($) $ in Millions	Dec. 31, 2016	Dec. 31, 2015
Property Plant And Equipment [Line Items]		
Capital lease obligations	$ 104	$ 87
Accumulated Capitalized Interest Costs	60	53
Electric Generation, Distribution and Transmission Equipment [Member]		
Property Plant And Equipment [Line Items]		
Capital lease obligations	$ 208	$ 178

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Property, Plant and Equipment - Additional Information (Detail) - USD ($) $ in Millions	12 Months Ended		
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Property Plant And Equipment [Abstract]			
Interest costs capitalized	$ 20	$ 13	$ 12
Tangible asset impairment charges	0	12	24
Depreciation	$ 779	$ 641	$ 563

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Asset Retirement Obligations - Reconciliation of ARO (Detail) - USD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2016	Dec. 31, 2015
Asset Retirement Obligation Disclosure [Abstract]		
Beginning Balance	$ 184	$ 234
Liabilities settled during the year	(7)	(16)
Liabilities incurred during the year	3	
Accretion expense	10	14
Revisions in estimated cash flows	(29)	(48)
Ending Balance	$ 161	$ 184

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Asset Retirement Obligations - Additional Information (Detail) - USD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2016	Dec. 31, 2015
Asset Retirement Obligation Disclosure [Abstract]		
Asset retirement obligation, restricted Cash	$ 2.0	$ 1.8
Estimated annual reduction in expense upon revision	$ 3.0	

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Debt - Schedule of Long-term Debt (Detail) - USD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2016	Dec. 31, 2015
Debt Instrument [Line Items]		
Capital lease obligations	$ 104	$ 87
Unamortized debt issuance costs and discount	(31)	(25)
Long-Term Debt	4,859	4,736
Less: debt due within one year, included in current liabilities	349	206
Total Non-current Debt	$ 4,510	4,530
First Mortgage Bonds - Fixed [Member]		
Debt Instrument [Line Items]		
Debt Instrument, Maturity Date, Start	2018	
Debt Instrument, Maturity Date, End	2045	
Long-Term Debt	$ 1,752	$ 1,815
First Mortgage Bonds - Fixed [Member] | Minimum [Member]		
Debt Instrument [Line Items]		
Debt instrument, interest rate	3.07%	3.07%
First Mortgage Bonds - Fixed [Member] | Maximum [Member]		
Debt Instrument [Line Items]		
Debt instrument, interest rate	10.60%	10.60%
Unsecured Pollution Control Notes - Fixed [Member]		
Debt Instrument [Line Items]		
Debt instrument maturity year	2020	
Long-Term Debt	$ 200	$ 200
Unsecured Pollution Control Notes - Fixed [Member] | Minimum [Member]		
Debt Instrument [Line Items]		
Debt instrument, interest rate	2.00%	2.00%
Unsecured Pollution Control Notes - Fixed [Member] | Maximum [Member]		
Debt Instrument [Line Items]		
Debt instrument, interest rate	2.375%	2.375%
Unsecured Pollution Control Notes – Variable [Member]		
Debt Instrument [Line Items]		
Debt instrument maturity year	2032	
Long-Term Debt	$ 62	$ 219
Debt instrument, interest rate	1.32%	
Unsecured Pollution Control Notes – Variable [Member] | Minimum [Member]		
Debt Instrument [Line Items]		
Debt instrument, interest rate		0.195%
Unsecured Pollution Control Notes – Variable [Member] | Maximum [Member]		
Debt Instrument [Line Items]		
Debt instrument, interest rate		1.181%
Other Various Non-current Debt - Fixed [Member]		
Debt Instrument [Line Items]		

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Debt Instrument, Maturity Date, Start	2017	
Debt Instrument, Maturity Date, End	2045	
Long-Term Debt	$ 2,772	$ 2,440
Other Various Non-current Debt - Fixed [Member] | Minimum [Member]		
Debt Instrument [Line Items]		
Debt instrument, interest rate	2.89%	2.89%
Other Various Non-current Debt - Fixed [Member] | Maximum [Member]		
Debt Instrument [Line Items]		
Debt instrument, interest rate	10.48%	10.48%
Obligations Under Capital Leases [Member]		
Debt Instrument [Line Items]		
Debt Instrument, Maturity Date, Start	2017	
Debt Instrument, Maturity Date, End	2023	
Obligations Under Capital Leases [Member] | Minimum [Member]		
Debt Instrument [Line Items]		
Debt instrument, interest rate	4.00%	4.00%
Obligations Under Capital Leases [Member] | Maximum [Member]		
Debt Instrument [Line Items]		
Debt instrument, interest rate	4.44%	4.44%

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Debt - Schedule of Long-term Debt (Parenthetical) (Detail) $ in Millions	Dec. 31, 2016 USD ($)
First Mortgage Bonds - Fixed [Member]	
Debt Instrument [Line Items]	
Bond pledged as collateral	$ 5,886

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Debt - Additional Information (Detail)	Apr. 05, 2016 USD ($)	1 Months Ended Nov. 30, 2016 USD ($)	12 Months Ended Dec. 31, 2016 USD ($) CreditFacility	Dec. 27, 2016 USD ($)	Dec. 19, 2016 USD ($)	May 13, 2016 USD ($)	Dec. 31, 2015 USD ($)	Oct. 07, 2010 USD ($)
Debt Instrument [Line Items]								
Repayment of debt		$ 100,000,000						
Debt instrument maturity date		Dec. 15, 2016						
Debt instrument repurchase amount				$ 64,000,000	$ 96,000,000			
Estimated fair value of debt			$ 5,204,000,000				$ 4,985,000,000	
Notes payable			161,000,000				163,000,000	
Line of credit borrowings							160,000,000	
Other notes payable			1,000,000				3,000,000	
Commercial paper			150,000,000					
Notes payable to affiliates			10,000,000					
Credit facility remaining borrowing capacity			1,350,000,000					
Joint Utility Revolving Credit Facility [Member]								
Debt Instrument [Line Items]								
Credit facility maximum borrowing capacity			$ 600,000,000					
Credit facility, termination date			2018-07					
UIL Credit Facility [Member]								
Debt Instrument [Line Items]								
Credit facility maximum borrowing capacity			$ 400,000,000			$ 1,000,000,000		
Credit facility, termination date			2016-11					
AVANGRID Credit Facility [Member]								
Debt Instrument [Line Items]								
Credit facility maximum borrowing capacity	$ 1,500,000,000							
Maturity date for credit facility			Apr. 05, 2021					
Number of credit facilities terminated | CreditFacility			3					
AVANGRID Credit Facility [Member] | Minimum [Member]								
Debt Instrument [Line Items]								
Credit facility initial fees range	0.10%							
AVANGRID Credit Facility [Member] | Maximum [Member]								

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Debt Instrument [Line Items]				
Credit facility initial fees range	0.175%			
AVANGRID Revolving Credit Facility [Member]				
Debt Instrument [Line Items]				
Credit facility maximum borrowing capacity		$ 300,000,000		
Credit facility, termination date		2019-05		
Level 3 [Member]				
Debt Instrument [Line Items]				
Estimated fair value of debt		$ 61,000,000		$ 204,000,000
AVANGRID [Member] | AVANGRID Credit Facility [Member]				
Debt Instrument [Line Items]				
Credit facility maximum borrowing capacity	$ 1,000,000,000			
NYSEG, RGE, CMP and UI [Member] | AVANGRID Credit Facility [Member]				
Debt Instrument [Line Items]				
Credit facility maximum borrowing capacity	250,000,000			
CNG and SCG [Member] | AVANGRID Credit Facility [Member]				
Debt Instrument [Line Items]				
Credit facility maximum borrowing capacity	150,000,000			
The Berkshire Gas Company [Member] | AVANGRID Credit Facility [Member]				
Debt Instrument [Line Items]				
Credit facility maximum borrowing capacity	$ 25,000,000			
3.25% Interest Notes [Member]				
Debt Instrument [Line Items]				
Debt instrument principal amount		$ 500,000,000		
Debt instrument maturity year		2026		
Interest rate on outstanding loans		3.25%		
4.625% Interest Notes [Member] | AVANGRID [Member]				
Debt Instrument [Line Items]				

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Debt instrument principal amount		$ 450,000,000
Debt instrument maturity year	2020	
Interest rate on outstanding loans		4.625%

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Debt - Schedule of Maturities and Repayments of Long-term Debt (Detail) - USD ($) $ in Millions	Dec. 31, 2016	Dec. 31, 2015
Debt Instrument [Line Items]		
Total	$ 4,510	$ 4,530
Non-current debt, including sinking fund obligations and capital lease payments, due over the next five [Member]		
Debt Instrument [Line Items]		
2017	349	
2018	180	
2019	358	
2020	723	
2021	308	
Total	$ 1,918	

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Fair Value of Financial Instruments and Fair Value Measurements - Fair Value of Assets and Liabilities (Detail) - USD ($) $ in Millions	Dec. 31, 2016	Dec. 31, 2015
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Derivative financial instruments, assets	$ 172	$ 177
Derivative financial instruments, liabilities	(153)	(185)
Netting [Member]		
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Derivative financial instruments, assets	(281)	(351)
Derivative financial instruments, liabilities	296	267
Available-for-sale Securities [Member]		
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Financial instruments, assets	40	39
Derivative Financial Instrument Power [Member]		
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Derivative financial instruments, assets	75	68
Derivative financial instruments, liabilities	(15)	(14)
Derivative Financial Instrument Power [Member] | Netting [Member]		
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Derivative financial instruments, assets	(42)	(71)
Derivative financial instruments, liabilities	39	55
Derivative Financial Instrument Gas [Member]		
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Derivative financial instruments, assets	77	80
Derivative financial instruments, liabilities	(43)	(72)
Derivative Financial Instrument Gas [Member] | Netting [Member]		
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Derivative financial instruments, assets	(239)	(280)
Derivative financial instruments, liabilities	257	212
Contracts For Differences [Member]		
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Derivative financial instruments, assets	20	29
Derivative financial instruments, liabilities	(95)	(96)
Derivative Financial Instrument Other [Member]		

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Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Derivative financial instruments, liabilities		(3)
Fair Value, Inputs, Level 1 [Member]		
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Derivative financial instruments, assets	191	277
Derivative financial instruments, liabilities	(237)	(236)
Fair Value, Inputs, Level 1 [Member] | Available-for-sale Securities [Member]		
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Financial instruments, assets	40	39
Fair Value, Inputs, Level 1 [Member] | Derivative Financial Instrument Power [Member]		
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Derivative financial instruments, assets	11	10
Derivative financial instruments, liabilities	(24)	(43)
Fair Value, Inputs, Level 1 [Member] | Derivative Financial Instrument Gas [Member]		
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Derivative financial instruments, assets	180	267
Derivative financial instruments, liabilities	(213)	(193)
Fair Value, Inputs, Level 2 [Member]		
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Derivative financial instruments, assets	80	106
Derivative financial instruments, liabilities	(61)	(52)
Fair Value, Inputs, Level 2 [Member] | Derivative Financial Instrument Power [Member]		
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Derivative financial instruments, assets	48	81
Derivative financial instruments, liabilities	(27)	(12)
Fair Value, Inputs, Level 2 [Member] | Derivative Financial Instrument Gas [Member]		
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Derivative financial instruments, assets	32	25
Derivative financial instruments, liabilities	(34)	(40)
Level 3 [Member]		
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Derivative financial instruments, assets	182	145
Derivative financial instruments, liabilities	(151)	(164)
Level 3 [Member] | Derivative Financial Instrument Power [Member]		

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Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Derivative financial instruments, assets	58	48
Derivative financial instruments, liabilities	(3)	(14)
Level 3 [Member] | Derivative Financial Instrument Gas [Member]		
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Derivative financial instruments, assets	104	68
Derivative financial instruments, liabilities	(53)	(51)
Level 3 [Member] | Contracts For Differences [Member]		
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Derivative financial instruments, assets	20	29
Derivative financial instruments, liabilities	$ (95)	(96)
Level 3 [Member] | Derivative Financial Instrument Other [Member]		
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Derivative financial instruments, liabilities		$ (3)

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Fair Value of Financial Instruments and Fair Value Measurements - Reconciliation of Changes in Fair Value of Financial Instruments (Detail) - USD ($) $ in Millions	12 Months Ended		
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Debt Instrument Fair Value Carrying Value [Abstract]			
Fair value as of January 1,	$ (19)	$ 57	$ 53
Gains for the year recognized in operating revenues	67	33	11
Losses for the year recognized in operating revenues		(8)	(1)
Total gains or losses for the period recognized in operating revenues	67	25	10
Gains recognized in OCI	1	2	
Losses recognized in OCI		(3)	(3)
Total gains or losses recognized in OCI	1	(1)	(3)
Net change recognized in regulatory assets and liabilities	(8)		
Purchases	3	(73)	14
Settlements	(9)	(14)	(26)
Transfers out of Level 3	[1] (4)	(13)	9
Fair value as of December 31,	31	(19)	57
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	$ 67	$ 25	$ 10

[1] Transfers out of Level 3 were the result of increased observability of market data.

