

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, 2015

Or

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

For the transition period from to

Commission File No. 001-37660



Avangrid, Inc.

(Exact name of registrant as specified in its charter)

New York
(State or other jurisdiction of
incorporation or organization)
157 Church Street
New Haven, Connecticut
(Address of principal executive offices)

4911
(Primary Standard Industrial
Classification Code Number)

14-1798693
(I.R.S. Employer
Identification No.)

06506
(Zip Code)

Telephone: (207) 688-6363
(Registrant's telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

<u>Title of each class</u>	<u>Name of each exchange on which registered</u>
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 the 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 ☒

State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2015, the last business day of the registrant's most recently completed second fiscal quarter: the registrant's common stock was not publicly traded.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: 308,962,088 shares of common stock, par value \$0.01, were outstanding as of March 28, 2016.

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 2016 Annual Meeting of the Shareholders are incorporated by reference into Part III to the extent described therein.

TABLE OF CONTENTS

<u>GLOSSARY OF TERMS AND ABBREVIATIONS</u>	1
<u>CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS</u>	5
<u>PART I</u>	6
<u>Item 1. <i>Business</i></u>	6
<u>Item 1A. <i>Risk Factors</i></u>	25
<u>Item 1B. <i>Unresolved Staff Comments.</i></u>	40
<u>Item 2. <i>Properties.</i></u>	40
<u>Item 3. <i>Legal Proceedings.</i></u>	40
<u>Item 4. <i>Mine Safety Disclosures.</i></u>	43
<u>Executive Officers of AVANGRID</u>	44
<u>PART II</u>	46
<u>Item 5. <i>Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.</i></u>	46
<u>Item 6. <i>Selected Financial Data</i></u>	47
<u>Item 7. <i>Management’s Discussion and Analysis of Financial Condition and Results of Operations</i></u>	48
<u>Item 7A. <i>Quantitative and Qualitative Disclosures About Market Risk</i></u>	77
<u>Item 8. <i>Financial Statements and Supplementary Data</i></u>	80
<u>Item 9. <i>Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.</i></u>	168
<u>Item 9A. <i>Controls and Procedures.</i></u>	168
<u>Item 9B. <i>Other information.</i></u>	168
<u>PART III</u>	169
<u>Item 10. <i>Directors, Executive Officers and Corporate Governance.</i></u>	169
<u>Item 11. <i>Executive Compensation.</i></u>	169
<u>Item 12. <i>Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.</i></u>	169
<u>Item 13. <i>Certain Relationships and Related Transactions, and Director Independence.</i></u>	169
<u>Item 14. <i>Principal Accounting Fees and Services.</i></u>	169
<u>Part IV</u>	170
<u>Item 15. <i>Exhibits and Financial Statement Schedules.</i></u>	170
<u>SIGNATURES</u>	175

GLOSSARY OF TERMS AND ABBREVIATIONS

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

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

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

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

Iberdrola, S.A. refers to the 81.5% controlling parent company 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.

Klamath Plant refers to the Klamath gas-fired cogeneration facility.

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.

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
Army Corps	U.S. Army Corps of Engineers
ARO	Asset retirement obligation
AVANGRID	AVANGRID, Inc.
Bcf	One billion cubic feet
Berkshire	The Berkshire Gas Company
BGEPA	Bald and Golden Eagle Protection Act
BLM	U.S. Bureau of Land Management
Cayuga	Cayuga Operating Company, LLC
CENG	Constellation Energy Nuclear Group, LLC
CfDs	Contracts for Differences
CFTC	Commodity Futures Trading Commission
CL&P	The Connecticut Light and Power Company
CMP	Central Maine Power Company
CNG	Connecticut Natural Gas Corporation
CSC	Connecticut Siting Council
DCF	Discounted cash flow
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
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
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	Ginna Facility and GNPP
Ginna Facility	R.E. Ginna Nuclear Power Plant
GNPP	Ginna Nuclear Power Plant
GSRP	Greater Springfield Reliability Project
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
LNS	Local Network Service
MBTA	Migratory Bird Treaty Act
Mcf	One thousand cubic feet of natural gas

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
MOU	Memorandum of Understanding
MPRP	Maine Reliability Power Program
MPUC	Maine Public Utilities Commission
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
Networks	Avangrid Networks, Inc.
New York TransCo	New York TransCo, LLC.
NIPSCO	Northern Indiana Public Service Company
NGA	Natural Gas Act of 1938
NGPSA	Natural Gas Pipeline Safety Act of 1968
NOL	Net operating loss
NPNS	Normal purchases and normal sales
NYISO	New York Independent System Operator, Inc.
NYPA	New York Power Authority
NYPSC	New York State Public Service Commission
NYSE	New York Stock Exchange
NYSEG	New York State Electric & Gas Corporation
OATT	Open Access Transmission Tariff
OCC	Office of Consumer Counsel
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
RGE	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
SEC	United States Securities and Exchange Commission
SNF	Spent Nuclear Fuel
SPHI	Scottish Power Holdings, Inc.
TEF	Tax equity financing arrangements
TGP	Tennessee Gas Pipeline Company LLC
TOTS	Transmission Owner Transmission Solutions
UI	The United Illuminating Company
UIL	UIL Holdings Corporation
WECC	Western Electricity Coordinating Council

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains a number of forward-looking statements. Forward-looking statements may be identified by the use of forward-looking terms such as “may,” “will,” “should,” “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 risks and uncertainties set forth under Part I, Item 1A, “Risk Factors” in this report. Specifically, forward-looking statements may include statements relating to:

- the future financial performance, anticipated liquidity and capital expenditures of the company;
- success in retaining or recruiting, or changes required in, our officers, key employees or directors;
- the risk that the businesses will not be coordinated successfully, or that the coordination will be more costly or more time consuming and complex than anticipated;
- disruption from the merger making it difficult to maintain business and operational relationships;
- adverse developments in general market, business, economic, labor, regulatory and political conditions;
- the impact of any cyber-breaches, 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.

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.

PART I

Item 1. Business

Overview

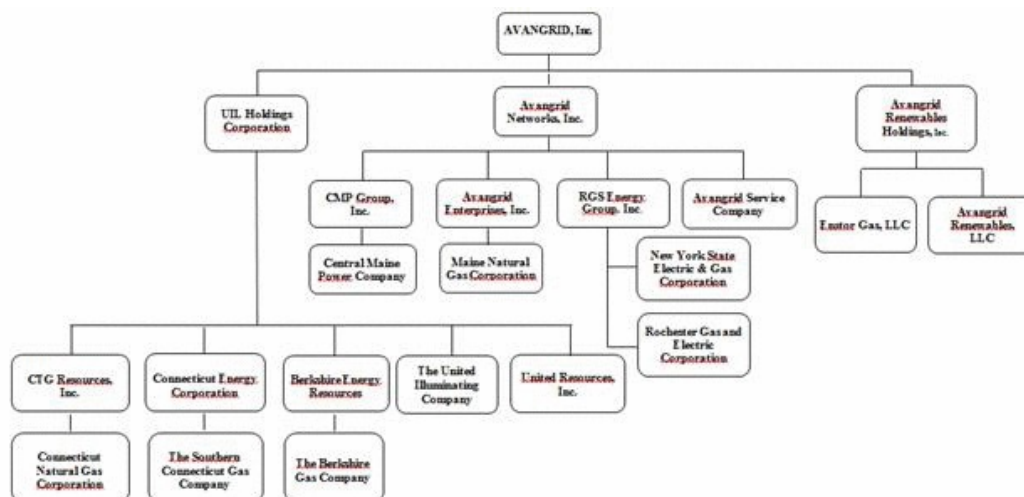
AVANGRID, Inc., or AVANGRID, formerly Iberdrola USA, Inc., is a New York corporation headquartered in New Gloucester, Maine. We are a direct, majority owned subsidiary of Iberdrola, S.A., a corporation (*sociedad anónima*) organized under the laws of Spain, one of the world's leading energy companies. Our primary business is ownership of our operating businesses, which are described below.

Our direct, wholly-owned subsidiaries include Avangrid Networks, Inc., or Networks, Avangrid Renewables Holdings, Inc., or ARHI, and UIL Holdings Corporation, or UIL. ARHI in turn holds subsidiaries including Avangrid Renewables LLC, or Renewables, and Enstor Gas, LLC, or Gas. Networks, along with UIL, owns and operates our regulated utility businesses, 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). Avangrid Service Company, a subsidiary of Networks, provides corporate and back office services on a consolidated basis to our subsidiaries.

On December 16, 2015, we completed an acquisition, 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."

The primary business of UIL is the ownership of its operating regulated utility businesses. The utility businesses consist of the electric distribution and transmission operations of The United Illuminating Company, or UI, and the natural gas transportation, distribution and sales operations of The Southern Connecticut Gas Company, or SCG, Connecticut Natural Gas Corporation, or CNG, and The Berkshire Gas Company, or Berkshire. For purposes of this document, all references to "Networks" include UIL and its subsidiaries, unless otherwise indicated.

After the acquisition UIL became a direct subsidiary of AVANGRID, which resulted in the following structure:



We currently anticipate that UIL and its subsidiaries will be moved under Networks in the first half of 2016. Through Networks, we own electric generation, transmission and distribution companies and natural gas distribution, transportation and sales companies in New York and Maine, and manage electric generation, transmission and distribution companies and natural gas distribution, transportation and sales companies in Connecticut and Massachusetts, delivering electricity to approximately 2.2 million electric utility customers and delivering natural gas to approximately 984,000 natural gas public utility customers as of December 31, 2015. 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 6,330 megawatts, or MW, as of December 31, 2015, including Renewables' share of joint projects, of which 5,643 MW was installed wind capacity. Approximately 67% of the capacity was contracted for an average period of 9.7 years as of December 31, 2015. As the second largest wind operator in the United States based on installed capacity as of December 31, 2015, Renewables strives to lead the transformation of the U.S. energy industry to a competitive, clean energy future. Renewables currently operates 53 wind farms in 18 states across the United States.

Through Gas, as of December 31, 2015 we own approximately 67.5 billion cubic feet, or Bcf, of net working gas storage capacity. Through Enstor Energy Services, LLC, Gas operates 53.25 Bcf of contracted or managed gas storage capacity in North America as of December 31, 2015.

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 of our audited combined and consolidated financial statements for the three years ended December 31, 2015, which is incorporated herein by reference.

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. 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; Renewables, which holds our renewable and thermal generation businesses, and gas storage and marketing businesses.

We were the corporate parent of SCG, CNG and Berkshire prior to UIL acquiring those companies in 2010.

On December 16, 2015, UIL became our wholly-owned subsidiary as a result of merging into Merger Sub, our wholly-owned subsidiary, with Merger Sub surviving as our wholly-owned subsidiary. Following the completion of the acquisition, Merger Sub was renamed "UIL Holdings Corporation" and we were renamed AVANGRID, Inc. On February 18, 2016, the following AVANGRID subsidiaries changed their names as set forth below:

Old Company Name	New Company Name
Iberdrola USA Networks, Inc.	Avangrid Networks, Inc.
Iberdrola USA Solutions, Inc.	Avangrid Solutions, Inc.
Iberdrola USA Group, LLC	Avangrid Management Company, LLC
Iberdrola USA Management Corporation	Avangrid Service Company
Iberdrola USA Enterprises, Inc.	Avangrid Enterprises, Inc.
Iberdrola USA Networks New York TransCo, LLC	Avangrid Networks New York TransCo, LLC
Iberdrola Energy Holdings, LLC	Enstor Gas, LLC
Iberdrola Energy Services, LLC	Enstor Energy Services, LLC
Iberdrola Renewables, LLC	Avangrid Renewables, LLC
Iberdrola Renewables Holdings, Inc.	Avangrid Renewables Holdings, Inc.
Iberdrola Arizona Renewables, LLC	Avangrid Arizona Renewables, LLC
Iberdrola Texas Renewables, LLC	Avangrid Texas Renewables, LLC
Iberdrola Logistic Services, LLC	Avangrid Logistic Services, LLC

Networks

Overview

Networks, a Maine corporation, along with UIL, a Connecticut corporation, hold 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 or through UIL:

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

For the year ended December 31, 2015, Networks distributed 37,528,920 megawatt-hours, or MWh, of electricity (includes 12 months of operation of UIL). As of December 31, 2015, Networks provided service to its 2.2 million customers in the states of New York, Maine, Connecticut and Massachusetts. 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, 2015. Furthermore, for the year ended December 31, 2015, Networks delivered more than 205 million dekatherms, or DTh, of natural gas (includes 12 months of operation of UIL), to approximately 984,000 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, 2015:

Utility	Rate Base ⁽¹⁾ (in billions)	Electricity Customers	Electricity Delivered (in MWh) For the year ended December 31, 2015	Natural Gas Customers December 31, 2015	Natural Gas Delivered (in DTh) For the year ended December 31, 2015
	December 31, 2015	December 31, 2015	December 31, 2015	December 31, 2015	December 31, 2015
NYSEG	\$ 2.4	885,000	15,711,000	265,000	56,533,000
RGE	\$ 1.6	375,000	7,110,000	310,000	51,498,000
CMP	\$ 2.3	616,979	9,256,920	—	—
MNG	\$ 0.1	—	—	4,432	15,400,000
UI	\$ 1.5	331,216	5,451,000	—	—
SCG	\$ 0.5	—	—	192,557	33,978,000
CNG	\$ 0.4	—	—	172,498	37,387,000
Berkshire	\$ 0.1	—	—	39,680	10,569,000

(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.

Over the last five years, Networks has invested nearly \$6.0 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. From 2009 to 2015, Networks increased capital expenditure investments in its New York and Maine regulated utilities by 131%, from \$315.0 million to \$727.0 million.

New York

As of December 31, 2015, NYSEG served approximately 885,000 electricity customers and 265,000 natural gas customers across more than 40% of upstate New York's geographic area, while RGE 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 2015, NYSEG and RGE's nine hydroelectric plants generated nearly 366 million kilowatt-hours, or kWh, of clean hydropower, which is enough energy to power 51,000 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 along with Central Hudson Gas and Electric Corporation, Consolidated Edison, Inc., National Grid, plc and Orange and Rockland Utilities, Inc. to develop a portfolio of interconnected transmission lines and substations to fulfill the objectives of the New York energy highway initiative, a proposal to install up to 3,200 MW of new electric generation and transmission capacity in order to deliver more power generated from upstate New York power plants to downstate New York.

Maine

As of December 31, 2015, CMP delivered electricity to more than 616,000 customers in an 11,000 square-mile service area in central and southern Maine. CMP has completed a \$1.4 billion investment plan for the construction of upgrades to the bulk power transmission grid in Maine, the largest transmission investment in the history of Maine, which includes the construction of five new 345-kilovolt, or kV, substations and related facilities linked by approximately 440 miles of new transmission lines (refers to the Maine Power Reliability Program, or MPRP). CMP in 2012 also completed a \$200.0 million investment, one-half of which was funded by the Department of Energy, or DOE, in advanced meter infrastructure, which included the installation of more than 600,000 smart meters for all of its electric customers. Smart meters monitor and record a customer's power consumption, eliminating the need for on-site meter reading.

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

MNG delivers natural gas to 4,432 customers in central and southern Maine and recently completed construction of the first natural gas pipeline in Augusta, Maine. Through MNG, Networks provides these communities in southern Maine with access to natural gas for the first time, offering a competitive and clean energy option to homes and businesses.

Connecticut

As of December 31, 2015, UI served more than 331,000 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, 2015, SCG and CNG provided local gas distribution services to approximately 364,000 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, 2015, Berkshire 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.

The rate base of Networks' regulated utilities has increased significantly over the last three years, mainly due to the investments in regulated projects, such as the Maine Reliability Power Program, or MPRP, transmission project in Maine and increased replacement of aging infrastructure and investments in smart grid automation. The rate base of Networks' regulated utilities for the years indicated below have been as follows:

Rate base	2013	2014	2015
	<i>(in millions)</i>		
NYSEG Electric	\$ 1,702	\$ 1,796	\$ 1,825
NYSEG Gas	482	508	531
RGE Electric	1,058	1,111	1,175
RGE Gas	427	444	446
Subtotal New York	<u>3,669</u>	<u>3,859</u>	<u>3,977</u>
CMP Dist	714	739	781
CMP Trans	1,252	1,467	1,472
MNG	47	64	60
Subtotal Maine	<u>2,013</u>	<u>2,270</u>	<u>2,313</u>
UI Dist	760	823	942
UI Trans	500	500	508
SCG	468	461	477
CNG	396	382	396
Subtotal Connecticut	<u>2,124</u>	<u>2,166</u>	<u>2,323</u>
Berkshire	<u>70</u>	<u>72</u>	<u>91</u>
Total	<u>\$ 7,876</u>	<u>\$ 8,367</u>	<u>\$ 8,704</u>

Earnings Sharing Mechanisms

The regulated utilities' rate plans approved by regulators in New York, Maine, Connecticut and Massachusetts typically 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:

	2013	2014	2015
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%: 10.90% - 11.65% 85% / 15%: over 11.65%; Based on Actual Equity Ratio up to 50%
NYSEG Gas	Same as above	Same as above	Same as above
RGE Electric	Same as above	Same as above	Same as above
RGE Gas	Same as above	Same as above	Same as above
CMP Dist.	50% / 50% over 11.0% Based on 47% Equity Ratio	No ESM	No ESM
CMP Trans.	No ESM	No ESM	No ESM
MNG	No ESM	No ESM	No ESM
UI	50% / 50% over 8.90%*	50% / 50% over 9.15%	50% / 50% over 9.15%
SCG	No ESM	No ESM	No ESM
CNG	No ESM	50% / 50% over 9.18%	50% / 50% over 9.18%
Berkshire	No ESM	No ESM	No ESM

* UI's rate case decision, effective in August 2013, increased the ROE threshold subject to ESM from 8.75% to 9.15%, resulting in a weighted average of 8.90% for calendar year 2013.

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. 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, when approved by the Commissioner of DEEP, and pursuant to the terms and conditions in the consent order, would require 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, upon its issuance and subject to its terms and conditions, UI would be 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 89% of Renewables’ combined installed capacity as of December 31, 2015. For the year ended December 31, 2015, Renewables produced approximately 14,135,000 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, 2015.

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 67% of its installed capacity as of December 31, 2015.

Renewables currently operates 53 wind farms in 18 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 a majority or 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, 2015. Renewables worked closely with the City of Klamath Falls, Oregon to develop the Klamath Plant, which has a current capacity of 536 MW, operating 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 126,000 MWh of renewable energy for the year ended December 31, 2015. 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
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			<u>3,105</u>	<u>5,643</u>

The Renewables meteorology team supports the commercial development of wind energy projects in Renewables’ pipeline by performing a wide variety of detailed investigations to characterize the expected wind energy production from a proposed wind farm in its pre-construction phase of development. These investigations include measuring the wind resource with several well-equipped meteorological masts, utilizing state of the art laser-based and acoustic-based remote sensing equipment, computational fluid dynamics modeling software, and energy modeling software packages that characterize wake losses from any upwind turbines that may be present. The Renewables fleet of measurement masts consists of over 160 towers that are currently in operation. Additionally, a total of 8 light detecting and ranging, and 6 sonic detecting and ranging, remote sensing devices are deployed at sites across the United States. These remote sensing devices allow hub-height wind speed measurement from a ground-based sensor that can be rapidly deployed and moved as the project matures or changes in nature. The resulting pre-construction energy production estimates that utilize these measurements have been shown to be accurate in a multi-year internal study that compares results to actual, operational data in a benchmarking analysis. This study provides a critical feedback loop that is used to define methodology requirements for future pre-construction energy production estimates to ensure confidence in project investment. Renewables’ commitment to obtaining robust atmospheric measurement is driven by a company culture that values business case confidence and understands the role that accurate meteorological data play in the pursuit of this goal.

Gas

The Gas business, based in Houston, Texas, operates a natural gas storage and natural gas trading business through its wholly-owned direct subsidiaries, Enstor, Inc., an Oregon corporation (natural gas storage) and Enstor Energy Services LLC, a Delaware limited liability company (natural gas trading). Gas owns and operates four natural gas storage facilities, with a total storage capacity of 88.5 Bcf and a net working gas storage capacity of 67.5 Bcf. Enstor Operating Company, LLC, a Texas limited liability company and wholly-owned direct subsidiary of Enstor, Inc., manages all four natural gas storage facilities. The demand for natural gas storage is dependent upon the seasonal differences in the weather. Since market prices and temporal price spreads for natural gas reflect the demand for these products and their availability at a given time, the overall operating results of Gas’ business may fluctuate substantially on a seasonal basis. Severe weather, such as ice and snow storms, hurricanes and other natural disasters may cause outages, bodily injury or property damage, which may require Gas to incur additional costs, such as operation and maintenance expenses, which may not be recoverable from customers. See “—Properties—Gas” for more information regarding Gas’ natural gas storage facilities. Enstor Energy Services LLC also contracts and manages natural gas storage and pipeline capacity throughout the United States and parts of Canada. Gas operates 53.25 Bcf of contracted or managed natural gas storage capacity in North America through Enstor Energy Services, LLC, as of December 31, 2015.

Regulatory Environment and Principal Markets

Federal Energy Regulatory Commission

Among other things, 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 FERC.

Pursuant to the FPA, electric utilities must maintain tariffs and rate schedules on file with FERC which govern the rates, terms and conditions for the provision of 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 FERC's jurisdiction. 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, FERC governs the return on equity, or ROE, 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. FERC approves the Networks' regulated electric utilities' transmission revenue requirements. Wholesale electric transmission revenues are recovered through formula rates that are approved by 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 RGE'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 FERC reporting and accounting regulations available to non-traditional public utilities; however, we cannot be assured that such authorizations or waivers will not be revoked for these affiliates or will be granted in the future to other affiliates.

Pursuant to a series of orders involving the ROE for regionally planned New England electric transmission projects, the FERC established a base-level transmission ROE of 11.14%, as well as 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.

Beginning in 2011, several parties filed three 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 and July 31, 2014, 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 that 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 is the administrative law judge's recommendation to the FERC Commissioners. The FERC is expected to make its final decision in late 2016 or early 2017.

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 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 finds that ISO-NE Transmission, Markets, and Services Tariff is unjust, unreasonable, and unduly discriminatory or preferential. 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. 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.

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.

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 EPCA 2005, the North American Electric Reliability Corporation, or NERC, has been certified by FERC as the Electric Reliability Organization to develop and oversee the enforcement of electric system reliability standards applicable throughout the United States. FERC-approved reliability standards may be enforced by 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 FERC oversight.

Gas’ current natural gas storage operations in the United States are subject to the jurisdiction of FERC under the Natural Gas Act of 1938, or NGA, as a Section 7(c) natural gas storage provider (i.e., Caledonia Energy Partners, L.L.C. and Freebird Gas Storage, LLC each with Enstor Operating Company, LLC as their manager) and by providing interstate storage and storage related services under Section 311 of the Natural Gas Policy Act of 1978 (i.e., Enstor Katy Storage and Transportation, L.P. and Enstor Grama Ridge Storage and Transportation, LLC with Enstor Operating Company, LLC as their general partner and manager, respectively), 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.

Furthermore, Gas’ natural gas trading operations in the United States are subject to the jurisdiction of FERC under EPCA 2005. FERC possesses regulatory oversight over gas markets, including the purchase, sale and transportation of gas by “any entity” in order to enforce the anti-market manipulation provisions in EPCA 2005. The gas distribution operations of NYSEG, RGE, SCG, CNG and Berkshire, similar to Gas, are also subject to 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 EPCA 2005. Additionally, Gas’ current natural gas trading operations are also subject to FERC regulation with respect to matters such as market manipulation and capacity release rules.

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 RGE 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 Berkshire 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.* NYSEG and RGE have each completed one distribution rate case decision since they were acquired by Iberdrola, S.A. in 2008. On September 17, 2009, NYSEG and RGE initiated a distribution rate case to allow the companies to recover past and future investments, provide safe and adequate service, and improve their credit ratings. On February 19, 2016, the NYSEG, RGE 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 RGE commencing May 1, 2016. The proposal balances 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 enhanced electric vegetation management to provide continued safe and reliable service. The allowed rate of return on common equity for NYSEG Electric, NYSEG Gas, RGE Electric and RGE 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 earnings levels, with customers receiving 50%, 75% and 90% of earnings over 9.5%, 10.0% and 10.5% of ROE, respectively, in the first year. Earnings thresholds would increase in subsequent 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 RGE 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 administrative law judges assigned to the New York rate case will issue a procedural schedule establishing the remaining procedure for review and decision on the proposal. We expect hearings on the proposal to be held in April 2016 and a NYPSC decision to be made in May 2016.

- *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 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 March 5, 2015, MNG filed a rate case in order to recover future investments and provide safe and adequate service. MNG requested a 10.0% ROE and 50% equity ratio. The MPUC Staff has recommended a separate revenue requirement for MNG's Augusta customers and MNG's non-Augusta customers. Staff has recommended a \$19.95 million disallowance of the Augusta Expansion investment based upon the Staff's conclusion that MNG's management of the Augusta Expansion Project was imprudent. On November 6, 2015, a stipulation was filed with the MPUC, which was executed by MNG, the Office of Public Advocate and the City of Augusta. The stipulation contained a combined revenue requirement for Augusta and Non-Augusta based on a 9.55% ROE and 50% equity ratio. The stipulation also provided for an initial Augusta investment disallowance of \$6 million and an investment phase-in of \$10 million. On December 22, 2015, MPUC rejected the proposed stipulation as not in the public interest. In January 2016, the administrative law judge established a new litigation schedule. The litigation was suspended at the end of January 2016 for settlement discussions. We cannot predict the outcome of the proceeding.

- *Connecticut.* In August 2013, PURA approved distribution rate schedules for UI for two years that became effective at that time and which, among other things, increased the UI distribution allowed ROE from 8.75% to 9.15%, 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, with interest, for refund to or recovery from customers, as applicable), and approved the establishment of the requested storm reserve. In connection with the approval by PURA of the acquisition, UI agreed not to file a rate case for new rates effective before January 1, 2017.

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.* Berkshire's rates are established by the DPU. Berkshire's 10-year rate plan, which was approved by the DPU and included an approved ROE of 10.5%, expired on January 31, 2012. Berkshire 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, Berkshire agreed not to file a rate case for new rates effective before June 1, 2018.

Further, 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 objectives. The proceeding is following a two-phased schedule with an order relating to policy determinations for DSP and related matters issued in February 2015 and an order for regulatory design and regulatory matters, expected in 2016. All electric utilities have been ordered to file an initial Distributed System Implementation Plan, or DSIP, by June 30, 2016. The DSIP will also include information regarding the potential deployment of Automated Metering Infrastructure, or AMI.

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

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 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 9.15%) 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.

Under Maine law 35-A.M.R.S.A §§ 3210-C, 3210-D, the MPUC is authorized to conduct periodic requests for proposals seeking long-term supplies of energy, capacity or RECs, from qualifying resources. The MPUC is further authorized to order Maine Transmission and Distribution Utilities to enter into contracts with sellers selected from the MPUC's competitive solicitation process. Pursuant to a MPUC Order dated October 8, 2009, CMP entered into a 20-year agreement with Evergreen Wind Power III, LLC, on March 31, 2010, to purchase capacity and energy from Evergreen's 60 MW Rollins wind farm in Penobscot County, Maine. CMP's purchase obligations under the Rollins contract are approximately \$7 million per year. In accordance with subsequent MPUC orders, CMP periodically auctions the purchased Rollins energy to wholesale buyers in the New England regional market. Under applicable law, CMP is assured recovery of any differences between power purchase costs and achieved market revenues through a reconcilable component of its retail distribution rates. Although the MPUC has conducted multiple requests for proposals under M.R.S.A §3210-C and has tentatively accepted long-term proposals from other sellers, these selections have not yet resulted in additional currently effective contracts with CMP.

New England East-West Solution

Pursuant to an agreement with CL&P, UI has the right to invest in, and own transmission assets associated with, the Connecticut portion of CL&P's, New England East West Solution, or NEEWS, projects to improve regional energy reliability. NEEWS originally consisted of four inter-related transmission projects being developed by subsidiaries of Northeast Utilities (doing business as Eversource Energy), the parent company of CL&P, in collaboration with National Grid USA. Three of the original projects have portions located in Connecticut: (1) the Greater Springfield Reliability Project, which was fully energized in November 2013, (2) the Interstate Reliability Project, which was placed in service in the fourth quarter of 2015 and (3) the Central Connecticut Reliability Project, the need for which is now planned to be addressed by CL&P's Greater Hartford Central Connecticut solutions, in which UI does not anticipate making any investments. Under the agreement, as of December 31, 2015, UI had made aggregate deposits of approximately \$45 million since its inception, with assets valued at approximately \$44.6 million having been transferred to UI. UI does not anticipate making any additional investments in NEEWS under the agreement.

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

Renewables' projects also are subject to local environmental and regulatory requirements, including county and municipal land use, zoning, building and transportation requirements. Permitting at the local municipal or county level often consists of obtaining a special use or conditional use permit under a land use ordinance or code, or, in some cases, rezoning in connection with the project. Obtaining a permit usually depends on Renewables demonstrating that the project will conform to 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 HLPSPA. PHMSA, through the NGPSA and HLPSPA, regulates the design, installation, testing, construction, operation, maintenance, repair, inspection, replacement and management of interstate and certain intrastate natural gas pipeline facilities. PHMSA has also developed regulations that require transportation pipeline operators to implement integrity management programs to comprehensively evaluate certain high risk areas along Gas' natural gas pipelines and take additional measures to protect natural gas pipeline segments located in highly populated areas.

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

Global Climate Change and Greenhouse Gas Emission Issues

Global climate change and greenhouse gas emission issues continue to receive an increased focus from state governments and the federal government. In November 2010, 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 of the new regulations. Similarly, Networks and UIL are subject to reporting requirements under provisions of the greenhouse gases regulations, which regulate electric transmission and distribution equipment that emit sulfur hexafluoride.

We are continually evaluating the regulatory risks and regulatory uncertainty presented by climate change and greenhouse gas emission concerns. 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 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 a proposed partial consent order that, when issued by the Commissioner of DEEP would require 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 proposed partial 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. Pursuant to the proposed partial consent order, upon its issuance and subject to its terms and conditions, UI would be obligated to comply with the proposed partial 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. The State is continuing to discuss English Station site access with the current owners and the proposed partial consent order has not been filed.

Customers

Networks delivers natural gas and electricity to residential, commercial and institutional customers through its regulated utilities in New York, Maine, Connecticut and Massachusetts. As a result of the acquisition of UIL, we now deliver natural gas and electricity to approximately 735,000 additional customers through our regulated utilities in Connecticut and Massachusetts. Networks' customer payment terms are regulated by the states of New York, with respect to NYSEG and RGE; Maine, with respect to CMP and MNG; Connecticut, with respect to UI, SCG and CNG; and Massachusetts, with respect to Berkshire, 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, or PPAs, allowing Renewables to limit its exposure to market volatility. Approximately 67% of Renewables' wind generating capacity is fully committed under PPAs with an average duration of 9.7 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 over 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, 2015. 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
RGE	Rochester, NY (3 locations)	Hydroelectric	57.5	1917—1960

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

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

The following table sets forth certain operating data relating to the electricity transmission and distribution activities of each of Networks' regulated utilities as of December 31, 2015.

