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Attachment 5.3-2

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VINEYARD WIND

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Attachment 5.6-1

AR Accounts (2016)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2016

Or

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

For the transition period from to

Commission File No. 001-37660

Avangrid, Inc.

(Exact name of registrant as specified in its charter)

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

Telephone: (207) 688-6000

(Registrant's telephone number, including area code)

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

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

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

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

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

The aggregate market value of the Avangrid, Inc.'s voting stock held by non-affiliates, computed by reference to the price at which the common equity was last sold as of the last business day of Avangrid, Inc.'s most recently completed second fiscal quarter (June 30, 2016) was $2,576 million based on a closing sales price of $46.06 per share.

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

DOCUMENTS INCORPORATED BY REFERENCE

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

Designated portions of the Proxy Statement relating to the 2017 Annual Meeting of the Shareholders are incorporated by reference into Part III to the extent described therein.

TABLE OF CONTENTS

GLOSSARY OF TERMS AND ABBREVIATIONS	1
CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS	6
PART I	7
Item 1. *Business*	7
Item 1A. *Risk Factors*	26
Item 1B. *Unresolved Staff Comments.*	42
Item 2. *Properties.*	42
Item 3. *Legal Proceedings.*	42
Item 4. *Mine Safety Disclosures.*	45
Executive Officers of AVANGRID	46
PART II	48
Item 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.*	48
Item 6. *Selected Financial Data*	50
Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*	51
Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*	83
Item 8. *Financial Statements and Supplementary Data*	86
Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.*	172
Item 9A. *Controls and Procedures.*	172
Item 9B. *Other information.*	173
PART III	174
Item 10. *Directors, Executive Officers and Corporate Governance.*	174
Item 11. *Executive Compensation.*	174
Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.*	174
Item 13. *Certain Relationships and Related Transactions, and Director Independence.*	174
Item 14. *Principal Accounting Fees and Services.*	174
Part IV	175
Item 15. *Exhibits and Financial Statement Schedules.*	175
SIGNATURES	181

GLOSSARY OF TERMS AND ABBREVIATIONS

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

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

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

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

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

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

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

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

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

Joint Proposal refers to the proposal, filed with the NYPSC on February 19, 2016 by NYSEG, RG&E and other signatory parties for a three-year rate plan for electric and gas service at NYSEG and RG&E commencing May 1, 2016.

Klamath Plant refers to the Klamath gas-fired cogeneration facility located in the city of Klamath, Oregon.

Merger Agreement refers to the Agreement and Plan of Merger, dated as of February 25, 2015, by and among Avangrid, Inc., Green Merger Sub, Inc. and UIL Holdings Corporation.

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

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

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

AMI	Automated Metering Infrastructure
AOCI	Accumulated other comprehensive income
ARHI	Avangrid Renewables Holdings, Inc.
ASC	Accounting Standards Codification
Asnat	Asnat Realty, LLC
Army Corps	U.S. Army Corps of Engineers
ARO	Asset retirement obligation
AVANGRID	Avangrid, Inc.
Bcf	One billion cubic feet
BGC	The Berkshire Gas Company
BGEPA	Bald and Golden Eagle Protection Act
BLM	U.S. Bureau of Land Management
BMG	Bank Mendes Gans, N.V.
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
CNG	Connecticut Natural Gas Corporation
DCF	Discounted cash flow
DEEP	Connecticut Department of Energy and Environmental Protection
DER	Distributed energy resources
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOE	Department of Energy
DOJ	Department of Justice
DPA	Deferred Payment Arrangements
DPU	Massachusetts Department of Public Utilities
DSIP	Distributed System Implementation Plan
DSP	Distributed System Platform
DTh	Dekatherm
EAMs	Earnings adjustment mechanisms
EBITDA	Earnings before interest, taxes, depreciation and amortization
EPA	Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
ERCOT	Electric Reliability Council of Texas
ESA	Endangered Species Act
ESC	Earnings Smart Community
ESM	Earnings sharing mechanism
Evergreen Power	Evergreen Power III, LLC
Exchange Act	The Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FirstEnergy	FirstEnergy Corp.
FPA	Federal Power Act
Gas	Enstor Gas, LLC
GenConn	GenConn Energy LLC
Ginna Facility	R.E. Ginna Nuclear Power Plant
GNPP	Ginna Nuclear Power Plant, LLC.
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
LNG	Liquefied natural gas
LNS	Local Network Service
MBTA	Migratory Bird Treaty Act
Mcf	One thousand cubic feet
Merger Sub	Green Merger Sub, Inc.
MEPCO	Maine Electric Power Corporation
MGP	Manufactured gas plants
MISO	Midcontinent Independent System Operator, Inc.
MHI	Mitsubishi Heavy Industries
MNG	Maine Natural Gas Corporation
MPRP	Maine Reliability Power Program
MPUC	Maine Public Utilities Commission
MtM	Mark-to-market
MW	Megawatts
MWh	Megawatt-hours
NAV	Net asset value
NEEWS	New England East West Solution
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NETOs	New England Transmission Owners
Networks	Avangrid Networks, Inc.
New York TransCo	New York TransCo, LLC.
NIPSCO	Northern Indiana Public Service Company
NGA	Natural Gas Act of 1938
NGPSA	Natural Gas Pipeline Safety Act of 1968
NOL	Net operating loss
NPNS	Normal purchases and normal sales

NYISO	New York Independent System Operator, Inc.
NYPA	New York Power Authority
NYPSC	New York State Public Service Commission
NYSE	New York Stock Exchange
NYSEG	New York State Electric & Gas Corporation
OATT	Open Access Transmission Tariiff
OCC	Office of Consumer Counsel
OCI	Other comprehesive income
OSHA	Occupational Safety and Health Act, as amended
PCB	Polychlorinated Biphenyls
PHMSA	Pipeline and Hazardous Materials Safety Administration
PPA	Power purchase agreement
PTF	Pool Transmission Facilities
PUCT	Public Utility Commission of Texas
PUHCA 2005	Public Utility Holding Company Act of 2005
PURA	Connecticut Public Utilities Regulatory Authority
RAM	Rate Adjustment Mechanism
RCRA	Resource Conservation and Recovery Act
RDM	Revenue decoupling mechanism
REC	Renewable Energy Certificate
RFP	Request for Proposals
Renewables	Avangrid Renewables, LLC
REV	Reforming the Energy Vision
RG&E	Rochester Gas and Electric Corporation
ROE	Return on equity
RNS	Regional Network Service
RPS	Renewable Portfolio Standards
RSSA	Reliability Support Services Agreement
RTO	Regional transmission organizations
SCG	The Southern Connecticut Gas Company
Scottish Power	Scottish Power Ltd.
SEC	United States Securities and Exchange Commission
SPHI	Scottish Power Holdings, Inc.
TEF	Tax equity financing arrangements
TGP	Tennessee Gas Pipeline Company LLC
TOTS	Transmission Owner Transmission Solutions
UI	The United Illuminating Company

UIL	UIL Holdings Corporation
U.S. GAAP	Generally accepted accounting principles for financial reporting in the United States.
VaR	Value-at- risk
VIEs	Variable interest entities
WECC	Western Electricity Coordinating Council

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

References in this Annual Report on Form 10-K to "AVANGRID," "the Company," "we," "our," and "us" refer to Avangrid, Inc. and its consolidated subsidiaries. This Annual Report on Form 10-K contains a number of forward-looking statements. Forward-looking statements may be identified by the use of forward-looking terms such as “may,” “will,” “should,” “can,” “expects,” “believes,” “anticipates,” “intends,” “plans,” “estimates,” “projects,” “assumes,” “guides,” “targets,” “forecasts,” “is confident that” and “seeks” or the negative of such terms or other variations on such terms or comparable terminology. Such forward-looking statements include, but are not limited to, statements about our plans, objectives and intentions, outlooks or expectations for earnings, revenues, expenses or other future financial or business performance, strategies or expectations, or the impact of legal or regulatory matters on business, results of operations or financial condition of the business and other statements that are not historical facts. Such statements are based upon the current beliefs and expectations of our management and are subject to significant risks and uncertainties that could cause actual outcomes and results to differ materially. Important factors that could cause actual results to differ materially from those indicated by such forward-looking statements include, without limitation:

- the future financial performance, anticipated liquidity and capital expenditures of the Company;
- actions or inactions of local, state or federal regulatory agencies;
- success in retaining or recruiting, our officers, key employees or directors;
- changes in levels or timing of capital expenditures;
- adverse developments in general market, business, economic, labor, regulatory and political conditions;
- fluctuations in weather patterns;
- technological developments;
- the impact of any cyber-breaches, grid disturbances, acts of war or terrorism or natural disasters; and
- the impact of any change to applicable laws and regulations affecting operations, including those relating to environmental and climate change, taxes, price controls, regulatory approval and permitting; and
- other presently unknown unforeseen factors.

Additional risks and uncertainties are set forth under Part I, Item 1A, “Risk Factors” in this report. Should one or more of these risks or uncertainties materialize, or should any of the underlying assumptions prove incorrect, actual results may vary in material respects from those expressed or implied by these forward-looking statements. You should not place undue reliance on these forward-looking statements. We do not undertake any obligation to update or revise any forward-looking statements to reflect events or circumstances after the date of this report, whether as a result of new information, future events or otherwise, except as may be required under applicable securities laws. Other risk factors are detailed from time to time in our reports filed with the Securities and Exchange Commission, or SEC, and we encourage you to consult such disclosures.

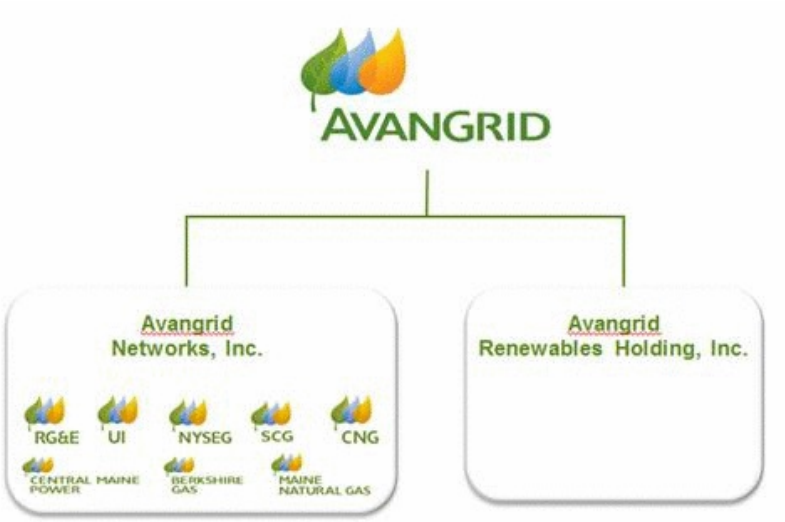
PART I

Item 1. *Business*

Overview

Avangrid, Inc., or AVANGRID, formerly Iberdrola USA, Inc., is a New York corporation headquartered in New Haven, Connecticut. AVANGRID is a diversified energy and utility company with more than $30 billion in assets and operations in 26 states. The company operates regulated utilities and electricity generation through two primary lines of business. Avangrid Networks includes eight electric and natural gas utilities, serving 3.1 million customers in New York and New England. Avangrid Renewables operates 6.5 gigawatts of electricity capacity, primarily through wind power, in states across the United States. AVANGRID employs approximately 7,000 people. The company was formed by a merger between Iberdrola USA, Inc. and UIL Holdings Corporation, or UIL, in 2015. Iberdrola S.A., a corporation *(sociedad anónima)* organized under the laws of the Kingdom of Spain, a worldwide leader in the energy industry, directly owns 81.5% of outstanding shares of AVANGRID common stock. Our primary business is ownership of our operating businesses, which are described below.

Our direct, wholly-owned subsidiaries include Avangrid Networks, Inc., or Networks, and Avangrid Renewables Holdings, Inc., or ARHI. ARHI in turn holds subsidiaries including Avangrid Renewables LLC, or Renewables. Networks, owns and operates our regulated utility businesses through its subsidiaries, including electric transmission and distribution and natural gas distribution, transportation and sales. Renewables operates a portfolio of renewable energy generation facilities primarily using onshore wind power and also solar, biomass and thermal power. The following chart depicts our current organizational structure.



Through Networks, we own electric generation, transmission and distribution companies and natural gas distribution, transportation and sales companies in New York, Maine, Connecticut and Massachusetts, delivering electricity to approximately 2.2 million electric utility customers and delivering natural gas to approximately 992,000 natural gas public utility customers as of December 31, 2016. The interstate transmission and wholesale sale of electricity by these regulated utilities is regulated by the Federal Energy Regulatory Commission, or FERC, under the Federal Power Act, or FPA, including with respect to transmission rates. Further, Networks' electric and gas distribution utilities in New York, Maine, Connecticut and Massachusetts are subject to regulation by the New York State Public Service Commission, or NYPSC, the Maine Public Utilities Commission, or MPUC, the Connecticut Public Utilities Regulatory Authority, or PURA, and the Massachusetts Department of Public Utilities, or DPU, respectively. Networks strives to be a leader in safety, reliability and quality of service to its utility customers.

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

ARHI also holds a subsidiary, Enstor Gas, LLC, or Gas, which owns non-core natural gas storage and gas trading businesses (Gas) through Enstor Energy Services LLC (gas trading) and Enstor Inc. (gas storage). Through Gas, as of December 31, 2016, we own approximately 67.5 billion cubic feet, or Bcf, of net working gas storage capacity. Gas operates 52.4 Bcf of contracted or managed natural gas storage capacity in North America through Enstor Energy Services, LLC, as of December 31, 2016.

Further information regarding the amount of revenues from external customers, including revenues by products and services, a measure of profit or loss and total assets for each segment for each of the last three fiscal years is provided in Note 23 to our audited consolidated financial statements contained in this Annual Report on Form 10-K.

History

We were incorporated in 1997 as a New York corporation under the name NGE Resources, Inc. and subsequently changed our name to Energy East Corporation. The stock of Energy East Corporation was publicly traded on the New York Stock Exchange, or the NYSE. In 2007, Iberdrola, S.A. acquired Scottish Power Ltd., or Scottish Power, including ScottishPower Holdings, Inc., or SPHI, the parent company of Scottish Power's U.S. subsidiaries. Through this acquisition, Iberdrola, S.A. acquired PPM Energy, a subsidiary that operated SPHI's U.S. wind business, thermal generation operations and the gas storage and energy management businesses and changed PPM Energy's name to Renewables. In 2008, Iberdrola, S.A. acquired Energy East Corporation and we changed our name to Iberdrola USA, Inc. in December 2009. In 2013, we completed an internal corporate reorganization to create a unified corporate presence for the Iberdrola brand in the United States, bringing all of its U.S. energy companies under one single holding company, Iberdrola USA, Inc. The internal reorganization, completed in November 2013, resulted in the concentration of our principal businesses in two major subsidiaries: Networks, which holds all of our regulated utilities; and Renewables, which holds our renewable and thermal generation businesses, and gas storage and marketing businesses.

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

On December 16, 2015, we completed an acquisition of UIL, pursuant to which UIL merged with and into our wholly-owned subsidiary, Green Merger Sub, Inc., or Merger Sub, with Merger Sub surviving as our wholly-owned subsidiary. The acquisition was effected pursuant to the Agreement and Plan of Merger, dated as of February 25, 2015, or the Merger Agreement, by and among us, Merger Sub, and UIL. Following the completion of the acquisition, Merger Sub was renamed "UIL Holdings Corporation" and we were renamed Avangrid, Inc. Immediately following the completion of the acquisition, former UIL shareowners owned 18.5% of the outstanding shares of common stock of AVANGRID, and Iberdrola owned the remaining shares. Effective as of April 30, 2016, UIL and its subsidiaries were transferred to a wholly-owned subsidiary of Networks.

Networks

Overview

Networks, holds our regulated utility businesses, including electric generation, transmission and distribution and natural gas distribution, transportation and sales. Networks serves as a super-regional energy services and delivery company through eight regulated utilities it owns directly:

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

For the year ended December 31, 2016, Networks distributed approximately 37,027,000 megawatt-hours, or MWh, of electricity. As of December 31, 2016, Networks provided electric service to its approximately 2.2 million customers in the states of New York, Maine and Connecticut. In total, the electric system of Networks' regulated utilities consisted of 8,482 miles of transmission lines, 70,916 miles of distribution lines and 826 substations as of December 31, 2016. Furthermore, for the year ended December 31, 2016, Networks delivered approximately 182 million dekatherms, or DTh, of natural gas, to approximately 992,000 customers, providing service in the states of New York, Maine, Connecticut and Massachusetts.

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

The following table sets forth certain information relating to the, rate base, number of customers and the amount of electricity or natural gas provided by each of Networks' regulated utilities for the year ended December 31, 2016:

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

(1) "Rate base" means the net assets upon which a utility can receive a specified return, based on the value of such assets. The rate base is set by the relevant regulatory authority and typically represents the value of specified property, such as plants, facilities and other investments of the utility. These rate base values have been calculated using the best estimates as of December 31, 2016.

During the last five years, Networks has invested nearly $5.8 billion in creating a delivery network with greater capacity and improved reliability, environmental security and sustainability, efficiency and automation. Networks continuously improves its grid to accommodate new requirements for advanced metering, demand response and enhanced outage management, while improving its flexibility for the integration and management of distributed energy resources, or DER.

New York

As of December 31, 2016, NYSEG served approximately 890,000 electricity customers and 265,000 natural gas customers across more than 40% of upstate New York's geographic area, while RG&E served approximately 375,000 electricity customers and 310,000 natural gas customers in a nine-county region centered around Rochester, in western New York.

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

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

Maine

As of December 31, 2016, CMP delivered electricity to more than 619,000 customers in an 11,000 square-mile service area in central and southern Maine. CMP completed a $1.4 billion investment plan for the construction of upgrades to the bulk power transmission grid in Maine, the largest transmission investment in the history of Maine, which includes the construction of five new

345-kilovolt, or kV, substations and related facilities linked by approximately 440 miles of new transmission lines (refers to the Maine Power Reliability Program, or MPRP).

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

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

Connecticut

As of December 31, 2016, UI served more than 332,000 residential, commercial and industrial customers in a service area of approximately 335 square miles in the southwestern part of Connecticut. The service area includes Bridgeport and New Haven and is home to a diverse array of business sectors including aerospace manufacturing, healthcare, biotech, financial services, precision manufacturing, retail and education. UI's retail electric revenues vary by season, with the highest revenues typically in the third quarter of the year reflecting seasonal rates, hotter weather and air conditioning use.

UI is also a party to a joint venture with certain affiliates of NRG Energy, Inc., pursuant to which UI holds 50% of the membership interests in GCE Holding LLC, whose wholly owned subsidiary, GenConn Energy LLC, or GenConn, operates peaking generation plants in Devon, Connecticut, or GenConn Devon, and Middletown, Connecticut, or GenConn Middletown.

As of December 31, 2016, SCG and CNG provided local gas distribution services to approximately 373,000 customers in the greater Hartford-New Britain area, Greenwich and the southern Connecticut coast from Westport to Old Saybrook, including the cities of Bridgeport and New Haven.

Massachusetts

As of December 31, 2016, BGC provided local gas distribution services to approximately 40,000 customers in a service area in western Massachusetts, which includes the cities of Pittsfield, North Adams and Greenfield.

Rate Base

These rate base values have been calculated using the best estimates as of December 31, 2016. The rate base of Networks' regulated utilities for the years indicated below have been as follows:

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

Earnings Sharing Mechanisms

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

	2014	2015	2016
NYSEG Electric	50% / 50%: 10.90% - 11.65% 85% / 15%: over 11.65%; Based on Actual Equity Ratio up to 50%	50% / 50%: 10.90% - 11.65% 85% / 15%: over 11.65%; Based on Actual Equity Ratio up to 50%	50% / 50%: 9.50% - 10.00% 75% / 25%: 10.00% - 10.50% 90% / 10%: over 10.50%; Based on Actual Equity Ratio up to 50% *
NYSEG Gas	Same as above	Same as above	Same as above
RG&E Electric	Same as above	Same as above	Same as above
RG&E Gas	Same as above	Same as above	Same as above
CMP Dist.	No ESM	No ESM	No ESM
CMP Trans.	No ESM	No ESM	No ESM
MNG	No ESM	No ESM	No ESM
UI	50% / 50% over 9.15%	50% / 50% over 9.15%	50% / 50% over 9.15%
SCG	No ESM	No ESM	No ESM
CNG	50% / 50% over 9.18%	50% / 50% over 9.18%	50% / 50% over 9.18%
BGC	No ESM	No ESM	No ESM

*No ESM from January through April 2016.

Merger Settlement Agreement – Connecticut and Massachusetts

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

In connection with the acquisition proceeding, UI signed a proposed partial consent order, or the consent order, that was issued by the Connecticut Department of Energy and Environmental Protection, or DEEP, in August 2016. The consent order requires UI to investigate and remediate certain environmental conditions within the perimeter of a former generation site on the Mill River in New Haven, the English Station site, that UI sold to Quinnipiac Energy in 2000 and which is currently owned by Evergreen Power, LLC and Asnat Realty LLC. Under the terms of the consent order, to the extent that costs of the investigation and remediation are less than $30 million, UI is required to remit to the State of Connecticut the difference between such costs and $30 million, to be applied to a public purpose as determined in the discretion of the Governor, the Attorney General of Connecticut and the Commissioner of DEEP. However, UI is obligated to comply with the consent order, even if the cost of such compliance exceeds $30 million. See Part I, Item 1, "Business – Environmental, Health and Safety - Management, Disposal and Remediation of Hazardous Substances" for more information.

Renewables

The Renewables business, based in Portland Oregon, is engaged primarily in the design, development, construction, management and operation of generation plants that produce electricity using renewable resources and, with more than 50 renewable energy projects, is one of the leaders in renewable energy production in the United States based on installed capacity. Renewables' primary business is onshore wind energy generation, which represents approximately 90% of Renewables' combined installed capacity as of December 31, 2016. For the year ended December 31, 2016, Renewables produced approximately 14,167,000 MWh of energy through wind power generation. Renewables had a pipeline of approximately 5,900 MW of future renewable energy projects in various stages of development as of December 31, 2016.

Typically, Renewables enters into long-term lease agreements with property owners who lease their land for renewable projects. Electricity generated at a wind project is then transmitted to customers through long-term agreements with purchasers. There are a limited number of turbine suppliers in the market. Renewables' largest turbine suppliers, Gamesa Wind US and GE Wind, in the aggregate supplied turbines which accounted for 70% of its installed wind capacity as of December 31, 2016. In June 2016, Siemens

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

Renewables currently operates 54 wind farms in 19 states across the United States. To monetize the tax benefits resulting from production tax credits and accelerated tax depreciation available to qualifying wind energy projects, Renewables has entered into "tax equity" financing structures with third party investors for a portion of its wind farms. Renewables holds 12 operating wind farms under these structures through limited liability companies jointly owned by one or more third party investors. These investors generally provide an up-front investment or, in some cases, enter into fixed and contingent notes for their membership interests in the financing structures. In return, the investors receive substantially all of the cash flows and tax benefits generated by the wind farms until such benefits achieve a negotiated return on their investment. Upon attainment of this target return, the sharing of the cash flows and tax benefits flip, with Renewables receiving substantially all of these amounts thereafter. We also have an option to repurchase the investor's interest within a certain timeframe after the target return is met. Renewables maintains operational and management control over the wind farm businesses, subject to investor approval of certain major decisions. See "—Properties—Renewables" for more information regarding Renewables' wind power generation properties.

Additionally, as part of the Renewables portfolio, Renewables operates two thermal generation facilities in the United States, with 636 MW of combined capacity as of December 31, 2016. Renewables worked closely with the City of Klamath Falls, Oregon to develop the Klamath Plant, which has a current capacity of 536 MW. The Klamath Plant operates by creating two useful forms of energy, electricity and process steam, from a single fuel source of natural gas. In addition, Renewables operates a highly flexible 100 MW Klamath Peaking Plant adjacent to the Klamath Plant, providing customers of Renewables additional capability to meet their peak summer and winter power needs.

In addition to its wind assets, Renewables operates two solar photovoltaic facilities with an installed capacity of 50 MW. The solar photovoltaic facilities produced over 132,000MWh of renewable energy for the year ended December 31, 2016. Solar accounted for 0.9% of the total renewable energy generation from Renewables in these same periods.

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

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

MFG	Model	Rating	Turbines	MW
Gamesa	G83	2.0	61	122
Gamesa	G87	2.0	643	1,286
Gamesa	G90	2.0	237	474
Gamesa	G97	2.0	101	202
Gamesa	G114	2.0	104	208
GE	1.5s	1.5	133	200
GE	1.5sle	1.5	1,072	1,608
MHI	MWT62/1.0	1.0	45	45
MHI	MWT92/2.4	2.4	168	403
MHI	MWT95/2.4	2.4	125	300
MHI	MWT102/2.4	2.4	1	2
NEG	NM48	0.7	3	2
Siemens	SWT2.3-93	2.3	44	101
Suzlon	S88	2.1	341	716
Vestas	V47	0.7	34	22
Vestas	V82	1.7	97	160
Total			3,209	5,852

The Renewables meteorology team supports the commercial development of wind energy projects in Renewables' pipeline by performing a wide variety of detailed investigations to characterize the expected wind energy production from a proposed wind farm 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 5 sonic detecting and ranging, remote sensing devices are deployed at sites across the United States. These remote sensing devices allow hub-height wind speed measurement from a ground-based sensor that can be rapidly deployed and moved as the project matures or changes in nature. The resulting pre-construction energy production estimates that utilize these measurements have been shown to be accurate in a multi-year internal study that compares results to actual, operational data in a benchmarking analysis. This study provides a critical feedback loop that is used to define methodology requirements for future pre-construction energy production estimates to ensure confidence in project investment. Renewables' commitment to obtaining robust atmospheric measurement is driven by a company culture that values business case confidence and understands the role that accurate meteorological data play in the pursuit of this goal.

Gas

The Gas business, based in Houston, Texas, operates a natural gas storage and natural gas trading business through its wholly-owned direct subsidiaries, Enstor, Inc., an Oregon corporation (natural gas storage) and Enstor Energy Services, LLC, a Delaware limited liability company (natural gas trading). Gas owns and operates four natural gas storage facilities, with a total storage capacity of 88.5 Bcf and a net working gas storage capacity of 67.5 Bcf. Enstor Operating Company, LLC, a Texas limited liability company and wholly-owned direct subsidiary of Enstor, Inc., manages all four natural gas storage facilities. The demand for natural gas storage is dependent upon the seasonal differences in the weather. Since market prices and temporal price spreads for natural gas reflect the demand for these products and their availability at a given time, the overall operating results of Gas' business may fluctuate substantially on a seasonal basis. Severe weather, such as ice and snow storms, hurricanes and other natural disasters may cause outages, bodily injury or property damage, which may require Gas to incur additional costs, such as operation and maintenance expenses, which may not be recoverable from customers. See "—Properties—Gas" for more information regarding Gas' natural gas storage facilities. Enstor Energy Services, LLC also contracts and manages natural gas storage and pipeline capacity throughout the United States and parts of Canada. Gas operates 52.4 Bcf of contracted or managed natural gas storage capacity in North America through Enstor Energy Services, LLC, as of December 31, 2016.

Regulatory Environment and Principal Markets

Federal Energy Regulatory Commission

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

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

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

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

Since 2011, several parties have filed four separate complaints with the FERC against ISO-NE and several New England transmission owners, including UI and CMP, claiming that the current approved base ROE of 11.14% was not just and reasonable, seeking a reduction of the base ROE and a refund to customers for the 15-month refund periods beginning October 1, 2011, December 27, 2012, July 31, 2014 and April 29, 2016, respectively.

In 2014, the FERC determined that the base ROE should be set at 10.57% for the first complaint refund period and that a utility's total or maximum ROE should not exceed 11.74%. The FERC issued an order consolidating the second and third complaints and establishing hearing procedures. The administrative law judge issued an initial decision in the second and third complaints on March 22, 2016. The initial decision determined that: (1) for the 15 month refund period in the second complaint, the base ROE should be 9.59% and the ROE Cap (base ROE plus incentive ROEs) should be 10.42% and (2) for the 15 month refund period in the third complaint and prospectively, the base ROE should be 10.90% and that the ROE Cap should be 12.19%. The initial decision in the second and third complaints is the administrative law judge's recommendation to the FERC Commissioners. The FERC is expected to make its final decision on the second and third complaints in mid-2017. The FERC has set the fourth complaint for settlement proceedings and hearing, with a final decision expected in 2018.

On March 3, 2015, the FERC issued an Order on Rehearing in the first complaint denying all rehearing requests from the complainants and the New England transmission owners. Appeals of the FERC's decisions on the first complaint are currently pending before the United States Court of Appeals for the D.C. Circuit.

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

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

The FERC has civil penalty authority over violations of any provision of Part II of the FPA, as well as any rule or order issued thereunder. FERC is authorized to assess a maximum civil penalty of $1.0 million per violation for each day that the violation continues. The FPA also provides for the assessment of criminal fines and imprisonment for violations under Part II of the FPA. Pursuant to the Energy Policy Act of 2005, or EPAct 2005, the North American Electric Reliability Corporation, or NERC, has been certified by the FERC as the Electric Reliability Organization for North America responsible for developing and overseeing the enforcement of electric system reliability standards applicable throughout the United States. FERC-approved reliability standards may be enforced by the FERC independently, or, alternatively, by NERC and the regional reliability organizations with frontline responsibility for auditing, investigating and otherwise ensuring compliance with reliability standards, subject to the FERC oversight.

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

The gas distribution operations of NYSEG, RG&E, SCG, CNG and BGC, similar to Gas, are also subject to the FERC regulation with respect to their gas purchases/sales and contracted transportation/storage capacity. FERC has civil penalty authority under the NGA to impose penalties for certain violations of up to $1.0 million per day for violations. FERC also has the authority to order the disgorgement of profits from transactions deemed to violate the NGA and EPAct 2005.