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Fair Value of Financial Instruments and Fair Value Measurements - Valuation of Instruments (Detail)	12 Months Ended Dec. 31, 2016 $ / MMBTU $ / MWh
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis Valuation Techniques [Line Items]	
Instruments	Fixed price power and gas swaps with delivery period > two years
Instrument Description	Transactions with delivery periods exceeding two years
Valuation Technique	Transactions are valued against forward market prices on a discounted basis
Valuation Inputs	Observable and extrapolated forward gas and power prices not all of which can be corroborated by market data for identical or similar products
CME SWAPS MARKETS (NYMEX) [Member]	
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis Valuation Techniques [Line Items]	
Index	NYMEX ($/MMBtu)
SP15 [Member]	
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis Valuation Techniques [Line Items]	
Index	SP15 ($/MWh)
Mid C [Member]	
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis Valuation Techniques [Line Items]	
Index	Mid C ($/MWh)
Cinergy [Member]	
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis Valuation Techniques [Line Items]	
Index	Cinergy ($/MWh)
Weighted Average [Member] | CME SWAPS MARKETS (NYMEX) [Member]	
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis Valuation Techniques [Line Items]	
Variability | $ / MMBTU	4.27
Weighted Average [Member] | SP15 [Member]	
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis Valuation Techniques [Line Items]	

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Variability Weighted Average [Member] | Mid C [Member] **Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis Valuation Techniques [Line Items]**	44.23
Variability Weighted Average [Member] | Cinergy [Member] **Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis Valuation Techniques [Line Items]**	35.44
Variability Maximum [Member] | CME SWAPS MARKETS (NYMEX) [Member] **Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis Valuation Techniques [Line Items]**	36.40
Variability | $ / MMBTU Maximum [Member] | SP15 [Member] **Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis Valuation Techniques [Line Items]**	7.37
Variability Maximum [Member] | Mid C [Member] **Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis Valuation Techniques [Line Items]**	80.28
Variability Maximum [Member] | Cinergy [Member] **Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis Valuation Techniques [Line Items]**	83.93
Variability Minimum [Member] | CME SWAPS MARKETS (NYMEX) [Member] **Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis Valuation Techniques [Line Items]**	77.49
Variability | $ / MMBTU Minimum [Member] | SP15 [Member] **Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis Valuation Techniques [Line Items]**	1.64
Variability Minimum [Member] | Mid C [Member]	14.25

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Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis Valuation Techniques [Line Items]	
Variability	3.60
Minimum [Member] | Cinergy [Member]	
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis Valuation Techniques [Line Items]	
Variability	18.53

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Fair Value of Financial Instruments and Fair Value Measurements - Additional Information (Detail)	12 Months Ended Dec. 31, 2016
Minimum [Member]	
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]	
Fair value input, gas or power delivery period (in years)	2 years

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Fair Value of Financial Instruments and Fair Value Measurements - Schedule of Fair Value Measurement (Detail) - Contracts For Differences [Member] - Level 3 [Member]	12 Months Ended Dec. 31, 2016 $ / MWh
Minimum [Member]	
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis Valuation Techniques [Line Items]	
Risk of non-performance	0.68%
Discount rate	1.47%
Forward pricing ($ per MW)	3.15
Maximum [Member]	
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis Valuation Techniques [Line Items]	
Risk of non-performance	0.81%
Discount rate	2.45%
Forward pricing ($ per MW)	9.55

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Derivative Instruments and Hedging - Additional Information (Detail) - USD ($)		12 Months Ended			
		Dec. 31, 2017	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Derivative Instruments and Hedging Activities Disclosures [Line Items]					
Gain (Loss) recognized in regulatory assets			$ 81,000,000	$ (74,000,000)	$ (175,000,000)
Derivative financial instruments, assets			172,000,000	177,000,000	
Gross Amounts of Recognized Liabilities			153,000,000	185,000,000	
Regulatory liabilities			19,800,000		
Reclassification to net income of (gains) losses on cash flow hedges, net of income taxes	[1]		(16,000,000)	7,000,000	5,000,000
UI [Member]					
Derivative Instruments and Hedging Activities Disclosures [Line Items]					
Derivative financial instruments, assets			19,000,000	29,000,000	
Regulatory Assets			75,000,000	68,000,000	
Gross Amounts of Recognized Liabilities			95,000,000	96,000,000	
Regulatory liabilities			$ 0	1,000,000	
Contracts For Differences [Member] | UI [Member]					
Derivative Instruments and Hedging Activities Disclosures [Line Items]					
Percentage of cost or benefit on contract allocated to customers			20.00%		
Contracts For Differences [Member] | CL&P [Member]					
Derivative Instruments and Hedging Activities Disclosures [Line Items]					
Percentage of cost or benefit on contract allocated to customers			80.00%		
Derivative financial instruments, assets			$ 0	1,000,000	
Gross Amounts of Recognized Liabilities			70,000,000	61,000,000	
Network [Member]					
Derivative Instruments and Hedging Activities Disclosures [Line Items]					
Net derivative losses related to discontinued cash flow hedges	[2]			(3,000,000)	(4,000,000)
Network [Member] | Cash Flow Hedging [Member]					
Derivative Instruments and Hedging Activities Disclosures [Line Items]					
Net derivative losses related to discontinued cash flow hedges			8,000,000	8,600,000	8,900,000
Ineffective portion of Cash flow hedge			0	0	0
Unrealized gain(loss) from hedging activities reported on OCI			$ (400,000)		

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Derivative Instruments Gain Loss To Be Reclassified From Accumulated OCI Into Interest Expense During Next Twelve Months		12 months		
Network [Member] | Cash Flow Hedging [Member] | Scenario, Forecast [Member]				
Derivative Instruments and Hedging Activities Disclosures [Line Items]				
Reclassification to net income of (gains) losses on cash flow hedges, net of income taxes	$ 8,000,000			
Derivative Instruments Gain Loss To Be Reclassified From Accumulated OCI Into Interest Expense During Next Twelve Months	$ 400,000			
Network [Member] | forward starting swaps [Member] | Cash Flow Hedging [Member]				
Derivative Instruments and Hedging Activities Disclosures [Line Items]				
Net loss related to previously settled forward starting swaps		$ 76,700,000	84,900,000	93,500,000
Network [Member] | Electricity Derivatives [Member]				
Derivative Instruments and Hedging Activities Disclosures [Line Items]				
Gain (Loss) recognized in regulatory assets		(12,300,000)	(34,300,000)	
Gain (Loss) reclassified from regulatory assets and liabilities into income		(66,700,000)	(46,900,000)	(21,300,000)
Network [Member] | Natural Gas Hedges [Member]				
Derivative Instruments and Hedging Activities Disclosures [Line Items]				
Gain (Loss) recognized in regulatory assets		3,500,000	(3,100,000)	
Gain (Loss) reclassified from regulatory assets and liabilities into income		$ (1,900,000)	(6,300,000)	$ (2,200,000)
Network [Member] | Fuel Derivatives [Member] | Cash Flow Hedging [Member] | Maximum [Member]				
Derivative Instruments and Hedging Activities Disclosures [Line Items]				
Maximum period of time of cash flow hedges		12 months		
Renewables and Gas Activities [Member] | Cash Flow Hedging [Member]				
Derivative Instruments and Hedging Activities Disclosures [Line Items]				
Ineffective portion of Cash flow hedge		$ (6,800,000)	4,800,000	
Unrealized gain(loss) from hedging activities reported on OCI		$ 13,600,000		
Derivative Instruments Gain Loss To Be Reclassified From Accumulated OCI Into Interest Expense During Next Twelve Months		12 months		

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Gain Recognized in OCI Derivatives Effective Portion	$ 400,000	2,300,000
Counter Party [Member]		
Derivative Instruments and Hedging Activities Disclosures [Line Items]		
Gross Amounts of Recognized Liabilities	12,000,000	
Cash Collateral Pledged	20,000,000	$ 11,000,000
Counter Party [Member] | UI [Member]		
Derivative Instruments and Hedging Activities Disclosures [Line Items]		
Derivative collateral obligation to be paid in decrease in credit rating below investment grade	$ 12,800,000	

[1] Reclassification is reflected in the operating expenses line item in the consolidated statements of income.

[2] 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.

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Derivative Instruments and Hedging - Summary of Unrealized Gains and Losses from Fair Value Adjustments (Detail) - USD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2015	Dec. 31, 2016
Regulatory Assets [Member]		
Derivative Instruments and Hedging Activities Disclosures [Line Items]		
Regulatory Assets (Liabilities) - Derivative assets (liabilities)	$ 1	$ 7
Regulatory Liabilities [Member]		
Derivative Instruments and Hedging Activities Disclosures [Line Items]		
Regulatory Assets (Liabilities) - Derivative assets (liabilities)		$ 1

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Derivative Instruments and Hedging - Net Notional Volume (Detail)	Dec. 31, 2016 MWh DTH gal	Dec. 31, 2015 MWh DTH gal
Network [Member] | Wholesale Electricity Contract [Member] | Long [Member]		
Derivative Instruments and Hedging Activities Disclosures [Line Items]		
Derivative non-monetary notional amount | MWh	5,600,000	6,700,000
Network [Member] | Natural Gas Contracts [Member] | Long [Member]		
Derivative Instruments and Hedging Activities Disclosures [Line Items]		
Derivative non-monetary notional amount	5,800,000	4,800,000
Network [Member] | Fleet Fuel Contracts [Member] | Long [Member]		
Derivative Instruments and Hedging Activities Disclosures [Line Items]		
Derivative non-monetary notional amount | gal	2,300,000	3,800,000
Renewables and Gas Activities [Member] | Long [Member] | Basis Swap [Member]		
Derivative Instruments and Hedging Activities Disclosures [Line Items]		
Derivative non-monetary notional amount	49,000,000	67,000,000
Renewables and Gas Activities [Member] | Short [Member] | Basis Swap [Member]		
Derivative Instruments and Hedging Activities Disclosures [Line Items]		
Derivative non-monetary notional amount	45,000,000	80,000,000
Renewables and Gas Activities [Member] | Wholesale Electricity Contract [Member] | Long [Member]		
Derivative Instruments and Hedging Activities Disclosures [Line Items]		
Derivative non-monetary notional amount | MWh	3,000,000	3,000,000
Renewables and Gas Activities [Member] | Wholesale Electricity Contract [Member] | Short [Member]		
Derivative Instruments and Hedging Activities Disclosures [Line Items]		
Derivative non-monetary notional amount | MWh	7,000,000	6,000,000
Renewables and Gas Activities [Member] | Foreign Exchange Forward [Member] | Long [Member]		
Derivative Instruments and Hedging Activities Disclosures [Line Items]		
Derivative non-monetary notional amount		4,000,000
Renewables and Gas Activities [Member] | Natural Gas and Other fuel Contracts [Member] | Long [Member]		
Derivative Instruments and Hedging Activities Disclosures [Line Items]		
Derivative non-monetary notional amount	329,000,000	332,000,000
Renewables and Gas Activities [Member] | Financial Power Contracts [Member]		
Derivative Instruments and Hedging Activities Disclosures [Line Items]		
Derivative non-monetary notional amount	8,000,000	7,000,000

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Derivative Instruments and Hedging - Offsetting of Derivatives, Locations in Consolidated Balance Sheet and Amounts of Derivatives (Detail) - USD ($) $ in Millions	Dec. 31, 2016	Dec. 31, 2015
Network [Member] | UIL Holdings [Member] | Current Assets [Member]		
Derivative Instruments And Hedging Activities Disclosures [Line Items]		
Total derivatives before offset of cash collateral	$ 12	$ 11
Total derivatives as presented in the balance sheet	12	11
Network [Member] | UIL Holdings [Member] | Current Assets [Member] | Not Designated as Hedging Instruments [Member]		
Derivative Instruments And Hedging Activities Disclosures [Line Items]		
Derivative assets	19	11
Derivative liabilities	(7)	
Derivative Fair Value, Net	12	11
Network [Member] | UIL Holdings [Member] | Current Assets [Member] | Designated as Hedging Instrument [Member]		
Derivative Instruments And Hedging Activities Disclosures [Line Items]		
Derivative liabilities		(3)
Derivative assets		3
Network [Member] | UIL Holdings [Member] | Noncurrent Assets [Member]		
Derivative Instruments And Hedging Activities Disclosures [Line Items]		
Total derivatives before offset of cash collateral	11	18
Total derivatives as presented in the balance sheet	11	18
Network [Member] | UIL Holdings [Member] | Noncurrent Assets [Member] | Not Designated as Hedging Instruments [Member]		
Derivative Instruments And Hedging Activities Disclosures [Line Items]		
Derivative assets	16	18
Derivative liabilities	(5)	
Derivative Fair Value, Net	11	18
Network [Member] | UIL Holdings [Member] | Noncurrent Assets [Member] | Designated as Hedging Instrument [Member]		
Derivative Instruments And Hedging Activities Disclosures [Line Items]		
Derivative liabilities		(6)
Derivative assets		6
Network [Member] | UIL Holdings [Member] | Current Liabilities [Member]		
Derivative Instruments And Hedging Activities Disclosures [Line Items]		
Total derivatives before offset of cash collateral	(33)	(67)
Cash collateral receivable	10	37
Total derivatives as presented in the balance sheet	(23)	(30)
Network [Member] | UIL Holdings [Member] | Current Liabilities [Member] | Not Designated as Hedging Instruments [Member]		

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Derivative Instruments And Hedging Activities Disclosures [Line Items]		
Derivative assets	7	
Derivative liabilities	(40)	(28)
Derivative Fair Value, Net	(33)	(28)
Network [Member] | UIL Holdings [Member] | Current Liabilities [Member] | Designated as Hedging Instrument [Member]		
Derivative Instruments And Hedging Activities Disclosures [Line Items]		
Derivative liabilities		(42)
Derivative Fair Value, Net		(39)
Derivative assets		3
Network [Member] | UIL Holdings [Member] | Noncurrent Liabilities [Member]		
Derivative Instruments And Hedging Activities Disclosures [Line Items]		
Total derivatives before offset of cash collateral	(74)	(69)
Cash collateral receivable	2	
Total derivatives as presented in the balance sheet	(72)	(69)
Network [Member] | UIL Holdings [Member] | Noncurrent Liabilities [Member] | Not Designated as Hedging Instruments [Member]		
Derivative Instruments And Hedging Activities Disclosures [Line Items]		
Derivative assets	5	
Derivative liabilities	(79)	(68)
Derivative Fair Value, Net	(74)	(68)
Network [Member] | UIL Holdings [Member] | Noncurrent Liabilities [Member] | Designated as Hedging Instrument [Member]		
Derivative Instruments And Hedging Activities Disclosures [Line Items]		
Derivative liabilities		(7)
Derivative Fair Value, Net		(1)
Derivative assets		6
Renewables and Gas Activities [Member] | Current Assets [Member]		
Derivative Instruments And Hedging Activities Disclosures [Line Items]		
Total derivatives before offset of cash collateral	104	157
Total derivatives as presented in the balance sheet	87	77
Cash collateral receivable (payable)	(17)	(80)
Renewables and Gas Activities [Member] | Current Assets [Member] | Not Designated as Hedging Instruments [Member]		
Derivative Instruments And Hedging Activities Disclosures [Line Items]		
Derivative liabilities	(118)	(85)
Derivative Fair Value, Net	80	101
Derivative assets	198	186
Renewables and Gas Activities [Member] | Current Assets [Member] | Designated as Hedging Instrument [Member]		
Derivative Instruments And Hedging Activities Disclosures [Line Items]		
Derivative liabilities	(1)	
Derivative Fair Value, Net	24	56
Derivative assets	25	56
Renewables and Gas Activities [Member] | Noncurrent Assets [Member]		