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
RGE	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, 2015.

Utility	State	Natural Gas Customers	Transmission Pipeline (in miles)	Distribution Pipeline (in miles)
NYSEG	New York	265,000	20	8,151
RGE	New York	310,000	105	10,592
MNG	Maine	4,432	2	190
SCG	Connecticut	192,557	—	2,391
CNG	Connecticut	172,498	—	2,118
Berkshire	Massachusetts	39,680	—	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.

Renewables

The following table sets forth Renewables' portfolio of wind projects as of December 31, 2015. 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 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.
(2) Jointly owned with Horizon Wind Energy; capacity amounts represent only Renewables' share of the wind farm.

Additionally, unless noted otherwise, Renewables owns the following solar and thermal facilities as of December 31, 2015.

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, 2015. 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 security measures in place designed to protect our facilities and assets, 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, in accordance with the Cybersecurity Risk Policy and with the Corporate Security Policy of Iberdrola, S.A. as adopted by us, 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 established a dedicated Corporate Security Office, responsible for improving and coordinating security across the company and have adopted a comprehensive company-wide physical and cyber security program, which is supported by a company-wide governance policy to manage, oversee and assist us in meeting our corporate, legal, and regulatory responsibilities with regard to the protection of our cyber, physical and information assets. However, as threats evolve and grow increasingly more sophisticated, we cannot ensure that a potential security breach may not occur or quantify the potential impact of such an event. We continue to invest in technology, processes, security measures and services to detect, mitigate and protect our assets, both physical and cyber. These investments include upgrades to network architecture and physical security measures, regular intrusion detection monitoring and compliance with emerging industry regulation.

Employees

As of December 31, 2015, we had 6,809 employees excluding 15 international assignees. Of these 6,809 employees, 47.7% are represented by a union. The following table provides an overview of the number of employees at each business segment as of December 31, 2015:

Business Segment	Number of Employees (excluding International Assignees)	% of Union Workforce Subject to Collective Bargaining Agreement
Networks	5,795	56.0%
Renewables	686	—
Gas	103	—
Corporate	225	—
Total	6,809	47.7%

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 Securities and Exchange Commission, or 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.

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 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, 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 NYSPSC, 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. FERC has the authority to impose penalties on our regulated utilities, which could be substantial, for violations of the FPA, the NGA, or related rules, including reliability and cyber security rules as described in further detail below. The Financial Accounting Standards Board, or FASB, or the SEC, may enact new accounting standards that could impact the way we are required to record revenue, expenses, assets and liabilities. Certain regulatory agencies have the authority to review and disallow recovery of costs that they consider excessive or imprudently incurred and to determine the level of return that our businesses are permitted to earn on invested capital.

The regulatory process, which may be adversely affected by the political, regulatory and economic environment in New York, Maine, Connecticut and Massachusetts, as applicable, may limit our ability to increase earnings and does not provide any assurance as to achievement of authorized or other earnings levels. The disallowance of the recovery of costs incurred by us or a decrease in the rate of return that we are permitted to earn on our invested capital could have a material adverse effect on our business, results of operation, financial condition and cash flows. Certain of these regulatory agencies also have the authority to audit the management and operations of our businesses in New York, Maine, Connecticut and Massachusetts and require or recommend operational changes. Such audits and post-audit work requires the attention of our management and employees and may divert their attention from other regulatory, operational or financial matters. The last management audit of UI by PURA was completed in 2015. This audit resulted in 64 recommendations. In

December 2015, UI filed its response to the audit's recommendations with PURA. The NYPSC is in process of an operations audit of staffing levels at major utilities. The audit is expected to be completed later in 2016. We cannot predict the outcome of this audit.

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 EAct 2005, owners, operators and users of bulk electric systems are subject to mandatory reliability standards developed by the NERC and are subject to oversight by 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 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 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.

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 RGE 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.

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.

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

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

The existing FERC-approved ISO-NE, transmission tariff allocates the costs of transmission facilities that provide regional benefits to all customers of participating transmission-owning utilities. 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 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 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, that 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. Violations of current or future laws, rules, regulations or other standards could expose our subsidiaries to regulatory and legal proceedings, disputes with, and legal challenges by, third parties, and potentially significant civil fines, criminal penalties and other sanctions, which could have an adverse effect on our operations, financial condition and cash flows.

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

Our regulated utilities in New York, Maine, Connecticut and Massachusetts are subject to periodic review of their rates by the NYPSC, MPUC, PURA and DPU respectively, and the retail rates charged to our regulated utilities' customers through base rates and cost recovery clauses are subject to the jurisdiction of the NYPSC, MPUC, PURA and DPU as applicable. New rates may be proposed by Network's businesses, which are then subject to review, modification and final authorization and implementation by regulators. Alternatively, regulators may review the rates of Networks' regulated utilities on their own motion. Networks' regulated utilities' rate plans cover specified periods, but rates determined pursuant to a plan generally continue in effect until a new rate plan is approved by the state utility regulator. Networks' regulated utilities' business rate plans approved by state utility regulators limit the rates Networks' regulated utilities can charge their customers. The rates are generally designed for, but do not guarantee, the recovery of Networks' regulated utilities' respective cost of service and the opportunity to earn a reasonable rate of return (ROE). Actual costs may increase due to inflation or other factors and exceed levels provided for such costs in the rate plans for Networks' regulated utilities. Utility regulators can initiate proceedings to prohibit Networks' regulated utilities from recovering from their customers the cost of service (including energy costs) that the regulators determine to have been imprudently incurred. Networks' regulated utilities defer for future recovery certain costs including major storm costs and environmental costs. In a number of proceedings in recent years, Networks' regulated subsidiaries have been denied recovery, or deferred recovery pending the next general rate case, including denials or deferrals related to major storm costs and construction expenditures. In some instances, denial of recovery may cause the regulated subsidiaries to record an impairment of assets. If Networks' regulated utilities' costs are not fully and timely recovered through the rates ultimately approved by regulators, our cash flows, results of operations and financial condition, and our ability to earn a return on investment and meet financial obligations, could be adversely affected.

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

In addition, there are pending challenges at FERC against New England transmission owners (including UI and CMP) seeking to lower the ROE that these transmission owners are allowed by 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 and for potential violations of the MBTA and BGEPA at its three wind farms located in the state of Washington.

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 less conducive to the development or operation of renewable energy facilities. Any reductions to, or the elimination of, governmental policies or other mechanisms that support renewable energy or the imposition of additional taxes or other assessments on renewable energy, could result in, among other items, the lack of a satisfactory market for the development of new renewable energy projects, Renewables abandoning the development of new renewable energy projects, a loss of Renewables' investments in the projects and reduced project returns, any of which could have a material adverse effect on our business, results of operations, financial condition and cash flows.

Our businesses may face risks related to obtaining governmental approvals and permits in respect of project siting, financing, construction, operation and the negotiation of project development agreements which could cause delay a project and could materially adversely affect our businesses, results of operations or financial condition.

Renewables owns, develops, constructs and/or operates electricity generation, including renewable and thermal generators, and associated transmission facilities. Networks develops, constructs, manages and operates transmission and distribution facilities to meet customer needs. As part of these operations, our businesses must periodically apply for licenses and permits from various local, state, federal and other regulatory authorities and abide by their respective conditions. In particular, with respect to Renewables, over the past 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 which could have a material adverse effect on our business, results of operations, financial condition and cash flows.

Under the EPCA 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, FERC and CFTC have promulgated new regulations that have increased compliance costs and imposed new reporting requirements on our businesses. For example, the Dodd-Frank Act substantially increased regulation of the over-the-counter derivative contracts market and futures contract markets, which impacts our businesses. The new regulations require our operating subsidiaries to comply with certain margin requirements for our over-the-counter derivative contracts with certain CFTC- or SEC-registered entities and if the rules implementing the new regulations require us to post significant amounts of cash collateral with respect to swap transactions, this could have a material adverse effect on our liquidity. We cannot predict the impact these new regulations will have on our businesses' ability to hedge their commodity and interest rate risks or on over-the-counter derivatives markets as a whole, but they could potentially have a material adverse effect on our businesses' risk exposure, as well as reduce market liquidity and further increase the cost of hedging activities.

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

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

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

Risks Relating to Our Business and Operations

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

A 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 which 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.

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, to restore service and repair damaged facilities, to obtain replacement power and to access available financing sources, that may not be recoverable from customers, which 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, many of operating facilities of Networks and Enstor, Inc., Gas' wholly-owned direct subsidiary, are located either in, or close to, densely populated public places. A failure of, or damage to, these facilities, could result in bodily injury or death, property damage, the release of hazardous substances or extended service interruptions. The cost of repairing damage to Networks' and Gas' facilities and the potential disruption of their operations due to storms, natural disasters or other catastrophic events could be substantial. In respect of our businesses where cost recovery is available, recovery of costs to restore service and repair damaged facilities is or may be subject to regulatory approval, and any determination by the regulator not to permit timely and full recovery of the costs incurred could have a material adverse effect on our business, results of operations, financial condition and cash flows.

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

Changing wind patterns or lower than expected wind resource could cause reductions in electricity generation at Renewables' projects, which could affect the revenues produced by these wind generating facilities. Renewables' wind projects are sited, developed and operated to maximize wind performance. Prior to siting a wind facility, detailed studies are conducted to measure the wind resource in order to estimate future production. However, wind patterns or wind resource in the future might deviate from historical patterns and are difficult to predict. These events could negatively impact the results of operations of Renewables, which may vary significantly from period to period, depending on the level of available resources. To the extent that resources are not available at planned levels, the financial results from these facilities may be less than expected. Changing wind patterns or lower than expected wind resources could also degrade equipment or components and the interconnection and transmission facilities' lives or maintenance costs. Replacement and spare parts for wind turbines and key pieces of electrical equipment may be difficult or costly to acquire or may be unavailable. The loss of any suppliers or service providers or inability to find replacement suppliers or service providers or to purchase turbines at rates currently offered by Renewables' existing suppliers or a change in the terms of Renewables' supply or operations and maintenance agreements, such as increased prices for maintenance services or for spare parts, could have a material adverse effect on Renewables' ability to construct and maintain wind farms or the profitability of wind farm development and operation.

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

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

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

Cyber breaches, acts of war or terrorism or grid disturbances resulting from internal or external sources could target our generation, transmission and distribution facilities or our information technology systems. In the regular course of business, we maintain sensitive customer, employee, financial and system operating information and are required by various federal and state laws to safeguard this information. Cyber or physical security intrusions could potentially lead to disabling damage to our generation, transmission and distribution facilities and to theft and the release of critical operating information or confidential customer or employee information, which could adversely affect our operations or adversely impact our reputation, and could result in significant costs, fines and litigation. Additionally, because our generation and transmission facilities are part of an interconnected regional grid, we face the risk of blackout due to a disruption on a neighboring interconnected system. 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, either through natural events such as lightning strikes that damage blades or in-ground electrical systems used to collect electricity from turbines, or through vandalism, such as gunshots into towers or other generating equipment. Such damage can cause disruption of operations for unspecified periods which may lead to operating losses at those locations.

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

Renewables has exposure to commodity price movements through their "natural" long positions in electricity and natural gas storage in addition to proprietary trading and hedging activities. Since market prices and temporal price spreads for natural gas reflect the demand for these products and their availability at a given time, the overall operating results of Gas' business may fluctuate substantially on a seasonal basis.

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

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

We are pursuing broader development investment opportunities related to all segments of our business, particularly in respect of additional opportunities related to electric transmission, renewable energy generation, interconnections to generating resources and other development investment opportunities. The development, construction and expansion of such projects involve numerous risks. Various factors could result in increased costs or result in delays or cancellation of these projects. Risks include regulatory approval processes, permitting, new legislation, economic events, environmental and community concerns, negative publicity, design and siting issues, difficulties in obtaining required rights of way, construction delays and cost overruns, including delays in equipment deliveries, particularly of wind turbines or transformers, severe weather, competition from incumbent facilities and other entities, and actions of strategic partners. For example, there may be delays or unexpected developments in completing current and future construction projects. While most of Renewables' construction projects are constructed under fixed-price and fixed-schedule contracts with construction and equipment suppliers, these contracts provide for limitations on the liability of these contractors to pay liquidated damages for cost overruns and construction delays. These circumstances could prevent Renewables' construction projects from commencing operations or from meeting original expectations about how much electricity it will generate or the returns it will achieve. In addition, for Renewables' projects that are subject to PPAs, substantial delays could cause defaults under the PPAs, which generally require the completion of project construction by a certain date at specified performance levels. A delay resulting in a wind project failing to qualify for federal production tax credits could result in losses that would be substantially greater than the amount of

liquidated damages paid to Renewables. In December 2015, the Consolidated Appropriations Act, 2016 extended the expiration date for this tax credit to December 31, 2019, for wind facilities commencing construction, with a phase-down beginning for wind projects commencing construction after December 31, 2016. 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, 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, RGE'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, these are temporary in nature and there is no assurance such mechanisms will always be extended. The progressive reduction in the costs of distributed energy assets, as a result of technological improvements, large scale deployment in certain jurisdictions and constructive support regimes could result in customer defection (individually or integrated in micro-grids) when a net benefit analysis of investing in self-supply and storage of energy compared to energy provided by utility service appears attractive for certain customer classes. Similarly, future investments in Networks could be impacted if adequate rate making does not fully contemplate the characteristics of an integrated reliable grid from a unified perspective, regardless of customer disconnection. Further, the interoperability, integration and standard connection of these distributed energy devices and systems could place a burden on the system of Networks' operating subsidiaries, without adequately compensating them. Furthermore, the technologies used in the renewable energy sector change and evolve rapidly. Techniques for the production of electricity from renewable sources are constantly improving and becoming more complex. In order to maintain Renewables' competitiveness and expand its business, Renewables must adjust effectively to changes in technology. If Renewables fails to react effectively to current and future technological changes in the sector in a timely manner, Renewables' future business growth, results of operations and financial condition could be materially adversely affected.

Renewables' revenue may be reduced significantly upon expiration 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.

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. 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. Recent reductions in oil prices demonstrate that it is difficult 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 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 Berkshire businesses, and their cash flows, results of operations and financial condition.

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

Our subsidiaries do not own all of the land on which their projects are located. For example, Renewables does not own all of the land on which its wind projects are located and Gas does not own all of the land on which its natural gas storage projects are located. Such projects generally are, and future projects may be, located on land occupied under long-term easements, leases and rights of way. The ownership interests in the land subject to these easements, leases and rights of way may be subject to mortgages securing loans or other liens and other easements, lease rights and rights of way of third parties that were created previously. As a result, some of the rights under such easements, leases or rights of way held by our operating subsidiaries may be subject to the rights of these third parties, and the rights of our operating subsidiaries to use the land on which their projects are or will be located and their projects' rights to such easements, leases and rights of way could be lost or curtailed. Any such loss or curtailment of the rights of our operating subsidiaries to use the land on which their projects are or will be located could have a material adverse effect on their business, results of operations, financial condition and cash flows.

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

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

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

There are inherent hazards and operation risks in gas distribution activities, such as leaks, accidental explosions and mechanical problems that could cause the loss of human life, significant damage to property, environmental pollution and impairment of operations. The location of pipelines and storage facilities near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. These activities may subject us to litigation and administrative proceedings that could result in substantial monetary judgments, fines or penalties. To the extent that the occurrence of any of these events is not fully covered by insurance or natural gas hedges, they could adversely affect our revenue, earnings and cash flow.

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

Our businesses and activities are exposed to the risks inherent in the construction and operation of our respective assets, such as electrical power plants, wind power plants and other renewable energy projects and natural gas storage facilities, including breakdowns, manufacturing defects, natural disasters, terrorist attacks, cyber attacks and sabotage. Our subsidiaries are also exposed to third party liability risks and environmental risks. While our operating subsidiaries maintain insurance coverage, such insurance may not continue to be offered on an economically feasible basis and may not cover all events that could give rise to a loss or claim involving the assets or operations of our subsidiaries. For example, Renewables currently has 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.

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 which could adversely impact our business, results of operations, financial condition and cash flows.

We provide defined benefit pension plans and other post-retirement benefits administered by our subsidiaries for a significant number of employees, former employees and retirees. Financial market disruptions and significant declines in the market values of the investments held to meet the pension and post-retirement obligations, discount rate assumptions, participant demographics and increasing longevity, and changes in laws and regulations may require us to make significant contributions to the plans. Large funding requirements or significant increases in expenses could adversely impact our business, results of operations, financial condition and cash flows.

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

The natural gas business benefits from price volatility and temporal price spreads. Variation in price spreads can impact the level of demand and the rates that can be charged for natural gas storage services. If natural gas prices and volatility remain low, or prices decline further, then the natural gas business could generate less revenue and lower demand for natural gas storage services. A sustained decline in these prices and volatility could have an adverse impact on gas business, results of operation, financial condition and cash flows.

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

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

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

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

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

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

Our cash balances and 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 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.

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 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 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 our common stock to fluctuate substantially, which may negatively affect the price and liquidity of our common stock. These fluctuations could cause you to lose all or part of your investment in 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 these analysts cease coverage of us or fail to publish reports on us regularly, demand for our common stock could decrease, which might cause our stock price and trading volume to decline.

Iberdrola, S.A. will exercise significant influence over us, and its interests in us 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, S.A. owns approximately 81.5% 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, S.A. 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, S.A. may conflict with the interests of our other shareholders. For example, Iberdrola, S.A. 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, S.A. This significant

concentration of share ownership may adversely affect the trading price for 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, S.A. or the perception that sales may be made by it could significantly reduce the market price of our common stock. We and Iberdrola, S.A. are parties to a shareholder agreement pursuant to which Iberdrola, S.A. will be generally restricted from transferring shares of our common stock, subject to certain exceptions. Iberdrola, S.A. 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, S.A. In addition, even if Iberdrola, S.A. does not sell a large number 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, S.A. 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, S.A. will also retain preemptive rights to protect against dilution in connection with issuances of equity by us. If Iberdrola, S.A. 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 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 nominating and corporate governance committee or a compensation committee, or to have such committees be composed entirely of independent directors; and
- the compensation of the chief executive officer be determined, or recommended to the board of directors for determination, either by a compensation committee comprised of independent directors or by a majority of the independent directors on the board of directors.

In light of our status as a controlled company, we currently rely on these exemptions. Accordingly, 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 common stock less attractive to some investors or otherwise harm our stock price.

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

Although we currently anticipate paying a regular quarterly dividend, any such determination to pay dividends is at the discretion of our board of directors and dependent on conditions such as our financial condition, earnings, legal requirements, including limitations under New York law, restrictions in our debt agreements that limit our ability to pay dividends to shareholders and other factors the board of directors deem relevant. Our board of directors may, in its sole discretion, change the amount or frequency of dividends or discontinue the payment of dividends entirely. For these reasons, 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 our annual report on Form 10-K for the fiscal year ending December 31, 2016, Section 404 of SOX will require 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 that 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, 2015:

Location	Type of Facility	Lease/Owned	Size (square feet)
New Haven, Connecticut	Office	Leased	51,300
Orange, Connecticut	Office	Owned	426,294
Augusta, Maine	Office	Leased	220,400
New Gloucester, Maine	Office	Leased	60,913
Rochester, New York	Office	Owned	122,493
Portland, Oregon	Office	Leased	57,027
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. 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 Corp., or FirstEnergy, under the Comprehensive Environmental Response, Compensation, and Liability Act to recover environmental cleanup costs at nineteen former manufactured gas sites. In July 2011, the District Court issued a decision and order in NYSEG’s favor. Based on past and future cleanup costs at the nineteen 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 Energy 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. 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.

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 and OneBeacon have answered the complaints admitting issuance of the policies and receipt of notice of the claims, but asserting a number of legal defenses. The legal discovery process is expected to close in 2016. We cannot predict the outcome of this matter.

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 includes two counts: (a) that the UIL directors breached their fiduciary duties by failing to engage in an appropriate process and failing to get a fair price; and (b) we aided and abetted that breach by rendering "substantial assistance" to the UIL directors. Subsequently, four other similar complaints were filed in Connecticut. The cases have been consolidated and transferred to the complex litigation court and the time to respond to the complaint has been extended by mutual agreement.

On October 2, 2015, the plaintiffs filed a consolidated amended complaint in the Superior Court for the Judicial District of Stamford/Norwalk, Complex Litigation Docket. The consolidated amended 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. Under the terms of the MOU, the defendants allowed the plaintiffs to conduct some additional confirmatory discovery, which was completed in February 2016, and agreed to negotiate in good faith in an effort to agree upon reasonable plaintiffs' counsel fees, but in any event to pay the plaintiffs' counsel fees as determined by the court. The plaintiffs agreed to petition the court to (1) certify the shareholder class, (2) approve the terms of the settlement, (3) decide the amount of attorneys' fees to be awarded to plaintiffs' counsel, and (4) dismiss the consolidated action.

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.

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 expected to rule on the summary judgment motions in early 2016. No trial date has been set. We cannot predict the ultimate outcome of this matter.

California Energy Crisis Litigation

Public Utilities Commission of the State of California v. Sellers of Long Term Contracts to the California Department of Water Resources (Federal Energy Regulatory Commission, Docket Nos. EL02-60-000 and EL02-62-000)

Two California agencies brought a complaint 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. The parties have filed pleadings in the remand proceedings to determine the procedural framework for proceeding with the remanded cases, including whether additional discovery and/or evidentiary hearings will be required. 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 is expected in April 2016. We cannot predict the outcome of this proceeding.

Yankee Nuclear Spent Fuel Disposal Claim

CMP and UI are stockholders in Connecticut Yankee Atomic Power Company and CMP is a stockholder in Maine Yankee Atomic Power Company and Yankee Atomic Energy Corporation, (collectively, the Yankee Companies). The Yankee Companies have completed the physical decommissioning of their respective generation facilities and are now engaged in the long-term storage of their spent nuclear fuel. Beginning in 1998 and every 6 years, in accordance with the relevant statute of limitations, the Yankee Companies file a lawsuit to recover damages from the DOE for breach of the Nuclear Spent Fuel Disposal Contract to remove Spent Nuclear Fuel, or SNF, 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 6 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 and UI's share was approximately \$3.8 million. The Federal Appeals Court affirmed the September 2010 U.S. Court of Federal Claims award of \$40.3 million to Connecticut Yankee Atomic Power Company; affirmed the Court of Federal Claims award of \$65 million to Maine Yankee Atomic Power Company; and increased Yankee Atomic Electric Company's damages award from \$21.4 million to \$37.8 million. The Phase I damage award became final on December 4, 2012. The Yankee Companies received payment from DOE in January 2013.

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 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). The damage awards flow through the Yankee Companies to shareholders to reduce retail customer charges. In January 2014 the DOE informed the Yankee Companies it would not appeal the Trial Court decision, as a result the Yankee Companies received full payment in April 2014.

In August 2013, the Yankee Companies filed a third round of claims against the DOE seeking damages for the years 2009-2014 (Phase III). The Phase III trial was completed in July 2015 and the Court 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 based on percentage ownership. We cannot predict the timing or amount of damage awards that may ultimately flow through to shareholders.

English Station

In January 2012, Evergreen Power, LLC and Asnat Realty LLC, 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. 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. These proceedings have been stayed pending the disposition of the proposed partial consent order described below.

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 of 2015. These proceedings have been stayed pending the disposition of the proposed partial consent order described below.

On September 16, 2015, in connection with the merger of UIL and AVANGRID, UI signed a proposed partial consent order that, when issued by the Commissioner of DEEP and subject to the terms and conditions in the proposed partial consent order, would require UI to investigate and remediate certain environmental conditions within the perimeter of the English Station site. Under the proposed partial 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. Pursuant to the proposed partial consent order, upon its issuance and subject to its terms and conditions, UI would be obligated to comply with the proposed partial 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. On September 30, 2015, the hearing officer in DEEP's administrative proceeding approved a motion for stay of further proceedings filed by DEEP, staying all proceedings on the administrative order for 120 days, subsequently extended by DEEP until a status conference scheduled for May 11, 2016.

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 Note 13 of our audited combined and consolidated financial statements for the three years ended December 31, 2015, which are incorporated herein by reference.

Item 4. *Mine Safety Disclosures.*

Not Applicable.

Executive Officers of AVANGRID

The names and ages of all executive officers of AVANGRID as of April 1, 2016 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	63	Chief Executive Officer
Richard J. Nicholas	60	Senior Vice President – Chief Financial Officer
Daniel Alcain	42	Senior Vice President – Controller
Frank Burkhartsmeier	51	Chief Executive Officer of Renewables
Sara J. Burns	60	President and Chief Executive Officer of CMP
Sheila Duncan	51	Senior Vice President – Human Resources & Corporate Administration
Ignacio Estella	46	Senior Vice President – Corporate Development
Daryl W. Gee	52	Chief Executive Officer of Gas
Robert D. Kump	54	President and Chief Executive Officer of Networks
Mark S. Lynch	62	President and Chief Executive Officer of NYSEG and RGE
R. Scott Mahoney	50	Senior Vice President – General Counsel and Chief Compliance Officer; Secretary
John J. Prete	58	President and Chief Executive Officer of UIL

(*) Age as of December 31, 2015.

James P. Torgerson. Mr. Torgerson was appointed Chief Executive Officer of AVANGRID on December 16, 2015 upon completion 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 Catholic Cemetery Association, Archdiocese of Hartford and a member of the Fairfield Business Council. 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 completion 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 Berkshire, CNG and SCG, all of which are subsidiaries of AVANGRID. Mr. Nicholas earned his undergraduate degree 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 Burkhartsmeier. Mr. Burkhartsmeier was appointed Chief Executive Officer of Renewables in April 2015. Mr. Burkhartsmeier 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. Burkhartsmeier 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. Ms. Duncan currently serves on the Board of the Scottish Huntington's Association. She holds a Master of Arts (Hons) from the University of Glasgow and is a Chartered Fellow of the Institute of Personnel & Development in the UK.

Ignacio Estella. Mr. Estella was appointed Senior Vice President – Corporate Development of AVANGRID on December 17, 2015. Previously, Mr. Estella served as Corporate Vice President of Business Origination of Iberdrola, S.A 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, S.A. 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 was appointed as AVANGRID's Chief Corporate Officer in January 2014. Mr. Kump also has served as a Director of AVANGRID's subsidiaries CMP, NYSEG, and RGE 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, Contoller 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 RGE in January 2010 and Chief Executive Officer in January, 2014. Mr. Lynch has served as President of NYSEG and RGE since 2009, both subsidiaries of AVANGRID. Mr. Lynch also served as President and CEO 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 is currently 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.

John J. Prete. Mr. Prete was appointed President and Chief Executive Officer of UIL on December 17, 2015. Mr. Prete previously served as Senior Vice President Electric Operations of UIL since May 2013 and currently serves as Senior Vice President and Chief Operating Officer of UI, a subsidiary of AVANGRID. Previously, Mr. Prete served as Vice President of Technical Services of UIL and Senior Vice President – Electric Transmission and Distribution of UI, from November 16, 2010 through May 2013, and Vice President – Transmission Business of UI from October 1, 2007 through November 2010. Mr. Prete holds a Bachelor's Degree from the University of Bridgeport and an Associate's Degree from the University of New Haven.

PART II

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

Market Information and Holders

Our common stock started 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 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.

Year Ended December 31, 2015	High	Low
Fourth quarter (beginning December 17, 2015)	\$ 38.90	\$ 32.45

As of March 28, 2016, there were 3,210 shareholders of record.

Dividends

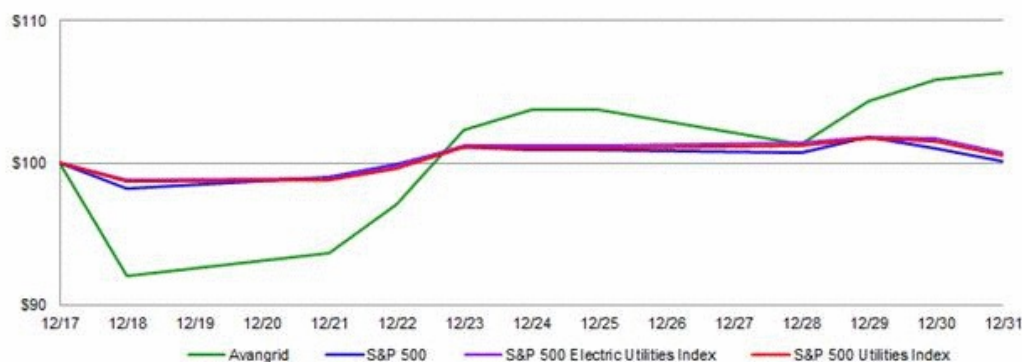
AVANGRID expects to follow policy of paying quarterly cash dividends, although there is no assurance as to the amount of future dividends which depends on future earnings, capital requirements, and financial condition.

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 Form 10-K.

Performance Graph

The line graph appearing below compares the change in AVANGRID's total shareholder return on its 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, 2015.

Stock Price Performance
December 17, 2015 – December 31, 2015



	December 17, 2015		December 31, 2015	
AVANGRID	\$	100	\$	106.30
S&P 500	\$	100	\$	100.70
S&P Electric Utilities Index	\$	100	\$	100.50
S&P Utilities Index	\$	100	\$	100.10

The above information assumes that the value of the investment in AVANGRID's common stock and each index was \$100 on December 17, 2015. No dividends were reinvested 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

None.

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

During the year ended December 31, 2015, we identified a correction necessary to certain depreciation and amortization expenses that were recorded in prior periods. For further details, refer to Note 2 in our combined and consolidated financial statements included in this Annual Report on Form 10-K. Accordingly, we have reflected the correction of these prior period amounts in the periods in which they originated and the following tables include our revised selected historical combined and consolidated statements of operations and balance sheet data for the years ended December 31, 2013 and 2012 and as of December 31, 2014 and 2013, respectively.

Consolidated and Combined Statements of Operations Data: *	Year Ended December 31, (millions, except per share data)				
	2015	2014	2013	2012	2011
Operating Revenues	\$ 4,367	\$ 4,594	\$ 4,313	\$ 4,055	\$ 4,761
Operating Income From Continuing Operations	513	885	179	262	72
Income (Loss) Before Income Tax	301	706	(15)	60	(257)
Income tax expense (benefit)	34	282	35	(117)	(213)
Net Income (Loss) From Continuing Operations	267	424	(50)	177	(44)
Net Income From Discontinued Operations	—	—	—	74	4
Net Income (Loss)	267	424	(50)	251	(40)
Less: Net income attributable to noncontrolling interests	—	—	1	1	2
Net Income (Loss) Attributable to AVANGRID, Inc.	267	424	(51)	250	(42)
Earnings (Loss) Per Common Share,					
Basic and Diluted:					
Earnings (loss) from continuing operations per common share, basic and diluted	1.05	1.68	(0.20)	0.69	(0.18)
Earnings (loss) from discontinued operations per common share, basic and diluted	—	—	—	0.30	0.02
Total Earnings (Loss) Per Common Share, Basic and Diluted	\$ 1.05	\$ 1.68	\$ (0.20)	\$ 0.99	\$ (0.16)
Weighted-average Number of Common Shares Outstanding:					
Basic	254,588,212	252,235,232	252,235,232	252,235,232	252,235,232
Diluted	254,605,111	252,235,232	252,235,232	252,235,232	252,235,232

Consolidated and Combined Balance Sheet Data:*	(millions)				
	2015	2014	2013	2012	2011
As of December 31,					
(Millions)					
Total Property, Plant and Equipment	20,711	17,133	16,715	16,643	16,618
Total Other Assets	3,795	2,075	2,137	2,376	2,401
Total Assets	\$ 30,743	\$ 24,162	\$ 23,170	\$ 23,671	\$ 23,915

As of December 31, (Millions)	2015	2014	(millions) 2013	2012	2011
Liabilities					
Current portion of debt	\$ 206	\$ 148	\$ 25	\$ 354	\$ 157
Non-current debt	4,530	2,489	2,669	2,780	2,876
Total Liabilities	15,677	11,685	11,119	12,323	12,809
Total Stockholder's Equity	15,053	12,461	12,036	11,334	11,079
Total Equity	\$ 15,066	\$ 12,477	\$ 12,051	\$ 11,348	\$ 11,106

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

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

You should read the following discussion of our financial condition and results of operations in conjunction with the consolidated financial statements and the notes thereto included elsewhere in this Annual Report on Form 10-K. In addition to historical consolidated financial information, the following discussion contains forward-looking statements that reflect our plans, estimates, and beliefs. Our actual results could differ materially from those discussed in the forward-looking statements. Factors that could cause or contribute to these differences include those discussed below and elsewhere in this Annual Report on Form 10-K, particularly in Part I, Item 1A, "Risk Factors."