Market Anti-Manipulation Regulation

The FERC and the Commodity Futures Trading Commission, or CFTC, monitor certain segments of the physical and futures energy commodities market pursuant to the FPA and the Commodity Exchange Act, including our businesses' energy transactions and operations in the United States. In July 2010, Congress passed the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which incorporated an expansion of the authority of the CFTC to prohibit market manipulation in the markets regulated by the CFTC. With regard to the physical purchases and sales of electricity and natural gas, the gathering storage, transmission and delivery of these energy commodities and any related trading or hedging transactions that some of our operating subsidiaries undertake, our operating subsidiaries are required to observe these anti-market manipulation laws and related regulations enforced by the FERC and CFTC. The FERC and CFTC hold substantial enforcement authority, including the ability to assess civil penalties of up to $1.0 million per day per violation, to order disgorgement of profits and to recommend criminal penalties.

State Regulation

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

Networks' regulated distribution utilities deliver electricity and/or natural gas to all customers in their service territory at rates established under cost of service regulation. Under this regulatory structure, Networks' regulated distribution utilities recover the cost of providing distribution service to their customers based on its costs, and earn a return on their capital investment in utility assets.

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

- *New York*. On May 20, 2015 NYSEG and RG&E initiated a distribution rate case to ensure that the companies are able to continue to provide safe, adequate and reliable service, continue to make investments to modernize infrastructure, enhance low income programs and improve both gas and electric reliability, while maintaining the Companies' financial integrity. On February 19, 2016, NYSEG, RG&E and other signatory parties filed a joint proposal, or the proposal, with the NYPSC for a three-year rate plan for electric and gas service at NYSEG and RG&E commencing May 1, 2016. The proposal was approved on June 15, 2016 by the NYPSC. The proposal balanced the varied interests of the signatory parties including but not limited to maintaining the companies' credit quality and mitigating the rate impacts to customers. The proposal reflects many customer benefits including acceleration of the companies' natural gas leak prone main replacement programs and increased funding for electric vegetation management to provide continued safe and reliable service. The allowed rate of return on common equity for NYSEG Electric, NYSEG Gas, RG&E Electric and RG&E Gas is 9.00%. The equity ratio for each company is 48%. The proposal includes an ESM applicable to each company. The customer share of earnings would increase at higher ROE levels, with customers receiving 50%, 75% and 90% of earnings over 9.5%, 10.0% and 10.5% of ROE, respectively, in the first rate year. Earnings are based on the lower of the actual equity ratio or 50%. Earnings thresholds increase in subsequent rate years. The proposal reflects the recovery of deferred NYSEG Electric storm costs of approximately $262 million, of which $123 million will be amortized over ten years and the remaining $139 million will be amortized over five years. The proposal also continues reserve accounting for qualifying Major Storms ($21.4 million annually for NYSEG Electric and $2.5 million annually for RG&E Electric). Incremental maintenance costs incurred to restore service in qualifying divisions will be chargeable to the Major Storm Reserve provided they meet certain thresholds.
- *Maine*. On May 1, 2013, CMP filed a distribution service rate case in order to recover past and future investments and provide safe and adequate service. On August 25, 2014, MPUC approved a stipulation agreement that provided for a distribution rate increase of approximately $24.3 million, effective July 1, 2014, with an allowed ROE of 9.45% and an allowed equity ratio of 50%.

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

On May 3, 2016, all active parties to the case filed a stipulation that settled all matters at issue in the case and reflected a 10-year rate plan through April 30, 2026. The MPUC approved the stipulation on May 17, 2016, for new rates effective June 1, 2016. The settlement structure for non-Augusta customers includes a 34.6% delivery revenue increase over five years with an allowed 9.55% ROE and 50% common equity ratio. The settlement structure for Augusta customers includes a 10-year rate plan with existing Augusta customers being charged rates equal to non-Augusta customers plus a surcharge that increases annually for five years. New Augusta customers will have rates set based on an alternate fuel market model. In year seven of the rate plan MNG will submit a cost of service filing for the Augusta area to determine if the rate plan should continue. This cost of service filing will exclude $15 million of initial 2012/2013 gross plant investment, however the stipulation allows for accelerated depreciation of these assets. If the Augusta area's cost of service filing illustrates results above a 14.55% ROE then the rate plan may cease, otherwise the rate plan would continue. A disallowance for the initial 2012/2013 gross plant investment is not part of the approved stipulation.

- *Connecticut*. In December 2016, PURA approved distribution rate schedules for UI for three years that became effective January 1, 2017 and which, among other things, provides for $57 million of cumulative distribution rate increases, an allowed ROE of 9.10% based on 50% equity, continued UI's existing earnings sharing mechanism, continued the existing decoupling mechanism (under which the actual energy delivery revenues are compared on a periodic basis with the authorized delivery revenues and the difference accrued, for refund to or recovery from customers, as applicable), and approved the continuation of the requested storm reserve

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

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

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

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

In April 2014 the NYPSC instituted its Reforming the Energy Visions, or REV, proceeding, the goals of which are to improve electric system efficiency and reliability, encourage renewable energy resources, support DER, and empower customer choice. In this proceeding, the NYPSC is examining the establishment of a Distributed System Platform, or DSP, to manage and coordinate DER, and provide customers with market data and tools to manage their energy use. The NYPSC has determined distribution utilities should be the DSP providers. The NYPSC also is examining how its regulatory practices should be modified to incent utility practices to promote REV proceeding objectives. The REV proceeding involves a two-phased schedule with an initial order relating to policy determinations for DSP and related matters issued in February 2015 and an initial order for regulatory design and regulatory matters issued in May 2016. All electric utilities were ordered to file an initial Distributed System Implementation Plan, or DSIP, by June 30, 2016. The DSIP was filed by NYSEG and RG&E and included information regarding the potential deployment of Automated Metering Infrastructure, or AMI. A separate petition for the cost recovery associated with full deployment of AMI was filed by NYSEG and RG&E in December 2016.

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 approximately 21 years. The obligations will phase in over a six-year solicitation period, and are expected to peak at an annual commitment level of about $13.6 million per year after all selected projects are online. Upon purchase, UI accounts for the RECs as inventory. UI expects to partially mitigate the cost of these contracts through the resale of the RECs. PA 11-80 provides that the remaining costs (and any benefits) of these contracts, including any gain or loss resulting from the resale of the RECs, are fully recoverable from (or credited to) customers through electric rates.

On October 23, 2013, PURA approved UI's renewable connections program filed in accordance with PA 11-80, pursuant to which UI will develop up to 10 MW of renewable generation. The costs for this program will be recovered on a cost of service basis. PURA established a base ROE to be calculated as the greater of: (A) the current UI authorized distribution ROE (currently 9.10%) plus 25 basis points and (B) the current authorized distribution ROE for The Connecticut Light and Power Company, or CL&P, (currently 9.17%), less target equivalent market revenues (reflected as 25 basis points). In addition, UI will retain a percentage of the market revenues from the project, which percentage is expected to equate to approximately 25 basis points on a levelized basis over the life of the project. UI expects the cost of this program, a planned 2.8 MW fuel cell facility in New Haven, solar photovoltaic and fuel cell facilities totaling 5 MW in Bridgeport, and a 2.2 MW fuel cell facility in Woodbridge, to be approximately $47 million.

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

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

Under Maine law 35-A M.R.S.A §§ 3210-C, 3210-D, the MPUC is authorized to conduct periodic requests for proposals seeking long-term supplies of energy, capacity or RECs, from qualifying resources. The MPUC is further authorized to order Maine Transmission and Distribution Utilities to enter into contracts with sellers selected from the MPUC's competitive solicitation process. Pursuant to a MPUC Order dated October 8, 2009, CMP entered into a 20-year agreement with Evergreen Wind Power III, LLC, on

March 31, 2010, to purchase capacity and energy from Evergreen's 60 MW Rollins wind farm in Penobscot County, Maine. CMP's purchase obligations under the Rollins contract are approximately $7 million per year. In accordance with subsequent MPUC orders, CMP periodically auctions the purchased Rollins energy to wholesale buyers in the New England regional market. Under applicable law, CMP is assured recovery of any differences between power purchase costs and achieved market revenues through a reconcilable component of its retail distribution rates. Although the MPUC has conducted multiple requests for proposals under M.R.S.A §3210-C and has tentatively accepted long-term proposals from other sellers, these selections have not yet resulted in additional currently effective contracts with CMP.

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

Environmental, Health and Safety

Permitting and Other Regulatory Requirements

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

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

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

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

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

Renewables. Renewables' projects are subject to a variety of state environmental review and permitting requirements. Many states where Renewables' projects are located, or may be located in the future, have laws that require state agencies to evaluate a broad array of environmental impacts before granting state permits. Generally, State agencies evaluate similar issues as federal agencies, including the project's impact on wildlife, historic sites, aesthetics, wetlands and water resources, agricultural operations and scenic areas. States may impose different or additional monitoring or mitigation requirements than federal agencies. Additional approvals may be required for specific aspects of a project, such as stream or wetland crossings, impacts to designated significant

wildlife habitats, storm water management and highway department authorizations for oversize loads and state road closings during construction. Permitting requirements related to transmission lines may be required in certain cases.

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

In addition to permits required under state and local laws, Renewables' projects may be subject to permitting and other regulatory requirements arising under federal law. For example, if a project is located near wetlands, a permit may be required from the U.S. Army Corps of Engineers, or Army Corps, with respect to the discharge of dredged or fill material into the waters of the United States. The Army Corps may also require the mitigation of any loss of wetland functions and values that accompanies the project's activities. In addition, Renewables may be required to obtain permits under the federal Clean Water Act for water discharges, such as storm water runoff associated with construction activities, and to follow a variety of best management practices to ensure that water quality is protected and impacts are minimized. Renewables' projects also may be located, or partially located, on lands administered by the U.S. Bureau of Land Management, or BLM. Therefore, Renewables may be required to obtain and maintain BLM right-of-way grants for access to, or operations on, such lands. To obtain and maintain a grant, there must be environmental reviews conducted, a plan of development implemented and a demonstration that there has been compliance with the plan to protect the environment, including measures to protect biological, archeological and cultural resources encountered on the grant.

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

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

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

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

Global Climate Change and Greenhouse Gas Emission Issues

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

We are continuously evaluating the regulatory risks and regulatory uncertainty presented by climate change and greenhouse gas emission. Such concerns could potentially lead to additional rules and regulations that impact how we operate our business. We expect that any costs of these rules and regulations would be recovered from customers.

OSHA and Certain Other Federal Safety Laws

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

Management, Disposal and Remediation of Hazardous Substances

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

On September 16, 2015, UI signed the consent order that was issued by DEEP in August 2016 related to the investigation and remediation of the English Station site. The consent order requires UI to investigate and remediate certain environmental conditions within the perimeter of the English Station site. Under the consent order, to the extent that the cost of this investigation and remediation is less than $30 million, UI is required to remit to the State of Connecticut the difference between such cost and $30 million to be applied to a public purpose as determined in the discretion of the Governor of the State of Connecticut, the Attorney General of the State of Connecticut, and the Commissioner of DEEP. However, UI is obligated to comply with the consent order even if the cost of such compliance exceeds $30 million. The State may discuss options with UI on recovering or funding any cost above $30 million, such as through public funding or recovery from third parties, however it is not bound to agree to or support any means of recovery or funding.

Customers

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

Renewables sells the majority of its output to large investor-owned utilities, public utilities and other credit-worthy entities. Additionally, Renewables generates and provides power, among other services, to federal and state agencies, institutional retail and joint action agencies. Offtakers typically purchase renewable energy from Renewables through long-term power purchase agreements,

or PPAs, allowing Renewables to limit its exposure to market volatility. Approximately 62% of Renewables' wind generating capacity is fully committed under PPAs as of December 31, 2016, with an average duration of 9.5 years. Renewables also delivers thermal output to wholesale customers in the Western United States.

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

Competition

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

Networks faces competition from self-contained micro-grids that integrate renewable energy sources in the areas served by Networks. However, there has been limited development of these micro-grids in Networks' service areas to date, and Networks expects that growth in distributed generation of renewable energy will continue due to financial incentives being provided by federal and state legislation. Networks has experienced significant growth in alternative distribution sources of generation on its network over the past ten years, with approximately 90% of the growth coming from solar photovoltaic facilities.

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

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

Properties

Networks

The following table sets forth certain information relating to Networks' electricity generation facilities and their respective locations, type and installed capacity as of December 31, 2016. Unless noted otherwise, Networks owns each of these facilities.

Operating Company	Facility Location	Facility Type	Installed Capacity (in MW)	Year(s) Commissioned
NYSEG	Newcomb, NY	Diesel Turbine	1.7	1967
NYSEG	Auburn, NY(1)	Natural Gas Turbine	7.3	2000
NYSEG	Eastern New York (6 locations)	Hydroelectric	61.4	1921—1983
RG&E	Rochester, NY (3 locations)	Hydroelectric	57.1	1917—1960

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

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

The following table sets forth certain operating data relating to the electricity transmission and distribution activities of each of Networks' regulated utilities as of December 31, 2016.

Utility	State	Substations	Transmission Lines (in miles)	Overhead Distribution Lines (in pole miles)	Underground Lines (in miles)	Total Distribution (in miles)	Electricity Customers
NYSEG	New York	435	4,463	32,319	2,702	35,021	885,000
RG&E	New York	153	1,025	6,091	2,834	8,925	375,000
CMP	Maine	209	2,856	21,056	1,428	22,484	616,979
UI	Connecticut	29	138	3,284	202	3,486	331,216

The following table sets forth certain operating data relating to the natural gas transmission and distribution activities of each of Networks' regulated utilities, as of December 31, 2016.

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

CNG owns and operates a liquefied natural gas, or LNG, plant which can store up to 1.2 Bcf of natural gas and can vaporize up to 97,000 Mcf per day of LNG to meet peak demand. SCG has contract rights to and operates a similar plant with the same capabilities to store up to 1.2 Bcf of natural gas. SCG's LNG facilities can vaporize up to 82,500 Mcf per day of LNG to meet peak demand. SCG and CNG have also contracted for 21 Bcf of storage with a maximum peak day delivery capability of 209,000 Mcf per day.

Renewables

The following table sets forth Renewables' portfolio of wind projects as of December 31, 2016. Unless noted otherwise, Renewables wholly owns each of these facilities.

Location	Wind Project	Turbines	Total Installed Capacity (MW)	Commercial Operation Date	North American Electric Reliability Corporation ("NERC") Region
Arizona	Dry Lake I	30 (Suzlon S88, 2.1 MW)	63	2009	WECC
	Dry Lake II	31 (Suzlon, 2.1 MW)	65	2010	
California	Dillon	45 (Mitsubishi, 1 MW)	45	2008	WECC
	Manzana	126 (GE, 1.5 MW)	189	2011	WECC
	Mountain View III	34 (Vestas V47, 0.66 MW)	22	2003	WECC
	Phoenix Wind Power	3 (Neg Micon (Vestas), 0.66 MW)	2	1999	WECC
	Shiloh	100 (GE, 1.5 MW)	150	2006	
Colorado	Colorado Green(1)	54 (GE, 1.5 MW)	81	2003	WECC
	Twin Buttes	50 (GE, 1.5 MW)	75	2007	
Illinois	Providence Heights	36 (Gamesa G87, 2.0 MW)	72	2008	MRO
	Streator Cayuga Ridge South	150 (Gamesa, 2.0MW)	300	2010	
Iowa	Barton	80 (Gamesa, 2.0 MW)	160	2009	MRO
	Flying Cloud	29 (GE, 1.5 MW)	44	2004	MRO
	New Harvest	50 (Gamesa G87, 2.0W)	100	2012	MRO
	Top of Iowa II	40 (Gamesa G87, 2.0 MW)	80	2008	MRO
	Winnebago I	10 (Gamesa G83, 2.0 MW)	20	2008	MRO
Kansas	Elk River	100 (GE, 1.5 MW)	150	2005	MRO
Massachusetts	Hoosac	19 (GE, 1.5 MW)	29	2012	NPCC
Minnesota	Elm Creek	66 (GE, 1.5 MW)	99	2008	MRO
	MinnDakota	100 (GE, 1.5 MW)	150	2008	MRO
	Trimont	67 (GE, 1.5 MW)	100	2005	MRO
	Elm Creek II	62 (Mitsubishi, 2.4)	149	2010	MRO
	Moraine I	34 (GE, 1.5 MW)	51	2003	MRO
	Moraine II	33 (GE, 1.5 MW)	50	2009	MRO
Missouri	Farmers City	73 (Gamesa G87, 2.0 MW)	146	2009	MRO
New Hampshire	Groton	24 (Gamesa G87, 2.0 MW)	48	2012	NPCC
	Lempster	12 (Gamesa, 2 MW)	24	2008	NPCC
New York	Hardscrabble	37 (Gamesa G90, 2MW)	74	2011	NPCC
	Maple Ridge I(2)	70 (Vestas V82, 1.65 MW)	116	2006	NPCC
	Maple Ridge II(2)	27 (Vestas V82, 1.65 MW)	45	2006	NPCC
North Carolina	Amazon Wind Farm US - East	104 (Gamesa G114, 2.0 MW)	208	2016	SERC
North Dakota	Rugby	71 (Suzlon S88, 2.1 MW)	149	2009	MRO
Ohio	Blue Creek	152 (Gamesa G90 – 2.0 MW)	304	2012	RFC
Oregon	Hay Canyon	48 (Suzlon S88, 2.1 MW)	101	2009	WECC
	Klondike I	16 (GE, 1.5 S – 1.5 MW)	24	2001	WECC
	Klondike II	50 (GE, 1.5 S – 1.5 MW)	75	2005	WECC
	Klondike III	44 (Siemens, 2.3 MW); 80 (GE, 1.5 SLE, 1.5 MW); 1 (Mitsubishi, 2.4 MW)	224	2007	WECC
	Klondike IIIa	51 (GE, 1.5 MW)	77	2008	WECC
	Leaning Juniper II	74 (GE, 1.5 MW); 43 (Suzlon, 2.1 MW)	201	2011	WECC
	Pebble Springs	47 (Suzlon S88/2100, 2.1 MW)	99	2009	WECC
	Star Point	47 (Suzlon, 2.1 MW)	99	2010	WECC
Pennsylvania	Casselman	23 (GE, 1.5 MW)	35	2008	RFC
	Locust Ridge I	13 (Gamesa G87, 2.0)	26	2006	RFC
	Locust Ridge II	51 (Gamesa G83, 2.0 MW)	102	2009	RFC
	South Chestnut	23 (Gamesa, 2.0 MW)	46	2012	RFC
South Dakota	Buffalo Ridge I	24 (Suzlon, 2.1 MW)	50	2009	MRO
	Buffalo Ridge II	105 (Gamesa G87, 2.0 MW)	210	2010	MRO
Texas	Baffin	101 (Gamesa G97, 2.0 MW)	202	2015	TRE
	Barton Chapel	60 (Gamesa, 2.0 MW)	120	2009	TRE
	Peñascal I	84 (Mitsubishi, 2.4 MW)	202	2009	TRE
	Peñascal II	84 (Mitsubishi, 2.4 MW)	202	2010	TRE
Washington	Big Horn I	133 (GE, 1.5 MW)	200	2006	WECC
	Big Horn II	25 (Gamesa, 2.0 MW)	50	2010	WECC
	Juniper Canyon	63 (Mitsubishi, 2.4 MW)	151	2011	WECC

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

Additionally, set forth below are the solar and thermal facilities operated by Renewables as of December 31, 2016. Unless otherwise noted, Renewables owns each such facility.

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

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

Gas

Gas owns and operates four natural gas storage facilities, all near key trading hubs. The following table provides an overview of these storage facilities as of December 31, 2016. Unless noted otherwise, Enstor, Inc., a wholly-owned direct subsidiary of Gas, owns and operates each of these facilities.

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

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

Infrastructure Protection and Cyber Security Measures

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

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

To manage these operational risks, pursuant to the AVANGRID Cybersecurity Risk Policy approved by the AVANGRID board and the Corporate Security Policy of Iberdrola, S.A. adopted by our board, we have implemented cyber and physical security measures and continue to strengthen our security posture by improving and expanding our physical and cyber security capabilities to protect critical assets.

In an effort to reduce our vulnerability to cyber attacks, we have appointed an officer responsible for Security and established a dedicated Corporate Security Office, responsible for improving and coordinating security and NERC Compliance across the company. We have adopted a comprehensive company-wide physical and cyber security program, which is supported by a governance program to manage, oversee and assist us in meeting our corporate, legal, and regulatory responsibilities with regard to the protection of our cyber, physical and information assets.

However, as threats evolve and grow increasingly more sophisticated, we cannot ensure that a potential security breach may not occur or quantify the potential impact of such an event. We continue to invest in technology, processes, security measures and services to predict, detect, mitigate and protect our assets, both physical and cyber. These investments include upgrades to our cyber-

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

Employees

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

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

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

Available Information

Copies of our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to these reports filed with the SEC may be requested, viewed, or downloaded on-line, free of charge, on our website www.avangrid.com. Printed copies of these reports may be obtained free of charge by writing to our Investor Relations Department at 157 Church Street, New Haven, Connecticut, 06506.

Item 1A. Risk Factors

Risks Relating to Our Regulatory Environment

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

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

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

Our businesses are subject to the jurisdiction of various federal, state and local regulatory agencies including, but not limited to, the FERC, the CFTC, the DOE, and the EPA. Further, Networks' regulated utilities in New York, Maine, Connecticut and Massachusetts are subject to the jurisdiction of the NYPSC, the MPUC, the New York State Department of Environmental Conservation, the Maine Department of Environmental Protection, the PURA, the CSC, the DEEP, and the DPU. These regulatory agencies cover a wide range of business activities, including, among other items, the retail and wholesale rates for electric energy, capacity and ancillary services, and for the transmission and distribution of these products, the costs charged to Networks' customers through tariffs including cost recovery clauses, the terms and conditions of Networks' services, procurement of electricity for Networks' customers, issuances of securities, the provision of services by affiliates and the allocation of those service costs, certain accounting matters, and certain aspects of the siting, construction and transmission and distribution systems. The FERC has the authority to impose penalties, which could be substantial, for violations of the FPA, the NGA, or related rules, including reliability and cyber security rules as described in further detail below. The Financial Accounting Standards Board, or FASB, or the SEC, may enact new accounting standards that could impact the way we are required to record revenue, expenses, assets and liabilities. Certain regulatory agencies have the authority to review and disallow recovery of costs that they consider excessive or imprudently incurred and to determine the level of return that our businesses are permitted to earn on invested capital.

The regulatory process, which may be adversely affected by the political, regulatory and economic environment in New York, Maine, Connecticut and Massachusetts, as applicable, may limit our ability to increase earnings and does not provide any assurance as to achievement of authorized or other earnings levels. The disallowance of the recovery of costs incurred by us or a decrease in the rate of return that we are permitted to earn on our invested capital could have a material adverse effect on our business, results of operation, financial condition and cash flows. Certain of these regulatory agencies also have the authority to audit the management and operations of our businesses in New York, Maine, Connecticut and Massachusetts and require or recommend operational changes. Such audits and post-audit work requires the attention of our management and employees and may divert their attention from other regulatory, operational or financial matters. The last management audit of UI by PURA was completed in 2015. This audit resulted in 64 recommendations. The last management audit of CNG and SCG was completed in 2016. This audit resulted in approximately 94 recommendations. The

NYPSC completed an operations staffing audit of all NY utilities in January 2017. The audit is under review and we expect it will result in approximately 17 specific recommendations for NYSEG and RG&E and one general recommendation for all NY utilities. The NYPSC plans to conduct a management audit of NYSEG and RG&E in 2017. The audit is expected to be completed in early 2018. We cannot predict the outcome of these audits.

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

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

As a result of the EPAct 2005, owners, operators and users of bulk electric systems are subject to mandatory reliability standards developed by NERC and are subject to oversight by the FERC in the U.S. and governmental authorities in Canada. The standards are based on the functions that need to be performed to ensure that the bulk electric system operates reliably. Networks' and Renewables' businesses have been, and will continue to be, subject to routine audits and monitoring with respect to compliance with applicable NERC reliability standards, including standards approved by the FERC that could result in an increase in the number of assets (including cyber-security assets) designated as "critical assets," which would subject such assets to NERC cyber-security standards. NERC and the FERC can be expected to continue to refine existing reliability standards as well as develop and adopt new reliability standards. Compliance with modified or new reliability standards may subject Networks' and/or Renewables' businesses to new requirements resulting in higher operating costs and/or increased capital expenditures. If Networks' and/or Renewables' businesses were found not to be in compliance with the mandatory reliability standards, it could be subject to penalties of up to $1.0 million per day per violation. Both the costs of regulatory compliance and the costs that may be imposed as a result of any actual or alleged compliance failures could have a material adverse effect on our business, results of operation, financial condition and prospects. NYSEG and RG&E will have onsite NERC operational audit and NYSEG, RG&E and CMP will have onsite CIP audit in 2017. We cannot predict the outcome of these audits.

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

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

Various other REV-related proceedings have also been initiated by the PSC, each of which is following its own schedule. These proceedings include the Clean Energy Fund, Demand Response Tariffs, Community Choice Aggregation, Large Scale Renewables, and Community Distributed Generation. As part of this initiative, NYSEG and RG&E entered into agreements with NYSERDA for Renewable Energy Credits (RECs) and Zero-Emission Credits (ZECs) in 2017 and have prepared updated tariffs for collection and payment.

Track 2 of the REV initiative is also underway, and through a NYPSC Staff Whitepaper review process, is examining potential changes in current regulatory, tariff, market design and incentive structures which could better align utility interests with achieving New York State and NYPSC policy objectives. New York utilities will also be addressing related regulatory issues in their individual rate cases. A Track 2 order was issued in May 2016, and includes guidance related to the potential for Earnings adjustment mechanisms (EAMs), platform service revenues, innovative rate designs, and data utilization and security. The companies, in December 2016, filed a proposal for the implementation of EAMs in the areas of system efficiency, energy efficiency, interconnections, and clean air. A collaborative process to review the companies' petition is expected to begin in the first quarter of 2017.

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

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

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

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

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

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

Our businesses are subject to environmental laws and regulations, including, but not limited to, extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality and usage, climate change, emissions of greenhouse gases (including, but not limited to carbon dioxide), waste management, hazardous wastes (including the clean-up of former manufactured gas and electric generation facilities), marine, avian and other wildlife mortality and habitat protection, historical artifact preservation, natural resources and health and safety (including, but not limited to, electric and magnetic fields from power lines and substations, and ice throw, shadow flicker and noise related to wind turbines) that could, among other things, prevent or delay the development of power generation, power or natural gas transmission, or other infrastructure projects, restrict the output of some existing facilities, limit the availability and use of some fuels required for the production of electricity, require additional pollution control equipment, and otherwise increase costs, increase capital expenditures and limit or eliminate certain operations. There are significant capital, operating and other costs associated with compliance with these environmental statutes, rules and regulations, and those costs could be even more significant in the future as a result of new legislation, the current trend toward more stringent standards, and stricter and more expansive application and enforcement of existing environmental regulations. For example, new laws, regulations or treaties relating to climate change could mandate new or increased requirements to control or reduce the emission of greenhouse gases, such as carbon dioxide, taxes or fees on fossil fuels or emissions, cap and trade programs, emission limits and clean or renewable energy standards or mandates that require curtailment of operations for certain periods of time due to potential electromagnetic interference. Violations of current or future laws, rules, regulations or other standards could expose our subsidiaries to regulatory and legal proceedings, disputes with, and legal challenges by, third parties, and potentially significant civil fines, criminal penalties and other sanctions, which could have an adverse effect on our operations, financial condition and cash flows.

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

Our regulated utilities in New York, Maine, Connecticut and Massachusetts are subject to periodic review of their rates by the NYPSC, MPUC, PURA and DPU, respectively, and the retail rates charged to our regulated utilities' customers through base rates and cost recovery clauses are subject to the jurisdiction of the NYPSC, MPUC, PURA and DPU, as applicable. New rates may be proposed by Network's businesses, which are then subject to review, modification and final authorization and implementation by regulators. Alternatively, regulators may review the rates of Networks' regulated utilities on their own motion. Networks' regulated utilities' rate plans cover specified periods, but rates determined pursuant to a plan generally continue in effect until a new rate plan is approved by the state utility regulator. Networks' regulated utilities' business rate plans approved by state utility regulators limit the rates Networks' regulated utilities can charge their customers. The rates are generally designed for, but do not guarantee, the recovery of Networks' regulated utilities' respective cost of service and the opportunity to earn a reasonable rate of return (ROE). Actual costs may increase due to inflation or other factors and exceed levels provided for such costs in the rate plans for Networks' regulated

utilities. Utility regulators can initiate proceedings to prohibit Networks' regulated utilities from recovering from their customers the cost of service (including energy costs) that the regulators determine to have been imprudently incurred. Networks' regulated utilities defer for future recovery certain costs including major storm costs and environmental costs. In a number of proceedings in recent years, Networks' regulated subsidiaries have been denied recovery, or deferred recovery pending the next general rate case, including denials or deferrals related to major storm costs and construction expenditures. In some instances, denial of recovery may cause the regulated subsidiaries to record an impairment of assets. If Networks' regulated utilities' costs are not fully and timely recovered through the rates ultimately approved by regulators, our cash flows, results of operations and financial condition, and our ability to earn a return on investment and meet financial obligations, could be adversely affected.

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

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

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

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

Violations of wildlife protection laws in certain jurisdictions may result in civil or criminal penalties, including violations of certain laws protecting migratory birds, endangered species and eagles. The ESA and analogous state laws restrict activities without a permit that may adversely affect endangered and threatened species or their habitat. The ESA also provides for private causes of actions against a development project, an operating facility, or the agency that oversees the alleged violation of law. Similar protections are offered to migratory birds under the MBTA, which implements various treaties and conventions between the United States and certain other nations for the protection of migratory birds and, pursuant to which the taking, killing or possessing of migratory birds is unlawful. Complying with the state and federal laws protecting migratory birds, endangered species and eagles may require implementation of operating restrictions or a temporary, seasonal, or permanent ban on operations in affected areas, which can have a material adverse effect on the revenue of those projects. For example, there have been recent sightings of the protected California condor at Renewables' Manzana wind facility. Any incidental taking of a California condor could result in substantial financial, legal and reputational harm to us. The DOJ is currently investigating Renewables for potential violations under the MBTA and the ESA at its Blue Creek facility. We cannot predict the outcome of this investigation.