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Derivative Instruments And Hedging Activities Disclosures [Line Items]		
Total derivatives before offset of cash collateral	108	112
Total derivatives as presented in the balance sheet	62	71
Cash collateral receivable (payable)	(46)	(41)
Renewables and Gas Activities [Member] | Noncurrent Assets [Member] | Not Designated as Hedging Instruments [Member]		
Derivative Instruments And Hedging Activities Disclosures [Line Items]		
Derivative liabilities	(4)	(14)
Derivative Fair Value, Net	104	99
Derivative assets	108	113
Renewables and Gas Activities [Member] | Noncurrent Assets [Member] | Designated as Hedging Instrument [Member]		
Derivative Instruments And Hedging Activities Disclosures [Line Items]		
Derivative Fair Value, Net	4	13
Derivative assets	4	13
Renewables and Gas Activities [Member] | Current Liabilities [Member]		
Derivative Instruments And Hedging Activities Disclosures [Line Items]		
Total derivatives before offset of cash collateral	(93)	(61)
Total derivatives as presented in the balance sheet	(52)	(61)
Cash collateral receivable (payable)	41	
Renewables and Gas Activities [Member] | Current Liabilities [Member] | Not Designated as Hedging Instruments [Member]		
Derivative Instruments And Hedging Activities Disclosures [Line Items]		
Derivative liabilities	(132)	(169)
Derivative Fair Value, Net	(54)	(52)
Derivative assets	78	117
Renewables and Gas Activities [Member] | Current Liabilities [Member] | Designated as Hedging Instrument [Member]		
Derivative Instruments And Hedging Activities Disclosures [Line Items]		
Derivative liabilities	(39)	(9)
Derivative Fair Value, Net	(39)	(9)
Renewables and Gas Activities [Member] | Noncurrent Liabilities [Member]		
Derivative Instruments And Hedging Activities Disclosures [Line Items]		
Total derivatives before offset of cash collateral	(30)	(25)
Total derivatives as presented in the balance sheet	(6)	(25)
Cash collateral receivable (payable)	24	
Renewables and Gas Activities [Member] | Noncurrent Liabilities [Member] | Not Designated as Hedging Instruments [Member]		
Derivative Instruments And Hedging Activities Disclosures [Line Items]		
Derivative liabilities	(16)	(29)
Derivative Fair Value, Net	(9)	(25)
Derivative assets	7	$ 4
Renewables and Gas Activities [Member] | Noncurrent Liabilities [Member] | Designated as Hedging Instrument [Member]		
Derivative Instruments And Hedging Activities Disclosures [Line Items]		

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Derivative liabilities	(21)
Derivative Fair Value, Net	$ (21)

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Derivative Instruments and Hedging - Effect of Derivatives in Cash Flow Hedging (Detail) - USD ($) $ in Millions	12 Months Ended		
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Derivative Instruments and Hedging Activities Disclosures [Line Items]			
(Loss) Gain Recognized in OCI Derivatives Effective Portion	[1] $ (42)	$ 57	
Network [Member]			
Derivative Instruments and Hedging Activities Disclosures [Line Items]			
(Loss) Recognized in OCI Derivatives Effective Portion	[2]	(3)	$ (4)
Loss Reclassified from Accumulated OCI Income Effective Portion	[2] 10	12	10
Renewables and Gas Activities [Member]			
Derivative Instruments and Hedging Activities Disclosures [Line Items]			
(Gain) Reclassified from Accumulated OCI Income Effective Portion	[1] (43)	(2)	
Interest Rate Contract [Member] | Network [Member] | Interest expense [Member]			
Derivative Instruments and Hedging Activities Disclosures [Line Items]			
Loss Reclassified from Accumulated OCI Income Effective Portion	[2] 8	9	9
Commodity Contract [Member]			
Derivative Instruments and Hedging Activities Disclosures [Line Items]			
(Loss) Gain Recognized in OCI Derivatives Effective Portion	[1] (42)	57	
Commodity Contract [Member] | Network [Member] | Operating expenses [Member]			
Derivative Instruments and Hedging Activities Disclosures [Line Items]			
(Loss) Recognized in OCI Derivatives Effective Portion	[2]	(3)	(4)
Loss Reclassified from Accumulated OCI Income Effective Portion	[2] 2	3	$ 1
Commodity Contract [Member] | Renewables and Gas Activities [Member] | Revenue [Member]			
Derivative Instruments and Hedging Activities Disclosures [Line Items]			
(Gain) Reclassified from Accumulated OCI Income Effective Portion	[1] $ (43)	$ (2)	

[1] Changes in OCI are reported on a pre-tax basis.

[2] 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.

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Derivative Instruments and Hedging - Fair Value of Derivative Contract (Detail) - Renewables and Gas Activities [Member] - USD ($) $ in Millions	Dec. 31, 2016	Dec. 31, 2015
Derivative Instruments and Hedging Activities Disclosures [Line Items]		
Derivative Fair Value, Net	$ 91	$ 62
Financial Power Contracts [Member]		
Derivative Instruments and Hedging Activities Disclosures [Line Items]		
Derivative Fair Value, Net	56	32
Long [Member] | Wholesale Electricity Contract [Member]		
Derivative Instruments and Hedging Activities Disclosures [Line Items]		
Derivative Fair Value, Net	(2)	(13)
Long [Member] | Foreign Exchange Forward [Member]		
Derivative Instruments and Hedging Activities Disclosures [Line Items]		
Derivative Fair Value, Net		(1)
Long [Member] | Natural Gas and Other fuel Contracts [Member]		
Derivative Instruments and Hedging Activities Disclosures [Line Items]		
Derivative Fair Value, Net	30	10
Long [Member] | Basis Swap [Member]		
Derivative Instruments and Hedging Activities Disclosures [Line Items]		
Derivative Fair Value, Net	3	1
Short [Member] | Wholesale Electricity Contract [Member]		
Derivative Instruments and Hedging Activities Disclosures [Line Items]		
Derivative Fair Value, Net	6	35
Short [Member] | Basis Swap [Member]		
Derivative Instruments and Hedging Activities Disclosures [Line Items]		
Derivative Fair Value, Net	$ (2)	$ (2)

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Derivative Instruments and Hedging - Effect of Trading and Non-Trading Derivatives (Detail) - Renewables and Gas Activities [Member] - USD ($) $ in Millions	12 Months Ended		
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Trading Derivatives [Member]			
Derivative Instruments and Hedging Activities Disclosures [Line Items]			
(Loss) Gain on Derivative, Net	$ (22)	$ (25)	$ 123
Trading Derivatives [Member] | Wholesale Electricity Contract [Member] | Long [Member]			
Derivative Instruments and Hedging Activities Disclosures [Line Items]			
(Loss) Gain on Derivative, Net	3	6	(9)
Trading Derivatives [Member] | Wholesale Electricity Contract [Member] | Short [Member]			
Derivative Instruments and Hedging Activities Disclosures [Line Items]			
(Loss) Gain on Derivative, Net	(7)	(5)	9
Trading Derivatives [Member] | Financial Power Contracts [Member]			
Derivative Instruments and Hedging Activities Disclosures [Line Items]			
(Loss) Gain on Derivative, Net	4		(2)
Trading Derivatives [Member] | Financial and Natural Gas Contracts [Member]			
Derivative Instruments and Hedging Activities Disclosures [Line Items]			
(Loss) Gain on Derivative, Net	(22)	(26)	125
Non-Trading Derivatives [Member]			
Derivative Instruments and Hedging Activities Disclosures [Line Items]			
(Loss) Gain on Derivative, Net	13	29	36
Non-Trading Derivatives [Member] | Wholesale Electricity Contract [Member] | Long [Member]			
Derivative Instruments and Hedging Activities Disclosures [Line Items]			
(Loss) Gain on Derivative, Net	9	(8)	(8)
Non-Trading Derivatives [Member] | Wholesale Electricity Contract [Member] | Short [Member]			
Derivative Instruments and Hedging Activities Disclosures [Line Items]			
(Loss) Gain on Derivative, Net	(20)	(5)	15
Non-Trading Derivatives [Member] | Financial Power Contracts [Member]			
Derivative Instruments and Hedging Activities Disclosures [Line Items]			
(Loss) Gain on Derivative, Net	(10)	24	30
Non-Trading Derivatives [Member] | Natural Gas and Other fuel Contracts [Member]			
Derivative Instruments and Hedging Activities Disclosures [Line Items]			
(Loss) Gain on Derivative, Net	$ 34	$ 18	$ (1)

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Commitments and Contingent Liabilities - Additional Information (Detail) $ in Millions	Oct. 14, 2016 USD ($)	May 03, 2016 USD ($)	Apr. 29, 2016	Mar. 25, 2016 USD ($)	Mar. 22, 2016	Oct. 21, 2015 USD ($)	Dec. 31, 2014 USD ($)	Jul. 31, 2014	Jan. 22, 2014	Dec. 26, 2012	1 Months Ended Nov. 30, 2013 USD ($)	1 Months Ended Dec. 31, 2012 USD ($)	12 Months Ended Dec. 31, 2016 USD ($) Unit MW	12 Months Ended Dec. 31, 2015 USD ($)	12 Months Ended Dec. 31, 2014 USD ($)	12 Months Ended Dec. 31, 2012 USD ($)	12 Months Ended May 31, 2016 USD ($)
Loss Contingencies [Line Items]																	
New rate plan		10 years															
Delivery revenue percentage		34.60%															
Requested return on equity base percentage		9.55%											9.20%				
Requested equity ratio		50.00%															
One-time gross plant investment		$ 15.0															
Cash Reserve																	$ 6.0
Approved return on equity									9.18%				10.50%				
Disclosure of Rate Matters													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)				
Regulatory liabilities													$ 1,753.0	$ 1,841.0			
Spent fuel litigation damages awarded, value				$ 76.8							$ 235.4					$ 160.0	
Spent fuel litigation damages settlement received	$ 41.6																
Litigation appeal expiration date													Jul. 18, 2016				
Adjustment regulatory deferral and earning sharing accruals												$ 9.8					
Staff issue settlement reserve												3.4				3.4	
Customer share of earnings sharing																2.4	
Price of the power purchase agreements													$ 259.0				
Operating lease expenses													70.6	47.7	$ 48.7		
Contingent rent payment for electricity generation facility													$ 22.2	22.2	20.4		
Sale of ownership interest percent							10.00%										
Proceeds from sale of ownership Interest							$ 19.6										

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Modified agreement monthly payment amount	$ 15.4	
Purchase power, description		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
Standby letters of credit		$ 2,600.0
Property, Plant and Equipment [Member]		
Loss Contingencies [Line Items]		
Future purchase commitment		$ 493.0
Power purchase commitments [Member]		
Loss Contingencies [Line Items]		
Purchase power, description		U.S. Power purchase commitments include the following: (i) a 55MW Biomass Power Purchase Agreement (PPA) for 12 years (five 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

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	NW wind assets that has monthly fixed payments (two years remaining)
Power purchase commitment | MW	55
Period of purchase commitment	12 months
Power purchase commitment, remaining period	5 months
Power purchase commitments [Member] | Guaranteed output / Guaranteed annual production [Member]	
Loss Contingencies [Line Items]	
Power purchase commitment | MW	34
Power purchase commitments [Member] | Hydro Capacity and Energy [Member]	
Loss Contingencies [Line Items]	
Period of purchase commitment	3 months
Power purchase commitment, remaining period	2 months
Power sales commitments [Member]	
Loss Contingencies [Line Items]	
Purchase power, description	Power sales commitments include: (i) a 55MW Biomass off-take agreement for 12 years (five 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

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					sales off merchant wind facilities.		
Power purchase commitment | MW					55		
Period of purchase commitment					12 months		
Power purchase commitment, remaining period					5 months		
Power sales commitments [Member] | Guaranteed output / Guaranteed annual production [Member]							
Loss Contingencies [Line Items]							
Power purchase commitment | MW					34.4		
Support Services [Member]							
Loss Contingencies [Line Items]							
Operating lease expenses					$ 114.9	79.9	
Support Services [Member] | Coal Fired Generating Station							
Loss Contingencies [Line Items]							
Operating lease expenses					$ 37.8	$ 25.5	$ 19.8
Number of Coal-Fired Generating Unit | Unit					2		
Connecticut Yankee Atomic Power Company [Member]							
Loss Contingencies [Line Items]							
Court of Federal Claims award				39.7			39.7
Spent fuel litigation damages awarded, value		32.6		126.3			
Spent fuel litigation damages settlement received	18.4						
Maine Yankee Atomic Power Company [Member]							
Loss Contingencies [Line Items]							
Court of Federal Claims award				$ 81.7			81.7
Spent fuel litigation damages awarded, value		24.6		37.7			
Spent fuel litigation damages settlement received	3.6						
CMP Distribution [Member]							
Loss Contingencies [Line Items]							
Share of the award credited back to customers				28.2	$ 36.5		
Spent fuel litigation damages settlement received					$ 21.5		
Period of purchase commitment					20 years		
UI [Member]							
Loss Contingencies [Line Items]							
Share of the award credited back to customers				12.0	$ 3.8		
Yankee Atomic Energy Corporation [Member]							

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Loss Contingencies [Line Items]					
Spent fuel litigation damages awarded, value		$ 19.6		73.3	
Spent fuel litigation damages settlement received	$ 19.6				
RG&E Electric [Member]					
Loss Contingencies [Line Items]					
Requested equity ratio					75.00%
Approved return on equity					9.00%
Percentage of revenue entitled			70.00%		70.00%
Ginna Nuclear Power Plant LLC [Member]					
Loss Contingencies [Line Items]					
Percentage of revenue entitled			30.00%		30.00%
Complaint I [Member]					
Loss Contingencies [Line Items]					
Regulatory liabilities					$ 21.6
Complaint II [Member]					
Loss Contingencies [Line Items]					
Requested return on equity base percentage				8.70%	
Disclosure of Rate Matters					On December 26, 2012, a second, ROE complaint (Complaint II) for a subsequent rate period was filed requesting the ROE 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.
Regulatory liabilities					$ 21.6
Complaint III [Member]					
Loss Contingencies [Line Items]					
Requested return on equity base percentage				8.84%	
Regulatory liabilities					$ 4.4
Complaint II and III [Member]					
Loss Contingencies [Line Items]					
Disclosure of Rate Matters					On November 24, 2014, FERC

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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 were held in June 2015 on Complaints II and III before a FERC Administrative Law Judge, relating to the refund periods and going forward period. 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)