We are a direct, majority owned subsidiary of Iberdrola, S.A., a corporation (*sociedad anónima*) organized under the laws of Spain, one of the world's leading energy companies. Our direct, wholly-owned subsidiaries include Networks, ARHI, and UIL. ARHI in turn holds subsidiaries including Renewables, and Gas. Networks, along with UIL, owns and operates our regulated utility businesses through its subsidiaries, including electric transmission and distribution and natural gas distribution, transportation and sales. Avangrid Service Company, a subsidiary of Networks, provides corporate and back office services on a consolidated basis to our subsidiaries. We anticipate UIL and its subsidiaries will be moved under Networks in the first half of 2016. 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. 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, S.A. through a stock dividend accounted for as a stock split, with no change to par value and, at par value of \$0.01 per share. UIL shareowners received an aggregate of 57,255,850 shares (including those held in trust as treasury stock) and an aggregate payment of \$595 million in cash. Immediately following the completion of the acquisition, former UIL shareowners owned 18.5% of the outstanding shares of common stock of AVANGRID, and Iberdrola, S.A. owned the remaining shares. 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 be recognized at their fair values as of the acquisition date. The goodwill generated from the acquisition amounted to \$1,754 million. The results of operations of UIL since the acquisition date have been included in the 2015 consolidated results of AVANGRID. Further information regarding the accounting for the acquisition is provided in Note 4 of our audited combined and consolidated financial statements for the three years ended December 31, 2015, which are incorporated herein by reference. For purposes of this Item 7, all references to "Networks" include UIL and its subsidiaries, unless otherwise indicated.

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 984,000 natural gas public utility customers as of December 31, 2015.

Networks, a Maine corporation, along with UIL, a Connecticut corporation, hold 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 or through UIL:

- NYSEG: serves electric and natural gas customers across more than 40% of the upstate New York geographic area;
- RGE: serves electric and natural gas customers within a nine-county region in western New York, centered around Rochester;
- UI: serves electric customers in southwestern Connecticut;

- CMP: serves electric customers in central and southern Maine;
- SCG: serves natural gas customers in Connecticut;
- CNG: serves natural gas customers in Connecticut; and
- Berkshire: serves natural gas customers in western Massachusetts
- MNG: 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 6,330 megawatts, or MW, as of December 31, 2015, including Renewables' share of joint projects, of which 5,643 MW was installed wind capacity. Approximately 67% of the capacity was contracted for an average period of 9.7 years as of December 31, 2015. As the second largest wind operator in the United States based on installed capacity as of December 31, 2015, Renewables strives to lead the transformation of the U.S. energy industry to a competitive, clean energy future. Renewables currently operates 53 wind farms in 18 states across the United States.

Through Gas, as of December 31, 2015 we own approximately 67.5 Bcf, of net working gas storage capacity. Gas operates 53.25 Bcf of contracted or managed natural gas storage capacity in North America through Enstor Energy Services, LLC, as of December 31, 2015.

Our operating revenues decreased by 5%, from \$4.6 billion for the year ended December 31, 2014 to \$4.4 billion for the year ended December 31, 2015.

The decrease in operating revenues was primarily due to a 10% decrease in revenues at Renewables primarily as a result of a reduction in output from our renewable generation facilities, unfavorable results from power trading activities and reduced trading opportunities created by lower price volatility in the northwest markets, decreased revenues in Gas of 123% due to unfavorable changes on mark-to-market, or MtM, derivatives, partially offset by a slight increase in Networks' revenues.

Net income decrease primarily related to a 20% increase in operations and maintenance at Networks as a result of higher expenses for labor, bad debt expense, and transmission system reliability support expenses, and a 10% decrease in revenues at Renewables primarily as a result of a reduction in output from our renewable generation facilities combined with unfavorable results from power trading activities and 123% decrease in revenues in Gas due to adverse market price volatility on derivatives, partially offset by a 22% decrease in purchased power, natural gas and fuel used for Networks as a result of lower gas sales volumes and rates in 2015 compared to 2014 and a slight increase in Networks' revenues.

Adjusted earnings before interest, tax, depreciation and amortization, or adjusted EBITDA, decreased by 21% from \$1.5 billion for the year ended December 31, 2014 to \$1.2 billion for the year ended December 31, 2015 primarily as a result of a 26% decrease in adjusted EBITDA at Renewables as a result of a reduction in output from our renewable generation facilities combined with unfavorable results from power trading activities, a 263% decrease in adjusted EBITDA in Gas due to unfavorable changes on MtM derivatives and a 3% decrease in adjusted EBITDA at Networks as a result of an increase in operations and maintenance and lower sales volumes and rates in 2015 compared to 2014.

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.

Immaterial Corrections to Prior Periods

During the year ended December 31, 2015, we identified a correction necessary to certain depreciation and amortization expenses that were recorded in prior periods. For further details, refer to Note 2 in our combined and consolidated financial statements included in this Annual Report on Form 10-K. Accordingly, we have reflected the correction of these prior period amounts in the periods in which they originated. “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” of this Form 10-K is based on the revised financial results for the year ended December 31, 2013.

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

Pursuant to Maine law, CMP earns revenue for the delivery of energy to its retail customers, but is prohibited from selling power to them. CMP generally does not enter into purchase or sales arrangements for power with ISO-NE, the New England Power Pool, or any other ISO or similar entity. CMP generally sells all of its power entitlements under its nonutility generator and other PPAs to unrelated third parties under bilateral contracts. If the MPUC does not approve the terms of bilateral contracts, it can direct CMP to sell power entitlements that it receives from those contracts on the spot market through ISO-NE. NYSEG and RGE 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 2016, 80% of its standard service load for the second half of 2016 and for 30% of its standard service load for the first half of 2017. 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."

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 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 RGE'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, RGE 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.

Pursuant to agreements with, or decisions of the NYPSC and, the MPUC, Networks' Maine and New York regulated utilities are each subject to a minimum equity ratio requirement that is tied to the capital structure assumed in establishing revenue requirements. Pursuant to these requirements, each of NYSEG, RGE, 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 RGE, 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, RGE, AVANGRID or Iberdrola, S.A. 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 September 17, 2009, NYSEG and RGE initiated a distribution rate case to allow the companies to recover past and future investments, provide safe and adequate service, and improve their credit ratings. On February 19, 2016, the NYSEG, RGE 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 RGE commencing May 1, 2016. The proposal balances 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 enhanced electric vegetation management to provide continued safe and reliable service. The delivery rate increase in the proposal can be summarized as follows:

Utility	May 1, 2016		May 1, 2017		May 1, 2018	
	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%
RGE Electric	3.0	0.70%	21.6	5.00%	25.9	5.70%
RGE 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, RGE Electric and RGE 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 earnings levels, with customers receiving 50%, 75% and 90% of earnings over 9.5%, 10.0% and 10.5% of ROE, respectively, in the first year. Earnings thresholds would increase in subsequent 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 RGE 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 administrative law judges assigned to the New York rate case will issue a procedural schedule establishing the remaining procedure for review and decision on the proposal. We expect hearings on the proposal to be held in April 2016 and a NYPSC decision to be made in May 2016.

On August 25, 2014, the MPUC approved a stipulation agreement for a CMP rate change which provided for a distribution rate increase of approximately \$24.3 million effective July 1, 2014 with an allowed ROE of 9.45% and an allowed equity ratio of 50%. On December 22, 2009, MPUC approved a stipulation which provided for a rate increase to MNG's base distribution rates for a three year period, with a 12% increase effective January 1, 2010, a 10% increase effective December 1, 2010 and another 10% increase effective December 1, 2011.

On March 5, 2015, MNG filed a rate case in order to further recover future investments and provide safe and adequate service. MNG requested a 10.0% ROE and 50% equity ratio. The MPUC Staff has recommended a separate revenue requirement for MNG's Augusta customers and MNG's non-Augusta customers. Staff has recommended a \$19.95 million disallowance of the Augusta Expansion investment based upon the Staff's conclusion that MNG's management of the Augusta Expansion Project was imprudent. On November 6, 2015, a stipulation was filed with the MPUC, which was executed by MNG, the Office of Public Advocate and the City of Augusta. The stipulation contained a combined revenue requirement for Augusta and Non-Augusta based on a 9.55% ROE and 50% equity ratio. The stipulation also provided for an initial Augusta investment disallowance of \$6 million and an investment phase-in of \$10 million. On December 22, 2015, MPUC rejected the proposed Stipulation as not in the public interest. In January 2016, the administrative law judge established a new litigation schedule. The litigation was suspended at the end of January 2016 for settlement discussions. We cannot predict the outcome of the proceeding. We reserved \$6 million for this case at the end of 2015.

In August 2013, PURA approved distribution rate schedules for UI for two years that became effective at that time and which, among other things, increased the UI distribution allowed ROE from 8.75% to 9.15%, continued UI's existing earnings sharing mechanism, continued the existing decoupling mechanism, and approved the establishment of the requested storm reserve. In accordance with the approval by PURA of the acquisition, UI agreed not to file a rate case for new rates effective before January 1, 2017.

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.

Berkshire's rates are established by the DPU. Berkshire's 10-year rate plan, which was approved by the DPU and included an approved ROE of 10.5%, expired on January 31, 2012. Berkshire 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, Berkshire 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 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. 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 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. 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 15 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 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 is the administrative law judge's recommendation to the FERC Commissioners. The

FERC is expected to make its final decision in late 2016 or 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 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. 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. FERC also found that the current RNS and 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.

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 have been 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.

In connection with the acquisition proceeding, UI signed a proposed partial consent order, or the consent order that, when approved by the Commissioner of DEEP, and pursuant to the terms and conditions in the consent order, would require 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, upon its issuance and subject to its terms and conditions, UI would be 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.

The following commitments have been made in Massachusetts:

- Customers of Berkshire 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.
- Berkshire will contribute \$1 million to alternative heating programs.
- Berkshire 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

The DEEP, Eversource Energy, National Grid and Unitil 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 Rhode Island. The RFP was issued in November 2015, and bids were received on January 28, 2016. AVANGRID companies have offered two transmission projects and three wind projects as components of various joint bids with other parties. The bids are currently under review by an evaluation team that is expected to select winning bids by the end of July 2016. 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.

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. The NYPSC staff Whitepaper for Track 2 was issued in the third quarter of 2015. New York utilities will also be addressing related regulatory issues in their individual rate cases. We expect an Order by the end of the second quarter of 2016.

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.

On July 11, 2014, GNPP filed a petition requesting that the NYPSC initiate a proceeding to examine a proposal for the continued operation of the Ginna Facility. Ginna asserted that "in the two preceding calendar years, 2012 and 2013, it had sustained cumulative losses at the Facility of nearly \$100 million (including the allocation of CENG corporate overhead)" and that "CENG has not been compensated for any operational risk or an appropriate return on its investment over this period." Based on the results of the 2014 Reliability Study, GNPP requested that: 1) the NYPSC determine that the continued operation of the Ginna Facility is required to preserve system reliability; and 2) the NYPSC issue an Order directing RGE to negotiate and file a Reliability Support Services Agreement, or RSSA, 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 an RSSA." As such, the NYPSC ordered RGE and GNPP to negotiate an RSSA.

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

On October 21, 2015, RGE, 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. RGE shall make monthly payments to Ginna in the amount of \$15.4 million. RGE 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 RGE to implement a rate surcharge effective January 1, 2016 to recover amounts paid to Ginna pursuant to the RSSA. RGE's payment obligation to Ginna shall not begin until the rate surcharge is in effect and FERC has issued an order authorizing the FERC Settlement agreement in the Settlement Docket. RGE 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 RGE to Ginna then the RSSA surcharge may continue past March 31, 2017 to recover up to \$2.3 million per month until the final payment has been recovered by RGE from ratepayers. In the month following the expiration of the term on March 31, 2017, Ginna shall prepare and issue an invoice to RGE for, and RGE 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. 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.

New York Transco

Networks holds an approximately 20% ownership interest in the New York Transco. The 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 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 FERC, including the base ROE, the ROE incentives, and the cost allocation. The 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, the New York Transco's owners' request for a 50 basis point adder for NY 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 the 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, 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.

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 Berkshire, 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 9.15%) plus 25 basis points and (B) the current authorized distribution ROE for CL&P, (currently 9.17%), less target equivalent market revenues (reflected as 25 basis points). In addition, UI will retain a percentage of the market revenues from the project, which percentage is expected to equate to approximately 25 basis points on a levelized basis over the life of the 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.

Under Maine law 35-A M.R.S.A §§ 3210-C, 3210-D, the MPUC is authorized to conduct periodic requests for proposals seeking long-term supplies of energy, capacity or RECs, from qualifying resources. The MPUC is further authorized to order Maine Transmission and Distribution Utilities to enter into contracts with sellers selected from the MPUC's competitive solicitation process. Pursuant to a MPUC Order dated October 8, 2009, CMP entered into a 20-year agreement with Evergreen Wind Power III, LLC, on March 31, 2010, to purchase capacity and energy from Evergreen's 60 MW Rollins wind farm in Penobscot County, Maine. CMP's purchase obligations under the Rollins contract are approximately \$7 million per year. In accordance with subsequent MPUC orders, CMP periodically auctions the purchased Rollins energy to wholesale buyers in the New England regional market. Under applicable law, CMP is assured recovery of any differences between power purchase costs and achieved market revenues through a reconcilable component of its retail distribution rates. Although the MPUC has conducted multiple requests for proposals under M.R.S.A §3210-C and has tentatively accepted long-term proposals from other sellers, these selections have not yet resulted in additional currently effective contracts with CMP.

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 includes provisions extending 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, previously issued 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. The IRS has not updated its guidance for the December 2015 extension. Multi-year extension of these credits is likely to provide opportunities for Renewables to develop, construct, and market new renewable generating facilities in several US markets.

Additionally, the federal government and many states and local jurisdictions have policies or other mechanisms, such as tax incentives or RPS that support the sale of energy from utility-scale renewable energy facilities, such as wind and solar energy facilities. As a result of budgetary constraints, political factors or otherwise, U.S., state or local governments from time to time may review their policies and other mechanisms that support renewable energy and consider actions that would make them less conducive to the development and operation of renewable energy facilities. Any reductions to, or the elimination of, governmental policies or other mechanisms that support renewable energy or the imposition of additional taxes or other assessments on renewable energy, could result in, among other items, the lack of a satisfactory market for the development of new renewable energy projects, Renewables abandoning the development of new renewable energy projects, a loss of Renewables' investments in the projects and

reduced project returns, any of which could have a material adverse effect on Renewables' business, financial condition, results of operations and prospects.

Renewable Energy Demand

Since the transmission and distribution of electricity is highly concentrated in most jurisdictions, there are a limited number of possible purchasers for utility-scale quantities of electricity in a given geographic location, including transmission grid operators, state and investor-owned power companies, public utility districts and cooperatives. 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. In 2015 we began designating those derivatives contracts at Renewables that qualify as hedges. This designation was made prospectively, and in accordance with all the requirements of hedge accounting.

Wind Conditions

If wind conditions are unfavorable, or if Renewables' wind turbines are not available for operation, Renewables projects' electricity generation and related revenue may be substantially below our expectations. Renewables' wind projects are sited, developed and operated to maximize wind performance. Prior to siting a wind facility, detailed studies are conducted to measure the wind resource in order to estimate future production. However, wind patterns or wind resource in the future might deviate from historical patterns. These events could also degrade equipment or components and the interconnection and transmission facilities' lives or maintenance costs. Historically, Renewables wind production is greater in the first, second and fourth quarters.

Wind Turbine Supply

Replacement and spare parts for wind turbines and key pieces of electrical equipment may be difficult or costly to acquire or may be unavailable. Although Renewables has expanded and diversified its supplier base, the loss of any of these suppliers or service providers or inability to find replacement suppliers or service providers or to purchase turbines at rates currently offered by Renewables' existing suppliers or a change in the terms of Renewables' supply or operations and maintenance agreements, such as increased prices for maintenance services or for spare parts, could have a material adverse effect on Renewables' ability to construct and maintain wind farms or the profitability of wind farm development and operation.

Gas

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

Results of Operations

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, (millions)					
	2015	%	2014	%	2013	%
Operating Revenues	\$ 4,367	100 %	\$ 4,594	100 %	\$ 4,313	100 %
Operating Expenses						
Purchased power, natural gas and fuel used	972	22	1,181	26	1,088	25
Operations and maintenance	1,808	42	1,560	34	1,541	36
Impairment of noncurrent assets	12	—	25	1	620	15
Depreciation and amortization	695	16	629	14	594	14
Taxes other than income taxes	367	8	314	7	291	7
Total Operating Expenses	3,854	88	3,709	81	4,134	96
Operating income	513	12	885	19	179	4
Other Income and (Expense)						
Other income and (expense)	55	1	52	1	54	1
Earnings (losses) from equity method investments	—	—	12	—	(3)	—
Interest expense, net of capitalization	(267)	(6)	(243)	(5)	(245)	(5)
Income Before Income Tax	301	7	706	15	(15)	—
Income tax expense (benefit)	34	1	282	6	35	1
Net Income (Loss)	267	6	424	9	(50)	(1)
Less: Net income attributable to noncontrolling interests	—	—	—	—	1	—
Net Income	\$ 267	6 %	\$ 424	9 %	\$ (51)	(1) %

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, 2015

	Total	Networks	Renewables	Gas	Other(1)
	(in millions)				
Operating revenues	\$ 4,367	\$ 3,386	\$ 1,067	\$ (19)	\$ (67)
Operating revenues %		78 %	24 %	—	(2) %
Operating expenses	\$ 3,854	\$ 2,849	\$ 967	\$ 66	\$ (28)
Operating expenses %		74 %	25 %	2 %	(1) %

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) %

Year Ended December 31, 2013

	Total	Networks	Renewables (in millions)	Gas	Other(1)
Operating revenues	\$ 4,313	\$ 3,319	\$ 1,097	\$ (27)	\$ (76)
Operating revenues %		77%	25%	—	(2)%
Operating expenses	\$ 4,134	\$ 2,616	\$ 975	\$ 620	\$ (77)
Operating expenses %		63%	24%	15%	(2)%

(1) Other amounts represent corporate and company eliminations.

Comparison of Period to Period Results of Operations

Our operating revenues decreased by 5%, from \$4.6 billion for the year ended December 31, 2014 to \$4.4 billion for the year ended December 31, 2015.

Our purchased power, natural gas and fuel used decreased by 18% from \$1.2 billion for the year ended December 31, 2014 to \$ 972 million for the year ended December 31, 2015.

Our operations and maintenance increased by 15% from \$1.6 billion for the year ended December 31, 2014 to \$1.8 billion for the year ended December 31, 2015.

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

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 in 2014 for the Yankee DOE phase 2 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 by \$122 million or 10% from approximately \$1.2 billion for the year ended December 31, 2014 to approximately \$1.1 billion. 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.

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 \$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 in changes relating to change in value of derivatives, with unrealized losses in 2015 compared to unrealized gains in 2014.

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

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. For additional information, please see Note 21 to our audited combined and consolidated financial statements for the year ended December 31, 2015 included in this Form 10-K.

Interest Expense, Net of Capitalization

Interest expense for the year ended December 31, 2015 increased \$24 million or 10% from \$243 million for the year ended December 31, 2014 to \$267 million. Networks expense increased \$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 (Benefit)

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%.

Year Ended December 31, 2014 Compared to the Year Ended December 31, 2013

Networks

Operating revenues for the year ended December 31, 2014 increased by \$78 million or 2% from \$3.3 billion for the year ended December 31, 2013 to \$3.4 billion. The increase in operating revenues was primarily related to increased volume of transmission of \$51 million and increased rates of \$65 million. Additionally, revenues increased by \$12 million associated with increased transmission sales related to growth in CMP. These increases were offset by decreases in the amount of \$37 million revenues associated with regulatory adjustments and New York rate decreases of \$12 million.

Purchased power, natural gas and fuel used for the year ended December 31, 2014 increased by \$99 million, or 10%, from \$1 billion for the year ended December 31, 2013 to \$1.1 billion. The increase in purchased power, natural gas and fuel used was due to the \$60 million increase in electric retail prices, as well as higher wholesale prices of \$5 million. Additionally, gas purchase expenses increased due to an increase in volume purchased of \$26 million and higher fuel prices in the amount of \$9 million.

Operations and maintenance during the year ended December 31, 2014 increased by \$47 million or 4% from approximately \$1.1 billion for the year ended December 31, 2013 to approximately \$1.0 billion. Operations and maintenance increased due to higher spending associated with weather, including storm-related expenses of \$15 million, uncollected debt of \$5 million, increased labor-related expenses (net of capitalization) of \$14 million, and \$15 million in revenue related to regulatory adjustments.

Renewables

Operating revenues for the year ended December 31, 2014 increased by \$92 million or 8% from \$1.1 billion for the year ended December 31, 2013 to \$1.2 billion. The increase was due to higher results from existing wind assets with output sold under long term contracts reflecting stronger wind resource of \$4 million, increased prices realized in the market on existing merchant wind assets of \$7 million, collection from customers and control area operators for curtailments and pass-through of transmission charges of \$5 million, favorable results from power trading activities due to significant price volatility in the northwest markets due to cold weather and abundant hydro conditions of \$15 million. Additionally, transmission revenue increased by \$2 million. The remaining increase of \$44 million is largely attributable to unrealized gains from changes in fair value of energy derivative transactions entered into for economic hedging purposes.

Purchased power, natural gas and fuel used for the year ended December 31, 2014 decreased by \$1 million, from \$194 million for the year ended December 31, 2013 to \$193 million. The decrease in purchased power was due to the reduction in generated power transmission of \$1 million.

Operations and maintenance for the year ended December 31, 2014 decreased by \$15 million or 4% from \$351 million for the year ended December 31, 2013 to \$336 million for the year ended December 31, 2014, primarily as a result of reductions in labor-related expenses of \$5 million, lower turbine maintenance fees of \$4 million, and decreases in indirect expenses of \$5 million.

Gas

Operating revenues for the year ended December 31, 2014 increased by \$111 million from negative revenues of \$27 million for the year ended December 31, 2013 to positive revenues of \$84 million. The increase in operating revenues was due to \$125 million unrealized gain driven by changes in MtM from a gain in value on storage and transport hedges due to average price decreases in 2014 compared to a loss in value due to average price increases in 2013.

Purchased power, natural gas and fuel used for the year ended December 31, 2014 decreased by \$3 million, or 75%, from \$4 million for the year ended December 31, 2013 to \$1 million. The decrease in purchased power, natural gas and fuel used was due to the decreased usage of gas in operation of storage facilities in the amount of \$3 million.

Operations and maintenance for the year ended December 31, 2014 remained consistent over the periods at \$40 million.

Depreciation, Amortization and Impairment of Non-Current Assets

Depreciation, amortization and impairment expenses for the years ended December 31, 2014 and December 31, 2013 were \$654 million and \$1.2 billion, respectively. The decrease of \$560 million was driven by a 2013 provision, relating mainly to natural gas storage facilities of \$382 million and impairment of goodwill of the Gas business of \$163 million in view of the potential long term low margins for natural gas, given the impact of shale gas on the North American energy market. Additionally, Renewables had year-over-year impairment decreases of \$51 million. This was offset by an increase in depreciation expense at Networks of \$18 million associated with increased transmission assets in Maine and increased base assets in New York.

Other Income and (Expense) and Equity Earnings

Other income and (expense) and equity earnings for the year ended December 31, 2014 increased by \$13 million from \$51 million other income for the year ended December 31, 2013 to \$64 million for the year ended December 31, 2014. The increase in other income is associated with higher equity earnings of which \$9 million is attributable to joint ventures of Renewables in the Flat Rock and Colorado Green projects.

Interest Expense, Net of Capitalization

Interest expense for the year ended December 31, 2014 and December 31, 2013 were \$243 million and \$245 million, respectively. The decrease of \$2 million or less than 1% shows the expenses were consistent over these periods driven primarily by Networks' debt costs.

Income Tax Expense (Benefit)

Income tax expense from continuing operations 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%. Income tax expense from continuing operations for the year ended December 31, 2013 was \$40 million higher than it would have been at the statutory federal income tax rate of 35% due predominately to the book impairment of non-deductible goodwill. This resulted in an effective tax rate of 233%.

Non-GAAP Financial Measures

We supplement the use of U.S. GAAP financial measures in this document with non-GAAP financial measures, including adjusted gross margin and adjusted EBITDA. We refer to these measures as "non-GAAP financial measures" given they are not required by, or presented in accordance with U.S. GAAP.

We define adjusted EBITDA as net income (loss) attributable to AVANGRID, adding back net income (loss) attributable to other non-controlling interests, income tax expense (benefit), depreciation and amortization, impairment of non-current assets and interest expense, net of capitalization, and then subtracting other income and (expense), earnings (losses) from equity method investments and income from discontinued operations. We also believe that presenting earnings excluding certain non-recurring items and reflecting a full twelve-month period for UIL, is useful in understanding and evaluating actual and projected financial performance and contribution of AVANGRID and to more fully compare and explain our results without including the impact of the non-recurring items and with reflecting pro forma information to reflect a full year of results for merged entities. Additionally, we evaluate the nature of our revenues and expenses and adjust to reflect classification by nature for evaluation of our non-GAAP financial measures as opposed to by function. The most directly comparable U.S. GAAP measure to adjusted EBITDA 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 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 also use these measures internally to establish budgets and operational goals to manage and monitor our business, as well as to evaluate our underlying historical performance. The non-GAAP financial measures may not be comparable to other similarly titled measures of other companies and have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of our operating results as reported under U.S. GAAP.

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 (loss) from continuing operations, net income or any other performance measures determined in accordance with U.S. GAAP.

Reconciliation of the Net Income (Loss) attributable to AVANGRID to the consolidated Adjusted EBITDA and adjusted gross margin before combining a full year of UIL results, non-recurring and by nature items for the years ended December 31, 2015, 2014 and 2013 is as follows:

Years Ended December 31, (Millions)	2015	2014	2013
Net Income (Loss) Attributable to AVANGRID, Inc.	\$ 267	\$ 424	\$ (51)
Add: Net income (loss) attributable to other noncontrolling interests	—	—	1
Income tax expense	34	282	35
Depreciation and amortization	695	629	594
Impairment of non-current assets	12	25	620
Interest expense, net of capitalization	267	243	245
Less: Other income and (expense)	55	52	54
Earnings (losses) from equity method investments	—	12	(3)
Consolidated Adjusted EBITDA before combining a full year of UIL results, non-recurring and by nature items	\$ 1,220	\$ 1,539	\$ 1,393
Add: Operations and maintenance (1)	1,808	1,560	1,541
Taxes other than income taxes	367	314	291
Less: Transmission wheeling (1)	149	143	149
Adjusted gross margin before combining a full year of UIL results, non-recurring and by nature items	\$ 3,246	\$ 3,270	\$ 3,076

(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.

The following tables set forth our adjusted EBITDA and adjusted gross margin before combining a full year of UIL results, non-recurring and by nature items by segment for each of the periods indicated and as a percentage of operating revenues:

Year Ended December 31, 2015

	Total	Networks	Renewables	Gas	Other(1)
	<i>(in millions)</i>				
Adjusted gross margin before combining a full year of UIL results, non-recurring and by nature items	\$ 3,246	\$ 2,417	\$ 865	\$ (20)	\$ (16)
Adjusted gross margin %		71 %	81 %	105 %	24 %
Adjusted EBITDA before combining a full year of UIL results, non-recurring and by nature items	\$ 1,220	\$ 865	\$ 456	\$ (62)	(39)
Adjusted EBITDA %		26 %	43 %	326 %	58 %

Year Ended December 31, 2014

	Total	Networks	Renewables	Gas	Other(1)
	<i>(in millions)</i>				
Adjusted gross margin before combining a full year of UIL results, non-recurring and by nature items	\$ 3,270	\$ 2,199	\$ 997	\$ 83	\$ (9)
Adjusted gross margin %		65 %	84 %	99 %	12 %
Adjusted EBITDA before combining a full year of UIL results, non-recurring and by nature items	\$ 1,539	\$ 891	\$ 613	\$ 38	(3)
Adjusted EBITDA %		26 %	52 %	45 %	4 %

Year Ended December 31, 2013

	Total	Networks	Renewables (in millions)	Gas	Other(1)
Adjusted gross margin before combining a full year of UIL results, non-recurring and by nature items	\$ 3,076	\$ 2,213	\$ 904	\$ (31)	\$ (10)
Adjusted gross margin %		67%	82%	115%	13%
Adjusted EBITDA before combining a full year of UIL results, non-recurring and by nature items	\$ 1,393	\$ 960	\$ 507	\$ (76)	\$ 2
Adjusted EBITDA %		29%	46%	281%	(3)%

(1) Other amounts represent corporate and company eliminations.

Comparison of Period to Period Results of Operations

Our adjusted gross margin before combining a full year of UIL results, non-recurring and by nature items decreased by \$24 million, or less than 1% from \$3,270 million for the year ended December 31, 2014 to \$3,246 million for the year ended December 31, 2015.

Our adjusted EBITDA before combining a full year of UIL results, non-recurring and by nature items decreased by \$319 million, or 21%, from \$1.5 billion for the year ended December 31, 2014 to \$1.2 billion for the year ended December 31, 2015.

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

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

Networks

Adjusted gross margin before combining a full year of UIL results, non-recurring and by nature items for the year ended December 31, 2015 increased by \$218 million 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 before combining a full year of UIL results, non-recurring and by nature items 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 before combining a full year of UIL results, non-recurring and by nature items and increase in operations and maintenance with the main drivers being increased spending in 2015 on reliability support services.

Renewables

Adjusted gross margin before combining a full year of UIL results, non-recurring and by nature items 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 before combining a full year of UIL results, non-recurring and by nature items 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 before combining a full year of UIL results, non-recurring and by nature items.

Gas

Adjusted gross margin before combining a full year of UIL results, non-recurring and by nature items 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 before combining a full year of UIL results, non-recurring and by nature items 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 before combining a full year of UIL results, non-recurring and by nature items.