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

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

Under the EPAct 2005 and the Dodd-Frank Act, our businesses are subject to enhanced FERC and CFTC statutory authority to monitor certain segments of the physical and financial energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of the electricity and gas markets. Under these laws, the FERC and CFTC have promulgated new regulations that have increased compliance costs and imposed new reporting requirements on our businesses. For example, the Dodd-Frank Act substantially increased regulation of the over-the-counter derivative contracts market and futures contract markets, which impacts our businesses. The new regulations require our operating subsidiaries to comply with certain margin requirements for our over-the-counter derivative contracts with certain CFTC- or SEC-registered entities and if the rules implementing the new regulations require us to post significant amounts of cash collateral with respect to swap transactions, this could have a material adverse effect on our liquidity. We cannot predict the impact these new regulations will have on our businesses' ability to hedge their commodity and interest rate risks or on over-the-counter derivatives markets as a whole, but they could potentially have a material adverse effect on our businesses' risk exposure, as well as reduce market liquidity and further increase the cost of hedging activities.

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

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

The electric generation facilities owned by Renewables rely on interconnection and/or transmission agreements and transmission networks in order to sell the energy generated by such facility. If the interconnection and/or transmission agreement of an electric generating facility Renewables owns is terminated for any reason, Renewables may not be able to replace it with an interconnection or transmission arrangement on terms as favorable as the existing arrangement, or at all, or it may experience significant delays or costs in securing a replacement. If a transmission network to which one or more of Renewables' electric generating facilities is connected experiences outages or curtailments, the affected projects may lose revenue. These factors could materially affect Renewables' ability 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 that contain facility fees and borrowing spread pricing that are a function of the credit rating of the borrower. A lower credit rating automatically increases the cost of these facilities. A downgrade to the lowest investment grade rating of the borrower would likely preclude access to the commercial paper market for NYSEG and CMP, which each have commercial paper programs. Lower credit ratings would also increase the cost of debt and equity capital and, depending on the rating and market conditions, can preclude access to the debt and equity capital markets. Any of these events could have a materially adverse effect on our business, results of operations, financial condition and cash flows.

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

Networks' ability to operate its electricity and natural gas transmission, transportation and distribution systems is critical to the financial performance of our business. The ongoing operation of Networks' facilities involves risks customary to the electric and natural gas industry that include the breakdown, failure, loss of use or destruction of Networks' facilities, equipment or processes or the facilities, equipment or processes of third parties due to war or acts of terrorism, operational and safety performance below expected levels, errors in the operation or maintenance of these facilities and the inability to transport electricity or natural gas to customers in an efficient manner. These and other occurrences could reduce potential earnings and cash flows and increase the costs of repairs and replacement of assets. Losses incurred by Networks in respect of such occurrences may not be fully recoverable through insurance or customer rates. Further, certain of Networks' facilities require periodic upgrading and improvement. In addition, unplanned outages typically increase Networks' operation and maintenance expenses. Any unexpected failure, including failure associated with breakdowns, forced outages or any unanticipated capital expenditures, accident, failure of major equipment, shortage of or inability to acquire critical replacement or spare parts could result in reduced profitability or regulatory penalties. For more information, see "*Risks Relating to Our Regulatory Environment*" above.

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

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

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

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

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

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

If Renewables experiences a prolonged interruption at one of its operating projects due to natural events or operational problems and such events are not fully covered by insurance, Renewables' electricity generation levels could materially decrease, which could

have a material adverse effect on its business, results of operation and financial condition and could adversely affect our cash flows, results of operations and financial position.

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

Cyber breaches, acts of war or terrorism or grid disturbances resulting from internal or external sources could target our generation, transmission and distribution facilities or our information technology systems. In the regular course of business, we maintain sensitive customer, employee, financial and system operating information and are required by various federal and state laws to safeguard this information. Cyber or physical security intrusions could potentially lead to disabling damage to our generation, transmission and distribution facilities and to theft and the release of critical operating information or confidential customer or employee information, which could adversely affect our operations or adversely impact our reputation, and could result in significant costs, fines and litigation. Additionally, because our generation and transmission facilities are part of an interconnected regional grid, we face the risk of blackout due to a disruption on a neighboring interconnected system. As threats evolve and grow increasingly more sophisticated, we cannot ensure that a potential security breach may not occur or quantify the potential impact of such an event. Any such cyber breaches could result in a significant decrease in revenues, significant expense to repair system damage or security breaches, adversely impact our reputation, regulatory penalties and liability claims, which could have a material adverse effect on our cash flows, results of operations and financial condition.

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

A physical attack on our transmission and distribution infrastructure could interfere with normal business operations and affect our ability to control our transmission and distribution assets. A physical security intrusion could potentially lead to theft and the release of critical operating information, which could adversely affect our operations or adversely impact our reputation, and could result in significant costs, fines and litigation. Additionally, certain of our power generation and transmission and distribution assets and equipment are at risk for theft and damage. For example, Networks is at risk for copper wire theft, especially, due to an increased demand for copper in the United States and internationally. Theft of copper wire or solar panels can cause significant disruption to Networks' and Renewables' operations, respectively, and can lead to operating losses at those locations. Furthermore, Renewables can incur damage to wind turbine equipment through vandalism, such as gunshots into towers or other generating equipment. Such damage can cause disruption of operations for unspecified periods which may lead to operating losses at those locations.

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

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

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

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

We are pursuing broader development investment opportunities related to all segments of our business, particularly in respect of additional opportunities related to electric transmission, renewable energy generation, interconnections to generating resources and other development investment opportunities. The development, construction and expansion of such projects involve numerous risks. Various factors could result in increased costs or result in delays or cancellation of these projects. Risks include regulatory approval processes, permitting, new legislation, economic events, environmental and community concerns, negative publicity, design and siting issues, difficulties in obtaining required rights of way, construction delays and cost overruns, including delays in equipment deliveries, particularly of wind turbines or transformers, severe weather, competition from incumbent facilities and other entities, and actions of strategic partners. For example, there may be delays or unexpected developments in completing current and future construction projects. While most of Renewables' construction projects are constructed under fixed-price and fixed-schedule contracts with construction and equipment suppliers, these contracts provide for limitations on the liability of these contractors to pay liquidated damages for cost overruns and construction delays. These circumstances could prevent Renewables' construction projects from commencing operations or from meeting original expectations about how much electricity it will generate or the returns it will achieve. In addition, for Renewables' projects that are subject to PPAs, substantial delays could cause defaults under the PPAs, which generally require the completion of project construction by a certain date at specified performance levels. A delay resulting in a wind project failing to qualify for federal production tax credits could result in losses that would be substantially greater than the amount of liquidated damages paid to Renewables. In December 2015, the Consolidated Appropriations Act, 2016 extended the expiration date for this tax credit to December 31, 2019, for wind facilities commencing construction, with a phase-down beginning for wind projects commencing construction after December 31, 2016. Furthermore, as required by Connecticut's Comprehensive Energy Strategy, CNG and SCG filed, jointly with Yankee Gas Services Company, a comprehensive natural gas expansion plan ("Expansion Plan") outlining a structured approach to add approximately 280,000 new gas heating customers (approximately 200,000 of which relate to SCG and CNG) state-wide over the next 10 years. In order to serve new customers to comply with the Expansion Plan, SCG and CNG need to lay significant miles of new pipeline, maintain, expand and potentially upgrade their existing distribution and/or storage infrastructure, and build new gate stations. Various factors may prevent or delay SCG and CNG from completing such projects or make completion more costly, such as the inability to obtain required approval from local or state regulatory and governmental bodies, public opposition to the project, lack of potential customers as a result of reduced economic benefits for switching to gas, inability to obtain adequate financing, construction delays, cost overruns, and inability to negotiate acceptable agreements relating to rights-of-way, construction or other material development components. As a result, SCG and CNG may not be able to adequately support the proposed customer growth, which would negatively impact their businesses, cash flows, results of operations and financial condition. Additionally, RG&E's Rochester Area Reliability Project, which includes the development of a new substation and transmission lines and was approved by the NYPSC, has encountered significant delays due to the concerns of landowners. Should any of these factors result in such delays or cancellations, our growth projections, financial position, results of operations, and cash flows could be adversely affected or our future growth opportunities may not be realized as anticipated.

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

The emergence of technology and initiatives designed to reduce greenhouse gas emissions or limit the effects of global warming and overall climate change has increased the development of new technologies for power generation, energy efficiency, and for investment in research and development to make those technologies more efficient and cost effective. There is a potential that new technology or rate design incentives could adversely affect the demand for services of our regulated subsidiaries thus impacting our revenues, which could adversely affect our cash flows, results of operations and financial concerns. For example, net energy metering allows electricity customers who supply their own electricity from on-site generation to pay only for the net energy obtained from the utility. Further, the behind-the-meter storage systems and grid integration components such as inverters or electronics could result in electricity delivery customers abandoning the grid system or replacing part of grid services with self-supply or self-balancing, which could impact the return on current or future Networks' assets deployed and designed to serve projected load. Such emergence of alternative sources of energy supply can result in customers relying on the power grid for limited use, such as in the case of a deficit or an emergency, or completely abandoning the grid, which is known as customer defection. While certain of the regulated utilities of Networks are subject to RDMs, they are either legislatively or regulatory in nature and there is no assurance such mechanisms will always be available. The progressive reduction in the costs of distributed energy assets, as a result of technological improvements, large scale deployment in certain jurisdictions and constructive support regimes could result in customer defection (individually or integrated in micro-grids) when a net benefit analysis of investing in self-supply and storage of energy compared to energy provided by utility service appears attractive for certain customer classes. Similarly, future investments in Networks could be impacted if adequate rate making does not fully contemplate the characteristics of an integrated reliable grid from a unified perspective, regardless of customer disconnection. Further, the interoperability, integration and standard connection of these distributed energy devices and

systems could place a burden on the system of Networks' operating subsidiaries, without adequately compensating them. Furthermore, the technologies used in the renewable energy sector change and evolve rapidly. Techniques for the production of electricity from renewable sources are constantly improving and becoming more complex. In order to maintain Renewables' competitiveness and expand its business, Renewables must adjust effectively to changes in technology. If Renewables fails to react effectively to current and future technological changes in the sector in a timely manner, Renewables' future business growth, results of operations and financial condition could be materially adversely affected.

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

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

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

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

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

Wind and solar energy demand is affected by the price and availability of other fuels, including nuclear, coal, natural gas and oil, as well as other sources of renewable energy. To the extent renewable energy, particularly wind energy, becomes less cost-competitive due to reduced government targets, increases in the cost of wind energy, as a result of new regulations, and incentives that favor alternative renewable energy, cheaper alternatives or otherwise, demand for wind energy and other forms of renewable energy could decrease. Slow growth or a long-term reduction in the demand for renewable energy could have a material adverse effect on Renewables' ability to grow its business.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Our cash balances and the cash balances at our subsidiaries may be deposited in banks, may be invested in liquid securities such as commercial paper or money market funds or may be deposited in a notional cash pooling account in which we are a participant along with other affiliates of the Iberdrola Group. Bank deposits in excess of federal deposit insurance limits would be subject to risks in the counterparty bank. Liquid securities and money market funds are subject to loss of principal, more likely in an adverse market situation, and to the risk of illiquidity. Moreover, under the agreement governing the notional cash pooling account mentioned above, credit balances in the cash pooling account are pledged as collateral for the debit balances of other cash pooling participants. We are therefore subject to the credit risk of the affiliated parties to the cash pooling agreement and to Iberdrola's ability to manage the overall liquidity of the Iberdrola Group.

We have identified a material weakness in our internal control over financial reporting which, if not remediated, could adversely affect our reputation, business or stock price.

In connection with the preparation of our consolidated financial statements for the year ended December 31, 2016, management along with our independent registered public accounting firm identified a material weakness in the internal control over financial

reporting. Management identified deficiencies related to: (1) the accounting for the change in the estimated useful life of certain elements of the wind farms at Renewables and other smaller deficiencies related to documentation of internal controls procedures, and enhancement of review controls at Renewables, (2) the preparation of the consolidated financial statements, specifically the classification and disclosure of financial information, and (3) the measurement and disclosure of income taxes. A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of our annual or interim consolidated financial statements will not be prevented or detected on a timely basis.

We are actively engaged in remediation efforts to address the material weakness in the internal control over financial reporting, including, among other things, (i) improving general internal control activities and policies, including processes to maintain sufficient documentation evidencing execution of these policies; (ii) increasing accounting personnel to devote additional time and resources related to financial reporting; (iii) educating and re-training internal control employees regarding internal control processes to mitigate identified risks and maintaining adequate documentation to evidence the effective design and operation of such processes; and (iv) implementing enhanced controls to monitor the effectiveness of the underlying business process controls. We believe, based on our evaluation to date, that this material weakness will be remediated by December 31, 2017. However, we cannot assure you that this will occur within the contemplated timeframe.

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

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

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

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

A majority of the employees at Networks' facilities are subject to collective bargaining agreements with various unions. Additionally, unionization activities, including votes for union certification, could occur among non-union employees. If union employees strike, participate in a work stoppage or slowdown or engage in other forms of labor strike or disruption, our subsidiaries could experience reduced power generation or outages if replacement labor is not procured. The ability to procure such replacement labor is uncertain, though risks are reduced by rigorous contingency planning. Strikes, work stoppages or an inability to negotiate future collective bargaining agreements on commercially reasonable terms could have a material adverse effect on our business, results of operations, financial condition and cash flows.

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

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

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

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

Risks Relating to Ownership of Our Common Stock

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

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

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

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

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

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

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

Iberdrola owns approximately 81.5% of outstanding shares of our common stock and will be able to exercise significant influence over our business policies and affairs, including the composition of our board of directors and any action requiring the approval of our shareholders, including the adoption of amendments to the certificate of incorporation and bylaws and the approval of a merger or sale of substantially all of our assets, subject to applicable law and the limitations set forth in the shareholder agreement. The directors designated by Iberdrola will have significant authority to effect decisions affecting our capital structure, including the issuance of additional capital stock, incurrence of additional indebtedness, the implementation of stock repurchase programs and the decision of whether or not to declare dividends.

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

Further, sales of our common stock by Iberdrola or the perception that sales may be made by it could significantly reduce the market price of shares of our common stock. We and Iberdrola are parties to a shareholder agreement pursuant to which Iberdrola will be generally restricted from transferring shares of our common stock, subject to certain exceptions. Iberdrola will also be restricted, for a period of three years after the completion of the proposed merger, from transferring more than an aggregate of 10% of the outstanding shares of our common stock in any transaction or series of transactions, unless all of our shareholders are entitled to participate in such transaction (on a *pro rata* basis) and are entitled to the same per share consideration to be received in such transaction as Iberdrola. In addition, even if Iberdrola does not sell a large number of shares of our common stock into the market, its right to transfer such shares may depress the price of our common stock. Furthermore, pursuant to the shareholder agreement and subject to the terms and conditions therein, Iberdrola will be entitled to customary registration rights of our common stock, including the right to choose the method by which the common stock are distributed, a choice as to the underwriter and fees and expenses to be borne by us. Iberdrola will also retain preemptive rights to protect against dilution in connection with issuances of equity by us. If Iberdrola exercises its registration rights and/or its preemptive rights, the market price of shares of our common stock may be adversely affected.

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

Under the rules of the NYSE, a company in which over 50% of the voting power is held by an individual, a group or another company is a "controlled company" and is not required to have:

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

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

Because we are a controlled company, you will not have the same protections afforded to shareholders of companies that are subject to all of the corporate governance requirements of the NYSE without regard to the exemptions available for "controlled companies." Our status as a controlled company could make our shares of common stock less attractive to some investors or otherwise harm our stock price.

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

Although we currently anticipate paying a regular quarterly dividend, any such determination to pay dividends is at the discretion of our board of directors and dependent on conditions such as our financial condition, earnings, legal requirements, including limitations under New York law, restrictions in our debt agreements that limit our ability to pay dividends to shareholders and other factors the board of directors deem relevant. Our board of directors may, in its sole discretion, change the amount or

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

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

As a public company, we are subject to reporting, disclosure control and other obligations under the Exchange Act, the Sarbanes-Oxley Act, or SOX, the Dodd-Frank Act, as well as rules adopted, and to be adopted, by the SEC and the NYSE. For example, beginning with this Annual Report on Form 10-K, Section 404 of SOX requires our management to report on the effectiveness of our internal control over financial reporting and our independent registered public accounting firm to attest to the effectiveness of our internal controls. Our management and other personnel will continue to devote a substantial amount of time to these compliance activities. If we are not able to comply with the requirements of Section 404 in a timely manner or if we are unable to conclude that our internal control over financial reporting is effective, our ability to accurately report our cash flows, results of operations or financial condition could be inhibited and additional financial and management resources could be required. Any failure to maintain internal control over financial reporting or if our independent registered public accounting firm determines the we have a material weakness or significant deficiency in our internal control over financial reporting, could cause investors to lose confidence in the accuracy and completeness of our financial reports, a decline in the market price of our common stock, or subject us to sanctions or investigations by the NYSE, the SEC or other regulatory authorities. Failure to remedy any material weakness or significant deficiency in our internal control over financial reporting, or to implement or maintain other effective control systems required of public companies, could also restrict our future access to the capital markets and reduce or eliminate the trading market for our common stock. Further, as a result of becoming a public company, we have incurred and will continue to incur higher legal, accounting and other expenses than we did as a private company, and these expenses may increase even more in the future.

Item 1B. ***Unresolved Staff Comments.***

None

Item 2. ***Properties.***

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

The following table sets forth the principal properties of AVANGRID, by location, type, lease or ownership and size as of December 31, 2016:

Location	Type of Facility	Lease/Owned	Size (square feet)
New Haven, Connecticut	Office	Leased	51,307
Orange, Connecticut	Office	Owned	337,586
Augusta, Maine	Office	Leased	220,400
New Gloucester, Maine	Office	Leased	60,913
Rochester, New York	Office	Owned	122,494
Portland, Oregon	Office	Leased	57,082
Houston, Texas	Office	Leased	21,571

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

Item 3. ***Legal Proceedings.***

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

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

FirstEnergy

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

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

FirstEnergy remains liable for a substantial share of clean up expenses at nine MPG sites. In January 2015, NYSEG sent FirstEnergy a demand for $16 million representing FirstEnergy's share of clean-up expenses incurred by NYSEG at the nine sites from January 2010 to November 2014 while the District Court appeal was pending. Nearly all of this amount has been paid by FirstEnergy. FirstEnergy would also be liable for a share of post 2014 costs, which, based on current projections, would be $26 million. This amount is being treated as a contingent asset and has not been recorded as either a receivable or a decrease to the environmental provision. Any recovery will be flowed through to NYSEG ratepayers.

Century Indemnity and OneBeacon

NYSEG filed suit in federal court on August 14, 2013 against two excess insurers, Century Indemnity and OneBeacon, who provided excess liability coverage to NYSEG. NYSEG seeks payment for clean-up costs associated with contamination at twenty-two former manufactured gas plants. Based on estimated clean-up costs of $282 million, the carriers' allocable share is approximately $89 million, excluding pre-judgment interest. Any recovery will be flowed through to NYSEG ratepayers.

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

Shareholder Derivative Action

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

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

Avangrid Renewables, LLC and Northern Indiana Public Service Company

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

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

California Energy Crisis Litigation

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

Joining with two other parties, Renewables filed a petition for certiorari in the United States Supreme Court on May 3, 2007. In an order entered on June 27, 2008, the Supreme Court granted Renewables' petition for certiorari, vacated the appellate court's judgment, and remanded the case to the appellate court for further consideration in light of the Supreme Court's decision in a similar case. In light of the Supreme Court's order, on December 4, 2008, the Ninth Circuit Court of Appeals vacated its prior opinion and remanded the complaint proceedings to the FERC for further proceedings consistent with the Supreme Court's rulings. In 2014 FERC assigned an administrative law judge to conduct evidentiary hearings. Following discovery, the FERC Trial Staff recommended that the complaint against Renewables be dismissed.

A hearing was held before an administrative law judge of the FERC in November and early December 2015. A preliminary proposed ruling by the administrative law judge was issued on April 12, 2016. The proposed ruling found no evidence that Renewables had engaged in any unlawful market contract that would justify finding the Renewables power purchase agreements unjust and unreasonable. However, the proposed ruling did conclude that price of the power purchase agreements imposed an excessive burden on customers in the amount of $259 million. Renewables position, as presented at hearings and agreed by the FERC Trial Staff, is that Renewables entered into bilateral power purchase contracts appropriately and complied with all applicable legal standards and requirements. The parties have submitted to the FERC briefs on exceptions to the administrative law judge's proposed ruling. There is no specific timetable to the FERC's ruling. We cannot predict the outcome of this proceeding.

Yankee Nuclear Spent Fuel Disposal Claim

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

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

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

In March 2016 the U.S. Court of Claims issued its decision in the Phase III case (the third six-year period, 2009-2014), awarding the Yankee Companies a combined $76.8 million (Connecticut Yankee $32.6 million, Maine Yankee $24.6 million and Yankee Atomic $19.6 million). The damage awards, less any amount retained to reduce future customer charges, will potentially flow through the Yankee Companies to shareholders, including CMP and UI, upon FERC approval, and will reduce retail customer charges or otherwise as specified by law. CMP and UI will receive their proportionate share of the awards that flow through based on

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

English Station

In January 2012, Evergreen Power, LLC (Evergreen Power) and Asnat Realty LLC (Asnat), then and current owners of a former generation site on the Mill River in New Haven (the English Station site) that UI sold to Quinnipiac Energy in 2000, filed a lawsuit in federal district court in Connecticut against UI seeking, among other things: (i) an order directing UI to reimburse the plaintiffs for costs they have incurred and will incur for the testing, investigation and remediation of hazardous substances at the English Station site and (ii) an order directing UI to investigate and remediate the site. This proceeding had been stayed in 2014 pending resolution of other proceedings before the Connecticut Department of Energy and Environmental Protection, or DEEP, concerning the English Station site. In December 2016, the court administratively closed the file without prejudice to reopen upon the filing of a motion to reopen by any party. In December 2013, Evergreen and Asnat filed a subsequent lawsuit in Connecticut state court seeking among other things: (i) remediation of the property; (ii) reimbursement of remediation costs; (iii) termination of UI's easement rights; (iv) reimbursement for costs associated with securing the property; and (v) punitive damages. This lawsuit had been stayed in May 2014 pending mediation. Due to lack of activity in the case, the court terminated the stay and scheduled a status conference on or before August 1, 2017.

On April 8, 2013, DEEP issued an administrative order addressed to UI, Evergreen Power, Asnat and others, ordering the parties to take certain actions related to investigating and remediating the English Station site. Mediation of the matter began in the fourth quarter of 2013 and concluded unsuccessfully in April 2015. This proceeding was stayed while DEEP and UI continue to work through the remediation process pursuant to the consent order described below. A status report was filed with the court in December 2016 and the next status report is due in May 2017.

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

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

Other Legal Proceedings

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

Item 4. *Mine Safety Disclosures.*

Not Applicable.

Executive Officers of AVANGRID

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

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

(*) Age as of December 31, 2016.

James P. Torgerson. Mr. Torgerson was appointed Chief Executive Officer of AVANGRID on December 16, 2015, upon consummation of the acquisition of UIL. Previously, Mr. Torgerson served as president and chief executive officer of UIL since 2006. Prior to 2006, Mr. Torgerson was president and chief executive officer of MISO. He is a trustee of the Yale-New Haven Hospital and a Director of Yale New Haven Health System. Mr. Torgerson is the chairman of the Connecticut Institute for the 21st Century. He is the former chairman and a director of the Connecticut Business and Industry Association and is a member of the board of the Edison Electric Institute and the American Gas Association. Mr. Torgerson is a trustee of the Hartford Bishops' Foundation for the Archdiocese of Hartford. Mr. Torgerson holds a bachelor's of business administration degree in accounting from Cleveland State University.

Richard J. Nicholas. Mr. Nicholas was appointed Chief Financial Officer of AVANGRID on December 17, 2015, upon consummation of the acquisition of UIL. Previously, Mr. Nicholas served as executive vice president and chief financial officer of two subsidiaries of AVANGRID, UIL and UI, from March 2005 until December 2015. Effective November 16, 2010, Mr. Nicholas was appointed chief financial officer of BGC, CNG and SCG, all of which are subsidiaries of AVANGRID. Mr. Nicholas earned his undergraduate degree in business and administration with a concentration in finance from Duquesne University and holds a M.B.A. from the University of New Haven.

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

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

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

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

Ignacio Estella. Mr. Estella was appointed Senior Vice President – Corporate Development of AVANGRID on December 17, 2015. Previously, Mr. Estella served as corporate vice president of business origination of Iberdrola from May 2009 until November 2013 and vice president – corporate development of Iberdrola USA, Inc., from December 2013 to December 16, 2015. He served as gas markets development director of Iberdrola between February 2007 and April 2009. Mr. Estella holds a degree in law and business administration from the Universidad Pontificia Comillas and a master of public administration, with concentration in regulation and industry analysis and negotiation and conflict resolution from Harvard University.

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

Robert D. Kump. Mr. Kump was appointed Chief Executive Officer of Networks in November 2010. Mr. Kump served as AVANGRID's Chief Corporate Officer in January 2014. Mr. Kump also has served as a director of AVANGRID's subsidiaries CMP, NYSEG, and RG&E since 2009, as the President of the Avangrid Management Company, LLC since March 2012 and as the Chief Executive Officer of AVANGRID Service Company since October 2009. Mr. Kump held various positions from February 1997 to October 2009 as AVANGRID's senior vice president and chief financial officer, vice president, controller and chief accounting officer, treasurer and secretary. Mr. Kump also previously held a number of positions at NYSEG from 1986 to 1997, including senior accountant-external financial reporting, director-investor relations, director-financial services, and treasurer. Mr. Kump earned a B.A. in accounting from Binghamton University and is a C.P.A. in New York.

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

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

Anthony Marone. Mr. Marone was appointed President and Chief Executive Officer of UIL on September 9, 2016. In this role, he has overall responsibility for Avangrid Networks' electric and natural gas operating companies in Connecticut and Massachusetts. Mr. Marone also serves as President – Connecticut and Massachusetts Operations and senior vice president of gas operations of Avangrid Service Company, overseeing the natural gas operations of Networks. Previously Mr. Marone served as senior vice president of customer and business services of UIL since May 14, 2013. Mr. Marone served as senior vice president – business services of UI and vice president of business services of UIL from November 16, 2010 to May 2013. Mr. Marone received his master's degree in engineering and business management from the University of New Haven and a bachelor's degree in mechanical engineering from the New York Institute of Technology.

PART II

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

Market Information and Holders

Our shares of common stock began trading on the New York Stock Exchange, or NYSE, on December 17, 2015, under the symbol "AGR." Prior to that time, there was no public market for shares of our common stock. The following table sets forth on a per share basis, for the periods indicated, the high and low sale prices of our common stock as reported by the NYSE.

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

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

Dividends

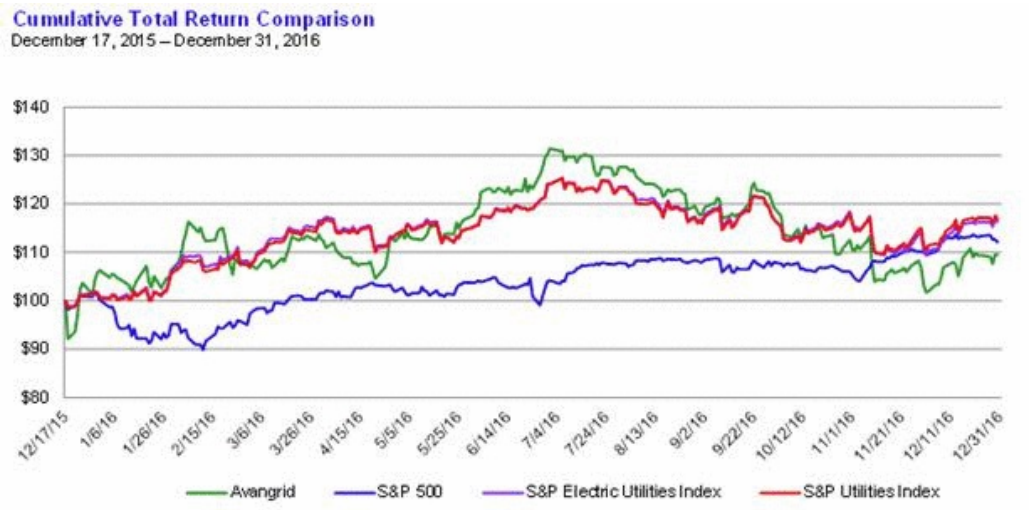
The quarterly cash dividends declared in 2016 were at a rate of $0.432 per share.

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

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

Performance Graph

The line graph appearing below compares the change in AVANGRID's total shareowner return on its shares of common stock with the return on the S&P Composite-500 Stock Index, the S&P Electric Utilities Index and the S&P Utilities Index for the period December 17, 2015 through December 31, 2016.



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

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

Recent Sales of Unregistered Securities

None.

Issuer Repurchases of Equity Securities

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

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

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

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***

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

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

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

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

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

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

AVANGRID is a diversified energy and utility company with more than $30 billion in assets and operations in 26 states. The company operates regulated utilities and electricity generation through two primary lines of business. Avangrid Networks includes eight electric and natural gas utilities, serving 3.1 million customers in New York and New England. Avangrid Renewables operates 6.5 gigawatts of electricity capacity, primarily through wind power, in states across the United States. AVANGRID employs approximately 7,000 people. The company was formed by a merger between Iberdrola USA, Inc. and UIL Holdings Corporation in 2015. Iberdrola S.A., or Iberdrola, a corporation *(sociedad anónima)* organized under the laws of the Kingdom of Spain, a worldwide leader in the energy industry, directly owns 81.5% of the outstanding shares of AVANGRID common stock. Our primary business is ownership of our operating businesses, which are described below.

Our direct, wholly-owned subsidiaries include Avangrid Networks, Inc., or Networks, and Avangrid Renewables Holdings, Inc., or ARHI. ARHI in turn holds subsidiaries including Avangrid Renewables LLC, or Renewables, and Enstor Gas, LLC, or Gas. Networks, owns and operates our regulated utility businesses through its subsidiaries, including electric transmission and distribution and natural gas distribution, transportation and sales. Renewables operates a portfolio of renewable energy generation facilities primarily using onshore wind power and also solar, biomass and thermal power. Gas operates our natural gas storage facilities and gas trading businesses through Enstor Energy Services LLC (gas trading) and Enstor Inc. (gas storage).