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				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 mid-2017.
Reasonably possible loss, in additional reserve, pre tax				$ 17.1
Phase III [Member] | CMP and UI [Member]				
Loss Contingencies [Line Items]				
Spent fuel litigation damages settlement received				$ 4.2
Unfavorable Regulatory Action [Member] | Complaint I [Member]				
Loss Contingencies [Line Items]				
Approved return on equity				10.57%
Unfavorable Regulatory Action [Member] | Complaint II [Member]				
Loss Contingencies [Line Items]				
Approved return on equity		9.59%		
Unfavorable Regulatory Action [Member] | Complaint III [Member]				
Loss Contingencies [Line Items]				
Approved return on equity		10.90%		
Unfavorable Regulatory Action [Member] | Complaint Four [Member]				
Loss Contingencies [Line Items]				
Approved return on equity	8.61%			
Before Amendment [Member]				
Loss Contingencies [Line Items]				
Approved return on equity				11.14%
Minimum [Member]				
Loss Contingencies [Line Items]				
Requested return on equity base percentage	14.55%			

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Spent fuel litigation damages awarded, value			$ 82.0		
Minimum [Member] | Connecticut Yankee Atomic Power Company [Member]					
Loss Contingencies [Line Items]					
Spent fuel litigation damages awarded, value					21.4
Maximum [Member]					
Loss Contingencies [Line Items]					
Approved return on equity				11.74%	
Maximum [Member] | Connecticut Yankee Atomic Power Company [Member]					
Loss Contingencies [Line Items]					
Spent fuel litigation damages awarded, value					$ 38.3
Maximum [Member] | Complaint II [Member]					
Loss Contingencies [Line Items]					
Approved return on equity		10.42%			
Maximum [Member] | Complaint III [Member]					
Loss Contingencies [Line Items]					
Approved return on equity		12.19%			
Maximum [Member] | Unfavorable Regulatory Action [Member] | Complaint Four [Member]					
Loss Contingencies [Line Items]					
Approved return on equity	11.24%				

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Commitments and Contingent Liabilities - Schedule of Future Minimum Lease Payment (Detail) $ in Millions	Dec. 31, 2016 USD ($)
Commitments And Contingencies Disclosure [Abstract]	
Operating lease, 2017	$ 106
Operating lease, 2018	28
Operating leases, 2019	28
Operating leases, 2020	26
Operating leases, 2021	28
Operating leases, 2022 and thereafter	487
Total operating lease	703
Capital lease, 2017	30
Capital lease, 2018	6
Capital leases, 2019	7
Capital leases, 2020	7
Capital leases, 2021	4
Capital leases, 2022 and thereafter	50
Total capital lease	104
Operating and capital leases, 2017	136
Operating and capital leases, 2018	34
Operating and capital leases, 2019	35
Operating and capital leases, 2020	33
Operating and capital leases, 2021	32
Operating and capital leases, 2022 and thereafter	537
Total operating and capital leases	$ 807

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Commitments and Contingent Liabilities - Schedule of Forward Purchases and Sales Commitments Under Power, Gas, and Other Arrangements (Detail) $ in Millions	12 Months Ended Dec. 31, 2016 USD ($)
Oil And Gas Delivery Commitments And Contracts [Line Items]	
Forward purchase commitments, 2017	$ 487
Forward purchase commitments, 2018	376
Forward purchase commitments, 2019	287
Forward purchase commitments, 2020	238
Forward purchase commitments, 2021	191
Forward purchase commitments, thereafter	1,008
Total forward purchase commitments	2,587
Forward sales commitments, 2017	159
Forward sales commitments, 2018	84
Forward sales commitments, 2019	59
Forward sales commitments, 2020	47
Forward sales commitments, 2021	33
Forward sales commitments, thereafter	26
Total forward sales commitments	408
Derivative Financial Instrument Gas [Member]	
Oil And Gas Delivery Commitments And Contracts [Line Items]	
Forward purchase commitments, 2017	284
Forward purchase commitments, 2018	245
Forward purchase commitments, 2019	205
Forward purchase commitments, 2020	161
Forward purchase commitments, 2021	127
Forward purchase commitments, thereafter	520
Total forward purchase commitments	1,542
Forward sales commitments, 2017	23
Forward sales commitments, 2018	4
Forward sales commitments, 2019	5
Forward sales commitments, 2020	5
Total forward sales commitments	37
Power [Member]	
Oil And Gas Delivery Commitments And Contracts [Line Items]	
Forward purchase commitments, 2017	168
Forward purchase commitments, 2018	108
Forward purchase commitments, 2019	68
Forward purchase commitments, 2020	65
Forward purchase commitments, 2021	52

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Forward purchase commitments, thereafter	379
Total forward purchase commitments	840
Forward sales commitments, 2017	132
Forward sales commitments, 2018	76
Forward sales commitments, 2019	53
Forward sales commitments, 2020	42
Forward sales commitments, 2021	33
Forward sales commitments, thereafter	26
Total forward sales commitments	362
Other Forward Purchases And Sales Commitments	
Oil And Gas Delivery Commitments And Contracts [Line Items]	
Forward purchase commitments, 2017	35
Forward purchase commitments, 2018	23
Forward purchase commitments, 2019	14
Forward purchase commitments, 2020	12
Forward purchase commitments, 2021	12
Forward purchase commitments, thereafter	109
Total forward purchase commitments	205
Forward sales commitments, 2017	4
Forward sales commitments, 2018	4
Forward sales commitments, 2019	1
Total forward sales commitments	$ 9

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Environmental Liabilities - Additional Information (Detail) $ in Millions	1 Months Ended					12 Months Ended			
	Sep. 11, 2014 USD ($)	Aug. 14, 2013 USD ($)	Sep. 09, 2011 USD ($)	Nov. 30, 2014 USD ($)	Jul. 31, 2011 USD ($)	Dec. 31, 2016 USD ($) site Location	Aug. 04, 2016 USD ($)	Dec. 31, 2015 USD ($)	Jan. 31, 2015 USD ($)
Environmental Exit Cost [Line Items]									
Number of sites with potential remediation obligations | site					25				
Number of sites where gas was manufactured in the past | site					53				
Number of sites for which we have entered into consent orders to investigate and remediate | site					49				
Costs related to investigation and remediation					$ 388.0			$ 397.0	
Accrual for environmental loss contingencies	$ 27.0				$ 26.0				
Damages for incurred costs payment amount	$ 22.0								
Refund of environmental remediation cost paid				$ 5.0					
Number of sites with modified decision | site					9				
Future costs that have been recorded as a receivable									$ 16.0
First Energy [Member]									
Environmental Exit Cost [Line Items]									
Reasonably possible loss, in additional reserve, net of tax					$ 60.0				
Environmental costs paid			$ 30.0						
First Energy [Member] | Past Costs [Member]									
Environmental Exit Cost [Line Items]									
Accrual for environmental loss contingencies			27.0						
First Energy [Member] | Pre-judgment Interest [Member]									
Environmental Exit Cost [Line Items]									

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Environmental costs paid	$ 3.0			
Century Indemnity and OneBeacon [Member]				
Environmental Exit Cost [Line Items]				
Reasonably possible loss, in additional reserve, net of tax	$ 89.0			
Number of hazardous waste sites | Location		22		
Legal discovery process expected closing year description		Century Idemnity and One Beacon have answered admitting issuance of the excess policies, but contesting coverage and providing documentation proving they received notice of the claims in the 1990s		
United Illuminating Company (UI)				
Environmental Exit Cost [Line Items]				
Estimated environmental liability		$ 1.7		9.5
Costs related to investigation and remediation		28.3	$ 30.0	20.5
Difference in pretax reflected as reversal of expense		$ 7.8		
Maximum [Member] | Century Indemnity and OneBeacon [Member]				
Environmental Exit Cost [Line Items]				
Reasonably possible loss, in additional reserve, net of tax	$ 282.0			
New York State Registry [Member]				
Environmental Exit Cost [Line Items]				
Number of sites with potential remediation obligations | site		15		
Number of sites where gas was manufactured in the past | site		8		
Maine's Uncontrolled Sites Program [Member]				
Environmental Exit Cost [Line Items]				
Number of sites with potential remediation obligations | site		6		

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Number of sites where gas was manufactured in the past | site Massachusetts Non- Priority Confirmed Disposal Site List [Member]	2
Environmental Exit Cost [Line Items] Number of sites with potential remediation obligations | site National Priorities List [Member]	1
Environmental Exit Cost [Line Items] Number of sites with potential remediation obligations | site Ten of Twenty-five Sites [Member]	9
Environmental Exit Cost [Line Items] Estimated environmental liability Another Ten Sites [Member]	$ 6.0
Environmental Exit Cost [Line Items] Estimated environmental liability Another Ten Sites [Member] | Minimum [Member]	8.0
Environmental Exit Cost [Line Items] Estimated environmental liability Another Ten Sites [Member] | Maximum [Member]	12.0
Environmental Exit Cost [Line Items] Estimated environmental liability New York Voluntary Cleanup Program [Member]	$ 22.0
Environmental Exit Cost [Line Items] Number of sites where gas was manufactured in the past | site Maine's Voluntary Response Action Program [Member]	11

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Environmental Exit Cost [Line Items]		
Number of sites where gas was manufactured in the past | site	3	
Manufactured Gas Plants | Connecticut [Member]		
Environmental Exit Cost [Line Items]		
Costs related to investigation and remediation	$ 97.0	$ 99.0
Manufactured Gas Plants | Minimum [Member]		
Environmental Exit Cost [Line Items]		
Costs related to investigation and remediation	221.0	
Manufactured Gas Plants | Maximum [Member]		
Environmental Exit Cost [Line Items]		
Costs related to investigation and remediation	$ 465.0	

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Income Taxes - Schedule of Current and Deferred Taxes Charged to (Benefit) Expense (Details) - USD ($) $ in Millions	12 Months Ended		
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Current			
Federal	$ (6)	$ (20)	$ (10)
State	8	(33)	31
Current taxes charged to (benefit) expense	2	(53)	21
Deferred			
Federal	414	136	218
State	2	(6)	82
Deferred taxes charged to expense	416	130	300
Production tax credits	(38)	(42)	(37)
Investment tax credits	(1)	(1)	(2)
Total Income Tax Expense	$ 379	$ 34	$ 282

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Income Taxes - Schedule of Differences between Tax Expense Per Statements of Income and Tax Expense at Statutory Federal Tax Rate (Details) - USD ($) $ in Millions	12 Months Ended		
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Income Tax Disclosure [Abstract]			
Tax expense at federal statutory rate	$ 353	$ 105	$ 247
Depreciation and amortization not normalized	61	15	15
Investment tax credit amortization	(1)	(1)	(2)
Tax return related adjustments	(2)	6	2
Production tax credits	(38)	(42)	(37)
Tax equity financing arrangements	(25)	(36)	(11)
Change in tax reserves			3
Changes in New York tax law			41
State tax expense (benefit), net of federal benefit	7	(25)	32
Non-deductible acquisition costs		9	
Other, net	24	3	(8)
Total Income Tax Expense	$ 379	$ 34	$ 282

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Income Taxes - Schedule of Deferred Tax Assets and Liabilities (Details) - USD ($) $ in Millions	Dec. 31, 2016	Dec. 31, 2015
Non-current Deferred Income Tax Liabilities (Assets)		
Property related	$ 5,195	$ 4,763
Unfunded future income taxes	216	211
Federal and state tax credits	(417)	(367)
Accumulated deferred investment tax credits	14	15
Federal and state NOL's	(1,397)	(1,367)
Joint ventures/partnerships	651	655
Nontaxable grant revenue	(581)	(595)
Other	(171)	(17)
Non-current Deferred Income Tax Liabilities	3,510	3,298
Add: Valuation allowance	31	19
Total Non-current Deferred Income Tax Liabilities	3,541	3,317
Less amounts classified as regulatory liabilities non-current deferred income taxes	565	519
Deferred income taxes	2,976	2,798
Deferred tax assets	2,565	2,346
Deferred tax liabilities	$ 6,106	$ 5,663

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Income Taxes - Additional Information (Details) - USD ($) $ in Millions	12 Months Ended Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014	Dec. 31, 2012
Income Taxes [Line Items]				
Valuation allowance, net of federal benefit	$ 10			$ 9
Increase in valuation allowance	12			
Tax credit carry forward	3			
Accruals for interest and penalties on tax reserves	2	$ 2	$ 3	
Unrecognized tax benefits that would impact effective tax rate	8			
Net decrease to unrecognized tax benefits	9			
State				
Income Taxes [Line Items]				
Valuation allowance, net of federal benefit	15	$ 10		
Tax credit carry forward	32			
Net operating loss carry forwards	241			
Recognized valuation allowance	$ 31			
Expiration year for net operating losses	2021			
Federal				
Income Taxes [Line Items]				
Net operating loss carry forwards	$ 3,600			
Expiration year for net operating losses	2028			
Expiration year for tax credits	2023			
Federal | Renewable Energy and Investment				
Income Taxes [Line Items]				
Tax credit carry forward	$ 394			
Federal | R&D				
Income Taxes [Line Items]				
Tax credit carry forward	394			
Federal | Other				
Income Taxes [Line Items]				
Tax credit carry forward	$ 394			

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Income Taxes - Schedule of Reconciliation of Unrecognized Income Tax Benefits (Details) - USD ($) $ in Millions	12 Months Ended		
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Income Tax Disclosure [Abstract]			
Beginning Balance	$ 36	$ 38	$ 41
Increases for tax positions related to prior years	8	1	20
Decreases for tax positions related to prior years	(4)		
Reduction for tax position related to settlements with taxing authorities		(3)	(23)
Ending Balance	$ 40	$ 36	$ 38

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Post-Retirement and Similar Obligations - Obligations and Funded Status (Detail) - USD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2016	Dec. 31, 2015
Pension Plan [Member]		
Change in plan assets		
Fair value of plan assets, Beginning balance	$ 2,664	
Fair Value of Plan Assets, Ending balance	2,672	$ 2,664
Other Postretirement Benefit Plan [Member]		
Change in plan assets		
Fair value of plan assets, Beginning balance	162	
Fair Value of Plan Assets, Ending balance	160	162
Networks and ARHI [Member] | Pension Plan [Member]		
Change in benefit obligation		
Benefit obligation, Beginning balance	3,509	2,620
Acquisition of UIL		1,019
Service cost	44	36
Interest cost	142	99
Actuarial gain	(43)	(105)
Special termination benefits		2
Benefits paid	(204)	(162)
Benefit Obligation, Ending balance	3,448	3,509
Change in plan assets		
Fair value of plan assets, Beginning balance	2,664	2,143
Acquisition of UIL		687
Actual return on plan assets	169	(31)
Employer contributions	43	27
Benefits paid	(204)	(162)
Fair Value of Plan Assets, Ending balance	2,672	2,664
Funded Status as of December 31,	(776)	(845)
Networks and ARHI [Member] | Other Postretirement Benefit Plan [Member]		
Change in benefit obligation		
Benefit obligation, Beginning balance	525	435
Acquisition of UIL		122
Service cost	5	5
Interest cost	21	16
Plan participants' contributions	7	4
Plan amendments		(1)
Actuarial gain	(24)	(31)
Benefits paid	(39)	(25)
Benefit Obligation, Ending balance	495	525
Change in plan assets		
Fair value of plan assets, Beginning balance	162	129