Year Ended December 31, 2014 Compared to the Year Ended December 31, 2013

Networks

Adjusted gross margin before combining a full year of UIL results, non-recurring and by nature items for the year ended December 31, 2014 decreased by \$14 million to \$2.2 billion. The decrease is associated with the increase in purchased power, natural gas and fuel used primarily due to the increase in electric retail prices, as well as higher wholesale prices. The remaining difference represents the cost of transmission wheeling year over year.

Adjusted EBITDA before combining a full year of UIL results, non-recurring and by nature items for the year ended December 31, 2014 decreased by \$69 million or 7% from \$960 million for the year ended December 31, 2013 to \$891 million. The decrease is primarily due to the reasons discussed above regarding adjusted gross margin before combining a full year of UIL results, non-recurring and by nature items and higher spending on operations and maintenance, including storm-related and labor-related expenses.

Renewables

Adjusted gross margin before combining a full year of UIL results, non-recurring and by nature items for the year ended December 31, 2014 increased by \$93 million or 10% from \$904 million for the year ended December 31, 2013 to \$997 million. The increase was due to higher results from existing wind assets with output sold under long term contracts reflecting stronger wind resource of \$4 million, increased prices realized in the market on existing merchant wind assets of \$7 million, collection from customers and control area operators for curtailments and pass-through of transmission charges of \$5 million, favorable results from power trading activities due to significant price volatility in the northwest markets due to cold weather and abundant hydro conditions of \$15 million. Additionally, transmission revenue increased by \$2 million. The remaining increase of \$44 million is largely attributable to unrealized gains for changes in fair value on energy derivative transactions entered into for economic hedging purposes.

Adjusted EBITDA before combining a full year of UIL results, non-recurring and by nature items for the year ended December 31, 2014 increased by \$106 million or 21% from \$507 million for the year ended December 31, 2013 to \$613 million. The increase was due to the same reasons discussed above for adjusted gross margin before combining a full year of UIL results, non-recurring and by nature items and the reduction in operating expenses compared to the prior period.

Gas

Adjusted gross margin before combining a full year of UIL results, non-recurring and by nature items for the year ended December 31, 2014 increased by \$114 million from negative \$31 million for the year ended December 31, 2013 to positive \$83 million. The increase was due to \$125 million unrealized gain driven by changes in MtM from a gain in value on storage and transport hedges due to average price decreases in 2014 compared to a loss in value due to average price increases in 2013.

Adjusted EBITDA before combining a full year of UIL results, non-recurring and by nature items for the year ended December 31, 2014 was positive \$38 million compared to negative \$76 million for the year ended December 31, 2013, an increase of \$114 million. The increase was due to the same reasons discussed above for adjusted gross margin before combining a full year of UIL results, non-recurring and by nature items.

The following table provides a reconciliation between Net Income (Loss) attributable to AVANGRID and adjusted gross margin and adjusted EBITDA after reflecting a full year results of UIL, non-recurring and by nature items for the years ended December 31, 2015, 2014 and 2013:

AVANGRID Consolidated

	Year Ended December 31,		
	(millions)		
	2015	2014	2013
Net Income (Loss) Attributable to AVANGRID, Inc.	\$ 267	\$ 424	\$ (51)
Adjustment for full year UIL and non-recurring items:			
Add: Net Income representing a full year for UIL	130	110	115
Merger Costs	71	5	—
Adjusted Net Income	\$ 468	\$ 539	\$ 64
Add: Net income (loss) attributable to other noncontrolling interests	—	—	1
Income tax expense including full year UIL, non-recurring and by nature items	169	376	128
Depreciation and amortization including full year UIL, non-recurring and by nature items	992	877	784
Impairment of non-current assets	12	25	620
Interest expense, net of capitalization including full year UIL, non-recurring and by nature items	309	300	332
Less: Other income and (expense)	55	52	75
Earnings (losses) from equity method investments including full year UIL and non-recurring items	11	23	12
Adjusted EBITDA after full year UIL, non-recurring and by nature items	\$ 1,884	\$ 2,042	\$ 1,842
Add: Operations and maintenance including full year UIL items (1)	1,506	1,521	1,484
Taxes other than income taxes including full year UIL items	529	500	472
Adjusted Gross Margin	\$ 3,919	\$ 4,063	\$ 3,798

(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.

Liquidity and Capital Resources

Our operating, investing, developing and acquisition activities have significant short-term liquidity and long-term capital requirements. 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, S.A. 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, 2015, we had cash and cash equivalents of \$427 million, as compared to \$482 million at December 31, 2014. In addition to cash on hand, we and our subsidiaries have access to committed credit facilities totaling \$1.3 billion.

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 broader Iberdrola Group and are a party to a notional cash pooling agreement with Bank Mendes Gans, N.V., or BMG, along with other Iberdrola, S.A. subsidiaries. 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. 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. Interest accrues on a daily basis at the rate of (i) overnight LIBOR minus 3 basis points for credit balances and (ii) overnight LIBOR plus 100 basis points for debit balances. Deposits are available for next day withdrawal. Deposits in the cash pooling account were \$449 million and \$353 million at December 31, 2014 and December 31, 2015, respectively. 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.

AVANGRID Revolving Credit Facility

In May 2012, we entered into a \$300 million revolving credit facility for the purpose of providing for our liquidity needs and those of our unregulated subsidiaries. The facility has a termination date in May 2019. We pay an annual facility fee of \$0.7 million. As of December 31, 2015 and December 31, 2014 the facility was undrawn.

The revolving credit facility contains a covenant that requires us to maintain a ratio of consolidated indebtedness to consolidated total capitalization that does not exceed 0.65 to 1.00 at any time. For purposes of calculating this maximum ratio of consolidated indebtedness to consolidated total capitalization, the facility excludes from consolidated net worth the balance of accumulated other comprehensive income, or AOCI, as it appears on the consolidated balance sheets.

Iberdrola Financiación, S.A.U. Credit Facility

In August 2011, we entered into a revolving credit facility with Iberdrola Financiación, S.A., a subsidiary of Iberdrola, S.A., under which we could borrow up to \$600 million. We terminated the facility on October 28, 2015. The facility was never utilized.

Joint Utility Revolving Credit Facility

In July 2011, NYSEG, RGE and CMP jointly entered into a bank provided revolving credit facility, the Joint Utility Facility, that allows maximum aggregate borrowings of up to \$600 million and expires in July 2018. Each subsidiary is currently subject to a \$200 million credit limit. Each borrower pays a facility fee ranging from fifteen to twenty basis points annually depending on the rating of its unsecured debt.

CMP and NYSEG have established commercial paper programs backstopped by the Joint Utility Facility. These companies use commercial paper as an alternative to revolving credit facilities as a source of short-term credit.

In the Joint Utility Facility each joint borrower covenants not to permit, without the lender's consent, its ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of consolidated indebtedness to total capitalization, the facility excludes from consolidated net worth the balance of AOCI as it appears on the consolidated balance sheets. As of December 31, 2015 and December 31, 2014 there were no outstanding loans, no outstanding commercial paper and \$14 million of outstanding letters of credit at both dates.

UIL Credit Facility

In November 2011 UIL, UI, CNG, SCG, and Berkshire became parties to a revolving credit agreement that will expire in November, 2016, or the UIL Credit Facility. In connection with the consummation of the acquisition, Merger Sub assumed all rights and obligations of UIL under the UIL Credit Facility through an assumption agreement dated as of December 15, 2015. The aggregate borrowing limit under the UIL Credit Facility is \$400 million, all of which is available to UIL, \$250 million of which is available to UI, \$150 million of which is available to each of CNG and SCG, and \$25 million of which is available to Berkshire, all subject to the aggregate limit of \$400 million. UIL pays a facility fee of twenty basis points annually.

The UIL Credit Facility contains a covenant that requires each borrower to maintain a ratio of consolidated indebtedness to consolidated total capitalization that does not exceed 0.65 to 1.00 at any time. For purposes of calculating this maximum ratio of consolidated indebtedness to consolidated total capitalization, the facility excludes from consolidated net worth unrealized gains and losses reflected in other comprehensive income in respect of qualified and non-qualified defined benefit pension plans, as well as other post-retirement benefit plans of such Borrower.

As of December 31, 2015 there were \$163 million in outstanding loans and \$4 million in outstanding letters of credit. We believe that we have sufficient liquidity resources to fund our operations and investments over the next 12 months.

Long-Term Capital Resources

We expect to meet our long-term capital requirements through the use of our cash surplus, credit facilities, cash from operations, and long-term borrowing. At December 31, 2015 we had no outstanding debt at the holding company level and \$4,736 million of long-term debt attributable to our subsidiaries (including the current portion thereof), which consisted of first mortgage bonds, fixed and variable unsecured pollution control notes and other various non-current debt, as further described below. We have investment grade ratings from Standard and Poor's, Moody's and Fitch and we believe that we could raise capital on competitive terms in the investment grade debt capital and/or bank markets.

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, RGE, 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, 2015. 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. Of the \$4,736 million of our long-term debt (including the current portion thereof) at December 31, 2015, \$4,132 million are obligations of Network's regulated utilities.

ARHI has historically been financed primarily with equity contributions from Iberdrola. The last such contribution of \$800 million was made in February 2013. ARHI 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 \$292 million, of which \$107 million is current, at December 31, 2015. ARHI has also sourced capital through sale-leaseback arrangements and project financing, the balance of which are included in long-term debt and totaled \$62 million at December 31, 2015.

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, 2015.

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.

Capital Expenditures

The regulated utilities' capital expenditures over the last 3 years have been the following:

	2013	2014	2015
	<i>(in millions)</i>		
NYSEG	\$ 235	\$ 247	\$ 259
RGE	195	181	157
CMP (non-MPRP(1))	149	172	120
CMP (MPRP)	255	112	108
MNG	36	15	3
UI	160	142	187
SCG	50	64	62
CNG	36	55	62
Berkshire	10	13	16
Total	<u>\$ 1,126</u>	<u>\$ 1,001</u>	<u>\$ 974</u>

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

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

	2013	2014	2015
	<i>(in millions)</i>		
Wind & solar	\$ 35	\$ 270	\$ 58
Thermal	19	14	11
Corporate(1)	5	9	8
Total capital expenditures	59	293	77
Cash grants(2)	(29)	—	—
Total capital expenditures less cash grants	<u>\$ 30</u>	<u>\$ 293</u>	<u>\$ 77</u>

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

(2) Payments received from the United States Department of Treasury under Section 1603 of the American Recovery and Reinvestment Act of 2009, as a reimbursement for a portion of the costs related to the construction of wind farms, and in lieu of production tax credits.

The yearly decreases from 2013 to 2015 in Networks capital expenditures are primarily due to a reduced spending for CMP's transmission project in Maine, the MPRP, with 2012 being the peak year for our investment for this multiyear project. Other investments have remained relatively flat across Networks during this period.

Renewables also made capital investments during this three year period. In 2015 there were capital expenditures of \$73 million on construction of the Desert Wind and other wind assets, \$11 million in capital expenditures on the Klamath gas-fired cogeneration facility, or 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.

In 2013, capital expenditures for Renewables included \$35 million related to the Baffin Bay wind asset, \$19 million of capital expenditures for the Klamath Plant, \$14 million on improvements to operating wind assets, and \$17 million in development costs, partially offset by \$42 million for refunds of unused wind turbine deposits and \$29 million received in cash grants under the U.S. Treasury cash grant program.

Capital Improvement Projects

An important part of our business strategy involves capital improvement projects. Through Networks we plan to invest a total of approximately \$6.7 billion from 2016 to 2020 to upgrade and expand electricity and natural gas transmission and distribution infrastructure. In the next 12 months, CMP plans to invest \$24 million in the Lewiston Loop project, which complements the already completed MPRP, a project which enhanced the bulk power transmission grid in Maine. In addition to that, CMP plans to invest \$32 million in its new Customer Relationship Management and Billing System. RGE plans to invest in the next 12 months \$77 million in the Ginna Retirement Transmission Alternative project to provide a transmission solution to address the planned retirement of the

Genina nuclear power plant near Rochester, \$6.2 million on the Rochester Area Reliability project to develop a new substation and transmission lines, \$35 million for the new line and upgrades in Station 23 related to the Rochester Area Reliability project and \$2 million on the Station 2 Generation Modernization Project for improvements at RGE's hydroelectric generating plant on the Genesee River. NYSEG plans to invest in the next 12 months \$26 million in the Marcy South Series Capacitance project to upgrade various elements of the transmission system between the Marcy and Fraser—Cooper Corners substations, \$22 million on the Auburn Transmission Project to construct a new electric transmission line over a distance of approximately 14.5 miles from the City of Auburn to the Town of Elbridge in New York.

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 will 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. This 2.5% equity interest, which totaled approximately \$1.6 million as of December 31, 2015, commits UIL to an initial capital investment opportunity that is expected to total up to approximately \$80 million, depending on the final pipeline configuration and design capacity. Pursuant to an option agreement with Kinder Morgan, UIL also has the option to acquire up to an additional 12.5% of equity interests in Northeast Expansion LLC under certain limited circumstances, including if certain additional firm transportation agreements for service on the NED pipeline are entered into or if TGP does not sell additional volume on the NED pipeline. Any increase in equity ownership would increase UIL's investment commitment proportionately. 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.

Through Renewables we plan to invest a total of approximately \$2.8 billion from 2016 to 2020 in order to add 1,400 MWs of generation capacity. 744 MW are approved for construction in 2016 and 2017 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, 2015, 2014 and 2013:

	Year Ended December 31,		
	2015	2014	2013
	(in millions)		
Cash Flows			
Net cash from operating activities	\$ 1,361	\$ 1,331	\$ 1,177
Net cash used in investing activities	(1,518)	(888)	(868)
Net cash from (used in) financing activities	102	(180)	(144)
Net (decrease) increase in cash and cash equivalents	\$ (55)	\$ 263	\$ 165

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 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 \$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.

In 2013, net cash provided by operating activities was approximately \$1.2 billion. During the period, Renewables contributed \$541 million of operating cash associated with wholesale sales of energy, Networks contributed \$556 million of operating cash as the result of regulated transmission and distribution sales of electricity and natural gas, and Gas contributed cash of \$89 million associated with gains on marketing of wholesale gas and gas storage services. We contributed cash of \$9 million in support of our segments. In addition, changes in working capital used \$16 million in cash. The cash from operating activities for the year ended December 31, 2013 compared to the year ended December 31, 2012 increased \$454 million, driven by a full year operation in 2013 of six new wind assets of 716 MW, favorable pricing and increased power generation at the Klamath facility. In addition, \$215 million of cash from operating activities was provided from the change in working capital. The \$181 million net change in our net operating assets and liabilities during the year ended December 31, 2013 was primarily attributable to a decrease in accounts receivable of \$56 million driven by improvements in collection, receipts from short-term deposits and guarantees of \$27 million, a decrease in accounts payable of \$208 million primarily driven by lower supply costs and an increase in regulatory assets driven by storm cost deferrals of \$29 million and environmental cost deferrals of \$68 million, partially offset by surcharge deferrals of \$33 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. During 2013 through 2015, we invested primarily in upgrading and expanding our electricity and natural gas infrastructure across our energy service and utility companies. The cost of investments however has been offset, partially, by refunds received from the U.S. Treasury cash grant program and from deposits made for turbine purchases and transmission interconnections.

In 2015, the cash used in investing activities was \$1.5 billion, compared to \$888 million in 2014 and \$868 million in 2013. The increase in 2015 compared to prior years 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, \$775 million in 2014, and \$906 million in 2013. The decrease from 2013 to 2015 in Networks capital expenditures are primarily due to a reduced spending for CMP's transmission project in Maine, the MPRP, with 2012 being the peak year for our investment for this multiyear project. 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 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.

In 2013, cash used in financing activities was \$144 million. Non-current note issuance of \$225 million and an equity contribution from Iberdrola, S.A. that included a cash infusion of \$153 million were offset by maturities of non-current debt of \$273 million, a reduction of \$165 million in short-term debt and payments on the tax equity financing arrangements of \$173 million.

Contractual Obligations

As of December 31, 2015, our contractual obligations (excluding any tax reserves) were as follows:

	Total	2016	2017	2018	2019	2020	Thereafter
	<i>(in millions)</i>						
Operating leases(1)	\$ 679	\$ 216	\$ 90	\$ 26	\$ 24	\$ 25	\$ 298
Projected future pension benefit plan contributions(2)	183	43	44	51	32	13	—
Long-term debt (including current maturities)(3)	4,736	206	302	162	354	721	2,991
Interest payments(4)	2,455	218	208	191	171	155	1,512
Material purchase commitments(5)	2,470	496	351	271	211	184	957
Total Contractual Obligations	\$ 10,523	\$ 1,179	\$ 995	\$ 701	\$ 792	\$ 1,098	\$ 5,758

- (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 ERISA 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) 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, 2015 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, 2015
- (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 combined and 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 combined and consolidated financial statements are recorded at the historical accounting basis of AVANGRID, which do not include purchase accounting adjustments related to Iberdrola, S.A.'s acquisition of AVANGRID in 2008.

Accounting for Regulated Public Utilities

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

Accounting for Pensions and Other Post-retirement Benefits

We provide pensions and other post-retirement benefits for a significant number of employees, former employees and retirees. We account for these benefits in accordance with the accounting rules for retirement benefits. In accounting for its pension and other post-retirement benefit plans, or the AVANGRID plans, assumptions are made regarding the valuation of benefit obligations and the performance of plan assets. Delayed recognition of differences between actual results and those assumed allows for a smoother recognition of changes in benefit obligations and plan performance over the working lives of the employees who benefit under the AVANGRID plans. The primary assumptions include the discount rate, the expected return on plan assets, health care cost trend rate, mortality assumptions and demographic assumptions. We apply consistent estimation techniques regarding our actuarial assumptions, where appropriate, across the AVANGRID plans of our operating subsidiaries. The estimation technique utilized to develop the discount rate for the AVANGRID plans is based upon the settlement of such liabilities as of December 31, 2015 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 2015, 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, 2015 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.

Goodwill

Goodwill is not amortized, but is subject to an assessment for impairment at least annually or more frequently if events occur or circumstances change that will more likely than not reduce the fair value of the reporting unit below its carrying amount. A reporting unit is an operating segment or one level below an operating segment and is the level at which goodwill is tested for impairment.

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

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

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

Renewables

Based on the results of our step one impairment test for Renewables, conducted in 2015, its estimated fair value exceeds carrying value by approximately 1.55%. Due to this 1.55% excess of fair value over carrying value in step one, step two calculations were performed according to the operating plans of the reporting unit, in order to assess whether a potential material impairment charge may be recognized in the near term.

The current operating plans of Renewables include significant assumptions and estimates associated with revenue growth, profitability and related cash flows, along with cash flows associated with taxes and capital expenditures. In addition, our projections contemplate the continuation of renewable energy projects in the future. The discount rate used to estimate fair value was risk-adjusted to consider economic conditions of Renewables, 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 kWh, changes in government incentives established to promote renewable energies and increases in capital expenditures per MW could have an adverse effect on our assumptions.

The conclusion of the step two analysis is that the implied fair value of the goodwill within Renewables is 1.28x of its carrying amount as of December 31, 2015. Management will continue to monitor the performance of the reporting unit and any potential implications on goodwill.

Impairment of Long Lived Assets

We evaluate property, plant, and equipment and other long lived assets for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment loss is required to be recognized if the carrying amount of the asset exceeds the undiscounted future net cash flows associated with that asset.

We determine the fair value of a long-lived asset (asset group) by applying the approaches prescribed under the fair value measurement accounting framework. Generally, the market approach and income approach are most relevant in the fair value measurement of our long-lived assets; however, due to the lack of available relevant observable market information in many circumstances, we often rely on the income approach. We develop the underlying assumptions consistent with our internal budgets and forecasts for such valuations. We use an internal discounted cash flow valuation model, or the DCF model, based on the principles of present value techniques, to estimate the fair value of our long-lived assets under the income approach. The DCF model estimates fair value by discounting AVANGRID's cash flow forecasts at an appropriate discount rate. Management applies considerable judgment in selecting several input assumptions during the development of our internal budgets and cash flow forecasts. Examples of the input assumptions that our budgets and forecasts are sensitive to include macroeconomic factors such as growth rates, industry demand, inflation, power prices and commodity prices. Whenever appropriate, management obtains these input assumptions from observable market data sources and extrapolates the market information if an input assumption is not observable for the entire forecast period. Many of these input assumptions are dependent on other economic assumptions, which are often derived from statistical economic models with inherent limitations such as estimation differences. Further, several input assumptions are based on historical trends which often do not recur. The input assumptions most significant to our budgets and cash flows are based on expectations of macroeconomic factors which may be volatile. The use of a different set of input assumptions could produce significantly different budgets and cash flow forecasts.

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

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

Capitalization and Recovery of Project Development Costs

Development and construction of our various facilities are carried out in stages. Project costs are expensed during early stage development activities. Once certain development milestones are achieved and it is probable that we can obtain future economic benefits from a project, salaries and wages for persons directly involved in the project, and engineering, permits, licenses, wind measurement and insurance costs are capitalized.

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

Fair Value Measurement

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

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

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

Income Tax

For the 2015 tax year, AVANGRID will file a consolidated federal income tax return, which will include the UIL taxable income or loss for the period from December 17, 2015 to December 31, 2015. UIL will file 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.

In addition, a consolidated federal income tax return, that included the taxable income or loss of ARHI and all of its subsidiaries for the entire 2013 tax year and the taxable income or loss of AVANGRID (without UIL), and all of its subsidiaries for the tax period of November 21, 2013 through December 31, 2013, was filed.

For the period of January 1, 2013 through November 20, 2013, AVANGRID (excluding ARHI and UIL) filed a consolidated federal income tax return that included the taxable income or loss of all its subsidiaries, which are 80% or more owned.

We use the liability method of accounting for income taxes. Deferred tax assets and liabilities reflect the expected future tax consequences based on enacted tax law of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts. In accordance with U.S. GAAP for regulated industries, our regulated subsidiaries have established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences. The investment tax credits are deferred when used and amortized over the estimated lives of the related assets.

Deferred tax assets and liabilities are measured at the expected tax rate for the period in which the asset or liability will be realized or settled, based on legislation enacted as of the balance sheet date. Changes in deferred income tax assets and liabilities that are associated with components of 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 combined and 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 combined and consolidated statements of operations.

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 combined and consolidated statements of operations.

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

At December 31, 2015, we had approximately \$2.4 billion of standby letters of credit, surety bonds, guarantees and indemnifications outstanding. These instruments provide financial assurance to the business and trading partners of the company and its subsidiaries in their normal course of business. The instruments only represent liabilities if the company 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, at December 31, 2015, neither the company nor its subsidiaries have any liabilities recorded for these instruments.

New Accounting Standards

Simplifying the Presentation of Debt Issuance Costs - In April 2015 the FASB issued an amendment that is intended to simplify the presentation of debt issuance costs.

Balance Sheet Classification of Deferred Taxes - In November 2015 the FASB issued an amendment that is intended to simplify the presentation of deferred income taxes by requiring entities that present a classified statement of financial position to classify deferred tax liabilities and assets as noncurrent in their balance sheet.

Pushdown Accounting - In November 2014 the FASB issued an amendment on when and how an acquired entity that is a business or nonprofit activity, whether public or nonpublic, can apply pushdown accounting in its separate financial statements upon the occurrence of an event in which an acquirer, either an individual or an entity, obtains control of the acquired entity.

Discontinued Operations and Disposals of Components of an Entity - In April 2014 the FASB issued an amendment that changed the requirements for the reporting of discontinued operations.

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.

Presentation of an Unrecognized Tax Benefit - In July 2013 the FASB issued guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss, or NOL, carryforward, a similar tax loss, or a tax credit carryforward exists.

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.

Application of the Normal Purchases and Normal Sales Scope Exception - In August 2015 the FASB issued amendments to specify that the use of locational marginal pricing by an ISO does not constitute net settlement of a contract for the purchase or sale of

electricity on a forward basis that necessitates transmission through, or delivery to a location within, a nodal energy market, even when legal title to the associated electricity is conveyed to the ISO during transmission.

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.

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

For further discussion of new accounting pronouncements affecting AVANGRID refer to Note 3 of our audited combined and consolidated financial statements for the three years ended December 31, 2015, 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.

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 2015 was \$14.0 million compared to a 2014 average of \$12.5 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, both physical and financial, to manage fluctuations in electricity

commodity prices in order to provide price stability to customers. It also uses natural gas futures and forwards to manage fluctuations in natural gas commodity prices in order to provide price stability to customers. It includes the cost or benefit of those contracts in the amount expensed for electricity or natural gas purchased when the related electricity is sold.

Because all gains or losses on Networks' commodity contracts will ultimately be passed on to retail customers, no sensitivity analysis is performed for Networks. Further information regarding the derivative financial instruments and sensitivity analysis is provided in Notes 11 and 12 of our audited combined and consolidated financial statements for the three years ended December 31, 2015, which are incorporated herein by reference.

Interest Rate Risk

Total debt outstanding, including tax equity of \$292 million and borrowings under the UIL Credit Facility of \$163 million, was \$5.2 billion at December 31, 2015 of which \$461 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 \$1.0 million annually. The estimated fair value of our debt excluding the debt associated with capital leases and tax equity at December 31, 2015 was \$4.9 billion, in comparison to a book value of \$4.7 billion.

There are no interest rate derivative contracts outstanding at December 31, 2015 and 2014.

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 2015, we contributed \$27 million to our pension plans. Our contribution to the pension plans in 2016 is expected to be approximately \$21 million.

The discount rate used in accounting for pension and other benefit obligations in 2015 ranged from 3.80% to 3.90%. The expected rate of return on plan assets for qualified pension benefits in 2015 ranged from 5.50% to 7.50%. The following tables reflect the estimated sensitivity associated with a change in certain significant actuarial assumptions (each assumption change is presented mutually exclusive of other assumption changes):

	Change in Assumption	Impact on 2015 Pension Expense Increase (Decrease)	
		Pension Benefits	Post Retirement
		<i>(in millions)</i>	
Increase in discount rate	50 basis points	\$ 13	\$ 2
Decrease in discount rate	50 basis points	(13)	(2)
Increase in return on plan asset	50 basis points	11	1
Decrease in return on plan asset	50 basis points	(11)	(1)

Credit Risk

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

Renewables and Gas are also exposed to credit risk through their energy marketing and trading operations. We manage counterparty credit risk for our subsidiaries with energy marketing and trading 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.

Some relevant considerations when assessing the credit risk exposure of the energy marketing and trading 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 marketing and trading 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 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 energy marketing and trading 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, 2015, approximately 98% of our energy marketing and trading counterparty credit risk exposure is associated with companies that have investment grade credit ratings.

The following table displays the credit quality of our trading counterparties as of December 31, 2015:

	Credit Exposure Before Cash Collateral	Cash Collateral	Net Credit Exposure
	<i>(in millions)</i>		
Investment Grade(1)	\$ 2,719	\$ —	\$ 2,719
A- and Greater	2,051	—	2,051
BBB+ and BBB	556	—	556
BBB-	112	—	112
Total Investment Grade	2,719	—	2,719
Non-investment grade(2) (3) (4)	54	4	50
Total	\$ 2,773	\$ 4	\$ 2,769

- (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 36.9% 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 0.2% 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 0.9% of the total gross credit exposure.
- (4) This category includes counterparties that have not been rated by Moody's or Standard & Poor's, and are considered non-investment grade based on our evaluation of the counterparty's creditworthiness. The five largest counterparty exposures, combined, for this category represented approximately 0.5% 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 Iberdrola, S.A. subsidiaries. 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 have the capacity to borrow from third parties through three separate credit facilities totaling \$1.3 billion. For more information, see the section entitled "—Liquidity and Capital Resources—Liquidity Resources" of this Form 10-K.

Networks

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

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

Renewables

Renewables has historically funded itself through a combination of normal operations and through 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, 2015 was \$292 million and the balance of leases and project financing was \$62 million. During 2015, Renewables authorized dividend payments of \$1.4 billion to AVANGRID, of which \$950 million was in cash (\$750 million paid in 2015) and the remainder in financial instruments.