On December 16, 2015, we completed our acquisition of UIL Holdings Corporation, or UIL. Immediately following the completion of the acquisition, former UIL shareowners owned 18.5% of the outstanding shares of common stock of AVANGRID, and Iberdrola owned the remaining shares. The acquisition was accounted for as a business combination. The results of operations of UIL since December 16, 2015, the acquisition date, have been included in the consolidated results of AVANGRID. Effective as of April 30, 2016, UIL and its subsidiaries were transferred to a wholly-owned subsidiary of Networks. Further information regarding the accounting for the acquisition is provided in Note 4 of our audited consolidated financial statements for the three years ended December 31, 2016, which are incorporated herein by reference.

Through Networks, we own electric generation, transmission and distribution companies and natural gas distribution, transportation and sales companies in New York, Maine, Connecticut and Massachusetts, delivering electricity to approximately 2.2 million electric utility customers and delivering natural gas to approximately 992,000 natural gas public utility customers as of December 31, 2016.

Networks, a Maine corporation, holds our regulated utility businesses, including electric transmission and distribution and natural gas distribution, transportation and sales. Networks serves as a super-regional energy services and delivery company through eight regulated utilities it owns directly:

- New York State Electric & Gas Corporation, or NYSEG, which serves electric and natural gas customers across more than 40% of the upstate New York geographic area;
- Rochester Gas and Electric, or RG&E, which serves electric and natural gas customers within a nine-county region in western New York, centered around Rochester;
- The United Illuminating Company, or UI, which serves electric customers in southwestern Connecticut;
- Central Maine Power Company, or CMP, which serves electric customers in central and southern Maine;
- The Southern Connecticut Gas Company, or SCG, which serves natural gas customers in Connecticut;
- Connecticut Natural Gas Corporation, or CNG, which serves natural gas customers in Connecticut;

- The Berkshire Gas Company, or BGC, which serves natural gas customers in western Massachusetts; and
- Maine Natural Gas Corporation, or MNG, which serves natural gas customers in several communities in central and southern Maine.

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

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

Summary of Results of Operations

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

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

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

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

See "*—Results of Operations*" for further analysis of our operating results for the year.

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

Networks

Electric Transmission and Distribution and Natural Gas Distribution

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

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

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

UI has wholesale power supply agreements in place for its entire standard service load for the first half of 2017, 80% of its standard service load for the second half of 2017, and 20% of its standard service load for the first half of 2018. Supplier of last resort service is procured on a quarterly basis, however, from time to time there are no bidders in the procurement process for supplier of last resort service and in such cases UI manages the load directly.

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

Revenues

Networks utilizes regulatory deferrals to evaluate its financial condition and operating performance by reconciling differences between actual revenue received or cost incurred with the rate allowances provided under the tariffs set by the state utilities commissions and FERC. Regulatory deferrals create regulatory assets and liabilities under FERC, consistent with U.S. GAAP financial accounting standards. Regulatory deferrals in New York include electric and gas supply costs, PPAs, downward net plant reconciliations, revenue decoupling, system benefit charges, renewable portfolio standards, energy efficiency portfolio standards, economic development programs, low income programs, gross receipt taxes, pension costs, other post-employment benefits costs, environmental remediation costs, major storm costs, downward adjustments for vegetation management, research and development, incremental maintenance initiatives, property taxes, REV initiatives, NEIL credits, credit and debit card fees, exogenous costs and certain legislative, accounting, regulatory and tax related actions. Regulatory deferrals in Maine include stranded costs, revenue decoupling, power tax regulatory asset, environmental remediation, storm reserve accounting, electric thermal storage pilot costs, standard offer retainage costs, AMI opt-out program costs, AMI deferral costs, AMI legal / health proceeding costs, conservation program costs, demand side management costs, low income program costs, electric lifeline program costs, make-ready line extension costs, electric vehicle pilot program costs and transmission planning and related cost allocation.

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

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

NYSEG's and RG&E's electric and natural gas rate plans and CMP's and UI's electric rates and CNG's gas rates, each contain a RDM under which their actual energy delivery revenues are compared on a periodic basis with the authorized delivery revenues and the difference accrued, with interest, for refund to or recovery from customers, as applicable.

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

Pursuant to agreements with, or decisions of the NYPSC and, the MPUC, Networks' Maine and New York regulated utilities are each subject to a minimum equity ratio requirement that is tied to the capital structure assumed in establishing revenue requirements.

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

Rates

On May 20, 2015, NYSEG and RG&E initiated a distribution rate case to ensure that the companies are able to continue to provide safe, adequate and reliable service, continue to make investments to modernize infrastructure, enhance low income programs and improve both gas and electric reliability, while maintaining the Companies' financial integrity. On February 19, 2016, the NYSEG, RG&E and other signatory parties filed a joint proposal, or the proposal, with the NYPSC for a three-year rate plan for electric and gas service at NYSEG and RG&E commencing May 1, 2016, which was approved on June 15, 2016 by the NYPSC. The proposal balanced the varied interests of the signatory parties including but not limited to maintaining the companies' credit quality and mitigating the rate impacts to customers. The proposal reflects many customer attributes including acceleration of the companies' natural gas leak prone main replacement programs and increased electric vegetation management to provide continued safe and reliable service. The delivery rate increase in the proposal can be summarized as follows:

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

The allowed rate of return on common equity for NYSEG Electric, NYSEG Gas, RG&E Electric and RG&E Gas is 9.00%. The equity ratio for each company is 48%. The proposal includes an ESM applicable to each company. The customer share of earnings would increase at higher ROE levels, with customers receiving 50%, 75% and 90% of earnings over 9.5%, 10.0% and 10.5% of ROE, respectively, in the first rate year. Earnings are based on the lower of the actual equity ratio or 50%. Earnings thresholds increase in subsequent rate years. The proposal reflects the recovery of deferred NYSEG Electric storm costs of approximately $262 million, of which $123 million will be amortized over ten years and the remaining $139 million will be amortized over five years. The proposal also continues reserve accounting for qualifying Major Storms ($21.4 million annually for NYSEG Electric and $2.5 million annually for RG&E Electric). Incremental maintenance costs incurred to restore service in qualifying divisions will be chargeable to the Major Storm Reserve provided they meet certain thresholds.

On August 25, 2014, the MPUC approved a stipulation agreement for a CMP rate change which provided for a distribution rate increase of approximately $24.3 million effective July 1, 2014 with an allowed ROE of 9.45% and an allowed equity ratio of 50%. On December 22, 2009, MPUC approved a stipulation which provided for a rate increase to MNG's base distribution rates for a three year 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. On May 3, 2016, all active parties to the case filed a stipulation which settled all matters at issue in the case and reflected a 10-year rate plan through April 30, 2026. The MPUC approved the stipulation on May 17, 2016, for new rates effective June 1, 2016. The settlement structure for non-Augusta customers includes a 34.6% delivery revenue increase over five years with an allowed 9.55% ROE and 50% common equity ratio. The settlement structure for Augusta customers includes a ten-year rate plan with existing Augusta customers being charged rates equal to non-Augusta customers plus a surcharge which increases annually for five years. New Augusta customers will have rates set based on an alternate fuel market model. In year seven of the rate plan MNG will submit a cost of service filing for the Augusta area to determine if the rate plan should continue. This cost of service filing will exclude $15 million of initial 2012/2013 gross plant investment, however the stipulation allows for accelerated depreciation of these assets. If the Augusta area's cost of service filing illustrates results above a 14.55% ROE then the rate plan may cease, otherwise the rate plan would continue. A disallowance for the initial 2012/2013 gross plant investment is not part of the approved stipulation. The reserve of $6 million for this case was reversed in May 2016.

In December 2016, PURA approved distribution rate schedules for UI for three years that became effective January 1, 2017, and which, among other things, provides for $57 million of cumulative distribution rate increases, an allowed ROE of 9.10% based on 50% equity, continued UI's existing earnings sharing mechanism, continued the existing decoupling mechanism, and approved the continuation of the requested storm reserve.

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

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

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

In September 2011, several New England governmental entities, including PURA, the Connecticut Attorney General and the OCC, filed a joint complaint with the FERC against ISO-NE and several New England transmission owners (including CMP and UI) claiming that the current approved base ROE used in calculating formula rates for transmission service under the ISO-NE Open Access Transmission Tariff by the New England transmission owners of 11.14% was not just and reasonable and seeking a reduction of the base ROE with refunds to customers for the refund period of October 1, 2011 through December 31, 2012, or the refund period. The FERC issued an order in 2014 to reset the base ROE at 10.57% and capped the incentive rate at 11.74% for applicable projects for the refund period. Two additional complaints have also been filed for subsequent periods. The complaints have been consolidated and the administrative law judge issued an initial decision on March 22, 2016. The initial decision determined that, (1) for the fifteen month refund period in the second complaint, the base ROE should be 9.59% and that the ROE Cap (base ROE plus incentive ROEs) should be 10.42% and (2) for the fifteen month refund period in the third complaint and prospectively, the base ROE should be 10.90% and that the ROE Cap should be 12.19%. The initial decision is the administrative law judge's recommendation to the FERC commissioners. The FERC is expected to make its final decision in early 2017. The results of the decision in the initial complaint, as well as the results of any future decisions, will be reconciled in future transmission rates. On April 29, 2016, a fourth, related, complaint was filed for a subsequent rate period requesting the base ROE be 8.61% and ROE Cap be 11.24%. CMP and UI, as part of the NETOs group, filed a response on June 3, 2016. On September 20, 2016, the FERC accepted the forth compliant, established a refund effective date of April 29, 2016, and set the matter for hearing. We cannot predict the outcome of the fourth complaint proceeding.

On December 28, 2015, the FERC issued an order instituting section 206 proceedings and establishing hearing and settlement judge procedures. Pursuant to section 206 of the FPA, the FERC found that ISO-NE Transmission, Markets, and Services Tariff is unjust, unreasonable, and unduly discriminatory or preferential. The FERC stated that ISO-NE's Tariff lacks adequate transparency and challenge procedures with regard to the formula rates for ISO-NE participating transmission owners, including UI and CMP. The FERC also found that the current Regional network service, or RNS, and Local Network Service, or LNS, formula rates appear to be

unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful as the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates.

Merger Settlement Agreement – Connecticut and Massachusetts

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

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

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

In connection with the acquisition proceeding, UI signed the partial consent order related to the investigation and remediation of the English Station site. To the extent that the investigation and remediation is less than $30 million, UI is required to remit to the State of Connecticut the difference between such costs and $30 million, to be applied to a public purpose as determined in the discretion of the Governor the Attorney General of Connecticut and the Commissioner of DEEP. However, UI is obligated to comply with the consent order even if the cost of such compliance exceeds $30 million. The state may discuss options with UI on recovering or funding any cost above $30 million, such as through public funding or recovery from third parties, however it is not bound to agree to or support any means of recovery or funding.

The following commitments were made in Massachusetts:

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

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

New England Clean Energy Request for Proposals

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

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

Reforming the Energy Vision

In April 2014, the NYPSC instituted its REV proceeding, the goals of which are to improve electric system efficiency and reliability, encourage renewable energy resources, support DER, and empower customer choice. In this proceeding, the NYPSC is examining the establishment of a DSP, to manage and coordinate DER, and provide customers with market data and tools to manage their energy use. The NYPSC is also examining how its regulatory practices should be modified to incentivize utility practices to promote REV objectives. REV has been divided into two tracks, Track 1 for market design and technology, and Track 2 for regulatory reform. REV proposes regulatory changes that are intended to promote more efficient use of energy, deeper penetration of renewable energy resources such as wind and solar, and wider deployment of DER, such as micro grids, on-site power supplies and storage. The NYPSC order on Track 1 affirmed that utilities would serve as the DSP and required utilities to file implementation plans before the end of 2015. Track 2 is undertaken in parallel with the Track 1, and examines changes in current regulatory, tariff, and market designs, and incentive structures to better align utility interests with achieving NYPSC's policy objectives. New York utilities will also be addressing related regulatory issues in their individual rate cases. A Track 2 order was issued in May 2016, and includes guidance related to the potential for earnings adjustment mechanisms, or EAMs, platform service revenues, innovative rate designs, and data utilization and security. The companies, in December 2016, filed a proposal for the implementation of EAMs in the areas of system efficiency, energy efficiency, interconnections, and clean air. A collaborative process to review the companies' petition is expected to begin in the first quarter of 2017.

Ginna Reliability Support Service Agreement

Ginna Nuclear Power Plant, LLC, or GNPP, which is a subsidiary of Constellation Energy Nuclear Group, LLC, or CENG, owns and operates the R.E. Ginna Nuclear Power Plant, or Ginna Facility, and together with GNPP, Ginna, a 581 MW single-unit pressurized water reactor located in Ontario, New York. In May 2014, NYISO produced a reliability study, confirming that the Ginna Facility needs to remain in operation to avoid bulk transmission and non-bulk local distribution system reliability violations in 2015 and 2018. In July 2014, GNPP filed a petition requesting that the NYPSC initiate a proceeding to examine a proposal for the continued operation of the Ginna Facility.

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

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

On October 21, 2015, RG&E, GNPP, New York Department of Public Service, Utility Intervention Unit and Multiple Intervenors filed a joint proposal with the NYPSC for approval of the RSSA, as modified. The joint proposal provides a term of the RSSA from April 1, 2015, through March 31, 2017. RG&E shall make monthly payments to Ginna in the amount of $15.4 million. RG&E will be entitled to 70% of revenues from Ginna's sales into the NYISO energy and capacity markets, while Ginna will be entitled to 30% of such revenues. The signatory parties recommend that the NYPSC authorize RG&E to implement a rate surcharge effective January 1, 2016, to recover amounts paid to Ginna pursuant to the RSSA. RG&E's payment obligation to Ginna did not begin until the rate surcharge was in effect and the FERC issued an order authorizing the FERC settlement agreement in the Settlement Docket. RG&E will use deferred rate credit amounts (regulatory liabilities) to offset the full amount of the deferred collection amount (including carrying costs), plus credit amounts to offset all RSSA costs that exceed $2.3 million per month, not to exceed a total use of credits in the amount of $110 million, applicable through June 30, 2017. To the extent that the available credits are insufficient to satisfy the final payment from RG&E to Ginna then the RSSA surcharge would continue past March 31, 2017, to recover up to $2.3 million per month until the final payment has been recovered by RG&E from ratepayers. In the month following the expiration of the term on March 31, 2017, Ginna shall prepare and issue an invoice to RG&E for, and RG&E shall pay to Ginna, a one-time payment in the amount of $11.5 million. This amount is being accrued pro-rata over the term of the agreement and will be recovered from ratepayers. If Ginna continues to deliver energy to the NYISO transmission system or makes available capacity to the

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

New York TransCo

Networks holds an approximately 20% ownership interest in New York TransCo, LLC. New York TransCo was established by the New York transmission utilities to develop, own, and operate electric transmission in New York. In December 2014, New York TransCo filed for regulatory approval of its rates, terms, and conditions with the FERC. The filing requests a formula base ROE of 10.6%, 150 basis points ROE incentives, construction work in progress, a formula rate mechanism, and a proposed cost allocation. Various parties, including the NYPSC, have protested the filing with the FERC, including the base ROE, the ROE incentives, and the cost allocation. New York TransCo will not make final decisions on transmission project development until the FERC decision.

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

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

Weather Impact

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

New Renewable Source Generation

Under Connecticut law Public Act 11-80, or PA 11-80, Connecticut electric utilities are required to enter into long-term contracts to purchase Connecticut Class I RECs, from renewable generators located on customer premises. Under this program, UI is required to enter into contracts totaling approximately $200 million in commitments over an approximate 21-year period. The obligations will phase in over a six-year solicitation period, and are expected to peak at an annual commitment level of about $13.6 million per year after all selected projects are online. Upon purchase, UI accounts for the RECs as inventory. UI expects to partially mitigate the cost of these contracts through the resale of the RECs. PA 11-80 provides that the remaining costs (and any benefits) of these contracts, including any gain or loss resulting from the resale of the RECs, are fully recoverable from (or credited to) customers through electric rates.

On October 23, 2013, PURA approved UI's renewable connections program filed in accordance with PA 11-80, through which UI will develop up to 10 MW of renewable generation. The costs for this program will be recovered on a cost of service basis. PURA established a base ROE to be calculated as the greater of: (A) the current UI authorized distribution ROE (currently 9.10%) plus 25

basis points and (B) the current authorized distribution ROE for CL&P, (currently 9.17%), less target equivalent market revenues (reflected as 25 basis points). In addition, UI will retain a percentage of the market revenues from the project, which percentage is expected to equate to approximately 25 basis points on a levelized basis over the life of the project. UI expects the cost of this program, a planned 2.8 MW fuel cell facility in New Haven, solar photovoltaic and fuel cell facilities totaling 5 MW in Bridgeport, and a 2.2 MW fuel cell facility in Woodbridge, to be approximately $47 million. Pursuant to Section 8 of Public Act 13-303, "An Act Concerning Connecticut's Clean Energy Goals," in January 2014, at the DEEP's direction, UI entered into three contracts for the purchase of RECs associated with an aggregate of 5.7 MW of energy production from biomass plants in New England. The costs of these agreements will be fully recoverable through electric rates.

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

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

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

Renewables

Renewable Energy Incentives

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

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

Renewable Energy Demand

Since the transmission and distribution of electricity is highly concentrated in most jurisdictions, there are a limited number of possible purchasers for utility-scale quantities of electricity in a given geographic location, including transmission grid operators, state and investor-owned power companies, public utility districts, cooperatives, and large commercial and industrial customers. As a result, there is a concentrated pool of potential buyers for electricity generated by Renewables' business, which may restrict their ability to negotiate favorable terms under new PPAs, and could impact their ability to find new customers for the electricity generated by their generation facilities should this become necessary. Furthermore, if the financial condition of these utilities and/or power purchasers deteriorated or the RPS programs, climate change programs or other regulations to which they are currently subject and that compel them to source renewable energy supplies change, demand for electricity produced by Renewables' businesses could be negatively impacted.

Energy Prices

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

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

Wind Conditions

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

Wind Turbine Supply

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

Gas

Gas benefits from price volatility and temporal price spreads, which impacts the level of demand for services and the rates that can be charged for natural gas storage services. On a system-wide basis, natural gas is typically injected into storage between April and October when natural gas prices are generally lower and withdrawn during the winter months of November through March when natural gas prices are typically higher. Largely due to the abundant supply of natural gas made available by hydraulic fracturing

techniques, natural gas prices have dropped significantly to levels that are near historic lows. If prices and volatility remain low or declines further, then the demand for natural gas storage services, and the prices that Gas will be able to charge for those services, may decline or be depressed for a prolonged period of time. Conversely, if prices and volatility remain high or increase then the demand for natural gas storage services and the prices that Gas will be able to charge for these services may increase for a period of time. In 2015 we began designating those derivatives contracts at Gas that qualify as hedges. This designation was made prospectively, and in accordance with all the requirements of hedge accounting.

Results of Operations

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

	Year Ended December 31, 2016				
	Total	Networks	Renewables	Gas	Other(1)
			(in millions)		
Operating Revenues	**$ 6,018**	**$ 5,030**	**$ 1,015**	**$ 32**	**$ (59)**
Operating Expenses					
Purchased power, natural gas and fuel used	1,286	1,174	152	—	(40)
Operations and maintenance	2,206	1,839	351	44	(28)
Impairment of non-current assets	—	—	—	—	—
Depreciation and amortization	804	466	313	25	—
Taxes other than income taxes	528	465	50	4	9
Total Operating Expenses	**4,824**	**3,944**	**866**	**73**	**(59)**
Operating Income	**1,194**	**1,086**	**149**	**(41)**	—
Other Income (Expense)					
Other income (expense)	76	46	30	2	(2)
Earnings (losses) from equity method investments	7	15	(8)	—	—
Interest expense, net of capitalization	(268)	(252)	(50)	(25)	59
Income Before Income Tax	**1,009**	**895**	**121**	**(64)**	**57**
Income tax expense	379	415	9	(22)	(23)
Net Income	**630**	**480**	**112**	**(42)**	**80**
Less: Net income attributable to noncontrolling interests	—	—	—	—	—
Net Income	**$ 630**	**$ 480**	**$ 112**	**$ (42)**	**$ 80**

	Year Ended December 31, 2015				
	Total	Networks	Renewables	Gas	Other(1)
			(in millions)		
Operating Revenues	**$ 4,367**	**$ 3,386**	**$ 1,067**	**$ (19)**	**$ (67)**
Operating Expenses					
Purchased power, natural gas and fuel used	972	821	202	1	(52)
Operations and maintenance	1,808	1,389	363	38	18
Impairment of non-current assets	12	—	12	—	—
Depreciation and amortization	695	328	344	23	—
Taxes other than income taxes	367	311	46	4	6
Total Operating Expenses	**3,854**	**2,849**	**967**	**66**	**(28)**
Operating Income	**513**	**537**	**100**	**(85)**	**(39)**
Other Income (Expense)					
Other income (expense)	55	44	105	3	(97)
Earnings (losses) from equity method investments	—	1	(5)	—	4
Interest expense, net of capitalization	(267)	(227)	(54)	(31)	45
Income Before Income Tax	**301**	**355**	**146**	**(113)**	**(87)**
Income tax expense	34	146	13	(44)	(81)
Net Income	**267**	**209**	**133**	**(69)**	**(6)**
Less: Net income attributable to noncontrolling interests	—	—	—	—	—
Net Income	**$ 267**	**$ 209**	**$ 133**	**$ (69)**	**$ (6)**

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

(1) Other amounts represent corporate and company eliminations.

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

Year Ended December 31, 2016

	Total	Networks	Renewables	Gas	Other(1)
			(in millions)		
Operating revenues	**$ 6,018**	**$ 5,030**	**$ 1,015**	**$ 32**	**$ (59)**
Operating revenues %		84%	17%	—	(1)%
Operating expenses	**$ 4,824**	**$ 3,944**	**$ 866**	**$ 73**	**$ (59)**
Operating expenses %		82%	18%	2%	—

Year Ended December 31, 2015

	Total	Networks	Renewables	Gas	Other(1)
			(in millions)		
Operating revenues	**$ 4,367**	**$ 3,386**	**$ 1,067**	**$ (19)**	**$ (67)**
Operating revenues %		78%	24%	(0)%	(2)%
Operating expenses	**$ 3,854**	**$ 2,849**	**$ 967**	**$ 66**	**$ (28)**
Operating expenses %		75%	25%	2%	(2)%

Year Ended December 31, 2014

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

(1) Other amounts represent corporate and company eliminations.

Comparison of Period to Period Results of Operations

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

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

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

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

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

Networks

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

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

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

Renewables

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

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

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

Gas

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

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

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

Depreciation, Amortization and Impairment of Non-Current Assets

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

Other Income and (Expense) and Equity Earnings

Other income and (expense) and equity earnings for the year ended December 31, 2016, increased by $28 million, or 49%, from $55 million other income for the year ended December 31, 2015, to $83 million. UIL contributed $22 million of income. Of the remaining $6 million, $31 million was as a result of the sale of the Iroquois equity investment, and $3 million was as a result of the sale of other investment. An additional $12 million of income results from the reversal of the Maine Natural Gas provision in the current period that was initially recorded at the end of 2015. Offsetting these amounts were a $13 million decrease primarily from interest income on regulatory deferrals, due to updates from the rate case activities, $5 million for reduced allowance for funds used during construction in Networks, $6 million for reduced earnings on equity method investments and $5 million due to a gain from tax equity financing arrangements' buyback recorded in 2015 that did not occur in 2016. Other various items caused a decrease of approximately $11 million in the period.

Interest Expense, Net of Capitalization

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

Income Tax Expense

The effective tax rate for the year ended December 31, 2016, was 37.6%, which is slightly higher than the 35% statutory federal income tax rate due to offsetting income tax matters. Increases were predominantly due to the impact of an adjustment of $126 million to unfunded future income tax to reflect the change from a flow through to normalization method following the approval of the proposal by the NYPSC, which was recorded in the second quarter of 2016 as an increase to income tax expense and an offsetting increase to revenue. This was offset by the recognition of production tax credits associated with wind and state income tax amounts including unitary filing amounts for our various states of operations. Income tax expense for the year ended December 31, 2015, was

$71 million lower than it would have been at the statutory federal income tax rate of 35%, primarily due to production tax credits, filing of amended returns in the State of New York and the impact of tax equity financing arrangements. This resulted in an effective tax rate of 11.30% for 2015.

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

Networks

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

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

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

Renewables

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

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

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

Gas

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

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

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

Depreciation, Amortization and Impairment of Non-Current Assets

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

Other Income and (Expense) and Equity Earnings

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

Interest Expense, Net of Capitalization

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

Income Tax Expense

Income tax expense for the year ended December 31, 2015, was $71 million lower than it would have been at the statutory federal income tax rate of 35% due predominately to production tax credits, filing of amended returns in the State of New York and the impact of tax equity financing arrangements. This resulted in an effective tax rate of 11.30%. Income tax expense for the year ended December 31, 2014, was $35 million higher than it would have been at the statutory federal income tax rate of 35% due predominately to remeasurement of the deferred income tax liability caused by the imposition of a unitary tax regime in New York effective January 1, 2015, production tax credits, and the impact of tax equity financing arrangements. This resulted in an effective tax rate of 39.94%.

Non-GAAP Financial Measures

To supplement our consolidated financial statements presented in accordance with U.S. GAAP, we consider certain non-GAAP financial measures that are not prepared in accordance with U.S. GAAP, including adjusted gross margin, adjusted EBITDA, adjusted net income and adjusted earnings per share, or adjusted EPS. The non-GAAP financial measures we use are specific to AVANGRID and the non-GAAP financial measures of other companies may not be calculated in the same manner. We use these non-GAAP financial measures, in addition to U.S. GAAP measures, to establish operating budgets and operational goals to manage and monitor our business, evaluate our operating and financial performance and to compare such performance to prior periods and to the performance of our competitors. We believe that presenting such non-GAAP financial measures is useful because such measures can be used to analyze and compare profitability between companies and industries because it eliminates the impact of financing and certain non-cash charges. In addition, we present non-GAAP financial measures because we believe that they and other similar measures are widely used by certain investors, securities analysts and other interested parties as supplemental measures of performance.

We define adjusted EBITDA as net income attributable to AVANGRID, adding back income tax expense, depreciation, amortization, impairment of non-current assets and interest expense, net of capitalization, and then subtracting other income and earnings from equity method investments. We define adjusted net income as net income adjusted to reflect the full 12-month period of results for UIL and to exclude gain on the sale of equity method and other investment, impairment of investment, costs related to the merger with UIL, mark-to-market adjustments to reflect the effect of mark-to-market changes in the fair value of derivative instruments used by AVANGRID to economically hedge market price fluctuations in related underlying physical transactions for the purchase and sale of electricity and adjustments for the non-core Gas storage business, for which we are exploring strategic options. We believe adjusted net income is more useful in understanding and evaluating actual and projected financial performance and contribution of AVANGRID core lines of business and to more fully compare and explain our results. Additionally, we evaluate the nature of our revenues and expenses and adjust to reflect classification by nature for evaluation of our non-GAAP financial measures

as opposed to by function. The most directly comparable U.S. GAAP measure to adjusted EBITDA and adjusted net income is net income. We also define adjusted gross margin as adjusted EBITDA adding back operations and maintenance and taxes other than income taxes and then subtracting transmission wheeling. We also define adjusted EPS as adjusted net income converted to an earnings per share amount.

The use of non-GAAP financial measures is not intended to be considered in isolation or as a substitute for, or superior to, AVANGRID's U.S. GAAP financial information, and investors are cautioned that the non-GAAP financial measures are limited in their usefulness, may be unique to AVANGRID, and should be considered only as a supplement to AVANGRID's U.S. GAAP financial measures. The non-GAAP financial measures may not be comparable to other similarly titled measures of other companies and have limitations as analytical tools.

Non-GAAP financial measures are not primary measurements of our performance under U.S. GAAP and should not be considered as alternatives to operating income, net income or any other performance measures determined in accordance with U.S. GAAP.

Reconciliation of the Net Income attributable to AVANGRID to adjusted EBITDA (non-GAAP) and adjusted gross margin (non-GAAP) before reflecting the full 12-month period of results for UIL, excluding gain on the sale of equity method and other investment, impairment of investment, costs related to the merger with UIL, impact from mark-to-market activities in Renewables and Gas storage business, and before adjustments to reflect the classification of revenues and expenses by nature for the years ended December 31, 2016, 2015 and 2014, respectively, is as follows:

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

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

(2) Adjusted EBITDA and adjusted gross margin are non-GAAP financial measures and are presented before reflecting the full 12-month period of results for UIL results, excluding gain on the sale of equity method and other investment, impairment of investment, costs related to the merger with UIL, impact from mark-to-market activities in Renewables and Gas storage business, and before adjustments to reflect the classification of revenues and expenses by nature. For additional details of these adjustments and reconciliation of net income to adjusted EBITDA and adjusted gross margin that reflect these adjustments see the table on pages 70-71 of this Annual Report on Form 10-K.

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

Year Ended December 31, 2016

	Total	Networks	Renewables	Gas	Other(1)
			(in millions)		
Adjusted gross margin (2)	**$ 4,472**	**$ 3,596**	**$ 863**	**$ 33**	**$ (20)**
Adjusted gross margin %		71%	85%	103%	34%
Adjusted EBITDA (2)	**$ 1,998**	**$ 1,551**	**$ 462**	**$ (15)**	**$ —**
Adjusted EBITDA %		31%	46%	(47)%	58%

Year Ended December 31, 2015

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

Year Ended December 31, 2014

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

(1) Other amounts represent corporate and company eliminations.

(2) Adjusted EBITDA and adjusted gross margin are non-GAAP financial measures and are presented before reflecting the full 12-month period of results for UIL results, excluding gain on the sale of equity method and other investment, impairment of investment, costs related to the merger with UIL, impact from mark-to-market activities in Renewables and Gas storage business, and before adjustments to reflect the classification of revenues and expenses by nature. For additional details of these adjustments and reconciliation of net income to adjusted EBITDA and adjusted gross margin that reflect these adjustments see the table on pages 70-71 of this Annual Report on Form 10-K.