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Acquisition of UIL		39
Actual return on plan assets	11	(4)
Employer contributions	30	21
Plan participants' contributions	7	4
Benefits paid	(39)	(25)
Withdrawals from VEBA	(11)	(2)
Fair Value of Plan Assets, Ending balance	160	162
Funded Status as of December 31,	$ (335)	$ (363)

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Post-Retirement and Similar Obligations - Summary of Liabilities Amount Recognized (Detail) - USD ($) $ in Millions	Dec. 31, 2016	Dec. 31, 2015
Pension Plan [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Non-current liabilities	$ (776)	$ (845)
Total	(776)	(845)
Other Postretirement Benefit Plan [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Current liabilities	(5)	(5)
Non-current liabilities	(330)	(358)
Total	$ (335)	$ (363)

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Post-Retirement and Similar Obligations - Additional Information (Detail) - USD ($)	12 Months Ended			
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014	Dec. 31, 2017
Defined Benefit Plan Disclosure [Line Items]				
Other	$ 342,000,000	$ 330,000,000		
Benefits plan, target asset allocation	37.00%			
Equity Securities [Member] | Minimum [Member]				
Defined Benefit Plan Disclosure [Line Items]				
Asset return seeking percentage category	35.00%			
Equity Securities [Member] | Maximum [Member]				
Defined Benefit Plan Disclosure [Line Items]				
Asset return seeking percentage category	54.00%			
Equity Alternative Securities [Member] | Minimum [Member]				
Defined Benefit Plan Disclosure [Line Items]				
Asset return seeking percentage category	3.00%			
Equity Alternative Securities [Member] | Maximum [Member]				
Defined Benefit Plan Disclosure [Line Items]				
Asset return seeking percentage category	20.00%			
Liability Hedging Assets [Member] | Minimum [Member]				
Defined Benefit Plan Disclosure [Line Items]				
Benefits plan, target asset allocation	43.00%			
Liability Hedging Assets [Member] | Maximum [Member]				
Defined Benefit Plan Disclosure [Line Items]				
Benefits plan, target asset allocation	45.00%			
Other Postretirement Benefit Plan [Member] | Large Cap Domestic Equities [Member]				
Defined Benefit Plan Disclosure [Line Items]				
Benefits plan, target asset allocation minimum range	27.00%			
Benefits plan, target asset allocation maximum range	66.00%			
Other Postretirement Benefit Plan [Member] | Small Cap Domestic Equities [Member]				
Defined Benefit Plan Disclosure [Line Items]				
Benefits plan, target asset allocation	5.00%			
Other Postretirement Benefit Plan [Member] | International Developed Markets [Member]				
Defined Benefit Plan Disclosure [Line Items]				
Benefits plan, target asset allocation	8.00%			
Other Postretirement Benefit Plan [Member] | Emerging Market Equity Securities [Member]				
Defined Benefit Plan Disclosure [Line Items]				
Benefits plan, target asset allocation	6.00%			
Other Postretirement Benefit Plan [Member] | Core Fixed Income [Member]				

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Defined Benefit Plan Disclosure [Line Items]					
Benefits plan, target asset allocation minimum range	24.00%				
Benefits plan, target asset allocation maximum range	31.00%				
Other Postretirement Benefit Plan [Member] | Global High Yield Fixed Income [Member]					
Defined Benefit Plan Disclosure [Line Items]					
Benefits plan, target asset allocation	4.00%				
Other Postretirement Benefit Plan [Member] | International Developed Market Debt [Member]					
Defined Benefit Plan Disclosure [Line Items]					
Benefits plan, target asset allocation	3.00%				
Other Postretirement Benefit Plan [Member] | Real Estate [Member]					
Defined Benefit Plan Disclosure [Line Items]					
Benefits plan, target asset allocation	6.00%				
Other Postretirement Benefit Plan [Member] | Tangible Assets [Member]					
Defined Benefit Plan Disclosure [Line Items]					
Benefits plan, target asset allocation	6.00%				
Other Postretirement Benefit Plan [Member] | Other Multi-asset Funds [Member]					
Defined Benefit Plan Disclosure [Line Items]					
Benefits plan, target asset allocation minimum range	3.00%				
Benefits plan, target asset allocation maximum range	11.00%				
Scenario, Forecast [Member] | Pension Plan [Member]					
Defined Benefit Plan Disclosure [Line Items]					
Defined benefit plan assets					$ 0
Scenario, Forecast [Member] | Other Postretirement Benefit Plan [Member]					
Defined Benefit Plan Disclosure [Line Items]					
Defined benefit plan assets					$ 0
Iberdrola Renewables Holding, Inc. (IRHI) [Member]					
Defined Benefit Plan Disclosure [Line Items]					
Retired employees currently receiving benefits				$ 118,500,000	
Iberdrola Renewables Holding, Inc. (IRHI) [Member] | Pension Plan [Member]					
Defined Benefit Plan Disclosure [Line Items]					
Expected contribution for pension benefit plans during 2017	$ 33,000,000				
Asset return seeking percentage category		7.50%	7.50%		
Iberdrola Renewables Holding, Inc. (IRHI) [Member] | Pension Plan [Member] | Minimum [Member]					
Defined Benefit Plan Disclosure [Line Items]					
Asset return seeking percentage category	7.40%				

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Iberdrola Renewables Holding, Inc. (IRHI) [Member] | Pension Plan [Member] | Maximum [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Asset return seeking percentage category	7.75%		
Iberdrola Renewables Holding, Inc. (IRHI) [Member] | Other Postretirement Benefit Plan [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Asset return seeking percentage category	7.16%		
Networks and ARHI [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Accumulated benefit obligation	$ 3,214,000,000	$ 3,261,000,000	
Networks and ARHI [Member] | Non-Qualified Pension Plans [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Other	57,000,000	59,000,000	
Networks and ARHI [Member] | Defined Contribution Plans [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Annual contributions made	$ 34,000,000	$ 17,000,000	$ 20,000,000
ARHI | Pension Plan [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Asset return seeking percentage category	5.50%	5.50%	6.90%
ARHI | Pension Plan [Member] | Equity Securities [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Benefits plan, target asset allocation	33.00%		
ARHI | Pension Plan [Member] | Fixed Income [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Benefits plan, target asset allocation	50.00%		
ARHI | Pension Plan [Member] | Other Investment Types [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Benefits plan, target asset allocation	17.00%		
ARHI | Other Postretirement Benefit Plan [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Asset return seeking percentage category	5.50%	5.75%	6.50%
ARHI | Other Postretirement Benefit Plan [Member] | Equity Securities [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Benefits plan, target asset allocation	48.00%		
ARHI | Other Postretirement Benefit Plan [Member] | Fixed Income [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Benefits plan, target asset allocation	49.00%		

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ARHI | Other Postretirement Benefit Plan [Member] | Other Investment Types [Member]	
Defined Benefit Plan Disclosure [Line Items]	
Benefits plan, target asset allocation	3.00%
AVANGRID Networks [Member] | Other Postretirement Benefit Plan [Member] | Equity Securities [Member]	
Defined Benefit Plan Disclosure [Line Items]	
Benefits plan, target asset allocation minimum range	46.00%
Benefits plan, target asset allocation maximum range	66.00%
AVANGRID Networks [Member] | Other Postretirement Benefit Plan [Member] | Fixed Income [Member]	
Defined Benefit Plan Disclosure [Line Items]	
Benefits plan, target asset allocation minimum range	30.00%
Benefits plan, target asset allocation maximum range	31.00%
AVANGRID Networks [Member] | Other Postretirement Benefit Plan [Member] | Other Investment Types [Member]	
Defined Benefit Plan Disclosure [Line Items]	
Benefits plan, target asset allocation minimum range	3.00%
Benefits plan, target asset allocation maximum range	23.00%

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Post-Retirement and Similar Obligations - Summary of Amounts Recognized in Other Comprehensive Income (Detail) - ARHI - USD ($) $ in Millions	12 Months Ended		
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Pension Plan [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Net (gain) loss	$ 23	$ 25	$ 22
Other Postretirement Benefit Plan [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Net (gain) loss	$ (3)	$ (1)	$ 8

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Post-Retirement and Similar Obligations - Summary of Recognized as Regulatory Assets or Regulatory Liabilities (Detail) - Iberdrola Renewables Holding, Inc. (IRHI) [Member] - USD ($) $ in Millions	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Pension Plan [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Net loss	$ 860	$ 994	$ 1,045
Prior service cost (credit)	7	9	12
Other Postretirement Benefit Plan [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Net loss	44	76	96
Prior service cost (credit)	$ (40)	$ (49)	$ (57)

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Post-Retirement and Similar Obligations - Schedule of Aggregate Projected and Accumulated Benefit Obligations of Fair Value of Plan Assets for Underfunded Plans (Detail) - Networks and ARHI [Member] - Pension Plan [Member] - USD ($) $ in Millions	Dec. 31, 2016	Dec. 31, 2015
Defined Benefit Plan Disclosure [Line Items]		
Projected Benefit Obligation Exceeds Fair Value of Plan Assets, Projected benefit obligation	$ 3,448	$ 3,509
Projected Benefit Obligation Exceeds Fair Value of Plan Assets, Accumulated benefit obligation	3,214	3,261
Projected Benefit Obligation Exceeds Fair Value of Plan Assets, Fair value of plan assets	2,672	2,664
Accumulated Benefit Obligation Exceeds Fair Value of Plan Assets, Projected benefit obligation	3,448	3,509
Accumulated Benefit Obligation Exceeds Fair Value of Plan Assets, Accumulated benefit obligation	3,214	3,261
Accumulated Benefit Obligation Exceeds Fair Value of Plan Assets, Fair value of plan assets	$ 2,672	$ 2,664

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Post-Retirement and Similar Obligations - Schedule of Net Periodic Benefit Cost and Other Changes in Plan Assets and Benefit Obligations Recognized (Detail) - USD ($) $ in Millions	12 Months Ended		
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Iberdrola Renewables Holding, Inc. (IRHI) [Member] | Pension Plan [Member]			
Net Periodic Benefit Cost:			
Service cost	$ 44	$ 36	$ 30
Interest cost	140	97	107
Expected return on plan assets	(199)	(156)	(161)
Amortization of prior service cost (benefit)	2	3	4
Amortization of net loss	123	130	94
Special termination benefit charge		2	
Settlement charge		2	
Net Periodic Benefit Cost	110	114	74
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities:			
Settlements		(2)	
Net loss (gain)	(11)	69	434
Amortization of net loss	(123)	(130)	(94)
Amortization of prior service (cost) benefit	(2)	(3)	(4)
Total Other Changes	(136)	(66)	336
Total Recognized	(26)	48	410
Iberdrola Renewables Holding, Inc. (IRHI) [Member] | Other Postretirement Benefit Plan [Member]			
Net Periodic Benefit Cost:			
Service cost	5	4	4
Interest cost	20	15	17
Expected return on plan assets	(8)	(7)	(7)
Amortization of prior service cost (benefit)	(9)	(9)	(11)
Amortization of net loss	8	7	
Net Periodic Benefit Cost	16	10	3
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities:			
Net loss (gain)	(24)	(12)	72
Amortization of net loss	(8)	(7)	
Current year prior service cost		(1)	
Amortization of prior service (cost) benefit	9	9	11
Total Other Changes	(23)	(11)	83
Total Recognized	(7)	(1)	86
ARHI | Pension Plan [Member]			

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Net Periodic Benefit Cost:			
Interest cost	2	2	2
Expected return on plan assets	(2)	(2)	(3)
Amortization of net loss	1	1	
Settlement charge	1		
Net Periodic Benefit Cost	2	1	(1)
Other Changes in plan assets and benefit obligations recognized in OCI:			
Net loss (gain)		4	6
Amortization of net loss	(1)	(1)	
Total Other Changes	(1)	3	6
Total Recognized	1	4	5
ARHI | Other Postretirement Benefit Plan [Member]			
Net Periodic Benefit Cost:			
Service cost		1	1
Interest cost	1	1	1
Amortization of prior service cost (benefit)			1
Amortization of net loss			1
Net Periodic Benefit Cost	1	2	4
Other Changes in plan assets and benefit obligations recognized in OCI:			
Net loss (gain)	(2)	(8)	(5)
Amortization of net loss			(1)
Amortization of prior service (cost)			(1)
Total Other Changes	(2)	(8)	(7)
Total Recognized	$ (1)	$ (6)	$ (3)

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Post-Retirement and Similar Obligations - Schedule of Amounts Expected to be Amortized from Regulatory Assets or Liabilities and OCI into Net Periodic Benefit Cost (Detail) - Scenario, Forecast [Member] $ in Millions	12 Months Ended Dec. 31, 2017 USD ($)
Pension Plan [Member] | OCI [Member]	
Defined Benefit Plan Disclosure [Line Items]	
Estimated net loss	$ 1
Regulatory Assets or Liabilities [Member] | Pension Plan [Member]	
Defined Benefit Plan Disclosure [Line Items]	
Estimated net loss	126
Estimated prior service cost (benefit)	2
Regulatory Assets or Liabilities [Member] | Other Postretirement Benefit Plan [Member]	
Defined Benefit Plan Disclosure [Line Items]	
Estimated net loss	5
Estimated prior service cost (benefit)	$ (9)

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Post-Retirement and Similar Obligations - Schedule of Weighted-Average Assumptions Used to Determine Benefit Obligations and Net Periodic Benefit Cost (Detail)	12 Months Ended		
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Iberdrola Renewables Holding, Inc. (IRHI) [Member] | Pension Plan [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Rate of compensation increase		4.00%	
Discount rate			4.90%
Expected long-term return on plan assets		7.50%	7.50%
Rate of compensation increase - Networks		4.10%	4.20%
Iberdrola Renewables Holding, Inc. (IRHI) [Member] | Pension Plan [Member] | Minimum [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Discount rate	4.12%	4.10%	
Rate of compensation increase	3.50%		
Discount rate	4.12%	3.80%	
Expected long-term return on plan assets	7.40%		
Rate of compensation increase - Networks	3.50%		
Iberdrola Renewables Holding, Inc. (IRHI) [Member] | Pension Plan [Member] | Maximum [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Discount rate	4.24%	4.24%	
Rate of compensation increase	4.20%		
Discount rate	4.24%	4.24%	
Expected long-term return on plan assets	7.75%		
Rate of compensation increase - Networks	4.20%		
Iberdrola Renewables Holding, Inc. (IRHI) [Member] | Other Postretirement Benefit Plan [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Discount rate			4.90%
Expected long-term return on plan assets	7.16%		
Iberdrola Renewables Holding, Inc. (IRHI) [Member] | Other Postretirement Benefit Plan [Member] | Nontaxable Trust [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Expected long-term return on plan assets	7.00%	7.50%	7.50%
Iberdrola Renewables Holding, Inc. (IRHI) [Member] | Other Postretirement Benefit Plan [Member] | Taxable Trust [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Expected long-term return on plan assets	4.50%	5.00%	5.00%
Iberdrola Renewables Holding, Inc. (IRHI) [Member] | Other Postretirement Benefit Plan [Member] | Minimum [Member]			