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of Avangrid, Inc. and subsidiaries (the “Company”) as of December 31, 2015 and 2014, and the related combined and consolidated statements of operations, comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2015. 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. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and 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, 2015 and 2014, and the combined and consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ Ernst & Young, LLP

New York, New York
April 1, 2016

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

AVANGRID, Inc. and Subsidiaries
Combined and Consolidated Statements of Operations

Years Ended December 31,	2015	2014	2013
(Millions, except for number of shares and per share data)			
Operating Revenues	\$ 4,367	\$ 4,594	\$ 4,313
Operating Expenses			
Purchased power, natural gas and fuel used	972	1,181	1,088
Operations and maintenance	1,808	1,560	1,541
Impairment of non-current assets	12	25	620
Depreciation and amortization	695	629	594
Taxes other than income taxes	367	314	291
Total Operating Expenses	3,854	3,709	4,134
Operating Income	513	885	179
Other Income and (Expense)			
Other income and (expense)	55	52	54
Earnings (losses) from equity method investments	—	12	(3)
Interest expense, net of capitalization	(267)	(243)	(245)
Income (Loss) Before Income Tax	301	706	(15)
Income tax expense	34	282	35
Net Income (Loss)	267	424	(50)
Less: Net income attributable to noncontrolling interests	—	—	1
Net Income (Loss) Attributable to AVANGRID, Inc.	\$ 267	\$ 424	\$ (51)
Earnings (Loss) Per Common Share, Basic:	\$ 1.05	\$ 1.68	\$ (0.20)
Earnings (Loss) Per Common Share, Diluted:	\$ 1.05	\$ 1.68	\$ (0.20)
Weighted-average Number of Common Shares Outstanding:			
Basic	254,588,212	252,235,232	252,235,232
Diluted	254,605,111	252,235,232	252,235,232

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

AVANGRID, Inc. and Subsidiaries
Combined and Consolidated Statements of Comprehensive Income (Loss)

Years Ended December 31,	2015	2014	2013
(Millions)			
Net Income (Loss)	\$ 267	\$ 424	\$ (50)
Other Comprehensive Income			
Amounts arising during the year:			
Gain on defined benefit plans, net of income taxes of \$2.2, \$0.6 and \$0.5, respectively	4	1	1
Amortization of pension cost for nonqualified plans, net of income taxes of \$1.7, (\$1.9) and \$1.0, respectively	3	(3)	(1)
Unrealized gain (loss) during the year on derivatives qualifying as cash flow hedges, net of income taxes of \$20.9, (\$1.4) and \$0, respectively	33	(2)	—
Reclassification to net income of losses on cash flow hedges, net of income taxes of \$4.9, \$4.1 and \$4.6, respectively	7	5	7
Other Comprehensive Income	47	1	7
Comprehensive Income (Loss)	314	425	(43)
Less:			
Comprehensive income attributable to noncontrolling interests	—	—	1
Comprehensive Income (Loss) attributable to AVANGRID, Inc.	\$ 314	\$ 425	\$ (44)

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

AVANGRID, Inc. and Subsidiaries
Consolidated Balance Sheets

As of December 31,	2015	2014
(Millions)		
Assets		
Current Assets		
Cash and cash equivalents	\$ 427	\$ 482
Accounts receivable and unbilled revenues, net	974	841
Accounts receivable from affiliates	70	50
Notes receivable from affiliates	6	—
Derivative assets	88	134
Fuel and gas in storage	307	229
Materials and supplies	98	98
Prepayments and other current assets	285	288
Regulatory assets	219	80
Total Current Assets	2,474	2,202
Property, plant and equipment, at cost	25,745	21,499
Less: accumulated depreciation	(6,372)	(5,762)
Net Property, Plant and Equipment in Service	19,373	15,737
Construction work in progress	1,338	1,396
Total Property, Plant and Equipment	20,711	17,133
Equity method investments	385	262
Other investments	64	91
Regulatory assets	3,314	2,399
Other Assets		
Goodwill	3,115	1,361
Intangible assets	556	569
Derivative assets	89	93
Other	35	52
Total Other Assets	3,795	2,075
Total Assets	\$ 30,743	\$ 24,162

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

AVANGRID, Inc. and Subsidiaries
Consolidated Balance Sheets

As of December 31,	2015	2014
(Millions, except share information)		
Liabilities		
Current Liabilities		
Current portion of debt	\$ 206	\$ 148
Tax equity financing arrangements	107	124
Notes payable	163	—
Interest accrued	61	39
Accounts payable	830	684
Accounts payable to affiliates	90	239
Taxes accrued	55	8
Derivative liability	91	103
Other current liabilities	285	262
Regulatory liabilities	147	165
Total Current Liabilities	2,035	1,772
Regulatory liabilities	1,841	1,229
Deferred income taxes regulatory	519	433
Other Non-current Liabilities		
Deferred income taxes	2,798	2,269
Deferred income	1,553	1,621
Pension and other postretirement	1,202	785
Tax equity financing arrangements	185	277
Derivative liability	94	38
Asset retirement obligations	184	234
Environmental remediation costs	406	284
Other	330	254
Total Other Non-current Liabilities	6,752	5,762
Non-current Debt	4,530	2,489
Total Non-current Liabilities	13,642	9,913
Total Liabilities	15,677	11,685
Commitments and Contingencies	—	—
Equity		
Stockholders' Equity:		
Common stock, \$.01 par value, 500,000,000 shares authorized, 309,491,082 and 252,235,232 shares issued; 308,864,609 and 252,235,232 shares outstanding, respectively	3	3
Additional paid-in capital	13,653	11,375
Retained earnings	1,449	1,182
Accumulated other comprehensive loss	(52)	(99)
Total Stockholders' Equity	15,053	12,461
Noncontrolling interests	13	16
Total Equity	15,066	12,477
Total Liabilities and Equity	\$ 30,743	\$ 24,162

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

AVANGRID, Inc. and Subsidiaries
Combined and Consolidated Statements of Cash Flows

Years Ended December 31,	2015	2014	2013
(Millions)			
Cash Flow from Operating Activities			
Net income (loss)	\$ 267	\$ 424	\$ (50)
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation and amortization	695	629	594
Impairment of non-current assets	12	25	620
Accretion expenses	14	14	14
Regulatory assets/liabilities amortization	101	(38)	(2)
Regulatory assets/liabilities carrying cost	41	35	21
Pension cost	115	74	96
(Earnings) losses from equity method investments	—	(12)	3
Unrealized losses (gains) on marked to market derivative contracts	10	(116)	4
Deferred taxes	87	261	58
Changes in current operating assets and liabilities, net of effects of acquisition			
Decrease (increase) in accounts receivable and unbilled revenues	160	(1)	56
Decrease (increase) in inventories	4	58	(1)
Decrease in other assets	(42)	(101)	(126)
(Decrease) increase in accounts payable	(10)	27	(208)
(Decrease) increase in other liabilities	(188)	(110)	123
Increase (decrease) in taxes accrued	21	(13)	2
Increase (decrease) in regulatory assets/liabilities	74	175	(27)
Net Cash provided by Operating Activities	1,361	1,331	1,177
Cash Flow from Investing Activities			
Capital expenditures	(1,082)	(1,030)	(944)
Proceeds from disposal of property, plant and equipment	—	—	2
Contributions in aid of construction	38	43	24
Government grants	17	4	31
Acquisition of business, net of \$48 million cash acquired	(547)	—	—
Proceeds from sale of businesses, net of cash	3	31	—
(Payments to) receipts from affiliates	(6)	10	—
Other investments and equity method investments	59	54	19
Net Cash used in Investing Activities	(1,518)	(888)	(868)
Cash Flow from Financing Activities			
Capital contributions from Parent	—	—	153
Non-current note issuance	350	—	225
Repayments of non-current debt	(141)	(27)	(273)
Proceeds (repayments) of other short-term debt, net	10	(14)	(165)
Proceeds from sales leaseback	—	—	110
Repayments of capital leases	(12)	(21)	(21)
Payments on tax equity financing arrangements	(102)	(119)	(173)
Contribution from noncontrolling interests	—	4	—
Dividends to noncontrolling interests	(3)	(3)	—
Net Cash Provided by (used in) Financing Activities	102	(180)	(144)
Net (Decrease) Increase in Cash and Cash Equivalents	(55)	263	165
Cash and Cash Equivalents, Beginning of Year	482	219	54
Cash and Cash Equivalents, End of Year	\$ 427	\$ 482	\$ 219
Supplemental Cash Flow Information			
Cash paid for interest, net of amounts capitalized	\$ 132	\$ 133	\$ 147
Cash paid (refund) for income taxes	7	21	(30)

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

AVANGRID, Inc. and Subsidiaries
Combined and Consolidated Statements of Changes in Equity

(Millions, except for number of shares)	AVANGRID, Inc. Stockholders					Total Stockholders' Equity	Noncontro- lling Interests	Total Equity
	Number of shares (*)	Common stock	Additional paid-in capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)			
Balances, December 31, 2012	252,235,232	\$ 3	\$ 10,629	\$ 809	\$ (107)	\$ 11,334	\$ 14	\$ 11,348
Net income (loss)	—	—	—	(51)	—	(51)	1	(50)
Other comprehensive income, net of tax of \$6.1	—	—	—	—	7	7	—	7
Comprehensive loss								(43)
Capital contribution	—	—	746	—	—	746	—	746
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
Treasury stock	(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

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

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

AVANGRID, Inc. and Subsidiaries
Notes to Combined and 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 through its principal subsidiaries AVANGRID Networks, Inc. (Networks), UIL Holdings Corporation (UIL) and AVANGRID Renewables Holding, Inc. (ARHI) in the regulated energy distribution, renewable energy generation (Renewables) and gas businesses (Gas), collectively (Renewables and Gas). AVANGRID is an 81.5% owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain. The remaining outstanding shares are publicly traded on the New York Stock Exchange and owned by various shareholders. AVANGRID was organized in 1997 as Energy East Corporation under the laws of New York as the holding company for the 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 and Maine. 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 & Electric Corporation (RGE) and Maine Natural Gas Company (MNG). 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 The United Illuminating Company (UI) and the natural gas transportation, distribution and sales operations of The Southern Connecticut Gas Company (SCG), Connecticut Natural Gas Corporation (CNG) and The Berkshire Gas Company.

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).

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

Note 2. Basis of Presentation

The accompanying combined and consolidated financial statements have been prepared in accordance with U.S GAAP and are presented on a combined basis prior to the Reorganization, and on a consolidated basis subsequent to the Reorganization. For the periods prior to the Reorganization the combined financial statements include AVANGRID, ARHI and Networks (combined entities) all of which were under common control of Iberdrola, and for the periods subsequent to the Reorganization, the consolidated financial statements include AVANGRID and its consolidated subsidiaries Networks and ARHI until December 16, 2015, and Networks, UIL and ARHI (consolidated entities) afterwards. The combined financial statements have been prepared on a combined basis to allow for comparability with the consolidated financial statements for the periods subsequent to the Reorganization. All intercompany transactions and accounts have been eliminated in all periods presented. All share and per share information included in the combined and consolidated financial statements have been retroactively adjusted to reflect the impact of the stock dividend.

As a result of the common control transfers occurring as part of the Reorganization, management recorded the net assets of ARHI in these combined and consolidated financial statements at the historical accounting basis of Iberdrola. The historical accounting basis of Iberdrola includes purchase accounting adjustments related to Iberdrola's acquisition of ARHI in 2007. At the time of the Reorganization, the holding of Networks was not considered to be a substantive operating entity as it did not hold any direct operations prior to it and the Networks businesses had always been a part of AVANGRID. As a result the net assets of Networks in these combined and consolidated financial statements are recorded at the historical accounting basis of AVANGRID, which do not include purchase accounting adjustments related to Iberdrola's acquisition of Energy East in 2008.

Immaterial corrections to prior periods

During the year ended December 31, 2015, we identified immaterial corrections to prior periods related to property, plant and equipment and depreciation expense in our Renewables reportable segment. The corrections resulted in an overstatement of depreciation expense and an understatement of income tax expense in the combined and consolidated statements of operations for the years ended December 31, 2013 and 2012. The recorded balances of accumulated depreciation were likewise overstated with deferred income tax liabilities being understated in the consolidated balance sheets as of December 31, 2014, 2013 and 2012. We evaluated the effects of these corrections on prior periods' combined and consolidated financial statements, individually and in the aggregate, in accordance with the guidance in Accounting Standards Codification (ASC) Topic 250, Accounting Changes and Error Corrections, ASC Topic 250-10-S99-1, Assessing Materiality, and ASC Topic 250-10-S99-2, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements, and concluded that no prior period is materially misstated. However, in accordance with the aforementioned ASC Topics, we have determined to revise our combined and consolidated financial statements for the prior periods presented herein.

As a result of the correction, the cumulative effect of the change on retained earnings as of December 31, 2013 and 2012 was an increase of \$21 million and \$7 million, respectively. Total assets, deferred income taxes, total other non-current liabilities, total non-current liabilities and total liabilities as reported in the table below are shown after reclassifications discussed in Note 3 of these combined and consolidated financial statements. Net loss per common share as reported in the table below is shown after retroactive application of stock split discussed in Note 17 of these combined and consolidated financial statements. The revision had no net impact on our net cash provided by operating activities for the year ended December 31, 2013. The segment information related to Renewables reportable segment as of and for the years ended December 31, 2014 and 2013 provided in Note 23 has also been revised to reflect these corrections.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

A summary of the effect of the correction on the consolidated balance sheet as of December 31, 2014 is as follows:

As of December 31, 2014	As Reported	Correction	As Revised
(Millions)			
Accumulated depreciation	\$ (5,796)	\$ 34	\$ (5,762)
Net Property, Plant and Equipment in Service	15,703	34	15,737
Total Property, Plant and Equipment	17,099	34	17,133
Total assets	24,128	34	24,162
Deferred income taxes	2,256	13	2,269
Total Other Non-current Liabilities	5,749	13	5,762
Total Non-current Liabilities	9,900	13	9,913
Total liabilities	11,672	13	11,685
Retained earnings	1,161	21	1,182
Total Stockholders' Equity	12,440	21	12,461
Total Equity	12,456	21	12,477
Total Liabilities and Equity	\$ 24,128	\$ 34	\$ 24,162

A summary of the effect of the correction on the combined and consolidated statement of operations for the year ended December 31, 2013 is as follows:

Year Ended December 31, 2013	As Reported	Correction	As Revised
(Millions, except per share data)			
Depreciation and amortization	\$ 617	\$ (23)	\$ 594
Total Operating Expenses	4,157	(23)	4,134
Operating income	156	23	179
Loss Before Income Tax	(38)	23	(15)
Income tax expense	26	9	35
Net Loss	(64)	14	(50)
Net Loss Per Common Share, Basic and Diluted:	\$ (0.26)	\$ (0.06)	\$ (0.20)

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 combined and consolidated financial statements:

(a) Principles of consolidation and combination

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.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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 combined and consolidated statements of operations 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.

(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 combined and consolidated statements of operations 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.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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 combined and consolidated statements of operations 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	30-35
	Hydroelectric power stations	40-90
	Wind power stations	25
	Gas storage	17-119
	Transport facilities	33-75
	Distribution facilities	15-80
Equipment	Conventional meters and measuring devices	17-41
	Computer software	3-10
Other	Buildings	9-75
	Operations offices	5-32

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.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

(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 combined and 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.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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 recognized at fair value 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 amounts related to AROs are included as other non-current assets in 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 company 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

We have undertaken several structured institutional partnership investment transactions that bring in external investors in certain of our wind farms in exchange for cash and notes receivable. Following an analysis of the economic substance of these transactions, we classify the consideration received at the inception of the arrangement as a liability in the consolidated balance sheets. Subsequently, this liability is amortized based on the cash and tax benefits provided to the tax equity investors.

(o) Debentures, bonds and bank borrowings

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

(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 sheet within “Materials and supplies.”

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

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

(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 combined and consolidated statements of operations 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 to 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, and to depreciate the capitalized cost over the useful life of the related asset. 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 2048.

(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

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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, RGE 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

For the 2015 tax year, AVANGRID will file a consolidated federal income tax return, which will include the UIL taxable income or loss for the period from December 17, 2015 to December 31, 2015. UIL will file 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 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.

In addition, a consolidated federal income tax return, that included the taxable income or loss of ARHI and all of its subsidiaries for the entire 2013 tax year and the taxable income or loss of AVANGRID (without UIL) and all of its subsidiaries for the tax period of November 21, 2013 through December 31, 2013, was filed.

For the period of January 1, 2013 through November 20, 2013, AVANGRID (excluding ARHI and UIL) filed a consolidated federal income tax return that included the taxable income or loss of all its subsidiaries, which are 80% or more owned.

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, 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.

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 combined and 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 combined and consolidated statements of operations.

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 combined and consolidated statements of operations.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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. We account for stock-based payment transactions based on the estimated fair value of awards, net of estimated forfeitures at the date of issuance. 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 for certain share-based awards until the employee becomes retirement eligible, if earlier. The total stock-based compensation expense, which is included in operations and maintenance of the combined and consolidated statements of operations for the years ended December 31, 2015, 2014 and 2013 was \$6.0 million, \$4.8 million and \$7.6 million, respectively. The total liability relating to stock-based compensation, which is included in other non-current liabilities, was \$17.5 million and \$16.8 million as of December 31, 2015 and 2014.

The Company's historical stock-based expense and liabilities are based on shares of its parent, Iberdrola S.A, and not on shares of the Company. The Company has total unrecognized costs for stock-based compensation of approximately \$1.0 million as of December 31, 2015. As of December 31, 2015 the Company maintained unvested performance shares that may be settled through the issuance of additional Company shares in future periods upon the achievement of certain conditions.

Reclassifications

Certain amounts have been reclassified in the consolidated balance sheet and combined and consolidated statements of operations to conform to the 2015 presentation. Amounts pertaining to sales and use tax of \$8 million and \$11 million for the years ended December 31, 2014 and 2013, respectively, have been reclassified from "Taxes other than income taxes" to "Operations and maintenance" in the combined and consolidated statements of operations. Additionally, current and non-current liabilities amounting to \$12 million and \$23 million, pertaining to the Rate refund – FERC ROE proceeding have been reclassified from "Other current liability" and "Other non-current liability" to current and non-current regulatory liabilities in the consolidated balance sheet as of December 31, 2014.

New Accounting Standards and Interpretations

(a) Simplifying the presentation of debt issuance costs

The Financial Accounting Standards Board (FASB) issued an amendment in April 2015 that is intended to simplify the presentation of debt issuance costs. Instead of presenting debt issuance costs as a deferred charge (that is, as an asset), the amendments require debt issuance costs related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with the presentation for debt discounts. The amendment is effective for public entities for financial statements issued for fiscal years beginning after December 15, 2015, and for interim periods within those fiscal years. As permitted, we have early adopted the amendment as of the beginning of the fourth quarter of 2015 and have applied it retrospectively to all periods presented. Accordingly, we reclassified the debt issuance costs from other noncurrent assets to noncurrent debt on our December 31, 2014 consolidated balance sheet, which decreased total assets, noncurrent debt and total liabilities by \$27 million.

(b) Balance sheet classification of deferred taxes

The FASB issued an amendment in November 2015 that is intended to simplify the presentation of deferred income taxes by requiring entities that present a classified statement of financial position to classify deferred tax liabilities and assets as noncurrent in their balance sheet. This aligns the presentation of deferred income tax liabilities and assets with International Financial Reporting Standards. The amendments do not affect the current requirement that deferred tax liabilities and assets of a tax-paying component of an entity be offset and presented as a single amount. The amendments are effective for public entities for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. As permitted, we have early adopted the amendments as of the beginning of the fourth quarter of 2015, and have elected retrospective application to all periods presented in order to simplify the presentation in our balance sheet. Accordingly, we reclassified the current deferred taxes to

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

noncurrent on our December 31, 2014 consolidated balance sheet, which decreased noncurrent deferred tax assets and liabilities by \$97 million.

(c) Pushdown accounting

In November 2014 the FASB issued an amendment on when and how an acquired entity that is a business or nonprofit activity, whether public or nonpublic, can apply pushdown accounting in its separate financial statements upon the occurrence of an event in which an acquirer, either an individual or an entity, obtains control of the acquired entity. The guidance provides an acquired entity with an option to apply pushdown accounting in its separate financial statements. As a result of the amendment, which was effective when issued, we were not required to apply pushdown accounting to the acquisition of Energy East by Iberdrola in 2008. Therefore, the net assets of Networks in these combined and consolidated financial statements are recorded at the historical accounting basis of AVANGRID, which do not include purchase accounting adjustments related to that acquisition.

(d) Discontinued operations and disposals of components of an entity

The FASB issued an amendment in April 2014 that changed the requirements for the reporting of discontinued operations. The new definition of discontinued operations limits reporting to disposals of components that represent strategic shifts that have, or will have, a major effect on an entity's operations and financial results. The amendments are effective for public business entities for annual periods beginning on or after December 15, 2014, and interim periods within those years. The adoption of the amendment did not materially affect our results of operations, financial position or cash flows.

(e) 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. 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 standard is effective for public entities 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 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. In March 2016 the FASB issued an accounting standards update that amends and clarifies the implementation guidance on principal versus agent considerations for reporting revenue gross rather than net, with the same deferred effective date. We are currently evaluating how the adoption of the amendment will affect our results of operations, financial position, and cash flows.

(f) Presentation of an unrecognized tax benefit

In July 2013 the FASB issued guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss (NOL) carryforward, a similar tax loss, or a tax credit carryforward exists. An unrecognized tax benefit, or a portion of an unrecognized tax benefit, is to be presented as a reduction to a deferred tax asset for an NOL carryforward, a similar tax loss, or a tax credit carryforward, with certain exceptions. The unrecognized tax benefit is to be presented as a liability and should not be combined with deferred tax assets to the extent that an NOL carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date under the tax law of the applicable jurisdiction to settle any additional income taxes that would result from the disallowance of a tax position or the tax law of the applicable jurisdiction does not require the entity to use, and the entity does not intend to use, the deferred tax asset for such purpose. AVANGRID adopted these amendments effective January 1, 2014. The adoption of these amendments did not materially affect our results of operations, financial position or cash flows.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

(g) Fair value measurement disclosures for certain investments

The FASB issued amendments in May 2015 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. We do not expect our adoption of the amendments to materially affect our results of operations, financial position, or cash flows.

(h) 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 do not expect our adoption of the amendments to affect our results of operations, financial position, or cash flows.

(i) Application of the normal purchases and normal sales scope exception

The FASB issued amendments in August 2015 to specify that the use of locational marginal pricing by an independent system operator (ISO) does not constitute net settlement of a contract for the purchase or sale of electricity on a forward basis that necessitates transmission through, or delivery to a location within, a nodal energy market, even when legal title to the associated electricity is conveyed to the ISO during transmission. As a result, the use of locational marginal pricing by the ISO does not cause that contract to fail to meet the physical delivery criterion of the normal purchases and normal sales (NPNS) scope exception. If the physical delivery criterion is met, along with all of the other criteria of the NPNS scope exception, an entity may elect to designate that contract as a normal purchase or normal sale. The amendments were effective upon issuance of the accounting standards update, which was August 10, 2015, and require prospective application. The adoption of these amendments did not materially affect our results of operations, financial position or cash flows.

(j) 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. This 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 these changes will be reclassified from accumulated other comprehensive income to earnings if the financial liability is settled before maturity. Public business 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).

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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 do not expect our adoption of the guidance to materially affect our results of operations, financial position, or cash flows.

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

The FASB issued amendments in September 2015 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. We cannot predict how our adoption of the amendments will affect our results of operation, financial position, or cash flows as it relates to the business combination with UIL. See Note 4 - "Acquisition of UIL."

(l) 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 expect our adoption of the new guidance will materially affect our results of operations and financial position.

(m) Derivative contract novations

The FASB issued amendments in March 2016 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 do not expect our adoption will materially affect our results of operations, financial position, and cash flows.

Use of Estimates and Assumptions

The preparation of our combined and 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 combined and consolidated financial statements, and the reported amounts of revenues and expenses during the reporting

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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 combined and 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 bargain 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 1% 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 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.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

The fair value 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 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 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 combined and consolidated statements of operations.

The following unaudited pro forma 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.

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

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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:

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

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

The fair value of assets acquired and liabilities assumed from our acquisition of UIL was based on a preliminary valuation and our estimates and assumptions are subject to change within the measurement period. 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. The primary areas of the purchase price that are not yet finalized include, but are not limited to contracts, equity method investments, provisions, contingent liabilities related to certain environmental sites, income taxes and goodwill. We will finalize these amounts no later than December 16, 2016. Under U.S. GAAP, the measurement period shall not exceed one year from the acquisition date. Measurement period adjustments that we determine to be material will be recognized in future periods in our consolidated financial statements.

The following is a summary of the preliminary allocation of the purchase price as of the acquisition date:

	(millions)
Current assets, including cash of \$48 million	\$ 500
Other investments	114
Property, plant and equipment, net	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 estimated consideration	\$ 2,873

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. As part of the preliminary allocation of the purchase price we have determined a fair value of contingent liabilities of approximately \$44.0 million relating to certain environmental sites.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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.

In connection with the acquisition proceeding, UI signed a proposed partial consent order, or consent order that, when approved by the Commissioner of DEEP, and pursuant to the terms and conditions in the consent order, would require 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, upon its issuance and subject to its terms and conditions, UI would be 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).

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:

- Customers of Berkshire 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.
- Berkshire will contribute \$1 million to alternative heating programs.
- Berkshire 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.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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.

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

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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. The FERC currently provides a base ROE of 10.57% and additional ROE incentive adders applicable to assets based upon vintage, voltage and other factors.

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 Federal Power Act (FPA), the FERC finds 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. The FERC also found that the current Regional Network Service (RNS) and Local Network Service (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 RGE 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 RGE effective from August 26, 2010 through December 31, 2013. The rate plans contain continuation provisions beyond 2013 if NYSEG and RGE do not request new rates to go into effect and the current base rates will stay in place.

The revenue requirements were based on a ten-percent allowed ROE applied to an equity ratio of forty-eight-percent. 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 RGE 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 RGE 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, RGE 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 RGE will 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 RGE filed electric and gas rate cases with the NYPSC. The companies requested rate increases for NYSEG electric, NYSEG gas and RGE gas. RGE electric proposed a rate decrease.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

On February 19, 2016, NYSEG, RGE 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 RGE commencing May 1, 2016. The Proposal balances 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 enhanced electric vegetation management to provide continued safe and reliable service. The delivery rate increase in the Proposal can be summarized as follows:

Utility	May 1, 2016		May 1, 2017		May 1, 2018	
	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%
RGE Electric	3.0	0.70%	21.6	5.00%	25.9	5.70%
RGE 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, RGE Electric and RGE 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 earnings levels, with customers receiving 50%, 75% and 90% of earnings over 9.5%, 10.0% and 10.5% of ROE, respectively, in the first year. Earnings thresholds would increase in subsequent 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 RGE 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 RGE'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 and the customer average interruption duration index. 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 RGE's bill reduction and arrears forgiveness Low Income Programs at the 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 rollout of Distribution Automation and Advanced Metering Infrastructure (AMI) to customers on circuits in the Ithaca region. The Companies will also pursue Non-Wires Alternative projects as described in the Proposal. 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 a 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 RGE continue their electric RDMs on a total revenue per class basis and their gas RDMs on a revenue per customer basis.

The Administrative Law Judges assigned to the New York rate case will issue a procedural schedule establishing the remaining procedure for review and decision on the Proposal. We expect hearings on the Proposal to be held in April 2016 and a NYPSC decision to be made in May 2016.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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 2016, 80% of its standard service load for the second half of 2016 and for 30% of its standard service load for the first half of 2017. 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 August 2013, PURA approved new distribution rate schedules for UI for two years which became effective at that time and which, among other things, increased the UI distribution and CTA allowed ROE from 8.75% to 9.15%, 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 establishment of the requested storm reserve. In accordance with the approval by PURA of the acquisition, UI agreed not to initiate a rate case for new rates effective before at least January 1, 2017.

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.

Berkshire's rates are established by the DPU. Berkshire's 10-year rate plan, which was approved by the DPU and included an approved ROE of 10.5%, expired on January 31, 2012. Berkshire 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, Berkshire 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 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 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 RGE are participating in the initiative with other New York utilities and are providing their unique perspective. NYPSC staff is currently conducting public statement hearings regarding REV across New York state. The NYPSC has issued a 2015 order in Track 1, which acknowledges the utilities' role as a Distribution System Platform (DSP) provider, and requires the utilities to file an initial Distribution System Implementation Plan (DSIP) by June 30, 2016. The DSIP will also include information regarding the potential deployment of Automated Metering Infrastructure (AMI).

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 Fund, Demand Response Tariffs, and Community Choice Aggregation.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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. We expect an Order by the end of the second quarter of 2016.

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.

On July 11, 2014, GNPP filed a petition requesting that the NYPSC initiate a proceeding to examine a proposal for the continued operation of the Ginna Facility. Ginna asserted that "in the two preceding calendar years, 2012 and 2013, it had sustained cumulative losses at the Facility of nearly \$100 million (including the allocation of CENG corporate overhead)" and that "CENG has not been compensated for any operational risk or an appropriate return on its investment over this period." Based on the results of the 2014 Reliability Study, GNPP requested that: 1) the NYPSC determine that the continued operation of the Ginna Facility is required to preserve system reliability; and 2) the NYPSC issue an Order directing RGE to negotiate and file a Reliability Support Services Agreement (RSSA) 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 an RSSA." As such, the NYPSC ordered RGE and GNPP to negotiate an RSSA.

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

On October 21, 2015, RGE, 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. RGE shall make monthly payments to Ginna in the amount of \$15.4 million. RGE 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 RGE to implement a rate surcharge effective January 1, 2016 to recover amounts paid to Ginna pursuant to the RSSA. RGE's payment obligation to Ginna shall not begin until the rate surcharge is in effect and FERC has issued an order authorizing the FERC Settlement agreement in the Settlement Docket. RGE 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 RGE to Ginna then the RSSA surcharge may continue past March 31, 2017 to recover up to \$2.3 million per month until the final payment has been recovered by RGE from ratepayers. In the month following the expiration of the term on March 31, 2017, Ginna shall prepare and issue an invoice to RGE for, and RGE shall pay to Ginna, a one-time payment in the amount of \$11.5 million, which will be recovered from ratepayers. 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.

New York Transco

Affiliates of National Grid, Central Hudson, NYSEG, and RGE, together with an affiliate of Consolidated Edison and Orange and Rockland Utilities, are part of a new organization, New York Transco. New York Transco is focused on developing electric transmission to meet future electricity needs of all New Yorkers and will develop New York transmission projects upon receipt of all necessary regulatory approvals.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

New York Transco members (Applicants) are requesting regulatory approval for a group of transmission projects expected to cost \$1.7 billion, funded through debt and equity. NYSEG and RGE allocated twenty-percent equity contribution amounts to approximately \$183 million over the period 2015 through 2018. Additional projects may be developed in the future. Equity investments will be expressly contingent on receiving necessary regulatory approvals and acceptable economic returns. The investment will be made through a Networks affiliate, Networks New York Transco, LLC, formed on November 3, 2014.

New York Transco filed with FERC in early December 2014. The filing requests a formula base ROE of 10.6%, plus one-hundred fifty basis points ROE incentives. The filing also requests recognition of construction work in process, abandoned plant, regulatory asset for pre-commercial costs, and sixty-percent equity for five years. Various parties, including the NYPSC, have protested the filing with FERC.

On April 2, 2015, the FERC issued an order granting, inter alia, Applicants' request for a 50 basis point adder for NY 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 the Applicants' 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, Applicants, 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.

Minimum Equity Requirements for Regulated Subsidiaries

Our regulated utility subsidiaries (NYSEG, RGE, CMP and Maine Natural Gas) of Maine and New York are each subject to a minimum equity ratio requirement that is tied to the capital structure assumed in establishing revenue requirements. 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. Movement of capital from our wholly owned unregulated subsidiaries is unrestricted.

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 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.

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 9.15%) plus 25 basis points and (B) the current authorized distribution ROE for CL&P (currently 9.17%), less target equivalent market revenues (reflected as 25 basis points). In addition, UI will retain a percentage of the market revenues from the project, which percentage is expected to equate to approximately 25 basis points on a levelized basis over the life of the project. UI expects the cost of this

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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.

New England East-West Solution

Pursuant to an agreement with The Connecticut Light and Power Company, or CL&P (the Agreement), UI has the right to invest in, and own transmission assets associated with, the Connecticut portion of CL&P’s New England East West Solution (NEEWS) projects to improve regional energy reliability. NEEWS originally consisted of four inter-related transmission projects being developed by subsidiaries of Northeast Utilities (doing business as Eversource Energy), the parent company of CL&P, in collaboration with National Grid USA. Three of the original projects have portions located in Connecticut: (1) the Greater Springfield Reliability Project (GSRP), which was fully energized in November 2013, (2) the Interstate Reliability Project (IRP), which was placed in service in the fourth quarter 2015 and (3) the Central Connecticut Reliability Project, the need for which is now planned to be addressed by CL&P’s Greater Hartford Central Connecticut solutions, in which UI does not anticipate making any investments.

Under the Agreement, as of December 31, 2015, UI had made aggregate deposits of approximately \$45 million since its inception, with assets valued at approximately \$44.6 million having been transferred to UI. UI does not anticipate making any additional investments in NEEWS under the agreement.

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, 2015 through December 31, 2015 of \$29.5 million and \$36.5 million for GenConn Devon and GenConn Middletown, respectively. In addition, PURA has ruled that GenConn project costs incurred that were in excess of the proposed costs originally submitted in 2008 were prudently incurred and are recoverable. Such costs are included in the determination of the 2015 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 rate base or are accruing a carrying cost until they will be included in rate base. The primary items that are not included in 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, asset retirement obligations, hedge losses and contracts for differences. The total amount of these items is \$2,825 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.