Comparison of Period to Period Results of Operations

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

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

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

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

Networks

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

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

Renewables

Adjusted gross margin for the year ended December 31, 2016, decreased by $2 million or less than 1% from $865 million for the year ended December 31, 2015, to $863 million. The decrease was primarily due to $5 million in unfavorable MtM changes on derivatives in 2016 compared to 2015 and a $2 million decrease in thermal results on lower merchant prices not offset by lower fuel

costs. Underlying gross margin on wind and solar increased by $4 million due to increased production of 642 GWh or 5% with average prices 4% lower due to expiring contracts resulting in more generation being sold merchant.

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

Gas

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

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

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

Networks

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

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

Renewables

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

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

Gas

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

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

The following table provides a reconciliation between Net Income attributable to AVANGRID and adjusted gross margin (non-GAAP) and adjusted EBITDA (non-GAAP) by segment after the full 12-month period of results for UIL, excluding gain on the sale of equity method and other investment, impairment of investment, costs related to the merger with UIL, impact from mark-to-market

activities in Renewables and Gas storage business, and after adjustments to reflect the classification of revenues and expenses by nature for the years ended December 31, 2016, 2015 and 2014, respectively:

	Year Ended December 31, 2016				
	Total	Networks	Renewables	Corporate *	Gas Storage
			(in millions)		
Net Income Attributable to Avangrid, Inc.	**$ 630**	**$ 480**	**$ 112**	**$ 80**	**$ (42)**
Adjustments:					
Sale of equity method and other investment	(36)	—	(3)	(33)	—
Impairment of investment	3	3	—	—	—
Mark-to-market adjustments - Renewables	(20)	—	(20)	—	—
Income tax impact of adjustments (1)	22	(1)	9	14	—
Gas Storage, net of tax	42	—	—	—	42
Adjusted Net Income	**$ 641**	**$ 482**	**$ 98**	**$ 61**	**$ —**
Add: Income tax expense (2)	287	290	35	(38)	—
Depreciation and amortization (3)	985	566	415	4	—
Interest expense, net of capitalization (4)	131	132	28	(28)	—
Less: Other income and (expense)	(2)	1	(3)	—	—
Earnings (losses) from equity method investments	4	15	(11)	—	—
Adjusted EBITDA (6)	**$ 2,042**	**$ 1,453**	**$ 589**	**$ (1)**	**$ —**
Add: Operations and maintenance (5)	1,319	1,089	234	(5)	—
Taxes other than income taxes	513	463	44	6	—
Adjusted gross margin (6)	**$ 3,873**	**$ 3,006**	**$ 867**	**$ —**	**$ —**

	Year Ended December 31, 2015				
	Total	Networks	Renewables	Corporate *	Gas Storage
			(in millions)		
Net Income Attributable to Avangrid, Inc.	**$ 267**	**$ 208**	**$ 133**	**$ (6)**	**$ (69)**
Adjustments:					
Add: Net Income representing the full 12-month period of results for UIL	133	133	—	—	—
Merger costs	122	89	—	34	—
Mark-to-market adjustments - Renewables	(25)	—	(25)	—	—
Income tax impact of adjustments (1)	(45)	(49)	9	(5)	—
Gas Storage, net of tax	69	—	—	—	69
Adjusted Net Income	**$ 521**	**$ 381**	**$ 117**	**$ 23**	**$ —**
Add: Income tax expense (2)	203	241	37	(76)	—
Depreciation and amortization (3)	1,047	586	461	—	—
Impairment of non-current assets	12	—	12	—	—
Interest expense, net of capitalization (4)	190	163	(37)	64	—
Less: Other income	1	1	—	—	—
Earnings (losses) from equity method investments	15	14	(4)	4	—
Adjusted EBITDA (6)	**$ 1,957**	**$ 1,356**	**$ 595**	**$ 7**	**$**
Add: Operations and maintenance (5)	1,339	1,122	229	(12)	—
Taxes other than income taxes	517	471	41	5	—
Adjusted gross margin (6)	**$ 3,813**	**$ 2,949**	**$ 865**	**$ —**	**$ —**

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

(1) Income tax impact of adjustments: $14 million from sale of equity method investment, $1 million from sale of other investment, $(1) million on impairment of investment and $8 million from MtM adjustment for the year ended December 31, 2016. Income tax impact of $54 million and $3 million relate to merger costs for the years ended December 31, 2015 and 2014, respectively. Income tax impact of $9 million and $13 million relate to MtM adjustment for the years ended December 31, 2015 and 2014, respectively.

(2) In addition to adjustments to include a full 12-month period of results for UIL, adjustments have been made for production tax credit for the amount of $34 million, $33 million and $28 million for the years ended December 31, 2016, 2015 and 2014, as they have been included in operating revenues in Renewables based on the by nature classification. Additionally, $126 million for unfunded future income taxes have been reclassified from revenues based on the by nature classification in Networks for the year ended December 31, 2015.

(3) In addition to adjustments to include a full 12-month period of results for UIL, adjustments have been made for the inclusion of vehicle depreciation of $22 million, $14 million and $16 million and bad debt provision of $50 million, $48 million and $87 million in Networks within depreciation and amortization from operations and maintenance based on the by nature classification for the years ended December 31, 2016, 2015 and 2014, respectively. Additionally, government grants of $6.6 million and $6.8 million in Networks and investment tax credits amortization of $91 million and $103 million in Renewables have been presented within other operating income and not within depreciation and amortization based on the by nature classification for the years ended December 31, 2016 and 2015, respectively

(4) In addition to adjustments to include a full 12-month period of results for UIL, adjustments have been made for allowance for funds used during construction, debt portion, to reflect these amounts within other income and expenses in Networks for the years ended December 31, 2016, 2015 and 2014, respectively.

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

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

* Includes corporate and other non-regulated entities.

The following tables provide a reconciliations between Net Income attributable to AVANGRID and Adjusted Net Income (non-GAAP), and EPS attributable to AVANGRID and adjusted EPS (non-GAAP) after reflecting the full 12- month period of results for UIL, excluding gain on the sale of equity method and other investment, impairment of investment, costs related to the merger with UIL, impact from mark-to-market activities in Renewables and Gas storage business, for the years ended December 31, 2016, 2015 and 2014, respectively:

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

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

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

(2) Mark-to-market adjustments relate to changes in the fair value of derivative instruments used by AVANGRID to economically hedge market price fluctuations in related underlying physical transactions for the purchase and sale of electricity and gas.

(3) Adjusted net income and adjusted earnings per share are non-GAAP financial measures and are presented after reflecting the full 12-month period of results for UIL, excluding gain on the sale of equity method and other investment, impairment of investment, costs related to the merger with UIL, impact from mark-to-market activities in Renewables and Gas storage business.

Liquidity and Capital Resources

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

Liquidity Resources

At December 31, 2016, we had cash and cash equivalents of $91 million, as compared to $427 million at December 31, 2015. In addition to cash on hand, we and our subsidiaries have access to committed credit facilities totaling $1.5 billion. See discussion of AVANGRID commercial paper program and AVANGRID credit facility below.

We optimize our liquidity within the United States through a series of arms'-length intercompany lending arrangements with our subsidiaries and among our regulated utilities to provide for lending of surplus cash to subsidiaries with liquidity needs, subject to the limitation that the regulated utilities may not lend to unregulated affiliates.

We manage our overall liquidity position as part of the group of companies controlled by Iberdrola, or the Iberdrola Group, and are a party to a notional cash pooling agreement with Bank Mendes Gans, N.V., BMG, along with other members of the Iberdrola Group. The notional cash pooling agreement aids the Iberdrola Group in efficient cash management and reduces the need for external borrowing by the pool participants. Parties to the agreement, including us, may deposit funds with or borrow from BMG, provided that the net balance of funds deposited or borrowed by all pool participants in the aggregate is not less than zero. Deposits are available for next day withdrawal. Deposit in the cash pooling account was $353 million at December 31, 2015. In advance of the United Kingdom "BREXIT" vote, we took steps to reposition our liquidity and our deposits with BMG were withdrawn and reinvested in money market accounts. The BMG balance at December 31, 2016 was zero. The deposit amounts are reflected in our consolidated balance sheet under cash and cash equivalents because our deposited surplus funds under the cash pooling agreement are highly-liquid short-term investments. We also have a bi-lateral demand note agreement with a Canadian affiliate of the Iberdrola Group under which we had notes payable balance outstanding of $10 million at December 31, 2016.

AVANGRID Commercial Paper Program

On May 13, 2016, AVANGRID established a commercial paper program with a limit of $1 billion that is backstopped by the AVANGRID credit facility (described below). As of December 31, 2016 and March 9, 2017, there was $150 million and $300 million of commercial paper outstanding, respectively.

AVANGRID Credit Facility

On April 5, 2016, AVANGRID and its subsidiaries, NYSEG, RG&E, CMP, UI, CNG, SCG and BGC entered into a revolving credit facility with a syndicate of banks, or the AVANGRID Credit Facility, that provides for maximum borrowings of up to $1.5 billion in the aggregate. Since the facility is a backstop to the AVANGRID commercial paper program, the amounts available under the facility at December 31, 2016 and March 9, 2017, were $1,350 million and $1,200 million, respectively.

Under the terms of the AVANGRID Credit Facility, each joint borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit established by the banks. AVANGRID's maximum sublimit is $1 billion, NYSEG, RG&E, CMP and UI have maximum sublimits of $250 million, CNG, and SCG have maximum sublimits of $150 million and BGC has a maximum sublimit of $25 million. Under the AVANGRID credit facility, each of the borrowers will pay an annual facility fee that is dependent on their credit rating. The facility fees will range from 10.0 to 17.5 basis points. The maturity date for the AVANGRID credit facility is April 5, 2021.

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

Long-Term Capital Resources

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

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

At December 31, 2016, we had $4,307 million of long-term debt (including the current portion thereof) outstanding in the Networks segment consisting of first mortgage bonds, senior unsecured notes, tax-exempt bonds and various other forms of debt. Network's regulated utilities are required by regulatory order to maintain a minimum ratio of common equity to total capital that is tied to the capital structure used in the establishment of their revenue requirements. Pursuant to these requirements, each of NYSEG, RG&E, CMP and MNG must maintain a minimum equity ratio equal to the ratio in its currently effective rate plan or decision measured using a trailing 13-month average. On a monthly basis, each utility must maintain a minimum equity ratio of no less than 300 basis points below the equity ratio used to set rates. Networks' regulated utilities were in compliance with these regulatory orders as of December 31, 2016. UI, SCG, CNG and BGC are restricted from paying dividends if paying such dividend would result in their respective common equity ratio being lower than 300 basis points below the equity percentage used to set rates in the most recent distribution rate proceeding as measured using a trailing 13-month average calculated as of the most recent quarter end. The regulated utilities periodically pay dividends to, or receive capital contributions from AVANGRID, in order to maintain the minimum equity ratio requirement. They each independently incur indebtedness by issuing investment grade debt securities.

At December 31, 2016, we had $70 million of long-term debt (including the current portion thereof) outstanding in the Renewables segment consistently principally of a sale-leaseback arrangement on a solar generation facility. Renewables has historically been financed primarily with equity contributions from Iberdrola. The last such contribution of $800 million was made in February 2013. Renewables has also sourced capital through tax equity financing arrangements associated with particular wind farm projects. The arrangements allocate tax losses and production tax credits to the tax equity investor in exchange for an initial contribution. The obligations created under the tax equity financing arrangements are recorded as a liability with an aggregate balance of $199 million, of which $96 million is current, at December 31, 2016.

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

In our credit facilities, long-term borrowing and tax-equity partnerships, we and our affiliates that are parties to the agreements are subject to covenants that are standard for such agreements. Affirmative covenants impose certain obligations on the borrower and negative covenants limit certain activities by the borrower. The agreements also define certain events of default, including but not limited to non-compliance with the covenants that may automatically in some circumstances, or at the option of the lenders in other circumstances, trigger acceleration of the obligations. We and our affiliates were in compliance with all such covenants at December 31, 2016.

Capital Requirements

Funding Future Common Dividend Payments

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

Capital Expenditures

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

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

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

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

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

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

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

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

In 2015 there were capital expenditures of $73 million on construction of the Amazon Wind Farm US - East (formerly Desert Wind) and other wind assets, $11 million in capital expenditures on the Klamath Plant, $31 million on improvements to operating wind assets and $9 million in development costs.

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

Capital Improvement Projects

An important part of our business strategy involves capital improvement projects. Through Networks we plan to invest a total of approximately $7.8 billion from 2017 to 2021 to upgrade and expand electricity and natural gas transmission and distribution infrastructure. In the next 12 months, CMP plans to invest $204 million, including the program to complete the Lewiston Loop project, which complements the already completed MPRP, a project which enhanced the bulk power transmission grid in Maine. In addition, CMP plans to continue developing its new customer relationship management and billing system and new transmission investments in the Maine Electric Power Corporation, or MEPCO, 388 rebuild. NYSEG plans to invest $336 million in the next 12 months, including a number of programs disclosed in Appendix P Schedule I of the proposal dated June 15, 2016, the most relevant ones: The FERC Bright Line project, Auburn transmission project, Columbia County transmission project, Gas Distribution Mains and Leak Prone Main replacement. RG&E plans to invest $299 million in the next 12 months, including a number of programs disclosed in Appendix P Schedule I of the proposal dated June 15, 2016, the most relevant ones: The FERC Bright Line, Rochester Area Reliability Project (RARP), Ginna Retirement Transmission Alternative (GRTA), Station 23 - New Downtown 115kV source,

Gas Distribution Mains and Leak Prone Main replacement. UIL plans to invest $393 million in the next 12 months, including a number of programs disclosed in the UI-Distribution PURA Order dated December 14 2016 related to new customers, system and corrective reliability, system resiliency, infrastructure replacement (substations and distribution system), and system operations. The most relevant investment for CNG will be the Rocky Hill Liquefied Natural Gas, or LNG, Plant Liquefaction System Replacement Project.

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

Through Renewables we plan to invest a total of approximately $4.0 billion from 2017 to 2021 in order to add 2,000 MWs of generation capacity. 601 MW are approved for construction in 2017 and 2018 and these projects have long-term associated PPA contracts.

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

Cash Flows

Our cash flows depend on many factors, including general economic conditions, regulatory decisions, weather, commodity price movements, and operating expense and capital spending control.

The following is a summary of the cash flows by activity for the years ended December 31, 2016, 2015 and 2014:

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

Operating Activities

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

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

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

In 2014, net cash provided by operating activities was approximately $1.3 billion. During the period, Renewables contributed $724 million of operating cash associated with wholesale sales of energy, Networks contributed $734 million of operating cash as the result of regulated transmission and distribution sales of electricity and natural gas, and Gas contributed cash of $17 million associated with gains on marketing of wholesale gas and gas storage services. We used $60 million in cash associated with operating expenses in support of our segments. In addition, changes in working capital used $84 million in cash. The cash from operating activities for the year ended December 31, 2014, compared to the year ended December 31, 2013, increased by $154 million and this is primarily driven by the increased revenues at Renewables due to increase in wind source, prices, power trading activities and abundant hydro conditions as well as Gas due to lower gas prices. The $35 million net change in our net operating assets and liabilities during the year ended December 31, 2014, was primarily attributable to a decrease in inventory costs driven by a decrease in inventory levels of $58 million, partially offset by storm cost deferrals of $20 million.

Investing Activities

Our investing activities have primarily focused on enhancing, automating, and reinforcing the asset base to support safety, reliability, and customer growth in accordance with the regulatory markets within which we operate, as well as constructing solar and wind assets and spending on gas generation assets. The increase in cash outflows related to capital expenditures in 2016 was largely due to the inclusion of UIL, which was not in the comparable period, adding $356 million. The cost of investments has been offset, partially, by contributions in aid of construction and proceeds from the sale of equity investments in 2016.

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

In 2015, the cash used in investing activities was $1.5 billion, compared to $888 million in 2014. The increase in 2015 compared to 2014 is primarily related to cash paid for acquisition of UIL (net of cash acquired) of $547 million. The cash outflows related to capital expenditures for Networks were $773 million in 2015 and $775 million in 2014. The remaining capital expenditure related cash outflows in 2015 represent principally capital expenditures in Renewables of $304 million. This amount is driven by significant progress in construction of the Baffin Bay wind asset in 2014. Under a turbine supply agreement, with Gamesa, payment for the supplied turbines did not take place until first quarter of 2015.

Financing Activities

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

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

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

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

Contractual Obligations

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

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

(1) Represents lease contracts relating to operational facilities, office building leases, and vehicle and equipment leases. These amounts represent our expected portion of the costs to pay as amounts related to contingent payments are predominantly linked to electricity generation at the respective facilities. Obligations under operating lease significantly decrease from 2016 onwards as commitments on Cayuga and Ginna facilities are scheduled to terminate from 2017.

(2) The qualified pension plans' contributions are generally based on the estimated minimum pension contributions required under the Employee Retirement Income Sensitivity Act of 1974, as amended, and the Pension Protection Act of 2006, as well as contributions necessary to avoid benefit restrictions and at-risk status and agreements with state regulatory agencies. These amounts represent estimates that are based on assumptions that are subject to change. The minimum required contributions for years after 2020 are not included as projection beyond 2020 are not available.

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

(4) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2016, and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2016

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

Critical Accounting Policies and Estimates

The financial statements provided herein have been prepared in accordance with U.S. GAAP and include the accounts of AVANGRID.

In preparing the accompanying financial statements, our management has made certain estimates and assumptions that affect the reported amounts of assets, liabilities, shareholder's equity, revenues and expenses, and the disclosures thereof. Our management recorded the net assets of ARHI in these consolidated financial statements at the historical accounting basis of AVANGRID. The historical accounting basis of AVANGRID includes purchase accounting adjustments related to AVANGRID's acquisition of ARHI in 2007. Prior to the 2013 reorganization of AVANGRID, Networks was not considered to be a substantive operating entity as it did not hold any direct operations and had always been a part of AVANGRID. As a result, the net assets of Networks in these consolidated financial statements are recorded at the historical accounting basis of AVANGRID, which do not include purchase accounting adjustments related to Iberdrola, S.A.'s acquisition of AVANGRID in 2008.

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

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

Accounting for Regulated Public Utilities

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, 2016, utilizing a hypothetical portfolio of actual, high quality bonds, which would generate cash flows required to settle the liabilities. We believe such an estimate of the discount rate accurately reflects the settlement value for plan obligations and results in cash flows which closely match the expected payments to participants.

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

During 2016, the Society of Actuaries issued updated mortality tables and projection scales. AVANGRID, in conjunction with its actuaries, performed an analysis to determine the appropriateness of adopting these tables and the related mortality projections. As a result, our pension and post-retirement plan liabilities as of December 31, 2016, reflect updated mortality assumptions.

Business Combinations

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

Goodwill

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

In assessing goodwill for impairment, we have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary, or step zero. If it is determined, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If we bypass step zero or perform the qualitative assessment but determine that it is more likely than not that its fair value is less than its carrying amount, a quantitative two step, fair value based test is performed. Step one compares the fair value of the reporting unit to its carrying amount, including goodwill. 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.

Networks

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

Renewables

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

Impairment of Long Lived Assets

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

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

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

Fair value of a long-lived asset (asset group) is sensitive to both input assumptions related to our budgets and cash flow forecasts and the discount rate. Further, estimates of long-term growth and terminal value are often critical to the fair value determination. As part of the impairment evaluation process, management analyzes the sensitivity of fair value to various underlying

assumptions. The level of scrutiny increases as the gap between fair value and carrying amount decreases. Changes in any of these assumptions could result in management reaching a different conclusion regarding the potential impairment, which could be material. Our impairment evaluations inherently involve uncertainties from uncontrollable events that could positively or negatively impact the anticipated future economic and operating conditions.

Capitalization and Recovery of Project Development Costs

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

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

Fair Value Measurement

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

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

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

Income Tax

AVANGRID will file a consolidated federal income tax return that includes the taxable income or loss of all its subsidiaries for the 2016 tax period.

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

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

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

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

Deferred tax assets and liabilities are measured at the expected tax rate for the period in which the asset or liability will be realized or settled, based on legislation enacted as of the balance sheet date. Changes in deferred income tax assets and liabilities that are associated with components of other comprehensive income, or OCI, are charged or credited directly to OCI. Significant judgment is required in determining income tax provisions and evaluating tax positions. Our tax positions are evaluated under a more-likely-than-not recognition threshold before they are recognized for financial reporting purposes. Valuation allowances are recorded to reduce deferred tax assets when it is not more-likely-than not that all or a portion of a tax benefit will be realized.

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

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

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

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

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

Off-Balance Sheet Arrangements

As of December 31, 2016, we had approximately $2.6 billion of standby letters of credit, surety bonds, guarantees and indemnifications outstanding. These instruments provide financial assurance to the business and trading partners of AVANGRID and its subsidiaries in their normal course of business. The instruments only represent liabilities if AVANGRID or its subsidiaries fail to deliver on contractual obligations. We therefore believe it is unlikely that any material liabilities associated with these instruments will be incurred and, accordingly, as of December 31, 2016, neither we nor our subsidiaries have any liabilities recorded for these instruments.

New Accounting Standards

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

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

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

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

Simplifying the Accounting for Measurement-Period Adjustments - In September 2015 the FASB issued amendments that require an acquirer to recognize adjustments to provisional amounts relating to a business combination that are identified during the measurement period in the reporting period in which the adjustment amounts are determined.

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

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

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

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

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

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

For further discussion of new accounting pronouncements affecting AVANGRID refer to Note 3 of our audited consolidated financial statements for the three years ended December 31, 2016, which are incorporated herein by reference.

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

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

Commodity Price Risk

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

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

Renewables merchant wind facilities are subject to fixed price power risk, which is hedged with fixed price power trades. Its combined cycle power plant is subject to heat rate risk, which is hedged with fixed price power and fixed price gas and basis positions. Contracted natural gas storage exposures are affected by gas price differentials across time. We manage this exposure with fixed price, basis, and index gas derivatives. In addition, contracted transport positions are subject to gas price risk across location (i.e., the price differentials between the receipt and delivery points associated with the leased pipelines). We hedge this exposure with basis swaps. Those measures mitigate our commodity price exposure, but do not completely eliminate it. Some long term hedges do not qualify for hedge accounting. This introduces some Mark to Market volatility into yearly profit and losses accounts.

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

Renewables and Gas use a 99% probability level over a five-day holding period, indicating that it can be 99% confident that losses over five days would not exceed that value. The average VaR for 2016 was $17.7 million compared to a 2015 average of $14.0 million.

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

Networks also experiences commodity price risk, due to volatility in the wholesale energy markets. Networks manages that risk through a combination of regulatory mechanisms, such as the pass-through of the market price of electricity and natural gas to customers, and through comprehensive risk management processes. Those measures mitigate our commodity price exposure, but do not completely eliminate it. Networks also uses electricity contracts as deemed appropriate, both physical and financial, to manage

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

Because all gains or losses on Networks' commodity contracts will ultimately be passed on to retail customers, no sensitivity analysis is performed for Networks. Further information regarding the derivative financial instruments and sensitivity analysis is provided in Notes 11 and 12 of our audited consolidated financial statements for the three years ended December 31, 2016, which are incorporated herein by reference.

Interest Rate Risk

Total debt outstanding, including tax equity of $199 million and commercial paper of $150 million, was $5.2 billion at December 31, 2016, of which $212 million had a floating interest rate; a change of 25 basis points in this interest rate would result in an interest expense fluctuation of approximately $0.5 million annually. The estimated fair value of our debt excluding the debt associated with capital leases and tax equity at December 31, 2016 was $5.1 billion, in comparison to a book value of $4.7 billion.

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

Pension and Post-Retirement Plans

We provide pensions and other post-retirement benefits for a significant number of employees, former employees and retirees. In applying relevant accounting policies, we have made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, discount rates, health care cost trends and future compensation. The cost of pension and other post-retirement benefits in future periods will depend on actual returns on plan assets, assumptions for future periods, contributions and benefit experience. In 2016, we contributed $44 million to our pension plans. Our contribution to the pension plans in 2017 is expected to be approximately $33 million.

The discount rate used in accounting for pension and other benefit obligations in 2016 ranged from 3.90% to 4.24%. The expected rate of return on plan assets for qualified pension benefits in 2016 ranged from 5.50% to 7.75%. The following tables reflect the estimated sensitivity associated with a change in certain significant actuarial assumptions (each assumption change is presented mutually exclusive of other assumption changes):

		Impact on 2016 Pension Expense Increase (Decrease)	
	Change in Assumption	Pension Benefits	Post Retirement
		(in millions)	
Increase in discount rate	50 basis points	$ (18)	$ (3)
Decrease in discount rate	50 basis points	18	3
Increase in return on plan asset	50 basis points	(13)	(1)
Decrease in return on plan asset	50 basis points	13	1

Credit Risk

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

Renewables and Gas are also exposed to credit risk through their energy management and gas storage operations. We manage counterparty credit risk for our subsidiaries with energy management and gas storage operations through established policies, including counterparty credit limits, and in some cases credit enhancements, such as cash prepayments, letters of credit, cash and other collateral and guarantees.

Some relevant considerations when assessing the credit risk exposure of the energy management and gas storage operations follows:

- Operations are primarily concentrated in the energy industry.
- Trade receivables and other financial instruments are predominately with energy, utility and financial services related companies, as well as municipalities, cooperatives and other trading companies in the U.S.
- Overall credit risk is managed through established credit policies by a Credit Risk Management group that is independent of the energy management and gas storage functions.
- Prospective and existing customers are reviewed for creditworthiness based upon established standards, with customers not meeting minimum standards providing various credit enhancements or secured payment terms, such as guarantees, letters of credit or the posting of margin cash collateral.
- Master netting agreements are used, where appropriate, to offset cash and non-cash gains and losses arising from derivative instruments with the same counterparty.

Based on our policies and risk exposures related to credit risk from its management and gas storage operations in ARHI, we do not anticipate a material adverse effect on our financial statements as a result of counterparty nonperformance. As of December 31, 2016, approximately 92% of our energy management and gas storage counterparty credit risk exposure is associated with companies that have investment grade credit ratings.

The following table displays the credit quality of our energy management and gas storage counterparties as of December 31, 2016:

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

(1) This category includes counterparties with minimum credit ratings of Baa3 assigned by Moody's and BBB- assigned by Standard & Poor's, if rated by both agencies. The five largest counterparty exposures, combined, for this category represented approximately 32.7% of the total gross credit exposure.

(2) This category includes counterparties with credit ratings that are below investment grade. The five largest counterparty exposures, combined, for this category represented approximately 5.2% of the total gross credit exposure.

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

(4) This category includes counterparties that have not been rated by Moody's or Standard & Poor's, and are considered non-investment grade based on our evaluation of the counterparty's creditworthiness. The five largest counterparty exposures, combined, for this category represented approximately 1.7% of the total gross credit exposure.

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

Treasury Management (including Liquidity Risk)

We manage our overall liquidity position as part of the broader Iberdrola Group and are a party to a notional cash pooling agreement with Bank Mendes Gans, N.V., or BMG, along with other members of the Iberdrola Group. We optimize our liquidity within the United States through a series of arms'-length intercompany lending arrangements with our subsidiaries and among the regulated utilities to provide for lending of surplus cash to subsidiaries with liquidity needs, subject to the limitation that the regulated utilities may not lend to unregulated affiliates. These arrangements minimize overall short-term funding costs and maximize returns on the temporary cash investments of the subsidiaries. We also have a bi-lateral demand note agreement with a Canadian affiliate of the Iberdrola Group. We have the capacity to borrow from third parties through Commercial Paper program and the $1.5 billion AVANGRID Credit Facility which backstops the Commercial Paper program. For more information, see the section entitled "—Liquidity and Capital Resources—Liquidity Resources" of this Annual Report on Form 10-K.

Networks

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

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

Renewables

Prior to becoming a subsidiary of AVANGRID in November 2013, Renewables was principally funded by equity contributions from Iberdrola, S.A. The last such equity contribution of $800 million was made in February 2013. Renewables has also raised a small percentage of its capital through tax equity partnerships, project loans and sale-leaseback arrangements. The balance of the outstanding tax equity financing arrangement at December 31, 2016, was $199 million and the balance of leases and project financing was $70 million. Presently, Renewables is a party to a cash pooling arrangement with Avangrid, Inc. All Renewables revenues are concentrated in and all Renewables disbursements are made from Avangrid, Inc. Net cash surpluses or deficits at Renewables are recorded as intercompany receivables or payables and these balances are periodically reduced to zero through dividends or capital contributions. In June 2016, Renewables recorded a net dividend of $962 million to Avangrid, Inc. to zero out account balances that had principally accumulated prior to November 2013.

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of Avangrid, Inc. and subsidiaries (the “Company”) as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2016. Our audits also included the financial statement schedule listed in the Index at Item 15(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits. We did not audit the consolidated balance sheet of UIL Holdings Corporation, a wholly-owned subsidiary acquired in 2015, which statement reflects total assets of $5,270 million as of December 31, 2015. That balance sheet was audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the balance sheet amounts included for UIL Holdings Corporation, is based solely on the report of other auditors.

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

In our opinion, based on our audits and, as to the balance sheet at December 31, 2015, the report of other auditors, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Avangrid, Inc. and subsidiaries at December 31, 2016 and 2015, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

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

/s/ Ernst & Young LLP

New York, New York
March 10, 2017

Report of Independent Registered Public Accounting Firm

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

We have audited Avangrid, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Avangrid, Inc. and subsidiaries' management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Report of Management on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

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

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

/s/ Ernst & Young LLP

New York, New York
March 10, 2017

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
Consolidated Statements of Income

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

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

Avangrid, Inc. and Subsidiaries
Consolidated Statements of Comprehensive Income

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

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

Avangrid, Inc. and Subsidiaries
Consolidated Balance Sheets

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

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

Avangrid, Inc. and Subsidiaries
Consolidated Balance Sheets

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

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

Avangrid, Inc. and Subsidiaries
Consolidated Statements of Cash Flows

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

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

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

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

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

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

Note 1. Background and Nature of Operations

Avangrid, Inc., formerly Iberdrola USA, Inc. (AVANGRID, we or the Company), is an energy services holding company engaged in the regulated energy distribution business through its principal subsidiary Avangrid Networks, Inc. (Networks). Effective as of April 30, 2016, UIL Holdings Corporation and its subsidiaries (UIL) were transferred to a wholly-owned subsidiary of Networks. AVANGRID is also in the renewable energy generation and gas storage and trading businesses through its principal subsidiary, Avangrid Renewables Holding, Inc. (ARHI). ARHI in turn holds subsidiaries including Avangrid Renewables LLC (Renewables) and Enstor Gas, LLC (Gas). Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain, owns 81.5% of the outstanding common stock of AVANGRID. The remaining outstanding shares are publicly traded on the New York Stock Exchange and owned by various shareholders. AVANGRID was organized in 1997 as NGE Resources, Inc. under the laws of New York as the holding company for its principal operating utility companies.