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Defined Benefit Plan Disclosure [Line Items]			
Discount rate	4.12%	4.10%	
Discount rate	4.12%	3.80%	
Iberdrola Renewables Holding, Inc. (IRHI) [Member] | Other Postretirement Benefit Plan [Member] | Maximum [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Discount rate	4.24%	4.24%	
Discount rate	4.24%	4.24%	
ARHI | Pension Plan [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Discount rate	3.81%	3.90%	
Discount rate	3.90%	3.90%	5.00%
Expected long-term return on plan assets	5.50%	5.50%	6.90%
ARHI | Other Postretirement Benefit Plan [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Discount rate	3.81%	3.90%	
Discount rate	3.90%	3.90%	5.00%
Expected long-term return on plan assets	5.50%	5.75%	6.50%

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Post-Retirement and Similar Obligations - Schedule of Assumed Health Care Cost Trend Rates Used to Determine Benefit Obligations (Detail)	12 Months Ended	
	Dec. 31, 2016	Dec. 31, 2015
Iberdrola Renewables Holding, Inc. (IRHI) [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Rate to which cost trend rate is assumed to decline (ultimate trend rate)	4.50%	4.50%
Year that the rate reaches the ultimate trend rate		2027
Iberdrola Renewables Holding, Inc. (IRHI) [Member] | Minimum [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Health care cost trend rate assumed for next year	7.00%	7.00%
Year that the rate reaches the ultimate trend rate	2026	
Iberdrola Renewables Holding, Inc. (IRHI) [Member] | Maximum [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Health care cost trend rate assumed for next year	9.00%	7.50%
Year that the rate reaches the ultimate trend rate	2028	
ARHI		
Defined Benefit Plan Disclosure [Line Items]		
Rate to which cost trend rate is assumed to decline (ultimate trend rate)	4.50%	4.50%
Year that the rate reaches the ultimate trend rate		2026
ARHI | Minimum [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Health care cost trend rate assumed for next year	6.75%	7.00%
Year that the rate reaches the ultimate trend rate	2026	
ARHI | Maximum [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Health care cost trend rate assumed for next year	8.50%	9.00%
Year that the rate reaches the ultimate trend rate	2028	

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Post-Retirement and Similar Obligations - Schedule of Effects of One-Percent Change In Assumed Health Care Cost Trend Rates (Detail) $ in Millions	12 Months Ended Dec. 31, 2016 USD ($)
Other Postretirement Benefit Plan [Member]	
Defined Benefit Plan Disclosure [Line Items]	
Effect on total of service and interest cost, 1% Increase	$ 1
Effect on postretirement benefit obligation, 1% Increase	14
Pension Plan [Member]	
Defined Benefit Plan Disclosure [Line Items]	
Effect on total of service and interest cost, 1% Decrease	(1)
Effect on postretirement benefit obligation, 1% Decrease	$ (12)

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Post-Retirement and Similar Obligations - Estimated Future Benefit Payments (Detail) - Improvement and Modernization Act of 2003 [Member] - Networks and ARHI [Member] $ in Millions	Dec. 31, 2016 USD ($)
Medicare Act Subsidy Receipts [Member]	
Defined Benefit Plan Disclosure [Line Items]	
2022 - 2026	$ 3
Pension Plan [Member]	
Defined Benefit Plan Disclosure [Line Items]	
2017	211
2018	212
2019	216
2020	219
2021	224
2022 - 2026	1,125
Other Postretirement Benefit Plan [Member]	
Defined Benefit Plan Disclosure [Line Items]	
2017	34
2018	34
2019	34
2020	35
2021	35
2022 - 2026	$ 169

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Post-Retirement and Similar Obligations - Fair Value of Benefits Plan Assets by Asset Category (Detail) - USD ($) $ in Millions	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Level 3 [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Fair value of assets, by asset category	$ 1,161	$ 981	$ 945
Level 3 [Member] | Real Estate Investment [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Fair value of assets, by asset category	61	89	75
Level 3 [Member] | Common Collective Trusts [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Fair value of assets, by asset category	821	490	449
Level 3 [Member] | Partnership/joint Venture Interests [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Fair value of assets, by asset category	5	84	79
Level 3 [Member] | Other, Principally Annuity, Fixed Income [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Fair value of assets, by asset category	274	318	$ 342
Pension Plan [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Fair value of assets, by asset category	2,672	2,664	
Pension Plan [Member] | Corporate Bond Securities [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Fair value of assets, by asset category	358	324	
Pension Plan [Member] | Real Estate Investment [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Fair value of assets, by asset category	61	89	
Pension Plan [Member] | Common Stocks [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Fair value of assets, by asset category	120	314	
Pension Plan [Member] | Preferred Stock [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Fair value of assets, by asset category	4	5	
Pension Plan [Member] | Cash and Cash Equivalents [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Fair value of assets, by asset category	49	57	
Pension Plan [Member] | U.S. Government Securities [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Fair value of assets, by asset category	172	171	
Pension Plan [Member] | Registered Investment Companies [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Fair value of assets, by asset category	122	114	

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Pension Plan [Member] | Common Collective Trusts [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	1,192	859
Pension Plan [Member] | Partnership/joint Venture Interests [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	5	84
Pension Plan [Member] | Other, Principally Annuity, Fixed Income [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	589	647
Pension Plan [Member] | Fair Value, Inputs, Level 1 [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	414	602
Pension Plan [Member] | Fair Value, Inputs, Level 1 [Member] | Common Stocks [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	120	314
Pension Plan [Member] | Fair Value, Inputs, Level 1 [Member] | Cash and Cash Equivalents [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category		3
Pension Plan [Member] | Fair Value, Inputs, Level 1 [Member] | U.S. Government Securities [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	172	171
Pension Plan [Member] | Fair Value, Inputs, Level 1 [Member] | Registered Investment Companies [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	122	114
Pension Plan [Member] | Fair Value, Inputs, Level 2 [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	1,097	1,081
Pension Plan [Member] | Fair Value, Inputs, Level 2 [Member] | Corporate Bond Securities [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	358	324
Pension Plan [Member] | Fair Value, Inputs, Level 2 [Member] | Preferred Stock [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	4	5
Pension Plan [Member] | Fair Value, Inputs, Level 2 [Member] | Cash and Cash Equivalents [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	49	54
Pension Plan [Member] | Fair Value, Inputs, Level 2 [Member] | Common Collective Trusts [Member]		

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Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	371	369
Pension Plan [Member] | Fair Value, Inputs, Level 2 [Member] | Other, Principally Annuity, Fixed Income [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	315	329
Pension Plan [Member] | Level 3 [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	1,161	981
Pension Plan [Member] | Level 3 [Member] | Real Estate Investment [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	61	89
Pension Plan [Member] | Level 3 [Member] | Common Collective Trusts [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	821	490
Pension Plan [Member] | Level 3 [Member] | Partnership/joint Venture Interests [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	5	84
Pension Plan [Member] | Level 3 [Member] | Other, Principally Annuity, Fixed Income [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	274	318
Other Postretirement Benefit Plan [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	160	162
Other Postretirement Benefit Plan [Member] | Common Stocks [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	23	24
Other Postretirement Benefit Plan [Member] | Money Market Funds [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	6	4
Other Postretirement Benefit Plan [Member] | Mutual Funds Fixed [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	41	36
Other Postretirement Benefit Plan [Member] | Government and Corporate Bonds [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	2	2
Other Postretirement Benefit Plan [Member] | Mutual Funds Equity		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	72	46
Other Postretirement Benefit Plan [Member] | Mutual Funds, Other [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	16	50

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Other Postretirement Benefit Plan [Member] | Fair Value, Inputs, Level 1 [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	118	153
Other Postretirement Benefit Plan [Member] | Fair Value, Inputs, Level 1 [Member] | Common Stocks [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	23	24
Other Postretirement Benefit Plan [Member] | Fair Value, Inputs, Level 1 [Member] | Money Market Funds [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	4	4
Other Postretirement Benefit Plan [Member] | Fair Value, Inputs, Level 1 [Member] | Mutual Funds Fixed [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	39	36
Other Postretirement Benefit Plan [Member] | Fair Value, Inputs, Level 1 [Member] | Mutual Funds Equity		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	43	46
Other Postretirement Benefit Plan [Member] | Fair Value, Inputs, Level 1 [Member] | Mutual Funds, Other [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	9	43
Other Postretirement Benefit Plan [Member] | Fair Value, Inputs, Level 2 [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	42	9
Other Postretirement Benefit Plan [Member] | Fair Value, Inputs, Level 2 [Member] | Money Market Funds [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	2	
Other Postretirement Benefit Plan [Member] | Fair Value, Inputs, Level 2 [Member] | Mutual Funds Fixed [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	2	
Other Postretirement Benefit Plan [Member] | Fair Value, Inputs, Level 2 [Member] | Government and Corporate Bonds [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	2	2
Other Postretirement Benefit Plan [Member] | Fair Value, Inputs, Level 2 [Member] | Mutual Funds Equity		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of assets, by asset category	29	
Other Postretirement Benefit Plan [Member] | Fair Value, Inputs, Level 2 [Member] | Mutual Funds, Other [Member]		
Defined Benefit Plan Disclosure [Line Items]		

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Fair value of assets, by asset category	$ 7	$ 7

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Post-Retirement and Similar Obligations - Changes in Fair Value of Plan Assets Based on Level 3 Inputs (Detail) - Level 3 [Member] - USD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2016	Dec. 31, 2015
Defined Benefit Plan Disclosure [Line Items]		
Fair value of plan assets, Beginning balance	$ 981	$ 945
Actual return on plan assets:		
Relating to assets sold during the year	(12)	(21)
Relating to assets still held at the reporting date	45	3
Purchases, sales and settlements	147	54
Fair Value of Plan Assets, Ending balance	1,161	981
Real Estate Investment [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of plan assets, Beginning balance	89	75
Actual return on plan assets:		
Relating to assets still held at the reporting date	2	10
Purchases, sales and settlements	(30)	4
Fair Value of Plan Assets, Ending balance	61	89
Common Collective Trusts [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of plan assets, Beginning balance	490	449
Actual return on plan assets:		
Relating to assets sold during the year	6	(3)
Relating to assets still held at the reporting date	51	(5)
Purchases, sales and settlements	274	49
Fair Value of Plan Assets, Ending balance	821	490
Partnership/joint Venture Interests [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of plan assets, Beginning balance	84	79
Actual return on plan assets:		
Relating to assets sold during the year	(19)	(19)
Relating to assets still held at the reporting date		19
Purchases, sales and settlements	(60)	5
Fair Value of Plan Assets, Ending balance	5	84
Other Investments [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of plan assets, Beginning balance	318	342
Actual return on plan assets:		
Relating to assets sold during the year	1	1
Relating to assets still held at the reporting date	(8)	(21)
Purchases, sales and settlements	(37)	(4)

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Fair Value of Plan Assets, Ending balance	$ 274	$ 318

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Equity - Additional Information (Detail) - USD ($) $ / shares in Units, $ in Millions		12 Months Ended					
	Dec. 15, 2015	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014 [1]	Dec. 31, 2013 [1]	Nov. 30, 2011	
Class Of Stock [Line Items]							
Common stock, authorized		500,000,000	500,000,000				
Common stock, issued		309,600,439	309,491,082			243	
Common stock, outstanding	252,235,232	308,993,149 [1]	308,864,609 [1]	252,235,232	252,235,232		
Common stock, par value		$ 0.01	$ 0.01				
Common stock		$ 3	$ 3				
Additional paid-in capital		$ 13,653	$ 13,653				
Treasury stock, shares		491,459	626,473				
Convertible preferred stock, shares outstanding		0	0				
Issuance of common stock, shares [1]		109,357	57,255,850				
Release of common stock held in trust [1]		135,014					
Repurchase of common stock, shares [1]		115,831					
Repurchase of common stock		$ 5					
Common stock issued from stock split	252,234,989						
Iberdrola Renewables Holding, Inc [Member]							
Class Of Stock [Line Items]							
Percentage of equity owned by parent		81.50%	81.50%				

[1] Par value of share amounts is $.01

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Equity - Accumulated Other Comprehensive Income (Loss) (Detail) - USD ($) $ in Millions	12 Months Ended			
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014	Dec. 31, 2013
Accumulated Other Comprehensive Income Loss [Line Items]				
Unrealized (loss) gain during period on derivatives qualifying as cash flow hedges, net of income tax expense (benefit)	$ (26)	$ 33	$ (2)	
Reclassification adjustment for losses on settled cash flow hedges, net of income tax expense(benefit)	(65)	(23)	(63)	$ (66)
Accumulated Other Comprehensive (Loss) Income	(86)	(52)	(99)	(100)
Gain on defined benefit plans, net of income taxes	7	4	1	
Reclassification adjustment for losses on settled cash flow hedges, net of income tax expense(benefit)	[1] (16)	7	5	
Net unrealized (loss) gain on derivatives qualifying as cash flow hedges	(42)	40	3	
Other comprehensive income, net of tax	(34)	47	1	
Reclassification out of Accumulated Other Comprehensive Income [Member]				
Accumulated Other Comprehensive Income Loss [Line Items]				
Reclassification adjustment for losses on settled cash flow hedges, net of income tax expense(benefit)	[1] (70)	(54)	(61)	(66)
Designated as Hedging Instrument [Member]				
Accumulated Other Comprehensive Income Loss [Line Items]				
Unrealized (loss) gain during period on derivatives qualifying as cash flow hedges, net of income tax expense (benefit)	5	31	(2)	
Qualified Pension Plan [Member]				
Accumulated Other Comprehensive Income Loss [Line Items]				
Loss on defined benefit plans, net of income tax expense (benefit)	(14)	(21)	(25)	(26)
Gain on defined benefit plans, net of income taxes	7	4	1	
Non-Qualified Pension Plans [Member]				
Accumulated Other Comprehensive Income Loss [Line Items]				
Loss on defined benefit plans, net of income tax expense (benefit)	(7)	(8)	(11)	$ (8)
Gain on defined benefit plans, net of income taxes	$ 1	$ 3	$ (3)	

[1] Reclassification is reflected in the operating expenses line item in the consolidated statements of income.