Most of the items related to NYSEG for which the amortization period has been characterized as to be determined in a future proceeding have been addressed in the Proposal. If the Proposal is approved, most of these items would be amortized over a five year period, except the portion of storm costs to be recovered over ten years and plant related tax items which will be amortized over the life of associated plant. Annual amortization expense for NYSEG would be approximately \$16.5 million per rate year. The RGE items that would begin being amortized are plant related tax items. A majority of the other items related to RGE, which net to a regulatory liability, will not be amortized until future proceedings or will be used to recover costs of the Ginna RSSA agreement.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

Current and non-current regulatory assets as of December 31, 2015 and 2014 consisted of:

As of December 31, (Millions)	2015	2014
Current		
Pension and other postretirement benefits cost deferrals	\$ 8	\$ —
Pension and other postretirement benefits	13	—
Storm costs	8	14
Temporary supplemental assessment surcharge	7	12
Hedges losses	37	34
Contracts for differences	18	—
Hardship programs	13	—
Deferred purchased gas	12	—
Deferred transmission expense	12	—
Environmental remediation costs	37	—
Other	54	20
Total Current Regulatory Assets	219	80
Non-current		
Pension and other postretirement benefits cost deferrals	151	125
Pension and other postretirement benefits	1,509	1,101
Storm costs	251	259
Deferred meter replacement costs	34	36
Unamortized losses on reacquired debt	23	25
Environmental remediation costs	271	247
Unfunded future income taxes	549	366
Asset retirement obligation	24	32
Deferred property tax	45	30
Federal tax depreciation normalization adjustment	158	128
Merger capital expense target customer credit	15	10
Debt premium	141	—
Contracts for differences	50	—
Hardship programs	29	14
Other	64	26
Total Non-current Regulatory Assets	\$ 3,314	\$ 2,399

“Pension and other postretirement benefits” represent the actuarial losses on the pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future pension expenses. “Pension and other postretirement benefits cost deferrals” include the difference between actual expense for pension and other postretirement benefits and the amount provided for in rates. The recovery of these amounts will be determined in future proceedings.

“Storm costs” for CMP, NYSEG, and RGE 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. Since the approval of the 2010 rate plan in New York, NYSEG has experienced unusually high levels of restoration costs resulting from various storms including Hurricane Sandy, Hurricane Irene, and Tropical Storm Lee. NYSEG’s deferred storm costs, reflecting the over (under) spending of actual costs compared with amounts currently allowed in rates, was \$(9) million and \$5 million for the years ended December 31, 2015 and 2014, respectively. NYSEG’s total deferral, including carrying costs, was \$247 million and \$241 million as of December 31, 2015 and 2014, respectively. The amortization will be determined in a future NYPSC proceeding. CMP’s deferred service restoration costs, primarily as a result of an ice storm in late December 2014, reflecting over (under) spending of actual costs compared with amounts allowed in rates, was \$(6) million and \$15 million for the years ended December 31, 2015 and 2014, respectively. CMP’s total deferral, including carrying costs, was \$12 million and \$32 million as of December 31, 2015 and 2014, respectively. Recovery of CMP’s deferred storm costs in the amount of \$28 million began with the effective date of its last rate case and occurs over a twenty-four month period. Recovery of incremental deferrals will be determined in a future proceeding.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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

“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. 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.

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

“Deferred property taxes” represent the customer portion of the difference between actual expense for property taxes and the amount provided for in rates. The amortization period is awaiting a future NYPSC rate proceeding.

“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 will be determined in future NYPSC and 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.

“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.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

Current and non-current regulatory liabilities as of December 31, 2015 and 2014 consisted of:

As of December 31, (Millions)	2015	2014
Current		
Reliability support services (Cayuga)	\$ 16	\$ 18
Plant decommissioning	—	13
Non by-passable charges	7	19
Energy efficiency portfolio standard	33	34
Gas supply charge and deferred natural gas cost	6	6
Transmission revenue reconciliation mechanism	16	23
Yankee DOE Phase I	5	23
Merger related rate credits	20	—
Revenue decoupling mechanism	14	8
Other	30	21
Total Current Regulatory Liabilities	147	165
Non-current		
Accrued removal obligations	1,084	721
Asset sale gain account	8	19
Carrying costs on deferred income tax bonus depreciation	116	81
Economic development	36	33
Merger capital expense target customer credit account	17	17
Pension and other postretirement benefits	90	50
Positive benefit adjustment	51	51
New York state tax rate change	17	16
Post term amortization	25	20
Theoretical reserve flow thru impact	31	24
Deferred property tax	15	51
Net plant reconciliation	10	10
Variable rate debt	32	25
Carrying costs on deferred income tax - Mixed Services 263(a)	31	20
Rate refund – FERC ROE proceeding	21	23
Merger related rate credits	24	—
Accumulated deferred investment tax credits	10	—
Asset retirement obligation	13	—
Middletown/Norwalk local transmission network service collections	19	—
Excess generation service charge	21	—
Low income programs	42	10
Unfunded future income taxes	27	—
Non-firm margin sharing credits	8	—
Deferred income taxes regulatory	519	433
Other	93	58
Total Non-current Regulatory Liabilities	\$ 2,360	\$ 1,662

“Reliability support services (Cayuga)” represent 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 fixed 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.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

“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 awaiting a future NYPSC rate proceeding.

“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 awaiting a future NYPSC rate proceeding.

“Economic development” represents the economic development program which enables NYSEG and RGE 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 RGE varies in any rate year from the level provided for in rates, the difference is refunded to ratepayers. The amortization period is awaiting a future NYPSC rate proceeding.

“Merger capital expense target customer credit” account was created as a result of NYSEG and RGE not meeting certain capital expenditure requirements established in the order approving the purchase of Energy East by Iberdrola. The amortization period is awaiting a future NYPSC rate proceeding.

“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. It also represents 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 acquisitions of Energy East. This is being used to moderate increases in rates. The amortization period is awaiting a future NYPSC rate proceeding.

“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 awaiting a future NYPSC rate proceeding.

“Post term amortization” represents the revenue requirement associated with certain expired joint proposal amortization items. The amortization period is awaiting a future NYPSC rate proceeding.

“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 awaiting a future NYPSC rate proceeding.

“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.

“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. 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.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

Note 7. Goodwill and Intangible assets

Goodwill by reportable segment as of December 31, 2015 and 2014 consisted of:

As of December 31, (Millions)	2015	2014
Networks	\$ 2,733	\$ 979
Renewables	380	380
Gas	—	—
Other (a)	2	2
Total	\$ 3,115	\$ 1,361

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

As of December 31, 2015 and 2014, the gross amounts of goodwill were \$2,733 million for Networks reportable segment, \$3,340 million for Renewables and Gas reportable segments and \$2 million for Corporation (which does not represent a segment), 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 \$1,754 million due to acquisition of UIL (See Note 4 – Acquisition of UIL – for further details).

Goodwill Impairment Assessment

For impairment testing purposes our reporting units are the same as operating segments, except for Networks, which contained two reporting units, Maine and New York as of December 31, 2014 and three reporting units, Maine, New York and UIL as of December 31, 2015. 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 RGE 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 \$1,754 million.

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

Our step one impairment testing includes various assumptions, primarily the discount rate, which is based on an estimate of our marginal, weighted average cost of capital, and forecasted cash flows. We test the reasonableness of the conclusions of our step one impairment testing using a range of discount rates and a range of assumptions for long term cash flows. In 2015 the impairment testing of goodwill for Networks includes Maine and New York reporting units.

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. None of these factors had changed significantly since 2014.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

Renewables

Based on the results of our step 1 impairment test for the Renewables reporting unit conducted in 2015, its estimated fair value exceeds carrying value by approximately 1.55%. 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.

2014

We had no impairment of goodwill in 2014 as a result of our impairment testing.

Networks

Based on the results of our step 1 impairment test conducted in 2014, the estimated fair value of each of the Networks reporting units was substantially in excess of their respective carrying value.

Renewables

Based on the results of our step 1 impairment test for the Renewables reporting unit conducted in 2014, its estimated fair value exceeds carrying value by approximately 1%. 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.

2013

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 2013 considering the substantial excess of fair value over the carrying value that was demonstrated in the 2011 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. None of these factors had changed significantly since 2011.

Renewables

Based on the results of our step 1 impairment test for the Renewables reporting unit conducted in 2013, the estimated fair value exceeded the carrying value by approximately 11%.

Gas

Based on the results of our step 1 impairment test the Gas reporting unit fair value analysis resulted in an implied fair value of goodwill of \$0 for this reporting unit, and consequently, a non-cash impairment charge in the amount of \$163 million was recorded for the year ended December 31, 2013. The inputs used to determine the fair value of the Gas reporting unit were based on forecasted cash flows, which are classified as Level 3 in the fair value hierarchy. The main reason for the impairment was the projected long-term low margins for natural gas given the impact of shale gas in the North American energy market. We elected to suspend the gas storage facility construction projects of this reporting unit until this scenario substantially changes.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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, 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

As of December 31, 2014	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
(Millions)			
Gas Storage rights	\$ 325	\$ (117)	\$ 208
Wind development	574	(220)	354
Other	56	(49)	7
Total Intangible Assets	\$ 955	\$ (386)	\$ 569

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, 2015, 2014 and 2013 amounted to \$54 million, \$66 million and \$72 million, respectively. We do not believe our future cash flows will impact the recoverability of our intangible assets.

We expect amortization expense for the five years subsequent to December 31, 2015, to be as follows:

Year ending December 31,	
(Millions)	
2016	\$ 27
2017	25
2018	24
2019	26
2020	25

As a result of writing off of fully amortized intangibles assets relating to Gas Storage rights, \$6.5 million was removed from both cost and accumulated amortization during 2015.

Wind development costs written off totaled \$42 million in 2013. These charges were included in Impairment of non-current assets in the combined and consolidated statements of operations.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

Note 8. Property, Plant and Equipment

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

As of December 31, 2015 (Millions)	Regulated	Nonregulated	Total
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.

Property, plant and equipment as of December 31, 2014 consisted of:

As of December 31, 2014 (Millions)	Regulated	Nonregulated	Total
Electric generation, distribution, transmission and other	\$ 8,625	\$ 9,798	\$ 18,423
Natural gas transportation, distribution and other	1,723	648	2,371
Other common operating property	654	51	705
Total Property, Plant and Equipment in Service (a)	11,002	10,497	21,499
Total accumulated depreciation (b)	(3,491)	(2,271)	(5,762)
Total Net Property, Plant and Equipment in Service	7,511	8,226	15,737
Construction work in progress	878	518	1,396
Total Property, Plant and Equipment	\$ 8,389	\$ 8,744	\$ 17,133

(a) Includes capitalized leases of \$158 million primarily related to electric generation, distribution, transmission and other.

(b) Includes accumulated amortization of capitalized leases of \$47 million.

Capitalized interest costs were \$13 million, \$12 million, and \$9 million for the years ended December 31, 2015, 2014 and 2013, respectively.

In view of the projected long-term low margins for natural gas as a result of the impact of shale gas in the North American energy market, in 2013 we abandoned the gas storage facility construction projects assigned to the gas reporting unit. Consequently, we impaired or wrote off certain gas storage projects and other facilities under construction for an amount of \$382 million, included in "Impairment of non-current assets" in the combined and consolidated statements of operations for the year ended December 31, 2013.

We also impaired or wrote off amounts of \$12 million, \$24 million, and \$33 million for the years ended December 31, 2015, 2014 and 2013 respectively, resulting from reassessment of the economic feasibility of its various Renewables development projects in construction.

Depreciation expense for the years ended December 31, 2015, 2014 and 2013 amounted to \$641 million, \$563 million and \$522 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.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

The reconciliation of ARO carrying amounts for the years ended December 31, 2015 and 2014 consisted of:

(Millions)	
As of December 31, 2013	\$ 209
Liabilities settled during the year	(1)
Liabilities incurred during the year	6
Accretion expense	14
Revisions in estimated cash flows	6
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

Several of the wind generation facilities have restricted cash for purposes of settling AROs. Restricted cash related to AROs was \$1.8 million and \$1.7 million as of December 31, 2015 and 2014, 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 combined and consolidated statements of operations.

We have AROs for which a liability has not been recognized because the fair value cannot be reasonably estimated due to indeterminate settlement dates, including for the removal of hydroelectric dams due to structural inadequacy or for decommissioning; the removal of property upon termination of an easement, right-of-way or franchise; and costs for abandonment of certain types of gas mains.

In 2015 we revised our model used to estimate the future undiscounted costs for removal of our wind and solar facilities, based upon a study performed by an independent engineering firm that specializes in such matters. This revision resulted in a lower estimate of future removal costs, which we estimate will result in a \$5 million annual reduction in expense going forward.

Note 10. Debt

Long-term debt as of December 31, 2015 and 2014 consisted of:

As of December 31, (Millions)	Maturity Dates	2015		2014	
		Balances	Interest Rates	Balances	Interest Rates
First mortgage bonds - fixed (a)	2016-2045	\$ 1,815	3.07%-10.60%	\$ 1,405	3.07%-8.00%
Unsecured pollution control notes - fixed	2020	200	2.00%-2.375%	132	2.125%-2.25%
Unsecured pollution control notes – variable	2032-2034	219	0.195%-1.181%	159	0.03%-0.461%
Other various non-current debt - fixed	2016-2045	2,440	2.89%-10.48%	889	3.24%-10.48%
Total Debt		\$ 4,674		\$ 2,585	
Obligations under capital leases	2020-2023	87	4%-4.44%	81	4%-4.44%
Unamortized debt (costs) premium, net		(25)		(29)	
Less: debt due within one year, included in current liabilities		206		148	
Total Non-current Debt		\$ 4,530		\$ 2,489	

(a) The first mortgage bonds have pledged collateral of substantially all the respective utility's properties of approximately \$5,682 million.

In January 2015, CMP issued \$150 million of first mortgage bonds in three tranches: \$65 million maturing in 2025 bearing a coupon of 3.15%, \$20 million maturing in 2030 bearing a coupon of 3.37%, and \$65 million maturing in 2045 bearing a coupon of 4.07%.

In April 2015, NYSEG issued \$200 million of fixed rate pollution control notes in four separate series. The notes have mandatory redemption dates in 2020. \$99 million of the notes bear an interest rate of 2.375% and \$101 million bear an interest rate of 2.00%.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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

(Millions)											
2016		2017		2018		2019		2020		Total	
\$	206	\$	302	\$	162	\$	354	\$	721	\$	1,745

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, 2015 and 2014.

Fair Value of Debt

The estimated fair value of debt amounted to \$4,985 million and \$2,962 million as of December 31, 2015 and 2014, 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 \$204 million and \$145 million, respectively, as of December 31, 2015 and 2014, 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

(a) AVANGRID Revolving credit facility

In May 2012, we entered into a \$300 million revolving credit facility for the purpose of providing for our liquidity needs and those of our unregulated subsidiaries. The facility has a termination date in May 2019. We pay an annual facility fee of \$0.7 million. As of December 31, 2015 and December 31, 2014 the facility was undrawn.

The revolving credit facility contains a covenant that requires us to maintain a ratio of consolidated indebtedness to consolidated total capitalization that does not exceed 0.65 to 1.00 at any time. For purposes of calculating this maximum ratio of consolidated indebtedness to consolidated total capitalization, the facility excludes from consolidated net worth the balance of accumulated other comprehensive income (AOCI) as it appears on the consolidated balance sheets.

(b) Iberdrola Financiación, S.A. credit facility

In August 2011, we entered into a revolving credit facility with Iberdrola Financiación, S.A., a subsidiary of Iberdrola, under which we could borrow up to \$600 million. The facility was terminated by AVANGRID on October 28, 2015. The facility was never utilized.

(c) Joint utility revolving credit facility

In July 2011, NYSEG, RGE and CMP jointly entered into a bank provided revolving credit facility (Joint Utility Facility) that allows maximum aggregate borrowings of up to \$600 million and expires in July 2018. Each subsidiary is currently subject to a \$200 million credit limit. Each borrower pays a facility fee ranging from fifteen to twenty basis points annually depending on the rating of its unsecured debt.

CMP and NYSEG have established commercial paper programs backstopped by the Joint Utility Facility. These companies use commercial paper as an alternative to revolving credit facilities as a source of short-term credit.

In the Joint Utility Facility each joint borrower covenants not to permit, without the lender's consent, its ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of consolidated indebtedness to total capitalization, the facility excludes from consolidated net worth the balance of AOCI as it appears on the consolidated balance sheets. As of December 31, 2015 and December 31, 2014 there were no outstanding loans, no outstanding commercial paper and \$14 million of outstanding letters of credit at both dates.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

(d) UIL credit facility

In November 2011 UIL, UI, CNG, SCG, and Berkshire became parties to a revolving credit agreement that will expire on November 30, 2016 (the UIL Credit Facility). The aggregate borrowing limit under the UIL Credit Facility is \$400 million, all of which is available to UIL, \$250 million of which is available to UI, \$150 million of which is available to each of CNG and SCG, and \$25 million of which is available to Berkshire, all subject to the aggregate limit of \$400 million. UIL pays a facility fee of twenty basis points annually.

The UIL Credit Facility contains a covenant that requires each borrower to maintain a ratio of consolidated indebtedness to consolidated total capitalization that does not exceed 0.65 to 1.00 at any time. For purposes of calculating this maximum ratio of consolidated indebtedness to consolidated total capitalization, the facility excludes from consolidated net worth unrealized gains and losses reflected in other comprehensive income in respect of qualified and non-qualified defined benefit pension plans, as well as other post-retirement benefit plans of such borrower.

As of December 31, 2015 there were \$163 million in outstanding loans bearing interest rate of 1.57%, and there was \$4 million in outstanding letters of credit.

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 noncurrent 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 RGE 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). RGE hedges all its electric load obligations using contracts for a NYISO location where an active market exists. The forward market prices used to value RGE'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 RGE 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, RGE 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

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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 financial instruments measured at fair value as of December 31, 2015 and 2014 consisted of:

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 (CfDs)	—	—	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 (CfDs)	—	—	(96)	—	(96)
Derivative financial instruments - other	—	—	(3)	—	(3)
Total	\$ (236)	\$ (52)	\$ (164)	\$ 267	\$ (185)
As of December 31, 2014 (Millions)	Level 1	Level 2	Level 3	Netting	Total
Securities portfolio (available for sale)	\$ 33	\$ —	\$ —	\$ —	\$ 33
Derivative assets					
Derivative financial instruments - power	11	83	48	(53)	89
Derivative financial instruments - gas	18	638	61	(579)	138
Total	29	721	109	(632)	\$ 227
Derivative liabilities					
Derivative financial instruments - power	(40)	(42)	(7)	53	(36)
Derivative financial instruments - gas	(25)	(614)	(42)	579	(102)
Derivative financial instruments - other	—	—	(3)	—	(3)
Total	\$ (65)	\$ (656)	\$ (52)	\$ 632	\$ (141)

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

The reconciliations of changes in the fair value of financial instruments based on Level 3 inputs for the years ended December 31, 2015, 2014 and 2013 consisted of:

(Millions)	2015	2014	2013
Fair value as of January 1,	\$ 57	\$ 53	\$ 5
Gains for the year recognized in operating revenues	33	11	21
Losses for the year recognized in operating revenues	(8)	(1)	(3)
Total gains or losses for the period recognized in operating revenues	25	10	18
Gains recognized in OCI	2	—	—
Losses recognized in OCI	(3)	(3)	—
Total gains or losses recognized in OCI	(1)	(3)	—
Purchases	(73)	14	47
Settlements	(14)	(26)	(15)
Transfers out of Level 3 (a)	(13)	9	(2)
Fair value as of December 31,	\$ (19)	\$ 57	\$ 53
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	\$ 25	\$ 10	\$ 18

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

For assets and liabilities that are recognized in the combined and 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. They represent the variability in prices for those transactions that fall into the illiquid period (beyond 2 years), using past and current views of prices for those future periods.

Instruments	Instrument Description	Valuation Technique	Valuation Inputs	Index	Variability		
					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)	\$ 4.56	\$ 7.37	\$ 1.76
				SP15 (\$/MWh)	\$46.82	\$80.28	\$19.75
				Mid C (\$/MWh)	\$37.93	\$83.93	\$6.75
				Cinergy (\$/MWh)	\$37.73	\$77.49	\$19.98

Our Level 3 valuations primarily consist of NYMEX gas and fixed price power swaps with delivery periods extending through 2017. The gas swaps are used to hedge both gas inventory in firm storage and merchant wind positions. The power swaps are traded at liquid hubs in the West and Midwest and are used to hedge merchant wind production in those regions.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

We performed a sensitivity analysis around the Level 3 gas and power positions to changes in the valuations inputs and concluded that no material change to the financial statements is expected given the following: (i) any changes in the fair value of the gas swaps hedging inventory would be expected to be largely offset by changes in the value of the inventory; (ii) any changes in the fair value of the gas swaps hedging merchant generation would be expected to be significantly offset by changes in the value of future power generation.

Future commodity prices are the significant unobservable inputs to fair value. Any significant increases in prices would result in a lower fair value of derivatives. Conversely, significant reductions in prices would result in a higher fair value of derivatives.

Two elements of the analytical infrastructure employed in valuing transactions are the price curves used in calculation of market value and the models themselves. Authorized trading points and associated forward price curves are maintained and documented by the Middle Office. Models used in valuation of the various products are developed and documented by the Structuring and Market Analysis group.

Transaction models are valued in part on the basis of forward price, correlation, and volatility curves. Descriptions of these curves and their derivations are maintained and documented by the Structuring and Market Analysis group. Forward price curves used in valuing the models are applied to the full duration of transactional models to a maximum of approximately thirty years.

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 the December 31, 2015 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, 2015
Risk of non-performance	0.06% - 0.88%
Discount rate	1.31% - 2.27%
Forward pricing (\$ per MW)	\$3.15 - \$11.19

Note 12. Derivative Instruments and Hedging

Our Networks, Renewables and Gas activities are exposed to certain risks, which are managed by using derivative instruments.

(a) Networks activities

NYSEG and RGE have a non by-passable wires charge adjustment that allows them to pass through any changes in 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 loss recognized in regulatory assets for electricity derivatives was \$34.3 million and \$28.8 million as of December 31, 2015 and 2014, respectively. The loss reclassified from regulatory assets into income, which is included in electricity purchased, was \$46.9 million, \$21.3 million, and \$2.2 million for the years ended December 31, 2015, 2014 and 2013, respectively.

NYSEG and RGE 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 RGE 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.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

The loss recognized in regulatory assets for natural gas hedges was \$3.1 million as of December 31, 2015. The loss recognized in regulatory assets for natural gas hedges was \$4.7 million as of December 31, 2014. The loss reclassified from regulatory assets into income, which is included in natural gas purchased, was \$6.3 million, \$2.2 million, and \$1.8 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Contracts for Differences (CfDs)

Pursuant to Connecticut's 2005 Energy Independence Act, the Connecticut Public Utilities Regulatory Authority (PURA) solicited bids to create new or incremental capacity resources in order to reduce federally mandated congestion charges, and selected four new capacity resources. To facilitate the transactions between the selected capacity resources and Connecticut electric customers, and provide the commitment necessary for owners of these resources to obtain necessary financing, PURA required that UI and The Connecticut Light and Power Company (CL&P) execute long-term contracts with the selected resources. In August 2007, PURA approved four CfDs, each of which specifies a capacity quantity and a monthly settlement that reflects the difference between a forward market price and the contract price. UI executed two of the contracts and CL&P executed the other two contracts. 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, 2015, UI has recorded a gross derivative 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 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 period from December 17, 2015 to December 31, 2015 were as follows:

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

The net notional volumes of the outstanding derivative instruments associated with Networks activities as of December 31, 2015 and 2014 consisted of:

As of December 31, (Millions)	2015	2014
Wholesale electricity purchase contracts (MWh)	6.7	6.6
Natural gas purchase contracts (Dth)	4.8	3.8
Fleet fuel purchase contracts (Gallons)	3.8	2.8

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

The location and amounts of derivatives designated as hedging instruments associated with Networks activities as of December 31, 2015 and 2014 consisted of:

(Millions)	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
As of December 31, 2015				
Commodity contracts:				
Electricity derivatives:				
Current	Current assets	\$ —	Current liabilities	\$ —
Non-current	Other assets	—	Other liabilities	—
Natural gas derivatives:				
Current	Current assets	—	Current liabilities	—
Non-current	Other assets	—	Other liabilities	—
Fleet fuel contracts				
Current	Current assets	—	Current liabilities	(2)
Non-current	Other assets	—	Other liabilities	(1)
Total		\$ —		\$ (3)
As of December 31, 2014				
Commodity contracts:				
Electricity derivatives:				
Current	Current assets	\$ —	Current liabilities	\$ (20)
Non-current	Other assets	—	Other liabilities	(9)
Natural gas derivatives:				
Current	Current assets	—	Current liabilities	(4)
Non-current	Other assets	—	Other liabilities	(1)
Fleet fuel contracts	Current assets	—	Current liabilities	(3)
Total		\$ —		\$ (37)

The effect of derivatives in cash flow hedging relationships on OCI and income for the years ended December 31, 2015, 2014 and 2013 consisted of:

Year Ended December 31, (Millions)	(Loss) Recognized in OCI on Derivatives	Location of (Loss) Reclassified from Accumulated OCI into Income	(Loss) Reclassified from Accumulated OCI into Income
	Effective Portion (a)	Effective Portion (a)	Effective Portion (a)
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)
2013			
Interest rate contracts	\$ —	Interest expense	\$ (11)
Commodity contracts	—	Operating expenses	(1)
Total	\$ —		\$ (12)

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

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

The net loss in accumulated OCI related to previously settled forward starting swaps and accumulated amortization is \$84.9 million, \$93.5 million, and \$102.5 million for the years ended December 31, 2015, 2014 and 2013, respectively. We recorded \$8.6 million, \$8.9 million, and \$11.2 million in net derivative losses related to discontinued cash flow hedges for the years ended December 31, 2015, 2014 and 2013, respectively. We will amortize approximately \$8.1 million of discontinued cash flow hedges in 2016.

The unrealized loss of \$2.7 million on hedge derivatives is reported in OCI because the forecasted transaction is considered to be probable as of December 31, 2015. We expect that those losses will be reclassified into earnings within the next twenty four months, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted energy transactions.

The offsetting of derivative assets as of December 31, 2015 and 2014 consisted of:

As of December 31, (Millions)	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet	Gross Amounts Not Offset in the Balance Sheet		Net Amount
				Financial Instruments	Cash Collateral Pledged	
2015						
Derivatives	\$ 10	\$ (10)	\$ —	\$ —	\$ —	\$ —
2014						
Derivatives	11	(11)	—	—	—	—

The offsetting of derivative liabilities as of December 31, 2015 and 2014 consisted of:

As of December 31, (Millions)	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Balance Sheet	Net Amounts of Liabilities Presented in the Balance Sheet	Gross Amounts Not Offset in the Balance Sheet		Net Amount
				Financial Instruments	Cash Collateral Pledged	
2015						
Derivatives	\$ (49)	\$ 46	\$ (3)	\$ —	\$ —	\$ (3)
2014						
Derivatives	(48)	11	(37)	—	37	—

(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.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

The net notional volumes of outstanding derivative instruments associated with Renewables and Gas activities as of December 31, 2015 and 2014 consisted of:

As of December 31, (MWh/Dth in Millions)	2015	2014
Wholesale electricity purchase contracts	3	2
Wholesale electricity sales contracts	6	7
Foreign exchange forward purchase contracts	4	—
Natural gas and other fuel purchase contracts	332	275
Financial power contracts	7	8
Basis swaps - purchases	67	160
Basis swaps - sales	80	161

The fair values of derivative contracts associated with Renewables and Gas activities as of December 31, 2015 and 2014 consisted of:

As of December 31, (Millions)	2015	2014
Wholesale electricity purchase contracts	\$ (13)	\$ (12)
Wholesale electricity sales contracts	35	44
Foreign exchange forward purchase contracts	(1)	(3)
Natural gas and other fuel purchase contracts	10	54
Financial power contracts	32	48
Basis swaps- purchases	1	(4)
Basis swaps- sales	(2)	(4)
Total	\$ 62	\$ 123

The offsetting of derivative assets as of December 31, 2015 and 2014 consisted of:

As of December 31, (Millions)	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet	Gross Amounts Offset in the Balance Sheet	Cash Collateral Pledged	Net Amount
				Financial Instruments		
2015						
Derivatives	\$ 489	\$ (341)	\$ 148	\$ (36)	\$ (15)	\$ 97
2014						
Derivatives	847	(620)	227	(66)	(73)	88

The offsetting of derivative liabilities as of December 31, 2015 and 2014 consisted of:

As of December 31, (Millions)	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Balance Sheet	Net Amounts of Liabilities Presented in the Balance Sheet	Gross Amounts Not Offset in the Balance Sheet	Cash Collateral Pledged	Net Amount
				Financial Instruments		
2015						
Derivatives	\$ (307)	\$ 221	\$ (86)	\$ 36	\$ 4	\$ (46)
2014						
Derivatives	(724)	620	(104)	66	1	(37)

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

The effect of trading derivatives associated with Renewables and Gas activities for the years ended December 31, 2015, 2014 and 2013 consisted of:

Years Ended December 31, (Millions)	2015	2014	2013
Wholesale electricity purchase contracts	\$ 6	\$ (9)	\$ 2
Wholesale electricity sales contracts	(5)	9	(1)
Financial power contracts	—	(2)	(4)
Financial and natural gas contracts	(26)	125	(21)
Total Gain (Loss)	\$ (25)	\$ 123	\$ (24)

Such gains and losses are included in revenue in the combined and consolidated statements of operations.

The effect of non-trading derivatives associated with Renewables and Gas activities for the years ended December 31, 2015, 2014 and 2013 consisted of:

Years Ended December 31, (Millions)	2015	2014	2013
Wholesale electricity purchase contracts	\$ (8)	\$ (8)	\$ 9
Wholesale electricity sales contracts	(5)	15	(2)
Financial power contracts	24	30	(19)
Natural gas and other fuel purchase contracts	18	(1)	16
Total Gain (Loss)	\$ 29	\$ 36	\$ 4

Such gains and losses are included in revenue and “Purchased power, natural gas and fuel used” operating expenses in the combined and consolidated statements of operations, 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 location and amounts of derivatives designated as hedging instruments associated with Renewables and Gas activities as of December 31, 2015 consisted of:

(Millions)	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
As of December 31, 2015				
Commodity contracts:				
Electricity derivatives:				
Current	Current assets	\$ 2	Current liabilities	\$ —
Non-current	Other assets	1	Other liabilities	—
Natural gas derivatives:				
Current	Current assets	50	Current liabilities	(9)
Non-current	Other assets	9	Other liabilities	—
Total		\$ 62		\$ (9)

Year Ended December 31, (Millions)	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)
2015			
Commodity contracts	\$ 57	Revenues	\$ (2)
Total	\$ 57		\$ (2)

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

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

Amounts will be reclassified from accumulated OCI into income in the period(s) 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 \$43.5 million of gains included in accumulated OCI at December 31, 2015 is expected to be reclassified into earnings within the next 12 months. During the year ended December 31, 2015 we recorded a net gain of \$4.8 million in earnings as a result of ineffectiveness from cash flow hedges. We recorded \$2.3 million in net derivative gain related to discontinued cash flow hedge for the year ended December 31, 2015.

(c) Counterparty credit risk management

NYSEG and RGE 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, 2015, UI would have had to post an aggregate of approximately \$18 million in collateral.