Reorganization

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

AVANGRID and ARHI were acquired by Iberdrola in 2008 and 2007, respectively, and they have been under common control of Iberdrola for all periods presented. Networks was formed as part of the Reorganization in November 2013. Networks is a public utility sub-holding company operating under the Public Utility Holding Company Act of 2005 with operations in New York, Maine, Connecticut and Massachusetts. The wholly owned subsidiaries and the operating utility companies of Networks include: CMP Group - Central Maine Power Company (CMP), RGS - New York State Electric & Gas Corporation (NYSEG), Rochester Gas and Electric Corporation (RG&E), Maine Natural Gas Company (MNG), The United Illuminating Company (UI), The Southern Connecticut Gas Company (SCG), Connecticut Natural Gas Corporation (CNG) and The Berkshire Gas Company (BGC). UI is also a party to a joint venture with certain affiliates of NRG Energy, Inc. (NRG affiliates) pursuant to which UI holds 50% of the membership interests in GCE Holding LLC, whose wholly owned subsidiary, GenConn Energy LLC (collectively with GCE Holding LLC, GenConn) operates peaking generation plants in Devon, Connecticut (GenConn Devon) and Middletown, Connecticut (GenConn Middletown). ARHI is the sub-holding company of the unregulated energy business that includes the renewable energy and the gas trading and storage businesses.

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

Acquisition of UIL

On December 16, 2015 (acquisition date), UIL Holdings Corporation, a Connecticut corporation (UIL), became a wholly-owned subsidiary of AVANGRID as a result of the merger of Green Merger Sub, Inc., a Connecticut corporation and a wholly-owned subsidiary of AVANGRID (Merger Sub), with UIL, with Merger Sub surviving as a wholly-owned subsidiary of AVANGRID (the acquisition). The acquisition was effected pursuant to the Agreement and Plan of Merger, dated as of February 25, 2015, by and among AVANGRID, Merger Sub, and UIL. Following the completion of the acquisition, Merger Sub was renamed “UIL Holdings Corporation.” In connection with the acquisition, we issued 309,490,839 shares of common stock of AVANGRID, out of which 252,234,989 shares were issued to Iberdrola through a stock dividend, accounted for as a stock split, with no change to par value, at par value of $0.01 per share, and 57,255,850 shares (including those held in trust as treasury stock) were issued to UIL shareowners in addition to payment of $10.50 in cash per each share of the common stock of UIL issued and outstanding at the acquisition date. Following the completion of the acquisition, former UIL shareowners owned 18.5% of the outstanding shares of common stock of AVANGRID and Iberdrola owned the remaining shares. See Note 4, Acquisition of UIL, for further details.

The regulated utility businesses of UIL consist of the electric distribution and transmission operations of UI and the natural gas transportation, distribution and sales operations of SCG, CNG and BGC.

UI is also a party to a joint venture with certain affiliates of NRG Energy, Inc. (NRG affiliates) pursuant to which UI holds 50% of the membership interests in GCE Holding LLC, whose wholly owned subsidiary, GenConn Energy LLC (collectively with GCE Holding

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

Note 2. Basis of Presentation

The accompanying consolidated financial statements have been prepared in accordance with U.S. GAAP and are presented on a consolidated basis, and therefore include the accounts of AVANGRID and its consolidated subsidiaries Networks and ARHI. Consolidated accounts of UIL have been included in the consolidated financial statements of AVANGRID since December 16, 2015, the date of acquisition of UIL. All intercompany transactions and accounts have been eliminated in all periods presented. All share and per share information included in the consolidated financial statements have been retroactively adjusted to reflect the impact of the stock dividend.

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

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

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

Significant Accounting Policies

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

(a) Principles of consolidation

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

(b) Revenue recognition

Revenue from the sale of energy by our regulated utilities is recognized in the period during which the sale occurs. The calculation of revenue earned but not yet billed is based on the number of days not billed in the month, the estimated amount of energy delivered during those days and the estimated average price per customer class for that month. Differences between actual and estimated unbilled revenue are usually immaterial.

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

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

(c) Regulatory accounting

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

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

(d) Business combinations

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

(e) Equity method investments

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

(f) Goodwill and other intangible assets

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

Goodwill is not amortized, but is subject to an assessment for impairment at least annually or more frequently if events occur or circumstances change that will more likely than not reduce the fair value of the reporting unit to which goodwill is assigned below its carrying amount. A reporting unit is an operating segment or one level below an operating segment and is the level at which goodwill is tested for impairment. In assessing goodwill for impairment we have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary (step zero). If it is determined, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If we bypass step zero or perform the qualitative assessment, but determine that it is more likely than not that its fair value is less than its carrying amount, a quantitative two step fair value based test is performed. Step one compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, step two is performed. Step two requires an allocation of fair value to the individual assets and liabilities using business combination accounting guidance to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than its carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense.

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

Intangible assets with finite lives are amortized on a straight-line basis over the useful economic life, which ranges from four to forty years, and assessed for impairment whenever there is an indication that the intangible asset may be impaired. The amortization

expense on intangible assets with finite lives is recognized in the consolidated statements of income as the expense category that is consistent with the function of the intangible assets.

(g) Property, plant and equipment

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

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

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

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

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

Major class	Asset Category	Estimated Useful Life (years)
Plant	Combined cycle plants	35
	Hydroelectric power stations	35-90
	Wind power stations	25-40
	Gas storage	25-40
	Transport facilities	40-56
	Distribution facilities	30-54
Equipment	Conventional meters and measuring devices	15-27
	Computer software	3-5
Other	Buildings	50-75
	Operations offices	4-50

Networks determines depreciation expense using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal, in service at each operating company. Consistent with FERC accounting requirements, Networks charges the original cost of utility plant retired or otherwise disposed of to accumulated depreciation.

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

(h) Impairment of long lived assets

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

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

(i) Fair value measurement

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

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

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

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

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

Categorization within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement.

(j) Available for sale securities

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

(k) Derivatives and hedge accounting

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

Derivatives that qualify and are designated for hedge accounting are classified as cash flow hedges. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the hedged cash flows of the underlying exposure is deferred in Other Comprehensive Income (OCI) and later reclassified into earnings when the underlying transaction occurs. For all designated and qualifying hedges, we maintain formal documentation of the hedge and effectiveness testing in accordance with the accounting standards for derivatives and hedging. If we determine that the derivative is no longer highly effective as a hedge, hedge accounting will be discontinued prospectively. For cash flow hedges of forecasted transactions, we estimate the future cash flows of the forecasted transactions and evaluate the probability of the occurrence and timing of such transactions. If we determine it is probable that the forecasted transaction will not occur, hedge gains and losses previously recorded in OCI are immediately recognized in earnings.

Changes in conditions or the occurrence of unforeseen events could require discontinuance of the hedge accounting or could affect the timing of the reclassification of gains or losses on cash flow hedges from OCI into earnings. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. Changes in the fair value of electric and natural gas hedge contracts are recorded to derivative assets or liabilities with an offset to regulatory assets or regulatory liabilities for our regulated operations.

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

(l) Cash and cash equivalents

Cash and cash equivalents comprises cash, bank accounts, and other highly-liquid short-term investments. We consider all highly liquid investments with a maturity date of three months or less when acquired to be cash equivalents and those investments are

included in “Cash and cash equivalents.” Restricted cash represents cash legally set aside for a specified purpose or as part of an agreement with a third party. Restricted cash is included in “Other non-current assets” on the consolidated balance sheets.

(m) Accounts receivable and unbilled revenue, net

We record accounts receivable at amounts billed to customers. Certain accounts receivable and payable related to our wholesale activities associated with generation and delivery of electric energy and associated environmental attributes, origination and marketing, natural gas storage, hub services, and energy management, are subject to master netting agreements with counterparties, whereby we have the legal right to offset the balances, which are settled on a net basis. Receivables and payables subject to such agreements are presented in our consolidated balance sheets on a net basis.

Accounts receivable include amounts due under Deferred Payment Arrangements (DPA). A DPA allows the account balance to be paid in installments over an extended period of time without interest, which generally exceeds one year, by negotiating mutually acceptable payment terms. The utility companies generally must continue to serve a customer who cannot pay an account balance in full if the customer (i) pays a reasonable portion of the balance; (ii) agrees to pay the balance in installments; and (iii) agrees to pay future bills within thirty days until the DPA is paid in full. Failure to make payments on a DPA results in the full amount of a receivable under a DPA being due. These accounts are part of the regular operating cycle and are classified as short term.

The allowance for bad debts account is established by using both historical average loss percentages to project future losses, and a specific allowance is established for known credit issues. Amounts are written off when we believe that a receivable will not be recovered.

(n) Tax equity financing arrangements-VIEs

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

We evaluate whether an entity is a variable interest entity (VIE) whenever reconsideration events as defined by the accounting guidance occur (See Note 19). An entity is considered to be a VIE when its total equity investment at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support, or its equity investors, as a group, lack the characteristics of having a controlling financial interest. A reporting company is required to consolidate a VIE as its primary beneficiary when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance, and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE.

(o) Debentures, bonds and bank borrowings

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

(p) Inventory

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

We also have materials and supplies inventories that are used for construction of new facilities and repairs of existing facilities. These inventories are carried and withdrawn at cost and reported on the balance sheets within “Materials and supplies.”

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

(q) Government grants

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

In accounting for government grants related to operating and maintenance costs, amounts receivable are recognized as an offset to expenses in the consolidated statements of income in the period in which the expenses are incurred.

(r) Deferred income

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

(s) Asset retirement obligations

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

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

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

(t) Environmental remediation liability

In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. Our environmental liabilities are recorded on an undiscounted basis. Our environmental liability accruals are expected to be paid through the year 2053.

(u) Post employment and other employee benefits

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

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

We account for defined benefit pension or other postretirement plans, recognizing an asset or liability for the overfunded or underfunded plan status. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. Our utility operations reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in other comprehensive income, as

management believes it is probable that such items will be recoverable through the ratemaking process. We use a December 31st measurement date for our benefits plans.

We amortize prior service costs for both the pension and other postretirement benefits plans on a straight-line basis over the average remaining service period of participants expected to receive benefits. For NYSEG, RG&E and UIL, we amortize unrecognized actuarial gains and losses over ten years from the time they are incurred as required by the NYPSC, PURA and DPU. For our other companies we use the standard amortization methodology under which amounts in excess of ten percent of the greater of the projected benefit obligation or market related value are amortized over the plan participants' average remaining service to retirement. Our policy is to calculate the expected return on plan assets using the market related value of assets. That value is determined by recognizing the difference between actual returns and expected returns over a five year period.

(v) Income tax

AVANGRID will file a consolidated federal income tax return that includes the taxable income or loss of all its subsidiaries for the 2016 tax period.

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

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

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

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

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

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

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

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

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

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

(w) Stock-based compensation

Stock-based compensation represents costs related to stock-based awards granted to employees. In the third quarter of 2016 we early adopted all the amendments to ASC 718, Compensation - Stock Compensation, issued in March 2016, to account for our stock based awards. We account for stock-based payment transactions based on the estimated fair value of awards reflecting forfeitures when they occur. The recognition period for these costs begin at either the applicable service inception date or grant date and continues throughout the requisite service period, or until the employee becomes retirement eligible, if earlier.

Reclassifications

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

New Accounting Standards and Interpretations

(a) Revenue from contracts with customers

In May 2014 the Financial Accounting Standards Board (FASB) issued ASC 606, Revenue from Contracts with Customers (ASC 606), replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The core principle is for an entity to recognize revenue to represent the transfer of goods or services to customers in amounts that reflect the consideration to which the entity expects to be entitled in exchange for those goods or services. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers. The original effective date for public entities was for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. In August 2015 the FASB issued an accounting standards update that defers by one year the original effective date of the revenue standard for all entities. Thus, the standard is now effective for annual reporting periods beginning after December 15, 2017, and interim periods therein, with early adoption as of the original effective date permitted. We do not plan to early adopt. Entities may apply the amendment retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). We will apply the modified retrospective method. We are currently evaluating how our adoption of the amendments will affect our results of operations, financial position, cash flows, and disclosures. We are considering the effects of the amendments on our ability to recognize revenue for certain contracts for our regulated utilities where collectability is in question and our accounting for contributions in aid of construction for our regulated utilities. In addition, the amendments will require us to capitalize, rather than expense, any costs to acquire new contracts. Additionally, classification differences are also expected to result, including recording our tax equity investments as noncontrolling interests. Some revenue arrangements, such as alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on our consolidated financial statements. The FASB has issued various additional accounting standards updates, with the same deferred effective date, as follows: in March 2016 to amend and clarify the implementation guidance on principal versus agent considerations for reporting revenue gross rather than net, in April 2016 to address implementation questions on identifying performance obligations and accounting for licenses of intellectual property. We do not expect significant effects as a result of those updates. In May 2016 the FASB issued a final update concerning narrow-scope improvements and practical expedients. We are currently evaluating the effects of that update.

(b) Fair value measurement disclosures for certain investments

In May 2015 the FASB issued amendments that affect reporting entities that elect to estimate the fair value of certain investments within scope using the net asset value (NAV) per share (or its equivalent) practical expedient, as specified. The amendments remove the requirement to categorize within the fair value hierarchy all investments for which the fair value is measured at NAV using the practical expedient. They also remove certain disclosure requirements for eligible investments and limit the required disclosures to investments for which the entity has elected to measure the fair value using the practical expedient. Assets that calculate NAV per share (or its equivalent), but for which the practical expedient is not applied will continue to be included in the fair value hierarchy.

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

(c) Simplifying the measurement of inventory

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

(d) Classifying and measuring financial instruments

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

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

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

In September 2015 the FASB issued amendments that require an acquirer to recognize adjustments to provisional amounts relating to a business combination that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. As a result, the acquirer is required to record, in the same period's financial statements, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. The entity is required to present separately on the face of the income statement or disclose in the notes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. The amendments are effective for public entities for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years. The amendments require prospective application to provisional amounts that occur after the effective date of the amendment and permit earlier application. The effects of our adoption of the amendments on our results of operation, financial position, or cash flows as it relates to the business combination with UIL have been disclosed in Note 4, Acquisition of UIL.

(f) Leases

In February 2016 the FASB issued new guidance that affects all companies and organizations that lease assets, and requires them to record on their balance sheet assets and liabilities for the rights and obligations created by those leases. A lease is an arrangement that conveys the right to control the use of an identified asset for a period of time in exchange for consideration. Concerning lease expense recognition, after extensive consultation, the FASB has ultimately concluded that the economics of leases can vary for a lessee, and those economics should be reflected in the financial statements. As a result, the amendments retain a distinction between finance leases and operating leases, while requiring both types of leases to be recognized on the balance sheet. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the criteria for distinguishing between capital leases and operating leases in current GAAP. By retaining a distinction between finance leases and operating leases, the effect of leases on the statement of comprehensive income and the statement of cash flows is largely unchanged from previous GAAP. Lessor accounting will remain substantially the same as current GAAP, but with some targeted improvements to align lessor accounting with the lessee accounting model and with the revised revenue recognition guidance issued in 2014. The updated guidance is effective for public entities for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, and early application is permitted. We are currently reviewing our contracts and are in the process of determining the proper application of the standard to these contracts in order to determine the impact that the adoption will have on our consolidated financial statements. We expect our adoption of the new guidance will materially affect our financial position through the recording of operating leases on the balance sheet as a right-of-use asset.

(g) Derivative contract novations

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

(h) Improvements to employee share-based payment accounting

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

(i) Measurement of credit losses on financial instruments

The FASB issued an accounting standards update in June 2016 that requires more timely recording of credit losses on loans and other financial instruments. The amendments affect entities that hold financial assets and net investment in leases that are not accounted for at fair value through net income (loans, debt securities, trade receivables, net investments in leases, off-balance-sheet credit exposures, etc.). They require an entity to present a financial asset (or group of financial assets) that is measured at amortized cost basis at the net amount expected to be collected. The allowance for credit losses is a valuation account that is deducted from the amortized cost basis of the financial asset(s) to present the net carrying value at the amount expected to be collected on the financial asset. The income statement reflects the measurement of credit losses for newly recognized financial assets, as well as the expected increases or decreases of expected credit losses that have taken place during the period. The measurement of expected credit losses is based on relevant information about past events, including historical experience, current conditions, and reasonable and supportable forecasts that affect the collectibility of the reported amount. An entity must use judgment in determining the relevant information and estimation methods appropriate in its circumstances. The amendments are effective for public entities that are SEC filers for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, with early adoption permitted. Entities are to apply the amendments on a modified retrospective basis for most instruments. We expect our adoption will not materially affect our results of operations, financial position, and cash flows.

(j) Certain classifications in the statement of cash flows

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

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

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

Use of Estimates and Assumptions

The preparation of our consolidated financial statements in conformity with U.S. GAAP requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the reporting periods. Significant estimates and assumptions are used for, but not limited to: (1) allowance for doubtful accounts and unbilled revenues; (2) asset

impairments, including goodwill; (3) depreciable lives of assets; (4) income tax valuation allowances; (5) uncertain tax positions; (6) reserves for professional, workers' compensation, and comprehensive general insurance liability risks; (7) contingency and litigation reserves; (8) fair value measurements; (9) earnings sharing mechanisms; (10) environmental remediation liabilities; and (11) AROs. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our consolidated financial statements will change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside specialists to assist in our evaluations, as necessary. Actual results could differ from those estimates.

Union collective bargaining agreements

We have approximately 48% of the employees covered by a collective bargaining agreement. Agreements which will expire within the coming year apply to approximately 6% of our employees.

Note 4. Acquisition of UIL

On December 16, 2015 (acquisition date), we completed our acquisition of UIL, a diversified energy company with its portfolio of regulated utility companies in Connecticut and Massachusetts that is expected to provide us with a greater flexibility to grow the combined regulated businesses through project development and create an enhanced platform to develop transmission and distribution projects in the Northeastern United States. In connection with the consummation of the acquisition we issued 309,490,839 shares of common stock of AVANGRID, out of which 252,234,989 shares were issued to Iberdrola through a stock dividend, accounted for as a stock split, with no change to par value, at par value of $0.01 per share, and 57,255,850 shares (including those held in trust as treasury stock) were issued to UIL shareowners in addition to payment of $595 million in cash. Following the completion of the acquisition, former UIL shareowners owned 18.5% of the outstanding shares of common stock of AVANGRID, and Iberdrola owned the remaining shares.

The acquisition was accounted for as a business combination. This method requires, among other things, that assets acquired and liabilities assumed in a business combination, with certain exceptions, be recognized at their fair values as of the acquisition date.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Merger Settlement Agreement

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

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

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

In connection with the acquisition proceeding, UI signed the consent order that, pursuant to the terms and conditions in the consent order, requires UI to investigate and remediate certain environmental conditions within the perimeter of the English Station site. To the extent that the investigation and remediation is less than $30 million, UI would remit to the State of Connecticut the difference between such costs and $30 million for a public purpose as determined in the discretion of the Governor the Attorney General of Connecticut and the Commissioner of DEEP. Pursuant to the consent order UI is obligated to comply with the consent order, even if the cost of such compliance exceeds $30 million. The state will discuss options with UI on recovering or funding any cost above $30 million such as through public funding or recovery from third parties, however it is not bound to agree to or support any means of recovery or funding (See Note 14, Environmental Liabilities – English Station, for further details).

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

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

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

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

As a result of the merger settlement agreement we have recorded $44 million as regulatory liabilities relating to the rate credits and an additional $19.8 million as liabilities, which primarily resulted in the net loss for UIL in the period following the acquisition date in 2015.

Note 5. Industry Regulation

Electricity and Natural Gas Distribution – Maine and New York

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

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

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

Each of the four Networks' New York and Maine supply companies must comply with regulatory procedures that differ in form but in all cases conform to the basic framework outlined above. Generally, tariff reviews cover various years and provide for a reasonable ROE, protection, and automatic adjustments for exceptional costs incurred and efficiency incentives.

CMP Distribution Rate Stipulation and New Renewable Source Generation

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

The rate stipulation agreement provided for an annual CMP distribution tariff increase of 10.7% or $24.3 million. The rate increase was based on a 9.45% ROE and 50% equity capital. CMP was authorized to implement a Rate Decoupling Mechanism (RDM) which protects CMP from variations in sales due to energy efficiency and weather. CMP also adjusted its storm costs recovery mechanism whereby it is allowed to collect in rates a storm allowance and to defer actual storm costs when such storm event costs exceed $3.5 million. CMP and customers share storm costs that exceed a certain balance on a fifty-fifty basis, with CMP's exposure limited to $3.0 million annually.

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

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

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

Transmission - FERC ROE Proceeding

See Note 13, Commitments and Contingent Liabilities, for a further discussion.

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

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

NYSEG and RG&E Rate Plans

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

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

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

In August 2010, NYSEG began amortizing $15.2 million per year of its $303.9 million theoretical excess depreciation reserve. On September 1, 2012, RG&E began amortizing $5.3 million per year of its $105 million theoretical excess depreciation reserve. Both amortization amounts reflect a twenty year amortization period. Theoretical excess depreciation is the difference between actual

accumulated depreciation taken to date and a theoretical reserve. The actual accumulated depreciation is the result of depreciation rates allowed in prior rate orders based on estimates of useful lives and net salvage values as determined in those cases. The theoretical reserve is the amount that would have accumulated if the depreciation rates in the new rate plan had been in place for the entire useful lives of the affected assets. Differences between the actual reserve and the theoretical reserve are normal aspects of utility ratemaking. The usual treatment is to flow any excess or deficiency back as an adjustment to depreciation expense over the remaining life of the property. However, in accordance with the new rate plan, NYSEG and RG&E moderate electric rates by recording the theoretical reserve amortization as a debit to accumulated depreciation and a credit to other revenues, and normalize a portion of the amortization from a tax perspective.

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

On February 19, 2016, NYSEG, RG&E and other signatory parties filed a Joint Proposal (proposal) with the NYPSC for a three-year rate plan for electric and gas service at NYSEG and RG&E commencing May 1, 2016. The proposal, which was approved by the NYPSC on June 15, 2016, balanced the varied interests of the signatory parties including but not limited to maintaining the companies' credit quality and mitigating the rate impacts to customers. The proposal reflects many customer benefits including: acceleration of the companies' natural gas leak prone main replacement programs and increased funding for electric vegetation management to provide continued safe and reliable service. The delivery rate increase in the proposal can be summarized as follows:

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

The allowed rate of return on common equity for NYSEG Electric, NYSEG Gas, RG&E Electric and RG&E Gas is 9.00%. The equity ratio for each company is 48%. The proposal includes an Earnings sharing mechanism (ESM) applicable to each company. The customer share of earnings would increase at higher ROE levels, with customers receiving 50%, 75% and 90% of earnings over 9.5%, 10.0% and 10.5% of ROE, respectively, in the first rate year. Earnings sharing is based on the lower of actual equity of 50%. Earnings thresholds increase in subsequent rate years.

The proposal reflects the recovery of deferred NYSEG Electric storm costs of approximately $262 million, of which $123 million is being amortized over ten years and the remaining $139 million is being amortized over five years. The proposal also continues reserve accounting for qualifying Major Storms ($21.4 million annually for NYSEG Electric and $2.5 million annually for RG&E Electric). Incremental maintenance costs incurred to restore service in qualifying divisions will be chargeable to the Major Storm Reserve provided they meet certain thresholds.

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

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

Electric and Gas regulated utilities – Connecticut and Massachusetts

The distribution rates and allowed ROEs for Networks' regulated utilities in Connecticut and Massachusetts are subject to regulation by the Connecticut Public Utilities Regulatory Authority (PURA) and the Massachusetts Department of Public Utilities (DPU), respectively.

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

UI has wholesale power supply agreements in place for its entire standard service load for the first half of 2017, 80% of its standard service load for the second half of 2017 and 20% of its standard service load for the first half of 2018. Supplier of last resort service is procured on a quarterly basis, however, from time to time there are no bidders in the procurement process for supplier of last resort service and in such cases UI manages the load directly.

In December 2016, PURA approved new distribution rate schedules for UI for three years which became effective January 1, 2017 and which, among other things, decreased the UI distribution and CTA allowed ROE from 9.15% to 9.10%, continued UI's existing earnings sharing mechanism by which UI and customers share on a 50/50 basis all distribution earnings above the allowed ROE in a calendar year, continued the existing decoupling mechanism, and approved the continuation of the requested storm reserve.

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

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

REV

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

REV is also intended to promote greater use of advanced energy management products to enhance demand elasticity and efficiencies. Track 1 of this initiative involves a collaborative process to examine the role of distribution utilities in enabling market based deployment of distributed energy resources to promote load management and greater system efficiency, including peak load reductions. NYSEG and RG&E are participating in the initiative with other New York utilities and are providing their unique perspective. The NYPSC issued a 2015 order in Track 1, which acknowledges the utilities' role as a Distribution System Platform (DSP) provider, and required the utilities to file an initial Distribution System Implementation Plan (DSIP) by June 30, 2016. The

companies filed the DSIP, which also included information regarding the potential deployment of Automated Metering Infrastructure (AMI) across its entire service territory. The companies, in December 2016, filed a petition to the NYPSC requesting approval for cost recovery associated with the full deployment of AMI, and a collaborative associated with this petition is expected to begin in the first quarter of 2017.

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

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

Ginna Reliability Support Service Agreement

Ginna Nuclear Power Plant, LLC (GNPP), which is a subsidiary of Constellation Energy Nuclear Group, LLC (CENG), owns and operates the R.E. Ginna Nuclear Power Plant (Ginna Facility and together with GNPP, Ginna), a 581 MW single-unit pressurized water reactor located in Ontario, New York. In May 2014, the New York Independent System Operator (NYISO) produced a Reliability Study, confirming that the Ginna Facility needs to remain in operation to avoid bulk transmission and non-bulk local distribution system reliability violations in 2015 and 2018. In July, 2014, GNPP filed a petition requesting that the NYPSC initiate a proceeding to examine a proposal for the continued operation of the Ginna Facility.

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

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

On October 21, 2015, RG&E, GNPP, New York Department of Public Service, Utility Intervention Unit and Multiple Intervenors filed a Joint Proposal with the NYPSC for approval of the RSSA, as modified. The Joint Proposal provides a term of the RSSA from April 1, 2015 through March 31, 2017. RG&E shall make monthly payments to Ginna in the amount of $15.4 million. RG&E will be entitled to 70% of revenues from Ginna's sales into the NYISO energy and capacity markets, while Ginna will be entitled to 30% of such revenues. The signatory parties recommend that the NYPSC authorize RG&E to implement a rate surcharge effective January 1, 2016, to recover amounts paid to Ginna pursuant to the RSSA. RG&E's payment obligation to Ginna did not begin until the rate surcharge was in effect and FERC issued an order authorizing the FERC Settlement agreement in the Settlement Docket. RG&E will use deferred rate credit amounts (regulatory liabilities) to offset the full amount of the Deferred Collection Amount (including carrying costs), plus credit amounts to offset all RSSA costs that exceed $2.3 million per month, not to exceed a total use of credits in the amount of $110 million, applicable through June 30, 2017. To the extent that the available credits are insufficient to satisfy the final payment from RG&E to Ginna then the RSSA surcharge would continue past March 31, 2017, to recover up to $2.3 million per month until the final payment has been recovered by RG&E from ratepayers. In the month following the expiration of the term on March 31, 2017, Ginna shall prepare and issue an invoice to RG&E for, and RG&E shall pay to Ginna, a one-time payment in the amount of $11.5 million, which will be recovered from ratepayers. If Ginna continues to deliver energy to the NYISO transmission system or makes available capacity to the NYISO markets after seventy-five days following March 31, 2017, Ginna shall pay RG&E a capital recovery balance in eight quarterly installments as long as Ginna is continuing to deliver energy or making available capacity throughout this period. The estimated capital recovery balance that is expected to be in place on March 31, 2017 is $20.1 million and will accrue interest unless amounts are prepaid by Ginna. The capital recovery balance will be refunded to ratepayers, to the extent collected, which is based on the term of the delivery of energy or capacity being made available by Ginna. On February 23, 2016, the

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

New York TransCo

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

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

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

Minimum Equity Requirements for Regulated Subsidiaries

Our regulated utility subsidiaries of Maine and New York (NYSEG, RG&E, CMP and MNG) are each subject to a minimum equity ratio requirement that is tied to the capital structure assumed in establishing revenue requirements. Pursuant to these requirements, each of NYSEG, RG&E, CMP and MNG must maintain a minimum equity ratio equal to the ratio in its currently effective rate plan or decision measured using a trailing 13-month average. On a monthly basis, each utility must maintain a minimum equity ratio of no less than 300 basis points below the equity ratio used to set rates. The minimum equity ratio requirement has the effect of limiting the amount of dividends that may be paid and may, under certain circumstances, require that the parent contribute equity capital. The regulated utility subsidiaries are prohibited by regulation from lending to unregulated affiliates. The regulated utility subsidiaries have also agreed to minimum equity ratio requirements in certain borrowing agreements. These requirements are lower than the regulatory requirements.

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

We had restricted net assets of approximately $4,291 million associated with the minimum equity requirements as of December 31, 2016.

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

New Renewable Source Generation

Under Connecticut law Public Act (PA 11-80), Connecticut electric utilities are required to enter into long-term contracts to purchase Connecticut Class I Renewable Energy Certificates, or RECs, from renewable generators located on customer premises. Under this

program, UI is required to enter into contracts totaling approximately $200 million in commitments over an approximate 21-year period. The obligations will phase in over a six-year solicitation period, and are expected to peak at an annual commitment level of about $13.6 million per year after all selected projects are online. Upon purchase, UI accounts for the RECs as inventory. UI expects to partially mitigate the cost of these contracts through the resale of the RECs. PA 11-80 provides that the remaining costs (and any benefits) of these contracts, including any gain or loss resulting from the resale of the RECs, are fully recoverable from (or credited to) customers through electric rates.