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Equity - Accumulated Other Comprehensive Income (Loss) (Parenthetical) (Detail) - USD ($) $ in Millions	12 Months Ended		
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Accumulated Other Comprehensive Income Loss [Line Items]			
Unrealized (loss) gain during period on derivatives qualified as cash flow hedges, income tax expense (benefit)	$ (15.8)	$ 20.9	$ (1.4)
Reclassification to net income of losses on cash flow hedges, income tax expense	11.0	4.9	4.1
Qualified Pension Plan [Member]			
Accumulated Other Comprehensive Income Loss [Line Items]			
Gain (loss) on defined benefit plans, income tax expense (benefit)	4.3	2.2	0.6
Non-Qualified Pension Plans [Member]			
Accumulated Other Comprehensive Income Loss [Line Items]			
Gain (loss) on defined benefit plans, income tax expense (benefit)	$ 0.4	$ 1.7	$ (1.9)

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Earnings Per Share - Schedule of Earnings Per Share, Basic and Diluted (Detail) - USD ($) $ / shares in Units, $ in Millions	3 Months Ended								12 Months Ended		
	Dec. 31, 2016	Sep. 30, 2016	Jun. 30, 2016	Mar. 31, 2016	Dec. 31, 2015	Sep. 30, 2015	Jun. 30, 2015	Mar. 31, 2015	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Numerator:											
Net income attributable to AVANGRID	$ 207	$ 109	$ 102	$ 212	$ 96	$ 54	$ 11	$ 106	$ 630	$ 267	$ 424
Denominator:											
Weighted average number of shares outstanding - basic									309,512,553	254,588,212	252,235,232
Weighted average number of shares outstanding - diluted									309,817,322	254,605,111	252,235,232
Earnings per share attributable to AVANGRID											
Earnings Per Common Share, Basic									$ 2.04	$ 1.05	$ 1.68
Earnings Per Common Share, Diluted									$ 2.04	$ 1.05	$ 1.68

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Tax Equity Financing Arrangements - Additional Information (Detail) - USD ($)	1 Months Ended	12 Months Ended		
	Oct. 31, 2015	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Tax Equity Financing Arrangements [Line Items]				
Accrued interest average rate		5.40%	8.50%	
Assets of variable interest entities (VIEs)		$ 1,343,000,000	$ 1,401,000,000	
Liabilities of variable interest entities (VIEs)		244,000,000	338,000,000	
Equity method investments of variable interest entities (VIEs)		387,000,000	385,000,000	$ 262,000,000
Upfront cash payments		0		
Gain on other income and (expense)	$ 5,000,000			
Variable Interest Entity, Primary Beneficiary [Member]				
Tax Equity Financing Arrangements [Line Items]				
Equity method investments of variable interest entities (VIEs)		$ 161,000,000	$ 169,000,000	
Aeolus I [Member]				
Tax Equity Financing Arrangements [Line Items]				
Percentage of equity owned by subsidiaries				10.00%

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Grants, Government Incentives and Deferred Income - Schedule of Changes in Deferred Income (Detail) - USD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2016	Dec. 31, 2015
Deferred Revenue Arrangement [Line Items]		
Beginning Balance	$ 1,553	$ 1,621
Recognized in income	(70)	(68)
Ending Balance	1,483	1,553
Government Grants [Member]		
Deferred Revenue Arrangement [Line Items]		
Beginning Balance	1,529	1,606
Recognized in income	(68)	(77)
Ending Balance	1,461	1,529
Other Deferred Income [Member]		
Deferred Revenue Arrangement [Line Items]		
Beginning Balance	24	15
Recognized in income	(2)	9
Ending Balance	$ 22	$ 24

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Grants, Government Incentives and Deferred Income - Additional Information (Detail) - USD ($) $ in Millions	Dec. 31, 2016	Dec. 31, 2015
Government Grants [Member]		
Deferred Revenue Arrangement [Line Items]		
Depreciable assets and contributions credited to property plant and equipment	$ 459	$ 390

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Equity Method Investments - Additional Information (Detail) $ in Millions	Dec. 31, 2014 USD ($)	3 Months Ended Mar. 31, 2016 USD ($)	12 Months Ended Dec. 31, 2016 USD ($) Plant JointVenture	Dec. 31, 2015 USD ($)	Dec. 31, 2014 USD ($)
Schedule Of Investments [Line Items]					
Equity method investments	$ 262.0		$ 387.0	$ 385.0	$ 262.0
Number of peaking generation plants | Plant			2		
Equity method investment, distributions received			$ 20.0	12.0	$ 19.0
Proceeds from sale of ownership Interest	$ 19.6				
Network [Member] | New York Transco [Member]					
Schedule Of Investments [Line Items]					
Equity method investments			$ 22.0		
Business combination, equity interest percentage			20.00%		
Shell Wind Energy Inc [Member]					
Schedule Of Investments [Line Items]					
Joint venture, ownership percentage			50.00%		
Equity method investments			$ 45.0	41.0	
Horizon Wind Energy LLC [Member]					
Schedule Of Investments [Line Items]					
Joint venture, ownership percentage			50.00%		
Number of joint ventures | JointVenture			2		
Flat Rock Wind Power LLC [Member]					
Schedule Of Investments [Line Items]					
Equity method investments			$ 128.0	143.0	
Flat Rock Wind Power II LLC [Member]					
Schedule Of Investments [Line Items]					
Equity method investments			$ 64.0	69.0	
NRG Energy Inc [Member]					
Schedule Of Investments [Line Items]					
Joint venture, ownership percentage			50.00%		
Equity method investments			$ 128.0	110.0	
Number of peaking generation plants | Plant			2		
Iroquois [Member]					
Schedule Of Investments [Line Items]					
Equity method investments				$ 22.0	
Proceeds from sale of ownership Interest		$ 53.8	$ 53.8		
Net income on disposition of business		$ 19.0	$ 19.0		

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Other Financial Statements Items - Schedule of Other Income and (Expense) (Detail) - USD ($) $ in Millions	12 Months Ended		
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Other Nonoperating Income Expense [Abstract]			
Allowance for funds used during construction	$ 26	$ 21	$ 17
Carrying costs on regulatory assets	14	28	29
Other	36	6	6
Total Other income and (expense)	$ 76	$ 55	$ 52

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Other Financial Statements Items - Additional Information (Detail) - USD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2016	Dec. 31, 2015
Accounts Notes And Loans Receivable [Line Items]		
Gain on sale of investment	$ 33	
Other	241	$ 35
Restricted Cash [Member]		
Accounts Notes And Loans Receivable [Line Items]		
Other	5	7
Deferred Payment Arrangements [Member]		
Accounts Notes And Loans Receivable [Line Items]		
Accounts receivable	54	$ 62
Safe Harbor Turbine Payments [Member]		
Accounts Notes And Loans Receivable [Line Items]		
Other	$ 186	

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Other Financial Statements Items - Schedule of Accounts Receivable (Detail) - USD ($) $ in Millions	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014	Dec. 31, 2013
Receivables [Abstract]				
Trade receivables	$ 1,183	$ 1,036		
Allowance for bad debts	(64)	(62)	$ (49)	$ (58)
Total Accounts Receivable	$ 1,119	$ 974		

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Other Financial Statements Items - Schedule of Change in Allowance For Bad Debts (Detail) - USD ($) $ in Millions	12 Months Ended		
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Receivables [Abstract]			
Beginning balance	$ 62	$ 49	$ 58
Current period provision	48	46	39
Write-off as uncollectible	(46)	(33)	(48)
Ending balance	$ 64	$ 62	$ 49

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Other Financial Statements Items - Schedule of Prepayments and Other Current Assets (Detail) - USD ($) $ in Millions	Dec. 31, 2016	Dec. 31, 2015
Receivables [Abstract]		
Prepaid other taxes	$ 153	$ 130
Broker margin and collateral accounts	32	46
Loans to third parties	3	3
Fixed-term deposits	3	11
Other pledged deposits	8	24
Prepaid expenses	53	53
Other	3	18
Total	$ 255	$ 285

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Other Financial Statements Items - Schedule of Other Current Liabilities (Detail) - USD ($) $ in Millions	Dec. 31, 2016	Dec. 31, 2015
Payables And Accruals [Abstract]		
Advances received	$ 107	$ 96
Accrued salaries	84	68
Short-term environmental provisions	34	35
Collateral deposits received	45	59
Pension and other postretirement	5	5
Other	4	22
Total	$ 279	$ 285

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Segment Information - Additional Information (Detail) $ in Millions	12 Months Ended		
	Dec. 31, 2016 USD ($) Segment	Dec. 31, 2015 USD ($)	Dec. 31, 2014 USD ($)
Segment Reporting Information [Line Items]			
Number of reportable segments | Segment	3		
Operating Revenues	$ 6,018	$ 4,367	$ 4,594
Regulated Electric Operations [Member]			
Segment Reporting Information [Line Items]			
Operating Revenues	3,686	2,779	2,726
Regulated Gas Operations [Member]			
Segment Reporting Information [Line Items]			
Operating Revenues	1,306	605	668
Other Networks [Member]			
Segment Reporting Information [Line Items]			
Operating Revenues	35	2	2
Renewable Energy Generation Of Renewables [Member]			
Segment Reporting Information [Line Items]			
Operating Revenues	1,000	1,051	1,180
Gas Storage Services [Member]			
Segment Reporting Information [Line Items]			
Operating Revenues	7	21	8
Gas Trading Operations [Member]			
Segment Reporting Information [Line Items]			
Operating Revenues	$ (14)	$ (92)	$ 4
Network [Member]			
Segment Reporting Information [Line Items]			
Number of reportable segments | Segment	1		
Number of operating segments | Segment	8		

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Segment information (Detail) - USD ($) $ in Millions	3 Months Ended								12 Months Ended		
	Dec. 31, 2016	Sep. 30, 2016	Jun. 30, 2016	Mar. 31, 2016	Dec. 31, 2015	Sep. 30, 2015	Jun. 30, 2015	Mar. 31, 2015	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Segment Reporting Information [Line Items]											
Revenue - external									$ 6,018	$ 4,367	$ 4,594
Depreciation and amortization									804	695	629
Operating income (loss) from continuing operations	$ 306	$ 217	$ 322	$ 349	$ 83	$ 161	$ 73	$ 196	1,194	513	885
Adjusted EBITDA									1,998	1,220	1,539
Earnings (loss) from equity method investments									7		12
Capital expenditures									1,707	1,082	1,030
Property, Plant and Equipment, VIEs	21,548				20,711				21,548	20,711	17,133
Equity method investments	387				385				387	385	262
Total assets	31,309				30,743				31,309	30,743	24,162
Impairment of non-current assets										12	25
Operating Segments [Member] | Network [Member]											
Segment Reporting Information [Line Items]											
Revenue - external									5,027	3,386	3,396
Revenue - intersegment									3		1
Depreciation and amortization									466	328	275
Operating income (loss) from continuing operations									1,086	537	616
Adjusted EBITDA									1,552	865	891
Earnings (loss) from equity method investments									15	1	
Capital expenditures									1,140	773	775
Property, Plant and Equipment, VIEs	13,032				12,363				13,032	12,363	8,389
Equity method investments	151				110				151	110	
Total assets	20,753				20,126				20,753	20,126	12,858
Operating Segments [Member] | Renewables [Member]											

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Segment Reporting Information [Line Items]					
Revenue - external			1,000	1,051	1,180
Revenue - intersegment			15	16	9
Depreciation and amortization			313	344	332
Operating income (loss) from continuing operations			149	100	257
Adjusted EBITDA			462	456	613
Earnings (loss) from equity method investments			(8)	(5)	2
Capital expenditures			561	304	250
Property, Plant and Equipment, VIEs	8,015	7,835	8,015	7,835	8,219
Equity method investments	236	253	236	253	262
Total assets	9,884	10,685	9,884	10,685	12,328
Impairment of non-current assets				12	24
Operating Segments [Member] | Gas [Member]					
Segment Reporting Information [Line Items]					
Revenue - external			(7)	(71)	12
Revenue - intersegment			39	52	72
Depreciation and amortization			25	23	22
Operating income (loss) from continuing operations			(41)	(85)	16
Adjusted EBITDA			(16)	(62)	38
Capital expenditures			6	5	5
Property, Plant and Equipment, VIEs	501	513	501	513	525
Total assets	1,124	1,265	1,124	1,265	1,393
Corporate and Intercompany Eliminations [Member]					
Segment Reporting Information [Line Items]					
Revenue - external	[1]		(2)	1	6
Revenue - intersegment	[1]		(57)	(68)	(82)
Operating income (loss) from continuing operations	[1]			(39)	(4)
Adjusted EBITDA	[1]			(39)	(3)
Earnings (loss) from equity method investments	[1]			4	10
Equity method investments	[1]	22		22	

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Total assets	[1]	$ (452)	$ (1,333)	$ (452)	$ (1,333) (2,417)
Impairment of non-current assets	[1]				$ 1

[1] Does not represent a segment. It mainly includes Corporate and intercompany eliminations.