We have various master netting arrangements in the form of multiple contracts with various single counterparties that are subject to contractual agreements that provide for the net settlement of all contracts through a single payment. Those arrangements reduce our exposure to a counterparty in the event of default on or termination of any single contract. For financial statement presentation purposes, we offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement. The amount of cash collateral used to offset against net derivative positions was \$84 million as of December 31, 2015. Under the master netting arrangements our obligation to return cash collateral was \$0.1 million and \$0.2 million as of December 31, 2015 and 2014, respectively. Derivative instruments settlements and collateral payments are included in "Other assets" and "Other liabilities" of operating activities in the combined and 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, 2015 is \$39.7 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. MNG requested a 10.0% ROE and 50% equity ratio. The MPUC Staff has recommended a separate revenue requirement for MNG's Augusta customers and MNG's non-Augusta customers. Staff also recommended a \$19.95 million disallowance of the August Expansion investment based upon the Staff's conclusion that MNG's management of the Augusta Expansion Project was imprudent.

On November 6, 2015, a stipulation was filed with the MPUC, which was executed by MNG, the Office of Public Advocate and the City of Augusta. The stipulation contained a combined revenue requirement for Augusta and Non-Augusta based on a 9.55% ROE and 50% equity ratio. The stipulation also provided for an initial Augusta investment disallowance of \$6 million and an investment phase-in of \$10 million. On December 22, 2015, MPUC rejected the proposed Stipulation as not in the public interest. In January 2016, the Administrative Law Judge established a new litigation schedule. The litigation was suspended at the end of January 2016 for settlement discussions. We cannot predict the outcome of the proceeding. We reserved \$6 million for this case at the end of 2015.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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 a just and reasonable level of 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 initial decision in the first complaint, establishing a methodology and setting the issues for a paper hearing. On October 16, 2014, FERC issued its final decision in the first complaint (Complaint I) setting the base ROE at 10.57%, and a maximum total ROE of 11.74% for the October 2011 – December 2012 period 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 initial 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. We cannot predict the outcome of this appeal.

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

On July 31, 2014, the Complainants filed a third, related, complaint (Complaint III) for a subsequent rate period requesting the ROE be reduced to 8.84%. On November 24, 2014, FERC accepted the third complaint, established a refund effective date of July 31, 2014, and set for consolidated hearing with Complaint II 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. 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 New England transmission owners 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 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 late 2016 or early 2017.

CMP and UI reserved for refunds for Complaints I, II and III consistent with the FERC's March 3, 2015 final Complaint I decision. The CMP and UI total reserve associated with Complaints I, II and III is \$23.9 million and \$4.2 million, respectively, as of December 31, 2015. If adopted as final, the impact of the initial decision would be an additional reserve for Complaints II and III of \$10.2 million, net of tax, which is based upon currently available information for these proceedings. We cannot predict the outcome of Complaint II and III proceedings.

Yankee Nuclear Spent Fuel Disposal Claim

CMP has an ownership interest in Maine Yankee, Connecticut Yankee, and Yankee Atomic, (the Yankee Companies), three New England single-unit decommissioned nuclear reactor sites, and UI has an ownership interest in Connecticut Yankee. Every six years, pursuant to the statute of limitations, the Yankee companies need to 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 \$40.3 million to Connecticut Yankee Atomic Power Company; affirmed the Court of Federal Claims award of \$65 million to Maine Yankee Atomic Power Company; and increased Yankee Atomic Electric Company's damages

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

award from \$21.4 million to \$37.8 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 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 based on percentage ownership. We cannot predict the timing or amount of damage awards that may ultimately flow through to shareholders.

NYPSC Staff Review of Earnings Sharing Calculations and Other Regulatory Deferrals

In December 2012, the NYPSC Staff (Staff) informed NYSEG and RGE 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 RGE reviewed the Staff's adjustments and work papers and provided a response in 2013. Staff has not yet replied to NYSEG's and RGE's response. NYSEG and RGE disagreed with certain staff conclusions and as a result have recorded a \$3.4 million reserve in December 2012 in anticipation of settling the Staff issues. In the proposal filed with the NYPSC (see Note 5) the parties agreed that \$2.4 million would be added to customer share of Earnings Sharing.

Middletown/Norwalk Transmission Project

The general contractor and two subcontractors responsible for civil construction work in connection with the installation of UI's portion of the Middletown/Norwalk Transmission Project's underground electric cable system filed lawsuits in Connecticut state court on September 22, 2009, March 23, 2009 and January 25, 2010, respectively. The claims, as revised by the general contractor in October 2011, sought payment for change order requests of approximately \$33.3 million, a 10% general contractor mark-up on any approved subcontractor change order claims (approximately \$2.3 million), interest, costs, and attorneys' fees. In December 2011, UI settled the claims brought by the two subcontractors and their respective lawsuits were dismissed, reducing UI's estimate of the general contractor's claims to approximately \$7.7 million, exclusive of the contractor's claims for interest, costs, and attorneys' fees. UI also pursued an indemnification claim against the general contractor for the payments made in settlement to the two subcontractors.

On September 3, 2013, the court found for UI on all claims but one related to certain change orders, and ordered UI to pay the Contractor approximately \$1.3 million, which has since been paid. The court also found against UI on the indemnification claims. On October 22, 2013, the general contractor filed an appeal of the Court's ruling. UI expects to recover any amounts paid to resolve the contractor and subcontractor claims through UI's transmission revenue requirements.

In April 2013, an affiliate of the general contractor for the Middletown/Norwalk Transmission Project, purporting to act as a shareholder on behalf of UIL Holdings, filed a complaint against the UIL Holdings Board of Directors alleging that the directors breached a fiduciary duty by failing to undertake an independent investigation in response to a letter from the affiliate asking for an investigation regarding alleged improper practices by UI in connection with the Middletown/Norwalk Transmission Project. In October 2013, the court granted the defendants' motion to dismiss the complaint, which dismissal was affirmed by the Connecticut

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

Appellate Court in March 2015. The period to file a petition for review by the Connecticut Supreme Court has passed and the case is now concluded.

Leases

Operating lease expense relating to operational facilities, office building leases, and vehicle and equipment leases was \$47.7 million, \$48.7 million and \$67.6 million for the years ended December 31, 2015, 2014 and 2013, respectively. Amounts related to contingent payments predominantly linked to electricity generation at the respective facilities was \$22.2 million, \$20.4 million and \$20.6 million for the years ended December 31, 2015, 2014 and 2013, respectively. Leases for most of the land on which wind farm facilities are located have various renewal and termination clauses.

In April 2013, we concluded a sale and subsequent lease-back transaction on one of our operating facilities for an initial cash receipt of \$110 million. Under the terms of the agreement, we will simultaneously sell and then lease back the facility over a fifteen-year period, with an option to repurchase the facility at the end of year ten. During the lease period, we will continue to maintain and operate the entire facility. We accounted for this as a capital sale lease-back transaction, under which a lease payable liability is recognized which is offset by the increase in cash.

On January 16, 2014, as required by its regulator, 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 \$25.5 million and \$19.8 million for the years ended December 31, 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, RGE, 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. RGE shall make monthly payments to GNPP in the amount of \$15.4 million. RGE 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.

Total future minimum lease payments as of December 31, 2015 consisted of:

(Millions) Year	Operating Leases(a)	Capital Leases(a)	Total
2016	\$ 216	\$ 9	\$ 225
2017	90	6	96
2018	26	6	32
2019	24	6	30
2020	25	7	32
2021 and thereafter	298	53	351
Total	\$ 679	\$ 87	\$ 766

(a) Payments related to the period of remaining useful life of facilities are on an undiscounted basis.

Power, Gas, and Other Arrangements

Power and Gas Supply Arrangements – Networks

NYSEG and RGE 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 RGE 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

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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, RGE, SCG, CNG and Berkshire Gas Company (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 reasonable 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.

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 lease 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 (six 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. Power sales commitments include: (i) a 55MW Biomass off-take agreement for 12 years (six 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, 2015 consisted of:

(Millions) As of December 31,	Purchases				Sales			
	Gas	Power	Other	Total	Gas	Power	Other	Total
2016	\$ 232	\$ 233	\$ 31	\$ 496	\$ 21	\$ 133	\$ 3	\$ 157
2017	203	123	25	351	3	84	2	89
2018	181	76	14	271	—	67	2	69
2019	149	54	8	211	—	48	1	49
2020	124	53	7	184	—	39	—	39
Thereafter	579	320	58	957	—	46	—	46
Totals	\$ 1,468	\$ 859	\$ 143	\$ 2,470	\$ 24	\$ 417	\$ 8	\$ 449

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

Guarantee Commitments to Third Parties

As of December 31, 2015, we had approximately \$2.4 billion of standby letters of credit, surety bonds, guarantees and indemnifications outstanding. These instruments provide financial assurance to the business and trading partners of the company and its subsidiaries in their normal course of business. The instruments only represent liabilities if the company 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, 2015, 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 \$616 million as of December 31, 2015.

Note 14. Environmental Liability

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

Waste sites

The Environmental Protection Agency and various state environmental agencies, as appropriate, have notified us that we are among the potentially responsible parties that may be liable for costs incurred to remediate certain hazardous substances at twenty-four waste sites, which do not include sites where gas was manufactured in the past. Fifteen of the twenty-four 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-four 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-four sites. We have paid remediation costs related to the remaining fourteen 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. 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 of those two sites are a 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-seven of the fifty-three sites.

Our estimate for all costs related to investigation and remediation of the fifty-three sites ranges from a minimum of \$235 million to \$468 million as of December 31, 2015. 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, 2015 the liability associated with other MGP sites, 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 \$99 million.

The liability to investigate and perform remediation at the known inactive gas manufacturing sites was \$397 million and \$312 million as of December 31, 2015 and 2014, 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 2048.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

The 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 Regulated Gas 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, 2015 and no amount of loss, if any, can be reasonably estimated at this time. In the past, the Regulated Gas 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 Energy 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. 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.

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. Any recovery will be flowed through to NYSEG ratepayers.

Century 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.

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 Quinpiac 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. 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.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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 of 2015.

On September 16, 2015, UI signed a Proposed Partial Consent Order that, when issued by the Commissioner of DEEP, and subject to the closing of the merger between UIL and AVANGRID and other terms and conditions in the Proposed Partial Consent Order, would require UI to investigate and remediate certain environmental conditions within the perimeter of the English Station site. Under the Proposed Partial 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. Pursuant to the Proposed Partial Consent Order, upon its issuance and subject to its terms and conditions, UI would be obligated to comply with the Proposed Partial 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. On September 30, 2015, the Hearing Officer in DEEP's administrative proceeding approved a Motion for Stay of further proceedings filed by DEEP, staying all proceedings on the administrative order for 120 days. On January 26, 2016 this Stay was extended for an additional 90 days. A status conference is scheduled for May 11, 2016. We cannot predict the outcome of this matter. As of December 31, 2015 we reserved \$20.5 million for this case and have accrued the remaining \$9.5 million in accordance with the settlement with PURA approving the acquisition.

Note 15. Income Taxes

Current and deferred taxes charged to (benefit) expense for the years ended December 31, 2015, 2014 and 2013 consisted of:

Years Ended December 31, (Millions)	2015	2014	2013
Current			
Federal	\$ (20)	\$ (10)	\$ (22)
State	(33)	31	(1)
Current taxes charged to (benefit) expense	(53)	21	(23)
Deferred			
Federal	136	218	60
State	(6)	82	42
Deferred taxes charged to expense	130	300	102
Production tax credits	(42)	(37)	(42)
Investment tax credits	(1)	(2)	(2)
Total Income Tax Expense	\$ 34	\$ 282	\$ 35

The differences between tax expense per the statements of operations and tax expense at the 35% statutory federal tax rate for the years ended December 31, 2015, 2014 and 2013 consisted of:

Years Ended December 31, (Millions)	2015	2014	2013
Tax expense (benefit) at federal statutory rate	\$ 105	\$ 247	\$ (5)
Depreciation and amortization not normalized	15	15	24
Investment tax credit amortization	(1)	(2)	(2)
Tax return related adjustments	6	2	7
Production tax credits	(42)	(37)	(42)
Tax equity financing arrangements	(36)	(11)	(23)
Change in tax reserves	—	3	(2)
Impairment of non-deductible goodwill	—	—	38
Changes in New York tax law	—	41	—
State tax expense (benefit), net of federal benefit	(25)	32	27
Non-deductible acquisition costs	9	—	—
Other, net	3	(8)	13
Total Income Tax Expense	\$ 34	\$ 282	\$ 35

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

Deferred tax assets and liabilities as of December 31, 2015 and 2014 consisted of:

As of December 31, (Millions)	2015	2014
Non-current Deferred Income Tax Liabilities (Assets)		
Property related	\$ 4,763	\$ 3,778
Unfunded future income taxes	211	146
Federal and state tax credits	(367)	(317)
Accumulated deferred investment tax credits	15	16
Federal and state NOL's	(1,367)	(1,266)
Joint ventures/partnerships	655	884
Nontaxable grant revenue	(595)	(622)
Other	(17)	66
Non-current Deferred Income Tax Liabilities	3,298	2,685
Add: Valuation allowance	19	17
Total Non-current Deferred Income Tax Liabilities	3,317	2,702
Less amounts classified as regulatory liabilities		
Non-current deferred income taxes	519	433
Non-current Deferred Income Tax Liabilities	\$ 2,798	\$ 2,269
Deferred tax assets	\$ 2,346	\$ 2,205
Deferred tax liabilities	5,663	4,907
Net Accumulated Deferred Income Tax Liabilities	\$ 3,317	\$ 2,702

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 or 2014. A valuation allowance of \$8 million, (net of federal benefit) and an additional valuation allowance of \$2 million (net of federal benefit) were established on various state NOLs and credits in 2014 and 2015, respectively.

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2015, 2014 and 2013 consisted of:

Years ended December 31, (Millions)	2015	2014	2013
Beginning Balance	\$ 38	\$ 41	\$ 91
Increases for tax positions related to prior years	1	20	4
Reduction for tax position related to settlements with taxing authorities	(3)	(23)	(54)
Ending Balance	\$ 36	\$ 38	\$ 41

Unrecognized income tax benefits represent income tax positions taken on income tax returns but not yet recognized in the combined and 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, \$3 million, and \$11 million for the years ended December 31, 2015, 2014 and 2013, respectively. If recognized, \$9 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, 2015 is estimated to be \$9 million primarily relating to anticipation of additional guidance to be released by the IRS.

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.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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.

As of December 31, 2015, 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, 2015, we had federal tax net operating losses of \$3.5 billion, federal renewable energy credits, federal R&D tax credits and other federal credits of \$338 million, state tax net operating losses of \$154 million in several jurisdictions and miscellaneous state tax credits of \$30 million available to carry forward and reduce future income tax liabilities. For state purposes, we recognized a valuation allowance of \$19 million. The federal and state net operating losses begin to expire in 2025, while the federal tax credits begin to expire in 2024.

Note 16. Post-retirement and Similar Obligations

Networks has funded noncontributory defined benefit pension plans that cover substantially all Networks employees. The plans provide defined benefits based on years of service and final average salary for employees hired before 2002. Employees hired in 2002 or later 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. 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 percentage of earnings. Instead, they will receive a minimum 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.

Networks has other postretirement health care benefit plans covering substantially all Networks' employees. The healthcare plans are contributory and participants contributions are adjusted annually.

The UI pension plan covers the majority of employees of UIL and UI. 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 have multiple qualified pension plans covering substantially all 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.

SCG and CNG also have plans providing other postretirement benefits for substantially all of their employees. These benefits consist primarily of health care, prescription drug and life insurance benefits, for retired employees and their dependents.

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.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

Obligations and funded status of Networks and ARHI as of December 31, 2015 and 2014 consisted of:

As of December 31, (Millions)	Pension Benefits		Postretirement Benefits	
	2015	2014	2015	2014
Change in benefit obligation				
Benefit obligation as of January 1,	\$ 2,620	\$ 2,316	\$ 435	\$ 385
Service cost	35	30	5	5
Interest cost	97	110	16	18
Plan participants' contributions	—	—	4	4
Plan amendments	—	—	(1)	—
Actuarial (gain) loss	(105)	439	(31)	64
Special termination benefits	2	—	—	—
Benefits paid	(158)	(275)	(25)	(41)
Benefit Obligation as of December 31,	2,491	2,620	403	435
Change in plan assets				
Fair value of plan assets as of January 1,	2,143	2,223	129	128
Actual return on plan assets	(21)	163	(4)	4
Employer contributions	27	32	21	38
Plan participants' contributions	—	—	4	4
Benefits paid	(158)	(275)	(25)	(41)
Withdrawal from VEBA	—	—	(2)	(4)
Fair Value of Plan Assets as of December 31,	1,991	2,143	123	129
Funded Status as of December 31,	\$ (500)	\$ (477)	\$ (280)	\$ (306)

Amounts recognized as of December 31, 2015 and 2014 consisted of:

As of December 31, (Millions)	Pension Benefits		Postretirement Benefits	
	2015	2014	2015	2014
Non-current assets	\$ —	\$ —	\$ —	\$ —
Current liabilities	—	—	(5)	(5)
Non-current liabilities	(500)	(477)	(275)	(301)
Total	\$ (500)	\$ (477)	\$ (280)	\$ (306)

Networks offered terminated vested employees an option to receive their future pension benefit as a lump sum in 2013. Approximately \$59.9 million of payments were made in 2013 as a result of terminated vested employees exercising the lump sum option. An additional \$5.8 million was paid in 2014. The lump sum payments did not trigger settlement accounting.

Networks made a similar offer during 2014 to retired employees who are currently receiving benefits. 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.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

The following table represents the change in benefit obligation, change in plan assets and the respective funded status of UIL's pension and other postretirement plans as of December 31, 2015, including purchase price allocation balances. Plan assets and obligations have been measured as of December 31, 2015.

(Millions)	Pension Benefits 2015	Other Postretirement Benefits 2015
Change in Benefit Obligation:		
Benefit obligation at December 17	\$ 1,019	\$ 122
Service cost	1	—
Interest cost	2	—
Benefits paid (including expenses)	(4)	—
Benefit obligation at December 31	\$ 1,018	\$ 122
Change in Plan Assets:		
Fair value of plan assets at December 17	\$ 687	\$ 39
Actual return on plan assets	(10)	—
Benefits paid (including expenses)	(4)	—
Fair value of plan assets at December 31	\$ 673	\$ 39
Funded Status at December 31:		
Projected benefits less than plan assets	\$ (345)	\$ (83)
Amounts Recognized in the Statement of Financial Position consist of:		
Non-current liabilities	\$ (345)	\$ (83)

Amounts recognized in OCI, before income taxes, for ARHI for the years ended December 31, 2015, 2014 and 2013 consisted of:

Years Ended December 31, (Millions)	2015	Pension Benefits 2014	2013	2015	Postretirement Benefits 2014	2013
Net (income) loss	\$ 25	\$ 22	\$ 16	\$ (1)	\$ 8	\$ 14

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, 2015, 2014 and 2013 for Networks consisted of:

Years Ended December 31, (Millions)	2015	Pension Benefits 2014	2013	2015	Postretirement Benefits 2014	2013
Net loss	\$ 982	\$ 1,045	\$ 704	\$ 76	\$ 96	\$ 24
Prior service cost (credit)	9	12	16	(49)	(57)	(67)

Amounts recognized as regulatory assets for the period from December 17, 2015 to December 31, 2015 for UIL consisted of:

(Millions)	Pension Benefits 2015	Other Postretirement Benefits 2015
Net loss	12	—

Our accumulated benefit obligation for all defined benefit pension plans of Networks and ARHI was \$2,334 million and \$2,436 million as of December 31, 2015 and 2014, respectively. CMP's and NYSEG's postretirement benefits were partially funded as of December 31, 2015 and 2014.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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, 2015 and 2014.

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, 2015 and 2014 consisted of:

As of December 31, (Millions)	Projected Benefit Obligation Exceeds Fair Value of Plan Assets		Accumulated Benefit Obligation Exceeds Fair Value of Plan Assets	
	2015	2014	2015	2014
Projected benefit obligation	\$ 2,491	\$ 2,620	\$ 2,491	\$ 2,620
Accumulated benefit obligation	2,334	2,436	2,334	2,436
Fair value of plan assets	1,991	2,143	1,991	2,143

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

As of December 31, (Millions)	Pension Benefits 2015
Projected benefit obligation	\$ 1,018
Accumulated benefit obligation	927
Fair value of plan assets	673

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, 2015, 2014 and 2013 consisted of:

(Millions) As of December 31,	Pension Benefits			Postretirement Benefits		
	2015	2014	2013	2015	2014	2013
Net Periodic Benefit Cost:						
Service cost	\$ 35	\$ 30	\$ 36	\$ 4	\$ 4	\$ 5
Interest cost	95	107	102	15	17	16
Expected return on plan assets	(154)	(161)	(166)	(7)	(7)	(7)
Amortization of prior service cost (benefit)	3	4	4	(9)	(11)	(14)
Amortization of net loss	130	94	120	7	—	3
Special termination benefit charge	2	—	—	—	—	—
Settlement charge	2	—	—	—	—	—
Net Periodic Benefit Cost	113	74	96	10	3	3
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities:						
Settlements	\$ (2)	\$ —	\$ —	\$ —	\$ —	\$ —
Net loss (gain)	69	434	(244)	(12)	72	(50)
Amortization of net (loss)	(130)	(94)	(120)	(7)	—	(3)
Current year prior service cost	—	—	—	(1)	—	(2)
Amortization of prior service (cost) benefit	(3)	(4)	(4)	9	11	14
Total Other Changes	(66)	336	(368)	(11)	83	(41)
Total Recognized	\$ 47	\$ 410	\$ (272)	\$ (1)	\$ 86	\$ (38)

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

Components of UIL's net periodic benefit cost and other changes in plan assets and benefit obligations recognized in income and regulatory assets for the period from December 17, 2015 to December 31, 2015 consisted of:

(Millions)	For the period from December 17, 2015 to December 31, 2015	
	Pension Benefits	Other Postretirement Benefits
Net Periodic Benefit Cost:		
Service cost	\$ 1	\$ —
Interest cost	2	—
Expected return on plan assets	(2)	—
Net periodic benefit cost	\$ 1	\$ —
Other Changes in Plan Assets and Benefit Obligations Recognized as a Regulatory Asset:		
Net (gain) loss	\$ —	\$ —
Total Other Changes	—	—
Total Recognized	\$ 1	\$ —

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, 2015, 2014 and 2013 consisted of:

(Millions) As of December 31,	Pension Benefits			Postretirement Benefits		
	2015	2014	2013	2015	2014	2013
Net Periodic Benefit Cost:						
Service cost	\$ —	\$ —	\$ —	\$ 1	\$ 1	\$ 1
Interest cost	2	2	2	1	1	1
Expected return on plan assets	(2)	(3)	(3)	—	—	—
Amortization of prior service cost	—	—	—	—	1	1
Amortization of net loss	1	—	1	—	1	—
Settlement charge	—	—	2	—	—	—
Net Periodic Benefit Cost (income)	1	(1)	2	2	4	3
Other Changes in plan assets and benefit obligations recognized in OCI:						
Net loss (gain)	4	6	(12)	(8)	(5)	7
Amortization of net (loss)	(1)	—	(3)	—	(1)	—
Amortization of prior service (cost)	—	—	—	—	(1)	(1)
Total Other Changes	3	6	(15)	(8)	(7)	6
Total Recognized	\$ 4	\$ 5	\$ (13)	\$ (6)	\$ (3)	\$ 9

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, 2016 consisted of:

Year Ended December 31, 2016 (Millions)	Pension Benefits	Postretirement Benefits
Estimated net loss	\$ 123	\$ 7
Estimated prior service cost (benefit)	2	(9)

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

Amounts expected to be amortized from OCI into net periodic benefit cost for the year ending December 31, 2016 consisted of:

Year Ended December 31, 2016 (Millions)	Pension Benefits	Postretirement Benefits
Estimated net loss	\$ 1	\$ —
Estimated prior service cost (benefit)	—	—

We expect that no pension benefit or postretirement benefit plan assets will be returned to us during the year ending December 31, 2016.

The weighted-average assumptions used to determine benefit obligations for Networks and ARHI as of December 31, 2015 and 2014 consisted of:

As of December 31,	Pension Benefits		Postretirement Benefits	
	2015	2014	2015	2014
Discount rate - Networks	4.10%	3.80%	4.10%	3.80%
Discount rate - ARHI	3.90%	3.90%	3.90%	3.90%
Rate of compensation increase - Networks	4.00%	4.10%	—	—

The weighted-average assumptions used to determine benefit obligations for UIL as of December 31, 2015 consisted of:

As of December 31,	Pension Benefits	Other Postretirement Benefits
	2015	2015
Discount rate	4.24%	4.24%
Average wage increase	3.50-3.80%	—
Health care trend rate (current year)	—	7.00%/9.00%
Health care trend rate (2019-2028 forward)	—	4.50%

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, 2015, 2014 and 2013 consisted of:

Years Ended December 31,	Pension Benefits			Postretirement Benefits		
	2015	2014	2013	2015	2014	2013
Discount rate - Networks	3.80%	4.90%	4.10%	3.80%	4.90%	4.10%
Discount rate - ARHI	3.90%	5.00%	4.00%	3.90%	5.00%	4.00%
Expected long-term return on plan assets - Networks	7.50%	7.50%	7.50%	—	—	—
Expected long-term return on plan assets - ARHI	5.50%	6.90%	6.50%	5.75%	6.50%	6.25%
Expected long-term return on plan assets - nontaxable trust - Networks	—	—	—	7.50%	7.50%	7.50%
Expected long-term return on plan assets - taxable trust - Networks	—	—	—	5.00%	5.00%	5.00%
Rate of compensation increase - Networks	4.10%	4.20%	4.00%	—	—	—

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

The weighted-average assumptions used to determine net periodic benefit cost for UIL for the period from December 17, 2015 to December 31, 2015 consisted of:

	For the period from December 17, 2015 to December 31, 2015	
	Pension Benefits	Other Postretirement Benefits
Discount rate	4.24%	4.24%
Average wage increase	3.50-3.80%	—
Return on plan assets	7.75-8.00%	5.56-8.00%
Health care trend rate (current year)	—	7.00%
Health care trend rate (2019 forward)	—	4.50%

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, RGE and UIL amortize unrecognized actuarial gains and losses over ten years from the time they are incurred as required by the NYPSC, PURA and DPU. Our other companies use the standard amortization methodology under which amounts in excess of ten-percent of the greater of the projected benefit obligation or market related value are amortized over the plan participants' average remaining service to retirement.

Assumed health care cost trend rates used to determine benefit obligations as of December 31, 2015 and 2014 consisted of:

As of December 31,	2015	2014
Health care cost trend rate assumed for next year - Networks	7.50%/7.00%	7.75%/7.25%
Health care cost trend rate assumed for next year - ARHI	7.00%/9.00%	7.75%/6.75%
Rate to which cost trend rate is assumed to decline (ultimate trend rate) - Networks	4.5%	4.5%
Rate to which cost trend rate is assumed to decline (ultimate trend rate) - ARHI	4.5%	4.75%
Year that the rate reaches the ultimate trend rate - Networks	2027	2027
Year that the rate reaches the ultimate trend rate - ARHI	2026	2025

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	9	(7)

Contributions

We make annual contributions in accordance with our funding policy of not less than the minimum amounts as required by applicable regulations. Networks and UIL expect to contribute \$21 million and \$22 million, respectively, to the pension benefit plans during 2016.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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, 2015 consisted of:

(Millions)	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
2016	\$ 154	\$ 26	\$ —
2017	156	27	—
2018	159	27	—
2019	161	27	—
2020	163	27	—
2021 - 2025	826	135	1

Expected benefit payments and Medicare Prescription Drug, Improvement and Modernization Act of 2003 subsidy receipts reflecting expected future service for UIL as of December 31, 2015 consisted of:

(Millions)	Pension Benefits	Other Postretirement Benefits	Medicare Act Subsidy Receipts
2016	\$ 48	\$ 7	\$ —
2017	50	7	—
2018	51	7	—
2019	53	7	—
2020	54	7	—
2021-2025	295	37	1

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 \$39 million and \$43 million at December 31, 2015 and 2014, respectively.

UI has established a supplemental retirement benefit trust and, through this trust, purchased life insurance policies on certain officers of UIL and UI to fund the future liability under the non-qualified supplemental plan. The total liability for these non-qualified plans, which is included in Other Non-current Liabilities, was \$20 million as of December 31, 2015.

Plan Assets

Our pension benefits plan assets for Networks and ARHI are held in two 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 thirty-five-percent in equity securities and twenty-percent in equity alternative investments. The Liability-Hedging asset class has a target allocation percentage of forty-five-percent. 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

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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. 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, 2015 consisted of:

As of December 31, 2015 (Millions)		Fair Value Measurements		
	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	511	—	21	490
Partnerships/joint venture interests	84	—	—	84
Real estate investments	89	—	—	89
Other, principally annuity, fixed income	322	—	4	318
Total	\$ 1,991	\$ 602	\$ 408	\$ 981

The fair values of pension benefits plan assets, by asset category, as of December 31, 2014 consisted of:

As of December 31, 2014 (Millions)		Fair Value Measurements		
	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	\$ 48	\$ 4	\$ 44	\$ —
U.S. government securities	177	177	—	—
Common stocks	447	360	87	—
Registered investment companies	116	116	—	—
Corporate bonds	367	23	344	—
Preferred stocks	4	—	4	—
Common collective trusts	477	—	28	449
Partnership/joint venture interests	79	—	—	79
Real estate investments	77	2	—	75
Other, principally annuity, fixed income	351	5	4	342
Total	\$ 2,143	\$ 687	\$ 511	\$ 945

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.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

- 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.

Fair value measurements using Level 3 inputs as of December 31, 2015, 2014 and 2013 consisted of:

(Millions)	Common Collective Trusts	Partnership Joint Venture Interests	Real Estate Investments	Other Investments	Total
As of December 31, 2013	\$ 458	\$ 57	\$ 67	\$ 337	\$ 919
Actual return on plan assets:					
Relating to assets sold during the year	6	—	—	—	6
Relating to assets still held at the reporting date	5	3	6	5	19
Purchases, sales and settlements	(20)	19	2	—	1
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

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 twenty-five-percent 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 forty-seven-percent equity securities, thirty-eight-percent fixed income, and fifteen-percent for all other investment types. The target allocations within allowable ranges are further diversified into twenty-percent large cap domestic equities, twelve-percent medium and small cap domestic equities, ten-percent international developed market, and five-percent emerging market equity securities. Fixed income investment targets and ranges are segregated into core fixed income at thirty-one-percent, global high yield fixed income at four-percent, and international developed market debt at three-percent. Other alternative investment targets are five-percent for real estate, five-percent for absolute return, and five-percent for tangible assets. 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.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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

As of December 31, 2015 (Millions)		Fair Value Measurements		
	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	11	11	—	—
Total	\$ 123	\$ 121	\$ 2	\$ —

The fair values of other postretirement benefits plan assets, by asset category, as of December 31, 2014 consisted of:

As of December 31, 2014 (Millions)		Fair Value Measurements		
	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	45	45	—	—
Common stocks	29	29	—	—
Mutual funds, other	12	12	—	—
Total	\$ 128	\$ 126	\$ 2	\$ —

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 December 31, 2015.

The following tables set forth the fair values of UIL's pension and other postretirement benefits plan assets as of December 31, 2015.