On October 23, 2013, PURA approved UI's renewable connections program filed in accordance with PA 11-80, through which UI will develop up to 10 MW of renewable generation. The costs for this program will be recovered on a cost of service basis. PURA established a base ROE to be calculated as the greater of: (A) the current UI authorized distribution ROE (currently 9.10%) plus 25 basis points and (B) the current authorized distribution ROE for Connecticut Light and Power Company, or CL&P (currently 9.17%), less target equivalent market revenues (reflected as 25 basis points). In addition, UI will retain a percentage of the market revenues from the project, which percentage is expected to equate to approximately 25 basis points on a levelized basis over the life of the project. UI expects the cost of this program, a planned 2.8 MW fuel cell facility in New Haven, solar photovoltaic and fuel cell facilities totaling 5 MW in Bridgeport, and a 2.2 MW fuel cell facility in Woodbridge to be approximately $47 million.

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

Equity Investment in Peaking Generation

UI is party to a 50-50 joint venture with NRG affiliates in GenConn, which operates two peaking generation plants in Connecticut. The two peaking generation plants, GenConn Devon and GenConn Middletown, are both participating in the ISO-New England markets. PURA has approved revenue requirements for the period from January 1, 2017 through December 31, 2017 of $28.8 million and $35.7 million for GenConn Devon and GenConn Middletown, respectively. PURA has ruled previously that GenConn project capital costs incurred were prudently incurred. Such costs are included in the 2017 approved revenue requirements.

Note 6. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations, our utilities capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric and natural gas rates. We base our assessment of whether recovery is probable on the existence of regulatory orders that allow for recovery of certain costs over a specific period, or allow for reconciliation or deferral of certain costs. When costs are not treated in a specific order we use regulatory precedent to determine if recovery is probable. Our operating utilities also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs. Substantially all assets or liabilities for which funds have been expended or received are either included in the rate base or are accruing a carrying cost until they will be included in the rate base. The primary items that are not included in the rate base or accruing carrying costs are the regulatory assets for qualified pension and other postretirement benefits, which reflect unrecognized actuarial gains and losses, debt premium, environmental remediation costs which is primarily the offset of accrued liabilities for future spending, unfunded future income taxes, which are the offset to the unfunded future deferred income tax liability recorded, asset retirement obligations, hedge losses and contracts for differences. The total amount of these items is approximately $2,357 million.

Regulatory assets and other regulatory liabilities shown in the tables below result from various regulatory orders that allow for the deferral and/or reconciliation of specific costs. Regulatory assets and regulatory liabilities are classified as current when recovery or refund in the coming year is allowed or required through a specific order or when the rates related to a specific regulatory asset or regulatory liability are subject to automatic annual adjustment.

On June 15, 2016, the NYPSC approved the proposal in connection with a three-year rate plan for electric and gas service at NYSEG and RG&E effective May 1, 2016. Following the approval of the proposal most of these items related to NYSEG are amortized over a five-year period, except the portion of storm costs to be recovered over ten years, and plant related tax items which are amortized over the life of associated plant. Annual amortization expense for NYSEG is approximately $16.5 million per rate year. RG&E items that are being amortized are plant related tax items, which are amortized over the life of associated plant, and unfunded deferred taxes being amortized over a period of fifty years. A majority of the other items related to RG&E, which net to a regulatory liability, remains deferred and will not be amortized until future proceedings or will be used to recover costs of the Ginna RSSA. Following the approval of the proposal by the NYPSC, unfunded future income taxes were adjusted for the amount of $126 million to reflect the

change from a flow through to normalization method, which has been recorded as an increase to income tax expense and an offsetting increase to revenue, during the year ended December 31, 2016. The amounts will be collected over a period of fifty years.

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

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

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

"Storm costs" for CMP, NYSEG, and RG&E are allowed in rates based on an estimate of the routine costs of service restoration. The companies are also allowed to defer unusually high levels of service restoration costs resulting from major storms when they meet certain criteria for severity and duration. The portion of storm costs for the amount of $123 million is being recovered over ten-year period and the remaining portion is being amortized over five years following the approval of the proposal by the NYPSC. CMP's total deferral, including carrying costs, was $2 million and $12 million as of December 31, 2016 and 2015, respectively. UI is allowed to defer costs associated with any storm totaling $1 million or greater for future recovery. UI's storm regulatory asset balance was $0 as of December 31, 2016.

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

"Unamortized losses on reacquired debt" represent deferred losses on debt reacquisitions that will be recovered over the remaining original amortization period of the reacquired debt.

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

"Unfunded future income taxes" represent unrecovered federal and state income taxes primarily resulting from regulatory flow through accounting treatment and are the offset to the unfunded future deferred income tax liability recorded. The income tax benefits or charges for certain plant related timing differences, such as removal costs, are immediately flowed through to, or collected from, customers. This amount is being amortized as the amounts related to temporary differences that give rise to the deferrals are recovered in rates. Following the approval of the proposal by the NYPSC, these amounts will be collected over a period of fifty years and the NYPSC Staff will perform an audit of the unfunded future income taxes and other tax assets to verify the balances.

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

"Deferred property taxes" represents the customer portion of the difference between actual expense for property taxes and the amount provided for in rates. The New York (NY) amount is being amortized over a five year period following the approval of the proposal by the NYPSC.

"Federal tax depreciation normalization adjustment" represents the revenue requirement impact of the difference in the deferred income tax expense required to be recorded under the IRS normalization rules and the amount of deferred income tax expense that was included in cost of service for rates years covering 2011 forward. The recovery period in NY is from 27 to 39 years and for CMP this will be determined in future Maine Public Utility Commission (MPUC) rate proceedings.

"Debt premium" represents the regulatory asset recorded to offset the fair value adjustment to the regulatory component of the non-current debt of UIL at the acquisition date. This amount is being amortized to interest expense over the remaining term of the related outstanding debt instruments.

"Hardship Programs" represent hardship customer accounts deferred for future recovery to the extent they exceed the amount in rates.

"Deferred Purchased Gas" represents the difference between actual gas costs and gas costs collected in rates.

"Contracts for Differences" represent the deferral of unrealized gains and losses on contracts for differences derivative contracts. The balance fluctuates based upon quarterly market analysis performed on the related derivatives. The amounts, which do not earn a return, are fully offset by a corresponding derivative asset/liability.

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

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

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

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

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

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

“Accrued removal obligations” represent the differences between asset removal costs recorded and amounts collected in rates for those costs. The amortization period is dependent upon the asset removal costs of underlying assets and the life of the utility plant.

“Asset sale gain account” represents the gain on NYSEG’s 2001 sale of its interest in Nine Mile Point 2 nuclear generating station. The net proceeds from the Nine Mile Point 2 nuclear generating station were placed in this account and will be used to benefit customers. The amortization period is five years following the approval of the proposal by the NYPSC.

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

“Economic development” represents the economic development program which enables NYSEG and RG&E to foster economic development through attraction, expansion, and retention of businesses within its service territory. If the level of actual expenditures for economic development allocated to NYSEG and RG&E varies in any rate year from the level provided for in rates, the difference is refunded to ratepayers. The amortization period is five years following the approval of the proposal by the NYPSC.

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

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

“Positive benefit adjustment” resulted from Iberdrola’s 2008 acquisition of Energy East. This is being used to moderate increases in rates. The amortization period is five years following the approval of the proposal by the NYPSC and included in the Ginna RSSA settlement.

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

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

“Theoretical reserve flow thru impact” represents the differences from the rate allowance for applicable federal and state flow through impacts related to the excess depreciation reserve amortization. It also represents the carrying cost on the differences. The amortization period is five years following the approval of the proposal by the NYPSC.

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

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

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

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

Note 7. Goodwill and Intangible assets

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

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

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

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

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

Goodwill Impairment Assessment

For impairment testing purposes our reporting units are the same as operating segments, except for Networks, which contained three reporting units, Maine, New York and UIL. The goodwill for the Maine reporting unit resulted from the purchase of CMP by Energy East in 2000 and amounted to $325 million. Separately, the goodwill for the New York reporting unit resulted primarily from the purchase of RG&E by Energy East in 2002 and amounted to $654 million. The goodwill for the UIL reporting unit was generated from the acquisition of UIL on December 16, 2015 and amounted to $1,765 million as of December 31, 2016, based on the finalized valuation of assets acquired and liabilities assumed.

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

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

2016

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

Networks

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

Renewables

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

2015

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

Networks

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

Renewables

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

Intangible assets

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

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

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

Gas Storage rights are being amortized on a straight-line basis over a 40-year estimated life. Wind development costs, with the exception of future 'pipeline' development costs, are amortized on a straight-line basis in accordance with the life of the related assets. Amortization expense for the years ended December 31, 2016, 2015 and 2014 amounted to $25 million, $54 million and $66 million, respectively. We believe our future cash flows will support the recoverability of our intangible assets.

We expect amortization expense for the five years subsequent to December 31, 2016, to be as follows:

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

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

Note 8. Property, Plant and Equipment

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

As of December 31, 2016	Regulated	Nonregulated	Total
(Millions)			
Electric generation, distribution, transmission and other	$ 10,343	$ 10,384	$ 20,727
Natural gas transportation, distribution and other	4,803	613	5,416
Other common operating property	877	43	920
Total Property, Plant and Equipment in Service (a)	**16,023**	**11,040**	**27,063**
Total accumulated depreciation (b)	(3,970)	(3,016)	(6,986)
Total Net Property, Plant and Equipment in Service	**12,053**	**8,024**	**20,077**
Construction work in progress	979	492	1,471
Total Property, Plant and Equipment	**$ 13,032**	**$ 8,516**	**$ 21,548**

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

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

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

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

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

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

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

Note 9. Asset retirement obligations

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

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

(Millions)	
As of December 31, 2014	**$ 234**
Liabilities settled during the year	(16)
Liabilities incurred during the year	—
Accretion expense	14
Revisions in estimated cash flows	(48)
As of December 31, 2015	**$ 184**
Liabilities settled during the year	(7)
Liabilities incurred during the year	3
Accretion expense	10
Revisions in estimated cash flows	(29)
As of December 31, 2016	**$ 161**

Several of the wind generation facilities have restricted cash for purposes of settling AROs. Restricted cash related to AROs was $2.0 million and $1.8 million as of December 31, 2016 and 2015, respectively. These amounts have been included as other non-current assets in the consolidated balance sheets. Accretion expenses are included in “Operations and maintenance” in the consolidated statements of income.

We have AROs for which a liability has not been recognized because the fair value cannot be reasonably estimated due to indeterminate settlement dates, including for the removal of hydroelectric dams due to structural inadequacy or for decommissioning;

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

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

Note 10. Debt

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

As of December 31,		2016		2015	
(Millions)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
First mortgage bonds - fixed (a)	2018-2045	$ 1,752	3.07%-10.60%	$ 1,815	3.07%-10.60%
Unsecured pollution control notes - fixed	2020	200	2.00%-2.375%	200	2.00%-2.375%
Unsecured pollution control notes – variable	2032	62	1.32%	219	0.195%-1.181%
Other various non-current debt - fixed	2017-2045	2,772	2.89%-10.48%	2,440	2.89%-10.48%
Obligations under capital leases	2017-2023	104	4%-4.44%	87	4%-4.44%
Unamortized debt issuance costs and discount		(31)		(25)	
Total Debt		**4,859**		**4,736**	
Less: debt due within one year, included in current liabilities		349		206	
Total Non-current Debt		**$ 4,510**		**$ 4,530**	

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

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

On December 19, 2016, AVANGRID, its subsidiary, UIL, and The Bank of New York Mellon, entered into a supplemental indenture, pursuant to which AVANGRID assumed from UIL all the obligations under the indenture dated as of October 7, 2010 between UIL and The Bank of New York Mellon and all obligations relating to $450 million in aggregate principal amount of 4.625% notes due 2020 issued by the predecessor company to UIL in 2010.

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

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

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

We make certain standard covenants to lenders in our third-party debt agreements, including, in certain agreements, covenants regarding the ratio of indebtedness to total capitalization. A breach of any covenant in the existing credit facilities or the agreements governing our other indebtedness would result in an event of default. Certain events of default may trigger automatic acceleration. Other events of default may be remedied by the borrower within a specified period or waived by the lenders and, if not remedied or waived, give the lenders the right to accelerate. Neither we nor any of our subsidiaries were in breach of covenants or of any obligation that could trigger the early redemption of our debt as of December 31, 2016 and 2015.

Fair Value of Debt

The estimated fair value of debt amounted to $5,204 million and $4,985 million as of December 31, 2016 and 2015, respectively. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the electricity industry and the credit ratings of the borrowers in each case. The fair value hierarchy pertaining to the fair value of debt is considered as Level 2, except for unsecured pollution control notes-variable with a fair value of $61 million and $204 million as of December 31, 2016 and 2015, respectively, which are considered Level 3. The fair value of these unsecured pollution control notes-variable are determined using unobservable interest rates as the market for these notes is inactive.

Short-term Debt

Outstanding Notes Payable

AVANGRID had $161 million and $163 million of notes payable as of December 31, 2016 and 2015, respectively. As of December 31, 2015, the balance consisted of $160 million of borrowings under the UIL credit facility and $3 million in other notes payable. As of December 31, 2016 the balance consisted of $150 million of commercial paper, $10 million in notes payable to affiliates and $1 million in other notes payable. AVANGRID's commercial paper program was established on May 13, 2016, has a limit of $1 billion and is backstopped by the AVANGRID credit facility described below.

AVANGRID Credit Facility

On April 5, 2016, AVANGRID and its subsidiaries, NYSEG, RG&E, CMP, UI, CNG, SCG and BGC entered into a revolving credit facility with a syndicate of banks, or the AVANGRID credit facility, that provides for maximum borrowings of up to $1.5 billion in the aggregate.

Under the terms of the AVANGRID credit facility, each joint borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit established by the banks. AVANGRID's maximum sublimit is $1 billion, NYSEG, RG&E, CMP and UI have maximum sublimits of $250 million, CNG, and SCG have maximum sublimits of $150 million and BGC has a maximum sublimit of $25 million. Under the AVANGRID credit facility, each of the borrowers will pay an annual facility fee that is dependent on their credit rating. The facility fees will range from 10.0 to 17.5 basis points. The maturity date for the AVANGRID credit facility is April 5, 2021.

As a condition of closing on the AVANGRID credit facility, three existing credit facilities were terminated: the AVANGRID revolving credit facility, which provided for maximum borrowings of up to $300M and had a scheduled termination date in May 2019; the joint utility revolving credit facility, to which NYSEG, RG&E and CMP were parties, which provided for borrowings of up to $600 million and which had a scheduled termination date in July 2018; the UIL credit facility, to which UIL, UI, SCG, CNG and BG were parties, which provided for maximum borrowings of $400 million and which had a scheduled termination date in November 2016.

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

Note 11. Fair Value of Financial Instruments and Fair Value Measurements

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

- We measure the fair value of our noncurrent investments using quoted market prices in active markets for identical assets and include the measurements in Level 1. The available for sale investments which are Rabbi Trusts for deferred compensation plans primarily consist of money market funds and are included in Level 1 fair value measurement.
- NYSEG and RG&E enter into electric energy derivative contracts to hedge the forecasted purchases required to serve their electric load obligations. They hedge their electric load obligations using derivative contracts that are settled based upon Locational Based Marginal Pricing published by the New York Independent System Operator (NYISO). RG&E hedges all its electric load obligations using contracts for a NYISO location where an active market exists. The forward market prices used to value RG&E's open electric energy derivative contracts are based on quoted prices in active markets for identical assets or liabilities with no adjustment required and therefore we include the fair value in Level 1. NYSEG has a combination of Level 1 and Level 2 fair values for its electric energy derivative contracts. A portion of its electric load obligations are exchange traded contracts in a NYISO location where an active market exists. The forward market prices used to value NYSEG's open electric energy derivative contracts are based on quoted prices in active markets for identical assets or liabilities with no adjustment required and therefore we include the fair value in Level 1. A portion of NYSEG's electric energy derivative contracts are non-exchange traded contracts that are valued using inputs that are directly observable for the asset or liability, or indirectly observable through corroboration with observable market data and therefore we include the fair value in Level 2.
- NYSEG and RG&E enter into natural gas derivative contracts to hedge their forecasted purchases required to serve their natural gas load obligations. The forward market prices used to value open natural gas derivative contracts are exchange-based prices for the identical derivative contracts traded actively on the New York Mercantile Exchange (NYMEX). Because we use prices quoted in an active market we include the fair value measurements in Level 1.
- NYSEG, RG&E and CMP enter into fuel derivative contracts to hedge their unleaded and diesel fuel requirements for their fleet vehicles. Exchange-based forward market prices are used but because an unobservable basis adjustment is added to the forward prices we include the fair value measurement for these contracts in Level 3.
- Contracts for differences (CfDs) entered into by UI are marked-to-market based on a probability-based expected cash flow analysis that is discounted at risk-free interest rates and an adjustment for non-performance risk using credit default swap rates. We include the fair value measurement for these contracts in Level 3 (See Note 12 for further discussion on CfDs).

We determine the fair value of our derivative assets and liabilities associated with Renewables and Gas activities utilizing market approach valuation techniques. Exchange-traded transactions, such as NYMEX futures contracts, that are based on quoted market prices in active markets for identical product with no adjustment are included in the Level 1 fair value. Contracts with delivery periods of two years or less which are traded in active markets and are valued with or derived from observable market data for identical or similar products such as over-the-counter NYMEX, foreign exchange swaps, and fixed price physical and basis and index trades are included in Level 2 fair value. Contracts with delivery periods exceeding two years or that have unobservable inputs or inputs that cannot be corroborated with market data for identical or similar products are included in Level 3 fair value. The unobservable inputs include historical volatilities and correlations for tolling arrangements and extrapolated values for certain power swaps. The valuation for this category is based on our judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists.

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

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

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

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

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

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

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

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

Level 3 Fair Value Measurement

The tables below illustrate the significant sources of unobservable inputs used in the fair value measurement of our Level 3 derivatives, and the variability in prices for those transactions classified as Level 3 derivatives.

As of December 31, 2016							
Instruments	Instrument Description	Valuation Technique	Valuation Inputs	Index	Avg.	Max.	Min.
Fixed price power and gas swaps with delivery period > two years	Transactions with delivery periods exceeding two years	Transactions are valued against forward market prices on a discounted basis	Observable and extrapolated forward gas and power prices not all of which can be corroborated by market data for identical or similar products	NYMEX ($/MMBtu)	$ 4.27	$ 7.37	$ 1.64
				SP15 ($/MWh)	$ 44.23	$ 80.28	$ 14.25
				Mid C ($/MWh)	$ 35.44	$ 83.93	$ 3.60
				Cinergy ($/MWh)	$ 36.40	$ 77.49	$ 18.53

Our Level 3 valuations primarily consist of NYMEX gas and fixed price power swaps with delivery periods extending through 2024 and 2032, respectively. The gas swaps are used to hedge both gas inventory in firm storage and merchant wind positions. The power swaps are used to hedge merchant wind production in the West and Midwest.

We performed a sensitivity analysis around the Level 3 gas and power positions to changes in the valuation inputs. Given the nature of the transactions in Level 3, the only material input to the valuation is the market price of gas or power for transactions with delivery periods exceeding two years. The fixed price power swaps are economic hedges of future power generation, with decreases in power prices resulting in unrealized gains and increases in power prices resulting in unrealized losses. The gas swaps are economic hedges of gas storage inventory and merchant generation, with decreases in gas prices resulting in unrealized gains and increases in gas prices resulting in unrealized losses. As all transactions are economic hedges of the underlying position, any changes in the fair value of these transactions will be offset by changes in the anticipated purchase/sales price of the underlying commodity.

Two elements of the analytical infrastructure employed in valuing transactions are the price curves used in calculation of market value and the models themselves. We maintain and document authorized trading points and associated forward price curves, and we develop and document models used in valuation of the various products.

Transactions are valued in part on the basis of forward price, correlation, and volatility curves. We maintain and document descriptions of these curves and their derivations. Forward price curves used in valuing the transactions are applied to the full duration of the transaction.

The determination of fair value of the CfDs (see Note 12 for further details on CfDs) was based on a probability-based expected cash flow analysis that was discounted at risk-free interest rates, as applicable, and an adjustment for non-performance risk using credit default swap rates. Certain management assumptions were required, including development of pricing that extended over the term of the contracts. We believe this methodology provides the most reasonable estimates of the amount of future discounted cash flows associated with the CfDs. Additionally, on a quarterly basis, we perform analytics to ensure that the fair value of the derivatives is consistent with changes, if any, in the various fair value model inputs. Significant isolated changes in the risk of non-performance, the discount rate or the contract term pricing would result in an inverse change in the fair value of the CfDs. Additional quantitative information about Level 3 fair value measurements of the CfDs is as follows:

Unobservable Input	Range at December 31, 2016
Risk of non-performance	0.68% - 0.81%
Discount rate	1.47% - 2.45%
Forward pricing ($ per MW)	$3.15 - $9.55

Note 12. Derivative Instruments and Hedging

Our Networks, Renewables and Gas activities are exposed to certain risks, which are managed by using derivative instruments. All derivative instruments are recognized as either assets or liabilities at fair value on the consolidated balance sheets in accordance with the accounting requirements concerning derivative instruments and hedging activities.

(a) Networks activities

NYSEG and RG&E have an electric commodity charge that passes through rates costs for the market price of electricity. They use electricity contracts, both physical and financial, to manage fluctuations in electricity commodity prices in order to provide price stability to customers. We include the cost or benefit of those contracts in the amount expensed for electricity purchased when the related electricity is sold. We record changes in the fair value of electric hedge contracts to derivative assets and / or liabilities with an offset to regulatory assets and / or regulatory liabilities, in accordance with the accounting requirements concerning regulated operations.

The amount recognized in regulatory assets for electricity derivatives was a loss of $12.3 million and $34.3 million as of December 31, 2016 and 2015, respectively. The loss reclassified from regulatory assets into income, which is included in electricity purchased, was $66.7 million, $46.9 million, and $21.3 million for the years ended December 31, 2016, 2015 and 2014, respectively.

NYSEG and RG&E have purchased gas adjustment clauses that allow them to recover through rates any changes in the market price of purchased natural gas, substantially eliminating their exposure to natural gas price risk. NYSEG and RG&E use natural gas futures and forwards to manage fluctuations in natural gas commodity prices to provide price stability to customers. We include the cost or benefit of natural gas futures and forwards in the commodity cost that is passed on to customers when the related sales commitments are fulfilled. We record changes in the fair value of natural gas hedge contracts to derivative assets and or liabilities with an offset to regulatory assets and or regulatory liabilities in accordance with the accounting requirements for regulated operations.

The amount recognized in regulatory assets for natural gas hedges was a gain of $3.5 million and a loss of $3.1 million as of December 31, 2016 and 2015, respectively. The loss reclassified from regulatory assets into income, which is included in natural gas purchased, was $1.9 million, $6.3 million, and $2.2 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Pursuant to PURA, UI and Connecticut's other electric utility, CL&P, each executed two long-term CfDs with certain incremental capacity resources, each of which specifies a capacity quantity and a monthly settlement that reflects the difference between a forward market price and the contract price. The costs or benefits of each contract will be paid by or allocated to customers and will be subject to a cost-sharing agreement between UI and CL&P pursuant to which approximately 20% of the cost or benefit is borne by or allocated to UI customers and approximately 80% is borne by or allocated to CL&P customers.

PURA has determined that costs associated with these CfDs will be fully recoverable by UI and CL&P through electric rates, and UI has deferred recognition of costs (a regulatory asset) or obligations (a regulatory liability). For those CfDs signed by CL&P, UI records its approximate 20% portion pursuant to the cost-sharing agreement noted above. As of December 31, 2016, UI has recorded a gross derivative asset of $19 million ($0 of which is related to UI's portion of the CfD signed by CL&P), a regulatory asset of $75 million, a gross derivative liability of $95 million ($70 million of which is related to UI's portion of the CfD signed by CL&P) and a regulatory liability of $0. As of December 31, 2015, UI has recorded a gross derivative asset of $29 million ($1 million of which is

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

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

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

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

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

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

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

As of December 31, 2015 (Millions)	Current Assets	Noncurrent Assets	Current Liabilities	Noncurrent Liabilities
Not designated as hedging instruments				
Derivative assets	$ 11	$ 18	$ —	$ —
Derivative liabilities	—	—	(28)	(68)
	11	18	(28)	(68)
Designated as hedging instruments				
Derivative assets	3	6	3	6
Derivative liabilities	(3)	(6)	(42)	(7)
	—	—	(39)	(1)
Total derivatives before offset of cash collateral	11	18	(67)	(69)
Cash collateral receivable	—	—	37	—
Total derivatives as presented in the balance sheet	$ 11	$ 18	$ (30)	$ (69)

The effect of derivatives in cash flow hedging relationships on OCI and income for the years ended December 31, 2016, 2015 and 2014, respectively, consisted of:

Year Ended December 31,	(Loss) Recognized in OCI on Derivatives	Location of Loss Reclassified from Accumulated OCI into Income	Loss Reclassified from Accumulated OCI into Income
(Millions)	Effective Portion (a)	Effective Portion (a)	
2016			
Interest rate contracts	$ —	Interest expense	$ 8
Commodity contracts	—	Operating expenses	2
Total	**$ —**		**$ 10**
2015			
Interest rate contracts	$ —	Interest expense	$ 9
Commodity contracts	(3)	Operating expenses	3
Total	**$ (3)**		**$ 12**
2014			
Interest rate contracts	$ —	Interest expense	$ 9
Commodity contracts	(4)	Operating expenses	1
Total	**$ (4)**		**$ 10**

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

The net loss in accumulated OCI related to previously settled forward starting swaps and accumulated amortization is $76.7 million, $84.9 million, and $93.5 million for the years ended December 31, 2016, 2015 and 2014, respectively. We recorded $8.0 million, $8.6 million, and $8.9 million in net derivative losses related to discontinued cash flow hedges for the years ended December 31, 2016, 2015 and 2014, respectively. We will amortize approximately $8.0 million of discontinued cash flow hedges in 2017. During the years ended December 31, 2016, 2015 and 2014, there was no ineffective portion for cash flow hedges.

The unrealized loss of $0.4 million on hedge derivatives is reported in OCI because the forecasted transaction is considered to be probable as of December 31, 2016. We expect that $0.4 million of those losses will be reclassified into earnings within the next twelve months. The maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted fleet fuel transactions is twelve months.

(b) Renewables and Gas activities

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

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

Both Renewables and Gas have proprietary trading operations that enter into fixed-price power and gas forwards in addition to basis swaps. The intent is to speculate on fixed-price commodity and basis volatility in the U.S. commodity markets.

Renewables will periodically designate derivative contracts as cash flow hedges for both its thermal and wind portfolios. To the extent that the derivative contracts are effective in offsetting the variability of cash flows associated with future power sales and gas purchases, the fair value changes are recorded in OCI. Any hedge ineffectiveness is recorded in current period earnings. For thermal operations, Renewables will periodically designate both fixed price NYMEX gas contracts and AECO basis swaps that hedge the fuel requirements of its Klamath facility. Renewables will also designate fixed price power swaps at various locations in the U.S. market to hedge future power sales from its Klamath facility and various wind farms.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Amounts will be reclassified from accumulated OCI into income in the period during which the transaction being hedged affects earnings or when it becomes probable that a forecasted transaction being hedged would not occur. Notwithstanding future changes in prices, approximately $13.6 million of losses included in accumulated OCI at December 31, 2016 is expected to be reclassified into earnings within the next 12 months. During the years ended December 31, 2016 and 2015, we recorded a net loss of $6.8 million and a net gain $4.8 million, respectively, in earnings as a result of ineffectiveness from cash flow hedges. We recorded $0.4 million and $2.3 million in net derivative gain related to discontinued cash flow hedge for the years ended December 31, 2016 and 2015.

(c) Counterparty credit risk management

NYSEG and RG&E face risks related to counterparty performance on hedging contracts due to counterparty credit default. We have developed a matrix of unsecured credit thresholds that are dependent on the counterparty's or the counterparty's guarantor's applicable credit rating, normally Moody's or Standard & Poor's. When our exposure to risk for a counterparty exceeds the unsecured credit threshold, the counterparty is required to post additional collateral or we will no longer transact with the counterparty until the exposure drops below the unsecured credit threshold.

The wholesale power supply agreements of UI contain default provisions that include required performance assurance, including certain collateral obligations, in the event that UI's credit rating on senior debt were to fall below investment grade. If such an event had occurred as of December 31, 2016, UI would have had to post an aggregate of approximately $12.8 million in collateral.

We have various master netting arrangements in the form of multiple contracts with various single counterparties that are subject to contractual agreements that provide for the net settlement of all contracts through a single payment. Those arrangements reduce our exposure to a counterparty in the event of default on or termination of any single contract. For financial statement presentation purposes, we offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement. The amounts of cash collateral under master netting arrangements that have not been offset against net derivative positions were $20 million and $11 million as of December 31, 2016 and 2015, respectively. Derivative instruments settlements and collateral payments are included in "Other assets" and "Other liabilities" of operating activities in the consolidated statements of cash flows.

Certain of our derivative instruments contain provisions that require us to maintain an investment grade credit rating on our debt from each of the major credit rating agencies. If our debt were to fall below investment grade, we would be in violation of those provisions and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit risk related contingent features that are in a liability position as of December 31, 2016 is $12 million, for which we have posted collateral.

Note 13. Commitments and Contingent Liabilities

We are party to various legal disputes arising as part of our normal business activities. We do not provide for accrual of legal costs expected to be incurred in connection with a loss contingency.