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Segment information - Reconciliation of Consolidated EBITDA to Consolidated Net Income (Detail) - USD ($) $ in Millions	12 Months Ended		
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Segment Reporting [Abstract]			
Consolidated Adjusted EBITDA	$ 1,998	$ 1,220	$ 1,539
Impairment of non-current assets		12	25
Depreciation and amortization	804	695	629
Interest expense, net of capitalization	268	267	243
Income tax expense	379	34	282
Other income and (expense)	76	55	52
Earnings from equity method investments	7		12
Net Income	$ 630	$ 267	$ 424

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Related Party Transactions - Schedule of Related Party Transactions (Detail) - USD ($) $ in Millions	12 Months Ended		
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Iberdrola Financiacion, S.A. [Member]			
Related Party Transaction [Line Items]			
Purchases From	$ (2)	$ (1)	$ (2)
Iberdrola Renovables Energia, S.L. [Member]			
Related Party Transaction [Line Items]			
Purchases From	(8)	(9)	(10)
Iberdrola Canada Energy Services, Ltd [Member]			
Related Party Transaction [Line Items]			
Purchases From	(37)	(55)	(49)
Iberdrola, S.A. [Member]			
Related Party Transaction [Line Items]			
Purchases From	(31)	(35)	(20)
Other Related Parties [Member]			
Related Party Transaction [Line Items]			
Sales To	21	3	12
Purchases From	$ (1)	$ (2)	$ (10)

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Related Party Transactions - Additional Information (Details) - USD ($)	12 Months Ended		
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Related Party Transaction [Line Items]			
Receivable from related party, write-off	$ 46,000,000	$ 33,000,000	$ 48,000,000
Impairments		12,000,000	25,000,000
Equity method investments	387,000,000	385,000,000	262,000,000
Contributions in aid of construction	69,000,000	38,000,000	$ 43,000,000
Gamesa Corporacion Tecnologica, S.A. [Member]			
Related Party Transaction [Line Items]			
Portion of amount receivable from related parties	1,000,000	68,000,000	
Affiliated Entity [Member] | Impairment of non-current assets [Member]			
Related Party Transaction [Line Items]			
Receivable from related party, write-off	10,000,000		
Impairments	$ 0		
Iberdrola, S.A. [Member] | Gamesa Corporacion Tecnologica, S.A. [Member]			
Related Party Transaction [Line Items]			
Business combination, equity interest percentage	20.00%		
Related party transaction, amount	$ 269,000,000	$ 70,000,000	
Payments to related party	$ 92,000,000		
Iberdrola, S.A. [Member] | Siemens AG And Gamesa Corporacion Tecnologica S.A. [Member]			
Related Party Transaction [Line Items]			
Business acquisition, percentage of voting interests acquired	8.10%		
Network [Member] | New York Transco [Member]			
Related Party Transaction [Line Items]			
Business combination, equity interest percentage	20.00%		
Increase in equity method investments	$ 21,000,000		
Equity method investments	22,000,000		
Total cash consideration received	67,000,000		
Proceed from contributions in assets transfer	43,000,000		
Contributions in aid of construction	22,000,000		
Proceed from contributions in advanced lease payment	$ 2,000,000		
Lease period of land and attachment right	99 years		
Portion of amount receivable from related parties	$ 11,000,000		

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Related Party Transactions - Schedule of Related Party Balances (Details) - USD ($) $ in Millions	Dec. 31, 2016	Dec. 31, 2015
Iberdrola Canada Energy Services, Ltd [Member]		
Related Party Transaction [Line Items]		
Owed By		$ 7
Owed To	$ (14)	(5)
Gamesa Corporacion Tecnologica, S.A. [Member]		
Related Party Transaction [Line Items]		
Owed By	1	68
Owed To	(181)	(77)
Iberdrola, S.A. [Member]		
Related Party Transaction [Line Items]		
Owed To	(30)	(3)
Iberdrola Energy Projects, Inc. [Member]		
Related Party Transaction [Line Items]		
Owed By		1
Owed To		(3)
Other Related Parties [Member]		
Related Party Transaction [Line Items]		
Owed By	22	
Owed To	(3)	$ (2)
Iberdrola Renovables Energia, S.L. [Member]		
Related Party Transaction [Line Items]		
Owed By	$ 2	

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Stock-Based Compensation - Additional Information (Detail) $ / shares in Units, $ in Millions	1 Months Ended		12 Months Ended		
	Dec. 31, 2016 USD ($) shares	Jul. 31, 2016 $ / shares shares	Dec. 31, 2016 USD ($) Installment $ / shares shares	Dec. 31, 2015 USD ($)	Dec. 31, 2014 USD ($)
Share Based Compensation Arrangement By Share Based Payment Award [Line Items]					
Number of shares authorized for stock-based compensation plans | shares	2,500,000		2,500,000		
Stock-based compensation expense			$ 0.6	$ 6.0	$ 4.8
Income tax benefit recognized for stock-based compensation arrangements			0.2	2.4	$ 1.9
Stock-based compensation other non-current liabilities	$ 9.5		$ 9.5	$ 17.5	
Iberdrola [Member]					
Share Based Compensation Arrangement By Share Based Payment Award [Line Items]					
Number of installment payments of employee related payables | Installment			2		
Iberdrola [Member] | Installment One [Member]					
Share Based Compensation Arrangement By Share Based Payment Award [Line Items]					
Employee related liabilities settlement date			Jun. 30, 2017		
Iberdrola [Member] | Installment Two [Member]					
Share Based Compensation Arrangement By Share Based Payment Award [Line Items]					
Employee related liabilities settlement date			Mar. 30, 2018		
Performance Shares Units [Member]					
Share Based Compensation Arrangement By Share Based Payment Award [Line Items]					
Number of PSUs granted | shares			1,335,416		
Share-based payment award options grant date fair value, per share | $ / shares			$ 31.92		
Unrecognized cost for non-vested PSUs	$ 22.0		$ 22.0		
Recognition of PSU costs, weighted-average period			5 years		
Performance Shares Units [Member] | Officers and Employees [Member]					
Share Based Compensation Arrangement By Share Based Payment Award [Line Items]					
Number of PSUs granted | shares	11,804	1,298,683			
Number of installment payments of employee related payables | Installment			3		

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Share-based payment award options grant date fair value, per share | $ / shares	$ 31.80
Share-based payment award options requisite service period	7 years
Share-based Compensation Award, Tranche One	
Share Based Compensation Arrangement By Share Based Payment Award [Line Items]	
Performance stock units vested amount installment payment year	2020
Share-based Compensation Award, Tranche Two	
Share Based Compensation Arrangement By Share Based Payment Award [Line Items]	
Performance stock units vested amount installment payment year	2021
Share-based Compensation Award, Tranche Three	
Share Based Compensation Arrangement By Share Based Payment Award [Line Items]	
Performance stock units vested amount installment payment year	2022

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Stock-Based Compensation - Summary of Nonvested PSUs (Detail) - Performance Shares Units [Member]	12 Months Ended Dec. 31, 2016 $ / shares shares
Share Based Compensation Arrangement By Share Based Payment Award [Line Items]	
Number of PSUs, Nonvested Balance – December 31, 2015 | shares	411,207
Number of PSUs granted | shares	1,335,416
Number of PSUs, Forfeited | shares	(36,592)
Number of PSUs, Vested | shares	(186,050)
Number of PSUs, Nonvested Balance – December 31, 2016 | shares	1,523,981
Weighted Average Grant Date Fair Value, Nonvested Balance – December 31, 2015 | $ / shares	$ 39.60
Weighted Average Grant Date Fair Value, Granted | $ / shares	31.92
Weighted Average Grant Date Fair Value, Forfeited | $ / shares	32.83
Weighted Average Grant Date Fair Value, Vested | $ / shares	40.84
Weighted Average Grant Date Fair Value, Nonvested Balance – December 31, 2016 | $ / shares	$ 33.01

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Schedule of Quarterly Financial Data (unaudited) (Detail) - USD ($) $ / shares in Units, $ in Millions	3 Months Ended								12 Months Ended		
	Dec. 31, 2016	Sep. 30, 2016	Jun. 30, 2016	Mar. 31, 2016	Dec. 31, 2015	Sep. 30, 2015	Jun. 30, 2015	Mar. 31, 2015	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Quarterly Financial Information Disclosure [Abstract]											
Operating revenues	$ 1,491	$ 1,418	$ 1,439	$ 1,670	$ 1,153	$ 1,048	$ 939	$ 1,227			
Operating Income	306	217	322	349	83	161	73	196	$ 1,194	$ 513	$ 885
Net Income	207	109	102	212	96	54	11	106	630	267	424
Net Income attributable to Avangrid, Inc.	$ 207	$ 109	$ 102	$ 212	$ 96	$ 54	$ 11	$ 106	$ 630	$ 267	$ 424
Earnings Per Common Share, Basic and Diluted: [1]	$ 0.67	$ 0.35	$ 0.33	$ 0.69	$ 0.37	$ 0.22	$ 0.04	$ 0.42			

[1] Based on weighted average number of 309 million shares outstanding each quarter in 2016 and 252 million shares for each quarter of 2015, except for fourth quarter of 2015, which is based on weighted average of 262 million shares as a result of the acquisition of UIL

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Schedule of Quarterly Financial Data (unaudited) (Parenthetical) (Detail) - shares shares in Millions	3 Months Ended							
	Dec. 31, 2016	Sep. 30, 2016	Jun. 30, 2016	Mar. 31, 2016	Dec. 31, 2015	Sep. 30, 2015	Jun. 30, 2015	Mar. 31, 2015
Selected Quarterly Financial Information [Line Items]								
Weighted average shares outstanding	309	309	309	309		252	252	252
UIL Holdings [Member]								
Selected Quarterly Financial Information [Line Items]								
Weighted average shares outstanding					262			

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Quarterly Financial Data (unaudited) - Additional Information (Detail) - USD ($) $ in Millions	3 Months Ended							12 Months Ended
	Dec. 31, 2014	Jun. 30, 2016	Mar. 31, 2016	Dec. 31, 2015	Sep. 30, 2015	Jun. 30, 2015	Mar. 31, 2015	Dec. 31, 2016
Selected Quarterly Financial Information [Line Items]								
Proceeds from sale of ownership Interest	$ 19.6							
Unfunded future income tax expense		$ 126.0						$ 126.0
Rate credits				$ 44.0				
Tax benefits				(63.0)				
UIL Holdings [Member]								
Selected Quarterly Financial Information [Line Items]								
Pre-tax merger related expenses				$ 18.5	$ 7.0	$ 8.0	$ 4.0	
Iroquois [Member]								
Selected Quarterly Financial Information [Line Items]								
Proceeds from sale of ownership Interest			$ 53.8					53.8
Net income on disposition of business			$ 19.0					$ 19.0

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Subsequent Events - Additional Information (Detail) - $ / shares		Feb. 16, 2017	Jan. 31, 2017	12 Months Ended Dec. 31, 2016	Mar. 01, 2017	Dec. 31, 2015	Nov. 30, 2011
Subsequent Event [Line Items]							
Release of common stock held in trust	[1]			135,014			
Common stock, par value				$ 0.01		$ 0.01	
Quarterly dividend payable, per share				$ 1.728			
Common stock, issued				309,600,439		309,491,082	243
Subsequent Event [Member]							
Subsequent Event [Line Items]							
Release of common stock held in trust			5,088				
Common stock, par value			$ 0.01		$ 0.01		
Dividend declared date		Feb. 16, 2017					
Quarterly dividend payable, per share		$ 0.432					
Dividend payment date		Apr. 03, 2017					
Dividend record date		Mar. 10, 2017					
Common stock, issued					70,493		

[1] Par value of share amounts is $.01

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Acquisition of UIL and Issuance of Common Stock - Additional Information (Detail) - USD ($) $ / shares in Units, $ in Millions	Feb. 16, 2017	Dec. 16, 2015	12 Months Ended Dec. 31, 2016	Mar. 01, 2017	Jan. 31, 2017	Dec. 31, 2015
Business Acquisition [Line Items]						
Effective date of business acquisition of UIL Holdings			Feb. 25, 2015			
Shares issued in connection with acquisition			309,490,839			
Business acquisition, share price			$ 10.50			
Common stock, par value			$ 0.01			$ 0.01
Repurchase of common stock, shares	[1]		115,831			
Repurchase of common stock			$ 5			
Subsequent Event [Member]						
Business Acquisition [Line Items]						
Common stock, par value				$ 0.01	$ 0.01	
Dividend declared date	Feb. 16, 2017					
Dividend payment date	Apr. 03, 2017					
Dividend record date	Mar. 10, 2017					
UIL Holdings [Member]						
Business Acquisition [Line Items]						
Shares issued in connection with acquisition		57,255,850				
Business acquisition, share price		$ 50.10	$ 10.50			
Avangrid, Inc [Member]						
Business Acquisition [Line Items]						
Repurchase of common stock, shares			115,831			
Repurchase of common stock			$ 5			

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Avangrid, Inc [Member] | Subsequent Event [Member]	
Business Acquisition [Line Items]	
Dividend declared date	Feb. 16, 2017
Quarterly dividend payable, per share	$ 0.432
Dividend payment date	Apr. 03, 2017
Dividend record date	Mar. 10, 2017
Avangrid, Inc [Member] | UIL Holdings [Member]	
Business Acquisition [Line Items]	
Effective date of business acquisition of UIL Holdings	Feb. 25, 2015
Issuance of share in connection of acquisition	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.
Shares issued in connection with acquisition	309,490,839
Business acquisition, share price	$ 10.50
Percentage of ownership	18.50%
Common stock, par value	$ 0.01
Avangrid, Inc [Member] | UIL Holdings [Member] | UIL shareowners [Member]	
Business Acquisition [Line Items]	

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Shares issued in connection with acquisition	57,255,850		
Avangrid, Inc [Member] | UIL Holdings [Member] | Iberdrola, S.A. [Member]			
Business Acquisition [Line Items]			
Shares issued in connection with acquisition	252,234,989		
Iberdrola Renewables Holding, Inc [Member]			
Business Acquisition [Line Items]			
Percentage of equity owned by parent		81.50%	81.50%

[1] Par value of share amounts is $.01

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Non-current Debt - Additional Information (Detail) - UIL, and The Bank of New York Mellon [Member] - USD ($) $ in Millions	Dec. 19, 2016	1 Months Ended Dec. 31, 2016
Debt Instrument [Line Items]		
Debt instrument principal amount	$ 450	
Debt instrument, interest rate	4.625%	
Debt instrument maturity year	2020	
Capital contribution to subsidiary by parent		$ 483

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Cash Dividends Paid by Subsidiaries (Detail) - USD ($) $ in Millions	12 Months Ended		
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Cash Dividend [Line Items]			
Cash dividends paid	$ 420	$ 1,111	$ 200
AVANGRID Networks [Member]			
Cash Dividend [Line Items]			
Cash dividends paid	220	59	$ 200
AVANGRID Renewables [Member]			
Cash Dividend [Line Items]			
Cash dividends paid	$ 200	750	
Other AVANGRID subsidiaries [Member]			
Cash Dividend [Line Items]			
Cash dividends paid		$ 302	

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Cash Dividends Paid by Subsidiaries - Additional Information (Detail) - USD ($) $ in Millions	1 Months Ended Dec. 31, 2016	12 Months Ended Dec. 31, 2016
Avangrid, Inc [Member]		
Cash Dividend [Line Items]		
Non cash dividend recorded by parent company		$ 827
Central Maine Power Company [Member]		
Cash Dividend [Line Items]		
Capital contribution to subsidiary by parent	$ 50	

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