December 31, 2015 (Millions)	Fair Value Measurements			
	Level 1	Level 2	Level 3	Total
Pension assets				
Mutual funds	\$ —	\$ 673	\$ —	\$ 673
Other postretirement benefit assets				
Mutual funds	32	7	—	39
Total	\$ 32	\$ 680	\$ —	\$ 712

The determination of fair values of the Level 2 co-mingled mutual funds were based on the Net Asset Value (NAV) provided by the managers of the underlying fund investments and the unrealized gains and losses. The NAV provided by the managers typically reflect the fair value of each underlying fund investment.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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 \$17 million, \$20 million and \$14 million for 2015, 2014, and 2013 respectively.

UIL has several 401(k) plans in which substantially all of its employees are eligible to participate. Employees may defer a portion of the compensation and invest in various investment alternatives. The matching expense for the period from December 17, 2015 to December 31, 2015, was immaterial.

Note 17. Equity

Our share capital consisted of 500,000,000 shares authorized, 309,491,082 shares issued and 308,864,609 shares outstanding, 81.5% owned by Iberdrola, each having a par value of \$0.01, for a total value of common stock capital of \$3 million and additional paid in capital of \$13,653 million as of December 31, 2015. Our share capital consisted of 500,000,000 shares authorized, 252,235,232 shares issued and 252,235,232 shares outstanding, wholly owned by Iberdrola, each having a par value of \$0.01, for a total value of common stock capital of \$3 million and additional paid in capital of \$11,375 million as of December 31, 2014. On December 15, 2015, the Board of Directors approved our common stock dividend, accounted for as 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's approval. All share and per share information included in the combined and consolidated financial statements have been retroactively adjusted to reflect the impact of the stock dividend. As a result, our share capital consisted of 500,000,000 shares authorized, 252,235,232 shares issued and 252,235,232 shares outstanding, wholly owned by Iberdrola, each having a par value of \$0.01, for a total value of common stock capital of \$3 million and additional paid in capital of \$11,375 million as of December 31, 2014. All common shares have the same voting and economic rights. We have 626,473 treasury shares and no convertible preferred shares as of December 31, 2015. We had no treasury shares or convertible preferred shares as of December 31, 2014.

In February 2013 prior to the reorganization, in which ARHI became a subsidiary of AVANGRID, ARHI issued shares to Iberdrola in return for \$153 million in cash, \$550 million in the form of a loan note and the remaining \$10 million in accrued interest on the loan note. The loan note was an obligation of AVANGRID and as a result of the reorganization in November 2013 the ARHI loan receivable and the AVANGRID loan payable have been eliminated in the combined and consolidated financial statements.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

Accumulated OCI (Loss)

Accumulated OCI for the years ended December 31, 2015, 2014 and 2013 consisted of:

Accumulated Other Comprehensive Income (Loss)	As of December 31, 2012	2013 Change	As of December 31, 2013	2014 Change	As of December 31, 2014	2015 Change	As of December 31, 2015
(Millions)							
Loss on revaluation of defined benefit plans, net of income tax expense of \$0.5 for 2013, \$0.6 for 2014 and \$2.2 for 2015	\$ (27)	\$ 1	\$ (26)	\$ 1	\$ (25)	\$ 4	\$ (21)
Loss for nonqualified pension plans, net of income tax expense (benefit) of \$1.0 for 2013, (\$1.9) for 2014 and \$1.7 for 2015	(7)	(1)	(8)	(3)	(11)	3	(8)
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 and \$20.9 for 2015	—	—	—	(2)	(2)	33	31
Reclassification adjustment for losses on settled cash flow hedges, net of income tax expense of \$4.6 for 2013, \$4.1 for 2014 and \$4.9 for 2015 (a)	(73)	7	(66)	5	(61)	7	(54)
Net unrealized (loss) gain on derivatives qualifying as cash flow hedges	(73)	7	(66)	3	(63)	40	(23)
Accumulated Other Comprehensive (Loss) Income	\$ (107)	\$ 7	\$ (100)	1	\$ (99)	\$ 47	\$ (52)

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

Note 18. Net Income (Loss) Per Share

Basic net income (loss) per share is computed by dividing net income (loss) attributable to AVANGRID by the weighted-average number of shares of our common stock outstanding. In 2015, while we did have securities that were dilutive, these securities did not result in a change on our net income (loss) per share calculation result for the year ended December 31, 2015. We did not have any potentially-dilutive securities for the years ended December 31, 2014 and 2013. In accordance with ASC Topic 260, Earnings per Share, we retroactively applied the stock split to prior years.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

We completed a series of reorganizations of entities under common control in November 2013. For purposes of computing net income (loss) per share, it is assumed that the Reorganization had occurred at the beginning of the earliest period presented consistent with the pooling of interest method. Therefore, the outstanding shares for the periods preceding the Reorganization reflect the series of reorganizations of entities under common control.

The calculations of basic and diluted earnings (loss) per share attributable to AVANGRID, including a reconciliation of the numerators and denominators for the years ended December 31, 2015, 2014 and 2013 consisted of:

Years Ended December 31,	2015	2014	2013
<i>(Millions, except for number of shares and per share data)</i>			
<i>Numerator:</i>			
Net income (loss) attributable to AVANGRID	\$ 267	\$ 424	\$ (51)
<i>Denominator:</i>			
Weighted average number of shares outstanding - basic	254,588,212	252,235,232	252,235,232
Weighted average number of shares outstanding - diluted	254,605,111	252,235,232	252,235,232
<i>Earnings per share attributable to AVANGRID</i>			
Earnings (Loss) Per Common Share, Basic	\$ 1.05	\$ 1.68	\$ (0.20)
Earnings (Loss) Per Common Share, Diluted	\$ 1.05	\$ 1.68	\$ (0.20)

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 combined and consolidated statements of operations. The presentation reflects revenues and expenses from the TEFs' operations on a fully consolidated basis. The liabilities are increased for cash contributed by the third-party investors, interest accrued, and the federal income tax impact to the third-party investors of the allocation of taxable income. Interest is accrued on the balance using the effective interest method and the third-party investors' targeted rate of return. The balance accrued interest at an average rate of 8.5% and 8.7% as of December 31, 2015 and 2014, 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.

We consider the following five structures to be TEFs: (1) Aeolus Wind Power I LLC, (2) Aeolus Wind Power II LLC, (3) Aeolus Wind Power III LLC, (4) Aeolus Wind Power IV LLC, and (5) 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 located throughout the U.S. 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.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

We repurchased a portion of the holding of one of the third-party investors for \$51.4 million in 2013. 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 combined and consolidated statements of operations.

Note 20. Grants, Government Incentives and Deferred Income

The changes in deferred income as of December 31, 2015 and 2014 consisted of:

(Millions)	Government grants	Other deferred income	Total
As of December 31, 2013	1,684	19	1,703
Additions	—	4	4
Recognized in income	(78)	(8)	(86)
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

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, 2015 and 2014.

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 \$390 million and \$323 million as of December 31, 2015 and 2014, 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. Our maximum exposure to loss is our net investment, of which the carrying amount was \$41 million and \$66 million as of December 31, 2015 and 2014, 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. Our maximum exposure to loss is our net investments, of which the carrying amount totaled \$143 million and \$146 million for Flat Rock Wind Power LLC, and \$69 million and \$50 million for Flat Rock Wind Power II LLC, as of December 31, 2015 and 2014, 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 \$110 million as of December 31, 2015.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

Summarized combined financial information for these equity method investments is as follows:

Years ended December 31, (Millions)	2015	2014	2013
Revenue	\$ 53	\$ 72	\$ 60
Loss from operations	(14)	—	(15)
Net loss	(10)	—	(15)

As of December 31, (Millions)	2015	2014
Current assets	\$ 45	\$ 11
Non-current assets	929	571
Current liabilities	26	10
Non-current liabilities	223	48
Members' equity	726	524
Ownership share	50%	50%
Equity method investment	\$ 363	\$ 262

None of our joint ventures have any contingent liabilities or capital commitments. Distributions received from equity method investments amounted to \$12 million, \$19 million, and \$9 million for the years ended December 31, 2015, 2014, and 2013 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.

We have other equity method investments with a carrying value of \$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, 2015, 2014 and 2013 consisted of:

Years ended December 31, (Millions)	2015	2014	2013
Allowance for funds used during construction	\$ 21	\$ 17	\$ 14
Carrying costs on regulatory assets	28	29	29
Other	6	6	11
Total Other income and (expense)	\$ 55	\$ 52	\$ 54

Accounts Receivable

Accounts receivable as of December 31, 2015 and 2014 consisted of:

As of December 31, (Millions)	2015	2014
Trade receivables	\$ 1,036	\$ 888
Other receivables	-	2
Allowance for bad debts	(62)	(49)
Total Accounts Receivable	\$ 974	\$ 841

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.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

The change in the allowance for bad debts as of December 31, 2015 and 2014 consisted of:

(Millions)		
As of January 1, 2013	\$	56
Current period provision		37
Write-off as uncollectible		(35)
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

DPA receivable balances were \$62 million and \$78 million as of December 31, 2015 and 2014, respectively.

Prepayments and Other Current Assets

Prepayments and other current assets as of December 31, 2015 and 2014 consisted of:

As of December 31,	2015	2014
(Millions)		
Prepaid other taxes	\$ 130	\$ 93
Broker margin and collateral accounts	46	57
Loans to third parties	3	3
Fixed-term deposits	11	25
Other pledged deposits	24	51
Prepaid expenses	53	32
Other	18	27
Total	\$ 285	\$ 288

Other current liabilities

Other current liabilities as of December 31, 2015 and 2014 consisted of:

As of December 31,	2015	2014
(Millions)		
Advances received	\$ 96	\$ 87
Accrued salaries	68	76
Short-term environmental provisions	35	36
Collateral deposits received	59	39
Pension and other postretirement	5	5
Other	22	19
Total	\$ 285	\$ 262

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 originated in New York and Maine, and upon the acquisition of UIL on December 16, 2015 regulated electric distribution, electric transmission and gas distribution activities originated 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

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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 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 (loss) adding back net income (loss) attributable to other non-controlling interests, income tax expense, depreciation and amortization, impairment of non-current assets and interest expense net of capitalization, and then subtracting other income and (expense) and earnings (losses) 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 combined and consolidated financial statements.

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 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	<u>\$ 20,126</u>	<u>\$ 10,685</u>	<u>\$ 1,265</u>	<u>\$ (1,333)</u>	<u>\$ 30,743</u>

(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.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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.

Segment information as of and for the year ended December 31, 2013 consisted of:

For the year ended December 31, 2013 (Millions)	Networks	Renewables	Gas	Other(a)	AVANGRID Consolidated
Revenue - external	\$ 3,311	\$ 1,087	\$ (98)	\$ 13	\$ 4,313
Revenue - intersegment	8	10	71	(89)	—
Impairment of noncurrent assets	—	75	545	—	620
Depreciation and amortization	257	310	26	1	594
Operating income (loss) from continuing operations	703	122	(647)	1	179
Adjusted EBITDA	960	507	(76)	2	1,393
Earnings (losses) from equity method investments	—	(7)	—	4	(3)
Capital expenditures	906	34	4	—	944
As of December 31, 2013					
Property, plant and equipment	7,887	8,302	526	—	16,715
Equity method investments	—	278	—	—	278
Total assets	\$ 11,771	\$ 11,966	\$ 1,495	\$ (2,062)	\$ 23,170

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

Included in revenue-external for the year ended December 31, 2013 are: \$2,665 million from regulated electric operations, \$644 million from regulated gas operations and \$2 million from other operations of Networks; \$1,087 million from renewable energy generation of Renewables; \$36 million from gas storage services and \$(134) million from gas trading operations of Gas.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

Reconciliation of consolidated Adjusted EBITDA to the AVANGRID consolidated Income (Loss) Before Income Tax for the years ended December 31, 2015, 2014 and 2013 is as follows:

Years Ended December 31, (Millions)	2015	2014	2013
Consolidated Adjusted EBITDA	\$ 1,220	\$ 1,539	\$ 1,393
Less:			
Impairment of non-current assets	12	25	620
Depreciation and amortization	695	629	594
Interest expense, net of capitalization	267	243	245
Add:			
Other income and (expense)	55	52	54
Earnings (losses) from equity method investments	—	12	(3)
Consolidated Income (Loss) Before Income Tax	\$ 301	\$ 706	\$ (15)

Note 24. Related Party Transactions

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

Related party transactions for the years ended December 31, 2015, 2014 and 2013 consisted of:

Years Ended December 31, (Millions)	2015		2014		2013	
	Sales To	Purchases From	Sales To	Purchases From	Sales To	Purchases From
Iberdrola Financiación, S.A.	—	\$ (1)	—	\$ (2)	—	\$ (2)
Iberdrola Renovables Energía, S.L.	—	(9)	—	(10)	—	(10)
Iberdrola Canada Energy Services, Ltd	—	(55)	—	(49)	2	(75)
Iberdrola Ingeniería y Construcción, S.A. U.	—	—	—	—	26	—
Scottish Power, Ltd	—	—	—	—	—	(6)
Other	3	(37)	12	(30)	16	(33)

In addition to the statements of operations 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 \$70 million and \$226 million as of December 31, 2015 and 2014, respectively.

In August 2011, we entered into a revolving credit facility with Iberdrola Financiación, S.A., a subsidiary of Iberdrola. The facility was terminated by AVANGRID on October 28, 2015. The facility was never utilized.

Related party balances as of December 31, 2015 and 2014 consisted of:

As of December 31, (Millions)	2015		2014	
	Owed By	Owed To	Owed By	Owed To
Iberdrola Canada Energy Services, Ltd	\$ 7	\$ (5)	\$ 1	\$ —
Gamesa Corporación Tecnológica, S.A.	68	(77)	33	(223)
Iberdrola Energy Projects, Inc.	1	(3)	15	(15)
Other	—	(5)	1	(1)

Transactions with our parent company (included in Other), Iberdrola, relate predominantly to 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 guarantying our performance. All costs that can be specifically allocated, to 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.

AVANGRID, Inc. and Subsidiaries
Notes to Combined and Consolidated Financial Statements (Continued)

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 combined and consolidated statements of operations for the year ended December 31, 2015. The collectability of amounts receivable from Gamesa are contingent upon other related parties fulfilling certain payments to Gamesa.

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 Iberdrola subsidiaries. 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.

Note 25. Quarterly financial data (unaudited)

Selected quarterly financial data for 2015 and 2014 are set forth below:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
(Millions, except per share data)				
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	\$ 106	\$ 11	\$ 54	\$ 96
Earnings Per Common Share, Basic and Diluted: (1)	\$ 0.42	\$ 0.04	\$ 0.22	\$ 0.37
2014				
Operating Revenues	\$ 1,556	\$ 938	\$ 982	\$ 1,118
Operating Income	\$ 414	\$ 132	\$ 153	\$ 186
Net Income	\$ 201	\$ 62	\$ 64	\$ 97
Net Income attributable to AVANGRID	\$ 200	\$ 63	\$ 64	\$ 97
Earnings Per Common Share, Basic and Diluted: (1)	\$ 0.79	\$ 0.25	\$ 0.25	\$ 0.38

- (1) Based on weighted average number of 252 million shares outstanding each quarter, 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, 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 26. Subsequent events

On February 17, 2016, Board of Directors of AVANGRID declared a quarterly dividend of \$0.432 per share on its common stock. This dividend is payable April 1, 2016 to shareholders of record at the close of business on March 10, 2016.

On February 17, 2016, we approved the sale of our interest in Iroquois Gas Transmission System L.P. (Iroquois) to an unaffiliated third party. The sale closed on March 31, 2016 with a sale price of \$53.8 million.

Schedule I—Financial Statements of Parent

AVANGRID, INC. (PARENT)
CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013
(Millions)

Years Ended December 31,	2015	2014	2013
Operating Revenues	\$ —	\$ —	\$ —
Operating Expenses			
Operating expense	38	2	17
Taxes other than income taxes	5	2	(15)
Total Operating Expenses	43	4	2
Operating Income	(43)	(4)	(2)
Other Income and (expense)			
Other income and (expense)	10	(1)	6
Equity earnings (loss) of subsidiaries	44	515	(37)
Interest expense	(14)	(34)	(22)
Income (Loss) Before Income Tax	(3)	476	(55)
Income tax expense (benefit)	(270)	52	(4)
Net Income (Loss)	\$ 267	\$ 424	\$ (51)

See accompanying notes to Schedule 1

Schedule I—Financial Statements of Parent

AVANGRID, INC. (PARENT)
CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
FOR THE YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013
(Millions)

Years Ended December 31,	2015	2014	2013
Net Income (Loss)	\$ 267	\$ 424	\$ (51)
Other comprehensive income of subsidiaries	47	1	7
Comprehensive Income (Loss)	\$ 314	\$ 425	\$ (44)

See accompanying notes to Schedule 1

Schedule I—Financial Statements of Parent

AVANGRID, INC. (PARENT)
CONDENSED FINANCIAL INFORMATION OF PARENT
BALANCE SHEETS
AS OF DECEMBER 31, 2015 AND 2014
(Millions)

As of December 31,	2015	2014
Assets		
Current Assets		
Cash and cash equivalents	\$ 125	\$ 3
Accounts receivable from subsidiaries	602	3
Notes receivable from subsidiaries	453	771
Prepayments and other current assets	16	57
Total current assets	1,196	834
Investments in subsidiaries	14,093	12,792
Other assets		
Deferred income taxes	148	—
Other	4	6
Total other assets	152	6
Total Assets	\$ 15,441	\$ 13,632
Liabilities		
Current Liabilities		
Notes payable to subsidiaries	\$ 321	\$ 652
Accounts payable and accrued liabilities	12	—
Accounts payable to subsidiaries	3	3
Interest accrued subsidiaries	1	7
Taxes accrued	44	141
Other current liabilities	4	2
Total current liabilities	385	805
Other non-current liabilities		
Deferred income taxes	—	14
Other	3	2
Total other non-current liabilities	3	16
Non-current debt with subsidiaries	—	350
Total non-current liabilities	3	366
Total Liabilities	388	1,171
Equity		
Stockholder's Equity:		
Common stock	3	3
Additional paid-in capital	13,653	11,375
Retained earnings	1,449	1,182
Accumulated other comprehensive loss	(52)	(99)
Total Equity	15,053	12,461
Total Liabilities and Equity	\$ 15,441	\$ 13,632

See accompanying notes to Schedule 1

Schedule I—Financial Statements of Parent

AVANGRID, INC. (PARENT)
CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013
(Millions)

Years Ended December 31,	2015	2014	2013
Cash Flow from Operating Activities			
Net income (loss)	\$ 267	\$ 424	\$ (51)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Amortization of other assets and liabilities	—	1	—
Deferred income taxes	(151)	24	61
Equity (earnings) loss of subsidiaries	(44)	(515)	37
Changes in current operating assets and liabilities:			
Accounts receivable from subsidiaries	(399)	(2)	—
Accounts payable and accrued liabilities	12	—	1
Accounts payable to subsidiaries	1	2	(6)
Interest accrued to subsidiaries	(5)	(1)	(12)
Taxes accrued	(96)	28	(46)
Other current assets and liabilities	35	7	(1)
Net Cash provided by (used in) Operating Activities	(380)	(32)	(17)
Cash Flow from Investing Activities			
Notes receivable from subsidiaries	317	(478)	(95)
Acquisition of subsidiary	(595)	—	—
Investments in subsidiaries	—	—	(165)
Return of capital from investments in subsidiaries	1,111	200	122
Other investments	—	11	5
Net Cash provided by (used in) Investing Activities	833	(267)	(133)
Cash Flow from Financing Activities			
Proceeds (repayments) of short-term notes payable from subsidiaries, net	(331)	302	150
Non-current debt with subsidiaries	—	—	(7)
Net Cash provided by (used in) Financing Activities	(331)	302	143
Net Increase (Decrease) in Cash and Cash Equivalents	122	3	(7)
Cash and Cash Equivalents, Beginning of Year	\$ 3	—	\$ 7
Cash and Cash Equivalents, End of Year	\$ 125	\$ 3	—
Supplemental Cash Flow Information			
Cash paid for interest	\$ 20	\$ 25	\$ 31
Cash refund for income taxes	—	6	53

See accompanying notes to Schedule 1

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 combined and consolidated financial statements and notes thereto of AVANGRID, Inc. and subsidiaries (Group).

AVANGRID, Inc. indirectly or directly owns all of the ownership interests of its significant subsidiaries. AVANGRID, Inc. relies on dividends or loans from its subsidiaries to fund dividends to its primary shareholder.

AVANGRID, Inc.'s significant accounting policies are consistent with those of the Group. For the purposes of these condensed financial statements, the Company's wholly owned and majority owned subsidiaries are recorded based upon its proportionate share of the subsidiaries net assets.

Immaterial corrections to prior periods

During the year ended December 31, 2015, a correction necessary to certain subsidiary's depreciation and amortization expenses that originated in prior periods was identified. AVANGRID assessed the materiality and determined that the cumulative impact of the amount was not material to the results of operation, financial position or cash flows in the previously issued financial statements and therefore, amendments of previously filed condensed financial information of AVANGRID are not required. However, management has determined to revise the prior periods included within these financial statements to reflect these updated amounts. Accordingly, the correction of these prior period amounts has been reflected in the periods in which they originated and the statement of operations for the year ended December 31, 2013 and the balance sheet as of December 31, 2014 have been revised. The correction resulted in a \$14 million increase in equity earnings and net income and a \$21 million increase in retained earnings and investments in subsidiaries, respectively, in the statement of operations for the year ended December 31, 2013 and balance sheet as of December 31, 2014. The revision had no net impact on the net cash provided by operating activities for the year ended December 31, 2013.

Note 2. Acquisition of UIL and Issue 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 February 17, 2016, Board of Directors of AVANGRID declared a quarterly dividend of \$0.432 per share on its common stock. This dividend is payable April 1, 2016 to shareholders of record at the close of business on March 10, 2016.

Note 3. Short-Term Credit Arrangements

AVANGRID Revolving Credit Facility

In May 2012, AVANGRID entered into a \$300 million revolving credit facility for the purpose of providing for liquidity needs and those of the unregulated subsidiaries. The facility has a termination date in May 2019. We pay an annual facility fee of \$0.7 million. As of December 31, 2015 and December 31, 2014 the facility was undrawn.

AVANGRID's revolving credit facility contains a covenant that requires it to maintain a ratio of consolidated indebtedness to consolidated total capitalization that does not exceed 0.65 to 1.00 at any time. For purposes of calculating this maximum ratio of consolidated indebtedness to consolidated total capitalization, the credit facility excludes from consolidated net worth the balance of AOCI as it appears in the consolidated balance sheets.

Iberdrola Financiación, S.A. Credit Facility

In August 2011, AVANGRID entered into a revolving credit facility with Iberdrola Financiación, S.A., a subsidiary of Iberdrola, under which AVANGRID may borrow up to \$600 million. The facility was terminated by AVANGRID on October 28, 2015. The facility was never utilized.

Note 4. Cash dividends paid by subsidiaries

Cash dividends paid by subsidiaries are as follows:

Years ended December 31, (In millions)	2015	2014	2013
AVANGRID Networks	\$ 59	\$ 200	\$ 110
AVANGRID Renewables	750	—	—
Other AVANGRID subsidiaries	302	—	12
	<u>\$ 1,111</u>	<u>\$ 200</u>	<u>\$ 122</u>

During 2015, Renewables authorized dividend payments of \$1.4 billion to AVANGRID, of which \$950 million was in cash (\$750 million paid in 2015) and the remainder in financial instruments. On February 4, 2016, AVANGRID subsidiary, CMP, declared a dividend of \$100 million payable to AVANGRID.

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 effective.

Exemption from Management's Report on Internal Control over Financial Reporting for the Fiscal Year Ended December 31, 2015

This Annual Report on Form 10-K does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of our independent registered public accounting firm due to a transition period established by the rules of the SEC for newly public companies.

Changes in Internal Control

There were no 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.

Limitations on Effectiveness of Controls and Procedures

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

Item 9B. Other Information.

On December 17, 2015, Mr. Daniel Alcain was appointed Senior Vice President and Controller of AVANGRID. There is no family relationship between Mr. Alcain and any director, executive officer or person nominated to be become a director or executive officer of AVANGRID and there is no arrangement or understanding between him and any other person pursuant to which he was appointed. For additional biographical information of Mr. Alcain, see Part I of this Annual Report on Form 10-K.

Mr. Alcain is entitled to participate in AVANGRID's Annual Incentive Plan and other incentive plans approved for AVANGRID executive officers.

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 2016 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2015.

Item 11. *Executive Compensation.*

The information required by this item is incorporated by reference to our Proxy Statement for the 2016 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2015.

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 2016 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2015.

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 2016 Annual Meeting of Shareholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2015.

Item 14. *Principal Accounting Fees and Services.*

The information required by this item is incorporated by reference to our Proxy Statement for the 2016 Annual Meeting of Shareholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2015.

Part IV

Item 15. Exhibits and Financial Statement Schedules.

a) The following documents are made a part of this Annual Report on Form 10-K:

1. Financial Statements—Our consolidated financial statements are set forth under Part II, Item 8 “Financial Statements and Supplementary Data.”
2. Financial Statement Schedules— Our financial statement schedules are set forth under Part II, Item 8 “Financial Statements and Supplementary Data.”
3. Exhibits—The following instruments and documents are included as exhibits to this report.

Exhibit Number	Exhibit Description
2.1	Agreement and Plan of Merger, dated as of February 25, 2015, by and among AVANGRID, Inc. (formerly Iberdrola USA, Inc.), Green Merger Sub, Inc. and UIL Holdings Corporation (incorporated herein by reference to Annex A to the proxy statement/prospectus included as Exhibit 2.1 in our Registration Statement on Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
3.1	Certificate of Incorporation of AVANGRID, Inc. (incorporated herein by reference to Exhibit 3.2 to Form 8-K filed with the Securities and Exchange Commission on December 18, 2015).
3.2	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).
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	Lease, dated as of July 7, 2003, between October Corporation and Energy East Management Corporation (incorporated herein by reference to Exhibit 10.3 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.4	First Amendment to Lease, effective as of July 10, 2012, between October Corporation and Iberdrola USA, Inc. Management Corporation (incorporated herein by reference to Exhibit 10.4 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.5	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).
10.6	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).
10.7	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).
10.8	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).

Exhibit Number	Exhibit Description
10.9	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).
10.10	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).
10.11	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).
10.12	Second Amendment and Extension Agreement, dated July 15, 2014, 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 New York America, N.A., as Syndication Agent, and Banco Bilbao Vizcaya Argentaria S.A., New York Branch, Santander Bank (formerly Sovereign Bank, N.A.), 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 10.12 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.13	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).
10.14	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).
10.15	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).
10.16	English Translation of Director Remuneration Policy of Iberdrola, S.A., as adopted by AVANGRID, Inc. (incorporated herein by reference to Exhibit 10.17 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015). †
10.17	English Translation of Senior Officer Remuneration Policy of Iberdrola, S.A., as adopted by AVANGRID, Inc. (incorporated herein by reference to Exhibit 10.18 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015). †
10.18	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). †
10.19	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). †
10.20	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). †
10.21	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). †

Exhibit Number	Exhibit Description
10.22	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). †
10.23	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). †
10.24	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). †
10.25	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). †
10.26	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).
10.27	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).
10.28	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). †
10.29	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). †
10.30	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). †
10.31	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). †
10.32	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). †
10.33	Assumption Agreement to \$400,000,000 Amended and Restated Credit Agreement, dated as of December 15, 2015, by and between Green Merger Sub, Inc. and JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated herein by reference to Exhibit 99.1 to Form 8-K filed with the Securities and Exchange Commission on December 18, 2015).
10.34	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). †
10.35	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). †
10.36	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). †
10.37	First Amendment, dated August 4, 2008, to Employment Agreement, dated as of July 8, 2005, between The United Illuminating Company and Richard J. Nicholas (incorporated herein by reference to Exhibit 10.14a of UIL Holdings Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2008). †

Exhibit Number	Exhibit Description
10.38	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). [†]
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.*
32.1	Chief Executive Officer and Chief Financial Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*
101.INS	XBRL Instance Document.*
101.SCH	XBRL Taxonomy Extension Schema Document.*
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.*
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.*
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.*
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.*

* Filed herewith.

[†] Compensatory plan or agreement.

0 Confidential treatment has been requested for portions of this document. The omitted portions of this document have been submitted separately to the Securities and Exchange Commission.

The foregoing list of exhibits does not include instruments defining the rights of the holders of certain long-term debt of AVANGRID, Inc. and its subsidiaries where the total amount of securities authorized to be issued under the instrument does not exceed ten percent (10%) of the total assets of AVANGRID, Inc. and its subsidiaries on a consolidated basis; and AVANGRID, Inc. hereby agrees to furnish a copy of each such instrument to the SEC on request.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

AVANGRID, Inc.

Date: April 1, 2016

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
<u>/s/ James P. Torgerson</u> James P. Torgerson	Director and Chief Executive Officer (Principal Executive Officer)	April 1, 2016
<u>/s/ Richard J. Nicholas</u> Richard J. Nicholas	Chief Financial Officer (Principal Financial Officer)	April 1, 2016
<u>/s/ Daniel Alcain</u> Daniel Alcain	Controller (Principal Accounting Officer)	April 1, 2016
<u>/s/ Ignacio Sánchez Galán</u> Ignacio Sánchez Galán	Chairman of the Board	April 1, 2016
<u>/s/ John E. Baldacci</u> John E. Baldacci	Director	April 1, 2016
<u>/s/ Pedro Azagra Blázquez</u> Pedro Azagra Blázquez	Director	April 1, 2016
<u>/s/ Arnold L. Chase</u> Arnold L. Chase	Director	April 1, 2016
<u>/s/ Alfredo Elías Ayub</u> Alfredo Elías Ayub	Director	April 1, 2016
<u>/s/ Carol Lynn Folt</u> Carol Lynn Folt	Director	April 1, 2016
<u>/s/ John L. Lahey</u> John L. Lahey	Director	April 1, 2016
<u>/s/ Santiago Martinez Garrido</u> Santiago Martinez Garrido	Director	April 1, 2016
<u>/s/ Juan Carlos Rebollo Liceaga</u> Juan Carlos Rebollo Liceaga	Director	April 1, 2016
<u>/s/ José Sainz Armada</u> José Sainz Armada	Director	April 1, 2016
<u>/s/ Alan D. Solomont</u> Alan D. Solomont	Director	April 1, 2016

LIST OF SUBSIDIARIES OF AVANGRID, INC.

<u>Name of Subsidiary</u>	<u>State or Jurisdiction of Incorporation Or Organization</u>
Avangrid Networks, Inc.(1)*	Maine
New York State Electric and 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.(1)	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
United Resources, Inc. (5)	Connecticut
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
Avangrid Service Company(2)	Delaware

- (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

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the 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 report dated April 1, 2016, with respect to the consolidated financial statements and schedule of Avangrid, Inc. included in this Annual Report (Form 10-K) for the year ended December 31, 2015.

/s/ Ernst & Young LLP

New York, New York
April 1, 2016

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
April 1, 2016

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: April 1, 2016

/s/ James P. Torgerson

James P. Torgerson
Director and Chief Executive Officer

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: April 1, 2016

/s/ Richard J. Nicholas

Richard J. Nicholas
Chief Financial Officer

CERTIFICATION OF PERIODIC FINANCIAL REPORT

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.
April 1, 2016

/s/ Richard J. Nicholas

Richard J. Nicholas
Chief Financial Officer
Avangrid, Inc.
April 1, 2016