MNG Rate Case

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

On May 3, 2016, all active parties to the case filed a stipulation that settled all matters at issue in the case and reflected a 10-year rate plan through April 30, 2026. The MPUC approved the stipulation on May 17, 2016, for new rates effective June 1, 2016. The settlement structure for non-Augusta customers includes a 34.6% delivery revenue increase over five years with an allowed 9.55% ROE and 50% common equity ratio. The settlement structure for Augusta customers includes a 10-year rate plan with existing Augusta customers being charged rates equal to non-Augusta customers plus a surcharge that increases annually for five years. New Augusta customers will have rates set based on an alternate fuel market model. In year seven of the rate plan MNG will submit a cost of service filing for the Augusta area to determine if the rate plan should continue. This cost of service filing will exclude $15 million of initial 2012/2013 gross plant investment, however the stipulation allows for accelerated depreciation of these assets. If the Augusta area's cost of service filing illustrates results above a 14.55% ROE then the rate plan may cease, otherwise the rate plan would continue. A disallowance for the initial 2012/2013 gross plant investment is not part of the approved stipulation. The reserve of $6 million for this case was reversed in May 2016.

Transmission - ROE Complaint – CMP and UI

On September 30, 2011, the Massachusetts Attorney General, Massachusetts Department of Public Utilities, Connecticut Public Utilities Regulatory Authority, New Hampshire Public Utilities Commission, Rhode Island Division of Public Utilities and Carriers, Vermont Department of Public Service, numerous New England consumer advocate agencies and transmission tariff customers collectively filed a complaint (Complaint I) with the FERC pursuant to sections 206 and 306 of the Federal Power Act. The filing parties seek an order from the FERC reducing the 11.14% base return on equity used in calculating formula rates for transmission service under the ISO-New England Open Access Transmission Tariff (OATT) to 9.2%. CMP and UI are New England Transmission Owners (NETOs) with assets and service rates that are governed by the OATT and will thereby be affected by any FERC order resulting from the filed complaint.

On June 19, 2014, the FERC issued its decision in Complaint I, establishing a methodology and setting an issue for a paper hearing. On October 16, 2014, FERC issued its final decision in the Complaint I setting the base ROE at 10.57%, and a maximum total ROE of 11.74% (base plus incentive ROE) for the October 2011 – December 2012 period as well as prospectively from October 16, 2014 and ordered the NETOs to file a refund report. On November 17, 2014 the NETOs filed a refund report.

On March 3, 2015, the FERC issued an order on requests for rehearing of its October 16, 2014 decision. The March order upheld the FERC's June 19, 2014 decision and further clarified that the 11.74% ROE cap will be applied on a project specific basis and not on a transmission owner's total average return. In June 2015 the NETOs filed an appeal in the U.S. Court of Appeals for the District of Columbia of the FERC's final order. The appeal is currently pending, and we cannot predict the outcome of this appeal.

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

On July 31, 2014, a third, ROE complaint (Complaint III) was filed for a subsequent rate period requesting the ROE be reduced to 8.84%. On November 24, 2014, FERC accepted the Complaint III, established a 15-month refund effective date of July 31, 2014, and set this matter consolidated with Complaint II for hearing in June 2015. Hearings were held in June 2015 on Complaints II and III before a FERC Administrative Law Judge, relating to the refund periods and going forward period. On July 29, 2015, post-hearing briefs were filed by parties and on August 26, 2015 reply briefs were filed by parties. On July 13, 2015, the NETOs filed a petition for review of FERC's orders establishing hearing and consolidation procedures for Complaints II and III with the U.S. Court of Appeals. The FERC Administrative Law Judge issued an Initial Decision on March 22, 2016. The Initial Decision determined that: (1) for the 15-month refund period in Complaint II, the base ROE should be 9.59% and that the ROE Cap (base ROE plus incentive ROEs) should be 10.42% and (2) for the 15 month refund period in Complaint III and prospectively, the base ROE should be 10.90% and that the ROE Cap should be 12.19%. The Initial Decision is the Administrative Law Judge's recommendation to the FERC Commissioners. The FERC is expected to make its final decision in mid-2017.

CMP and UI reserved for refunds for Complaints I, II and III consistent with the FERC's March 3, 2015 final decision in Complaint I. The CMP and UI total reserve associated with Complaints I, II and III is $21.6 million and $4.4 million, respectively, as of December 31, 2016. If adopted as final, the impact of the initial decision would be an additional aggregate reserve for Complaints II and III of $17.1 million, which is based upon currently available information for these proceedings. We cannot predict the outcome of the Complaint II and III proceedings.

On April 29, 2016, a fourth ROE complaint (Complaint IV) was filed for a rate period subsequent to prior complaints requesting the base ROE be 8.61% and ROE Cap be 11.24%. The NETOs filed a response to the Complaint IV on June 3, 2016. On September 20, 2016, FERC accepted the Complaint IV, established a 15-month refund effective date of April 29, 2016, and set the matter for hearing and settlement judge procedures. A range of possible outcomes is not able to be determined at this time due to the preliminary state of this matter. We cannot predict the outcome of the Complaint IV proceeding. Hearings are being held later this year with an expected Initial Decision from the Administrative Law Judge in 2017.

Yankee Nuclear Spent Fuel Disposal Claim

CMP has an ownership interest in Maine Yankee Atomic Power Company, Connecticut Yankee Atomic Power Company, and Yankee Atomic Electric Company, (the Yankee Companies), three New England single-unit decommissioned nuclear reactor sites, and UI has an ownership interest in Connecticut Yankee Atomic Power Company. Every six years, pursuant to the statute of limitations, the Yankee Companies file a lawsuit to recover damages from the Department of Energy (DOE or Government) for breach of the Nuclear Spent Fuel Disposal Contract to remove Spent Nuclear Fuel (SNF) and Greater than Class C Waste (GTCC) as required by contract

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

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

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

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

NYPSC Staff Review of Earnings Sharing Calculations and Other Regulatory Deferrals

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

California Energy Crisis Litigation

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

Joining with two other parties, Renewables filed a petition for certiorari in the United States Supreme Court on May 3, 2007. In an order entered on June 27, 2008, the Supreme Court granted Renewables' petition for certiorari, vacated the appellate court's judgment, and remanded the case to the appellate court for further consideration in light of the Supreme Court's decision in a similar case. In light of the Supreme Court's order, on December 4, 2008, the Ninth Circuit Court of Appeals vacated its prior opinion and remanded the complaint proceedings to the FERC for further proceedings consistent with the Supreme Court's rulings. In 2014 FERC assigned an administrative law judge to conduct evidentiary hearings. Following discovery, the FERC Trial Staff recommended that the complaint against Renewables be dismissed.

A hearing was held before an administrative law judge of FERC in November and early December 2015. A preliminary proposed ruling by the administrative law judge was issued on April 12, 2016. The proposed ruling found no evidence that Renewables had engaged in any unlawful market contract that would justify finding the Renewables power purchase agreements unjust and unreasonable. However, the proposed ruling did conclude that price of the power purchase agreements imposed an excessive burden on customers in the amount of $259 million. Renewables position, as presented at hearings and agreed by FERC Trial Staff, is that Renewables entered into bilateral power purchase contracts appropriately and complied with all applicable legal standards and requirements. The parties have submitted to FERC briefs on exceptions to the administrative law judge's proposed ruling. There is no specific timetable to FERC's ruling. We cannot predict the outcome of this proceeding.

Leases

Operating lease expense relating to operational facilities, office building leases, and vehicle and equipment leases was $70.6 million, $47.7 million and $48.7 million for the years ended December 31, 2016, 2015 and 2014, respectively. Amounts related to contingent payments predominantly linked to electricity generation at the respective facilities was $22.2 million, $22.2 million and $20.4 million for the years ended December 31, 2016, 2015 and 2014, respectively. Leases for most of the land on which wind farm facilities are located have various renewal and termination clauses.

On January 16, 2014, as required by the NYPSC, NYSEG renewed a Reliability Support Services Agreement (RSS Agreement) with Cayuga Operating Company, LLC (Cayuga) for Cayuga to provide reliability support services to maintain necessary system reliability through June 2017. Cayuga owns and operates the Cayuga Generating Facility (Facility), a coal-fired generating station that includes two generating units. Cayuga will operate and maintain the RSS units and manage and comply with scheduling deadlines and requirements for maintaining the Facility and the RSS units as eligible energy and capacity providers and will comply with dispatch instructions. NYSEG will pay Cayuga a monthly fixed price and will also pay for capital expenditures for specified capital projects. NYSEG will be entitled to a share of any capacity and energy revenues earned by Cayuga. We account for this arrangement as an operating lease. The net expense incurred under this operating lease was $37.8 million, $25.5 million and $19.8 million for the years ended December 31, 2016, 2015 and 2014, respectively.

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

On October 21, 2015, RG&E, GNPP and multiple intervenors filed a Joint Proposal with the regulator for approval of the modified RSS Agreement for the continued operation of the Ginna Facility through March 2017. RG&E shall make monthly payments to GNPP in the amount of $15.4 million. RG&E will be entitled to 70% of revenues from GNPP's sales into the energy and capacity markets, while GNPP will be entitled to 30% of such revenues. We account for this arrangement as an operating lease. The net expense incurred under this operating lease was $114.9 million and $79.9 million for the years ended December 31, 2016 and 2015, respectively.

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

Year	Operating Leases	Capital Leases	Total
		(Millions)	
2017	$ 106	$ 30	$ 136
2018	28	6	34
2019	28	7	35
2020	26	7	33
2021	28	4	32
2022 and thereafter	487	50	537
Total	**$ 703**	**$ 104**	**$ 807**

Power, Gas, and Other Arrangements

Power and Gas Supply Arrangements – Networks

NYSEG and RG&E are the providers of last resort for customers. As a result, the companies buy physical energy and capacity from the NYISO. In accordance with the NYPSC's February 26, 2008 Order, NYSEG and RG&E are required to hedge on behalf of non-demand billed customers. The physical electric capacity purchases we make from parties other than the NYISO are to comply with the hedge requirement for electric capacity. The companies enter into financial swaps to comply with the hedge requirement for physical electric energy purchases. Other purchases, from some Independent Power Producers (IPPs) and NYPA are from contracts entered into many years ago when the companies made purchases under contract as part of their supply portfolio to meet their load requirement. More recent IPP purchases are required to comply with the companies' Public Utility Regulatory Policies Act (PURPA) purchase obligation.

NYSEG, RG&E, SCG, CNG and BGC (collectively the Regulated Gas Companies) satisfy their natural gas supply requirements through purchases from various producers and suppliers, withdrawals from natural gas storage, capacity contracts and winter peaking supplies and resources. The Regulated Gas Companies operate diverse portfolios of gas supply, firm transportation capacity, gas storage and peaking resources. Actual gas costs incurred by each of the Regulated Gas Companies are passed through to customers through state regulated purchased gas adjustment mechanisms, subject to regulatory review.

The Regulated Gas Companies purchase the majority of their natural gas supply at market prices under seasonal, monthly or mid-term supply contracts and the remainder is acquired on the spot market. The Regulated Gas Companies diversify their sources of supply by amount purchased and location and primarily acquire gas at various locations in the US Gulf of Mexico region, in the Appalachia region and in Canada.

The Regulated Gas Companies acquire firm transportation capacity on interstate pipelines under long-term contracts and utilize that capacity to transport both natural gas supply purchased and natural gas withdrawn from storage to the local distribution system.

The Regulated Gas Companies acquire firm underground natural gas storage capacity using long-term contracts and fill the storage facilities with gas in the summer months for subsequent withdrawal in the winter months.

Winter peaking resources are primarily attached to the local distribution systems and are either owned or are contracted for by the Regulated Gas Companies, each of which is a Local Distribution Company. Each Regulated Gas Company owns or has rights to the natural gas stored in an LNG facility directly attached to its distribution system.

Other arrangements include UI's long-term contracts to purchase RECs.

Power, Gas, and Other Arrangements – Renewables and Gas

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

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

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

Guarantee Commitments to Third Parties

As of December 31, 2016, we had approximately $2.6 billion of standby letters of credit, surety bonds, guarantees and indemnifications outstanding. These instruments provide financial assurance to the business and trading partners of AVANGRID and its subsidiaries in their normal course of business. The instruments only represent liabilities if AVANGRID or its subsidiaries fail to deliver on contractual obligations. We therefore believe it is unlikely that any material liabilities associated with these instruments will be incurred and, accordingly, as of December 31, 2016, neither we nor our subsidiaries have any liabilities recorded for these instruments.

Property, Plant and Equipment

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

Note 14. Environmental Liabilities

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

Waste sites

The Environmental Protection Agency and various state environmental agencies, as appropriate, have notified us that we are among the potentially responsible parties that may be liable for costs incurred to remediate certain hazardous substances at twenty-five waste sites, which do not include sites where gas was manufactured in the past. Fifteen of the twenty-five sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites; six sites are included in Maine's Uncontrolled Sites Program and one site is included on the Massachusetts Non- Priority Confirmed Disposal Site list. The remaining sites are not included in any registry list. Finally, nine of the twenty-five sites are also included on the National Priorities list. Any liability may be joint and severable for certain sites.

We have recorded an estimated liability of $6 million related to ten of the twenty-five sites. We have paid remediation costs related to the remaining fifteen sites and do not expect to incur additional liabilities. Additionally, we have recorded an estimated liability of $8 million related to another ten sites where we believe it is probable that we will incur remediation costs and or monitoring costs, although we have not been notified that we are among the potentially responsible parties or that we are regulated under State Resource Conservation and Recovery Act programs. It is possible the ultimate cost to remediate these sites may be significantly more than the accrued amount. Our estimate for costs to remediate these sites ranges from $12 million to $22 million as of December 31, 2016. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination, and the portion of remediation attributed to us.

Manufactured Gas Plants

We have a program to investigate and perform necessary remediation at our fifty-three sites where gas was manufactured in the past (Manufactured Gas Plants, or MGPs). Eight sites are included in the New York State Registry; eleven sites are included in the New York Voluntary Cleanup Program; three sites are part of Maine's Voluntary Response Action Program and with two of such sites being part of Maine's Uncontrolled Sites Program. The remaining sites are not included in any registry list. We have entered into consent orders with various environmental agencies to investigate and where necessary remediate forty-nine of the fifty-three sites.

Our estimate for all costs related to investigation and remediation of the fifty-three sites ranges from $221 million to $465 million as of December 31, 2016. Our estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial actions, changes in technology relating to remedial alternatives, and changes to current laws and regulations.

As of December 31, 2016 and 2015, the liability associated with MGP sites in Connecticut, the remediation costs of which could be significant and will be subject to a review by PURA as to whether these costs are recoverable in rates, was $97 million and $99 million, respectively.

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

Certain other Connecticut and Massachusetts regulated gas companies own or have previously owned properties where MGPs had historically operated. MGP operations have led to contamination of soil and groundwater with petroleum hydrocarbons, benzene and metals, among other things, at these properties, the regulation and cleanup of which is regulated by the federal Resource Conservation and Recovery Act as well as other federal and state statutes and regulations. Each of the companies has or had an ownership interest in one or more such properties contaminated as a result of MGP-related activities. Under the existing regulations, the cleanup of such sites requires state and at times, federal, regulators' involvement and approval before cleanup can commence. In certain cases, such contamination has been evaluated, characterized and remediated. In other cases, the sites have been evaluated and characterized, but not yet remediated. Finally, at some of these sites, the scope of the contamination has not yet been fully characterized; no liability was recorded in respect of these sites as of December 31, 2016 and no amount of loss, if any, can be reasonably estimated at this time. In the past, the companies have received approval for the recovery of MGP-related remediation expenses from customers through rates and will seek recovery in rates for ongoing MGP-related remediation expenses for all of their MGP sites.

FirstEnergy

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

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

FirstEnergy remains liable for a substantial share of clean up expenses at nine MPG sites. In January 2015, NYSEG sent FirstEnergy a demand for $16 million representing FirstEnergy's share of clean-up expenses incurred by NYSEG at the nine sites from January 2010 to November 2014 while the District Court appeal was pending. Nearly all of this amount has been paid by FirstEnergy. FirstEnergy would also be liable for a share of post 2014 costs, which, based on current projections, would be $26 million. This amount is being treated as a contingent asset and has not been recorded as either a receivable or a decrease to the environmental provision. Any recovery will be flowed through to NYSEG ratepayers.

Century Indemnity and OneBeacon

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

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

English Station

In January 2012, Evergreen Power, LLC (Evergreen Power) and Asnat Realty LLC (Asnat), then and current owners of a former generation site on the Mill River in New Haven (the English Station site) that UI sold to Quinnipiac Energy in 2000, filed a lawsuit in federal district court in Connecticut against UI seeking, among other things: (i) an order directing UI to reimburse the plaintiffs for costs they have incurred and will incur for the testing, investigation and remediation of hazardous substances at the English Station site and (ii) an order directing UI to investigate and remediate the site. This proceeding had been stayed in 2014 pending resolutions of other proceedings before DEEP concerning the English Station site. In December 2016, the court administratively closed the file without prejudice to reopen upon the filing of a motion to reopen by any party. In December 2013, Evergreen and Asnat filed a subsequent lawsuit in Connecticut state court seeking among other things: (i) remediation of the property; (ii) reimbursement of remediation costs; (iii) termination of UI's easement rights; (iv) reimbursement for costs associated with securing the property; and (v) punitive damages This lawsuit had been stayed in May 2014 pending mediation. Due to lack of activity in the case, the court terminated the stay and scheduled a status conference on or before August 1, 2017.

On April 8, 2013, DEEP issued an administrative order addressed to UI, Evergreen Power, Asnat and others, ordering the parties to take certain actions related to investigating and remediating the English Station site. Mediation of the matter began in the fourth quarter of 2013 and concluded unsuccessfully in April 2015. This proceeding was stayed while DEEP and UI continue to work through the remediation process pursuant to the consent order described below. A status report was filed with the court in December 2016 and the next status report is due in May 2017.

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

In connection with the consent order, on August 4, 2016, DEEP also issued a Consent Order to Evergreen Power, Asnat, and certain related parties that provides UI access to investigate and remediate the English Station site consistent with the consent order. UI has initiated its process to investigate and remediate the environmental conditions within the perimeter of the English Station site pursuant to the consent order.

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

Note 15. Income Taxes

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

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

The differences between tax expense per the statements of income and tax expense at the 35% statutory federal tax rate for the years ended December 31, 2016, 2015 and 2014 consisted of:

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

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

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

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

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

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

Unrecognized income tax benefits represent income tax positions taken on income tax returns but not yet recognized in the consolidated financial statements. The accounting guidance for uncertainty in income taxes provides that the financial effects of a tax position shall initially be recognized when it is more likely than not based on the technical merits the position will be sustained upon examination, assuming the position will be audited and the taxing authority has full knowledge of all relevant information.

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

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

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

All federal tax returns filed by ARHI from the periods ended March 31, 2004, to December 31, 2009, are closed for adjustment. Generally, the adjustment period for the individual states we filed in is at least as long as the federal period.

As of December 31, 2016, UIL is subject to audit of its federal tax return for years 2013 and 2014. UIL income tax years 2010 through 2014 are open and subject to Connecticut and Massachusetts audit.

As of December 31, 2016, we had federal tax net operating losses of $3.6 billion, federal renewable energy and investment tax credits, federal R&D tax credits and other federal credits of $394 million, state tax net operating losses of $241 million in several jurisdictions and miscellaneous state tax credits of $32 million available to carry forward and reduce future income tax liabilities. For state purposes, we recognized a valuation allowance of $31 million. The federal net operating losses begin to expire in 2028, while the federal tax credits begin to expire in 2023. The more significant state net operating losses begin to expire in 2021.

Note 16. Post-retirement and Similar Obligations

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

Networks has other postretirement health care benefit plans covering the majority of Networks employees. The plans were closed to newly-hired non-union employees at the end of 2011. The plans had been closed to union employees in prior years. The pre-Medicare-eligible healthcare plans are contributory and participants' contributions are adjusted annually. Networks average contribution to these plans is limited at a level determined in prior periods. Except for a small group of "grandfathered" retirees, all Medicare eligible retirees that choose to participate are provided with a subsidy through a Health Reimbursement Account (HRA) to purchase coverage on the individual market.

With the acquisition of UIL, Networks also includes pension and other postretirement plans of UIL operating utility companies. The UI pension plan covers the majority of employees of UI and UIL corporate. The plan was closed to newly-hired employees in 2005. UI also has a non-qualified supplemental pension plan for certain employees and a non-qualified retiree-only pension plan for certain early retirement benefits.

The Regulated Gas Companies in Connecticut and Massachusetts have multiple qualified pension plans covering a majority of their union and management employees. These entities also have non-qualified supplemental pension plans for certain employees. The qualified pension plans are traditional defined benefit plans or cash balance plans for those hired on or after specified dates. In some cases, neither of these plans is offered to new employees and have been replaced with enhanced 401(k) plans for those hired on or after specified dates.

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

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

ARHI has funded defined benefit pension plans for eligible employees hired prior to January 1, 2008. The benefit is based on participant's age, service, and five years average pay at the time of the freeze date of April 30, 2011. ARHI has other postretirement health care benefit plans covering eligible retirees and employees hired prior to January 1, 2008. Health and life insurance rates are based on age and service points at the time of retirement.

Obligations and funded status of Networks and ARHI as of December 31, 2016 and 2015 consisted of:

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

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

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

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

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

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

We have determined that all Networks' regulated operating companies are allowed to defer as regulatory assets or regulatory liabilities items that would have otherwise been recorded in accumulated OCI pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans.

Amounts recognized as regulatory assets or regulatory liabilities for Networks for the years ended December 31, 2016, 2015 and 2014 for Networks consisted of:

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

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

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

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

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

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

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

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

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

The net periodic benefit cost for postretirement benefits represents the amount expensed for providing health care benefits to retirees and their eligible dependents. We include the net periodic benefit cost in other operating expenses net of capitalized portion.

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

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

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

Year Ended December 31, 2017	Pension Benefits	Postretirement Benefits
(Millions)		
Estimated net loss	$ 1	$ —
Estimated prior service cost (benefit)	—	—

We expect that no pension benefit or postretirement benefit plan assets will be returned to us during the year ending December 31, 2017.

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

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

The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rates by developing yield curves derived from a portfolio of high grade noncallable bonds with yields that closely match the duration of the expected cash flows of our benefit obligations.

The weighted-average assumptions used to determine net periodic benefit cost for Networks and ARHI for the years ended December 31, 2016, 2015 and 2014 consisted of:

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

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

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

As of December 31,	2016	2015
Health care cost trend rate assumed for next year - Networks	7.00%/9.00%	7.50%/7.00%
Health care cost trend rate assumed for next year - ARHI	6.75%/8.50%	7.00%/9.00%
Rate to which cost trend rate is assumed to decline (ultimate trend rate) - Networks	4.50%	4.50%
Rate to which cost trend rate is assumed to decline (ultimate trend rate) - ARHI	4.50%	4.50%
Year that the rate reaches the ultimate trend rate - Networks	2026 / 2028	2027
Year that the rate reaches the ultimate trend rate - ARHI	2026 / 2028	2026

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

(Millions)	1% Increase	1% Decrease
Effect on total of service and interest cost	$ 1	$ (1)
Effect on postretirement benefit obligation	$ 14	$ (12)

Contributions

We make annual contributions in accordance with our funding policy of not less than the minimum amounts as required by applicable regulations. Networks expect to contribute $33 million to the pension benefit plans during 2017.

Estimated Future Benefit Payments

Expected benefit payments and Medicare Prescription Drug, Improvement and Modernization Act of 2003 subsidy receipts reflecting expected future service for Networks and ARHI as of December 31, 2016 consisted of:

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

Non-Qualified Pension Plans

Networks and ARHI also sponsor various unfunded pension plans for certain current employees, former employees and former directors. The total liability for these plans, which is included in Other Non-current Liabilities, was $57 million and $59 million at December 31, 2016 and 2015, respectively.

Plan Assets

Our pension benefits plan assets for Networks and ARHI are held in three master trusts. This provides for a uniform investment manager lineup and an efficient, cost effective means of allocating expenses and investment performance to each plan. Our primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our risk tolerance. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. Our primary means for achieving capital preservation is through diversification of the trusts'

investments while avoiding significant concentrations of risk in any one area of the securities markets. Further diversification is achieved within each asset group through utilizing multiple asset managers and systematic allocation to various asset classes and providing broad exposure to different segments of the equity, fixed income, and alternative investment markets.

Networks' asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets within broad categories of asset classes made up of Return-Seeking and Liability-Hedging investments. Within the Return-Seeking category, we have targets of 35%-54% in equity securities and 3%-20% in equity alternative investments. The Liability-Hedging asset class has a target allocation percentage of 43%-45%. Return-Seeking investments generally consist of domestic, international, global, and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking assets also include investments in real estate, absolute return, and strategic markets. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS, and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

ARHI's investment portfolio contains a diversified blend of equity, fixed income, and other investments. In ARHI's asset allocation policy we have established targets of 33% for equity investments, 50% for fixed income investments and 17% for other assets classes. Equity investments are diversified across U.S. and non-U.S. stocks, investment styles, and market capitalization ranges. Fixed income investments are primarily invested in U.S. bonds and may also include some non-U.S. bonds. Other asset classes, including real estate, absolute return, and real return, are used to enhance long-term returns while improving portfolio diversification. We primarily minimize the risk of large losses through diversification but also through monitoring and managing other aspects of risk through quarterly investment portfolio reviews, annual liability measurements, and periodic asset and liability studies.

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

As of December 31, 2016		Fair Value Measurements		
(Millions)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 49	$ —	$ 49	$ —
U.S. government securities	172	172	—	—
Common stocks	120	120	—	—
Registered investment companies	122	122	—	—
Corporate bonds	358	—	358	—
Preferred stocks	4	—	4	—
Common collective trusts	1,192	—	371	821
Partnerships/joint venture interests	5	—	—	5
Real estate investments	61	—	—	61
Other, principally annuity, fixed income	589	—	315	274
Total	**$ 2,672**	**$ 414**	**$ 1,097**	**$ 1,161**

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

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

Valuation Techniques

We value our pension benefits plan assets as follows:

- Cash and cash equivalents - Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities, common stocks and registered investment companies - at the closing price reported in the active market in which the security is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.
- Mutual funds - based upon quoted market prices in active markets, which represent the Net Asset Value (NAV) of the shares held.
- Preferred stocks - at the closing price reported in the active market in which the individual investment is traded.
- Common/collective trusts and Partnership/joint ventures - using the NAV provided by the administrator of the fund. The NAV is based on the value of the underlying assets owned by the fund, minus its liabilities, and then divided by the number of shares outstanding. The NAV is classified as Level 2 if the plan has the ability to redeem the investment with the investee at NAV per share at the measurement date. Redemption restrictions or adjustments to NAV based on unobservable inputs result in the fair value measurement being classified as Level 3 if those inputs are significant to the overall fair value measurement.
- Real estate investments - based on a discounted cash flow approach that includes the projected future rental receipts, expenses and residual values because the highest and best use of the real estate from a market participant view is as rental property.
- Other investments, principally annuity and fixed income - Level 1: at the closing price reported in the active market in which the individual investment is traded. Level 2: based on yields currently available on comparable securities of issuers with similar credit ratings. Level 3: when quoted prices are not available for identical or similar instruments, under a discounted cash flows approach that maximizes observable inputs such as current yields of similar instruments but includes adjustments for certain risks that may not be observable such as credit and liquidity risks.

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

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

Our postretirement benefits plan assets are held with trustees in multiple voluntary employees' beneficiary association (VEBA) and 401(h) arrangements and are invested among and within various asset classes to achieve sufficient diversification in accordance with our risk tolerance. This is achieved for our postretirement benefits plan assets through the utilization of multiple institutional mutual and money market funds, providing exposure to different segments of the fixed income, equity and short-term cash markets. Approximately 37% of the postretirement benefits plan assets are invested in VEBA and 401(h) arrangements that are not subject to income taxes with the remainder being invested in arrangements subject to income taxes.

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

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

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

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

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

Valuation Techniques

We value our postretirement benefits plan assets as follows:

- Money market funds and mutual funds - based upon quoted market prices in active markets, which represent the NAV of shares held.
- Government bonds, and common stocks - at the closing price reported in the active market in which the security is traded.
- Corporate bonds - based on yields currently available on comparable securities of issuers with similar credit ratings.

Pension and postretirement benefit plan equity securities did not include any Iberdrola common stock as of both December 31, 2016 and 2015.

Defined contribution plans

We also have defined contribution plans defined as 401(k)s. The annual contributions made through these plans for Networks and ARHI amounted to $34 million, $17 million and $20 million for 2016, 2015, and 2014 respectively.

Note 17. Equity

As of December 31, 2016, our share capital consisted of 500,000,000 shares of common stock authorized, 309,600,439 shares issued and 308,993,149 shares outstanding, 81.5% of which is owned by Iberdrola, each having a par value of $0.01, for a total value of common stock of $3 million and additional paid in capital of $13,653 million. As of December 31, 2015, our share capital consisted of 500,000,000 shares of common stock authorized, 309,491,082 shares issued and 308,864,609 shares outstanding, 81.5% of which was owned by Iberdrola, each having a par value of $0.01, for a total value of common stock capital of $3 million and additional paid in of $13,653 million. We had 491,459 and 626,473 shares of common stock held in trust and no convertible preferred shares outstanding as of December 31, 2016 and December 31, 2015, respectively. During the year ended December 31, 2016, we issued 109,357 shares of common stock and released 135,014 shares of common stock held in trust each having a par value of $0.01.

On April 28, 2016, we entered into a repurchase agreement with J.P. Morgan Securities, LLC. (JPM), pursuant to which JPM will, from time to time, acquire, on behalf of AVANGRID, shares of common stock of AVANGRID. The purpose of the stock repurchase program is to allow AVANGRID to maintain the relative ownership percentage of Iberdrola at 81.5%. The stock repurchase program may be suspended or discontinued at any time upon notice. During the year ended December 31, 2016, we repurchased 115,831 shares of common stock of AVANGRID in the open market. The total cost of repurchase, including commissions, was $5 million.

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

Accumulated OCI (Loss)

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

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

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

Note 18. Earnings Per Share

Basic earnings per share is computed by dividing net income attributable to AVANGRID by the weighted-average number of shares of our common stock outstanding. In 2016 and 2015, while we did have securities that were dilutive, these securities did not result in a change to our earnings per share calculations for the years ended December 31, 2016 and 2015. We did not have any potentially-dilutive securities for the year ended December 31, 2014. In accordance with Accounting Standards Codification (ASC) Topic 260, Earnings per Share, we retroactively applied the stock split to prior periods presented.

The calculations of basic and diluted earnings per share attributable to AVANGRID for the years ended December 31, 2016, 2015 and 2014, consisted of:

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

Note 19. Tax equity financing arrangements

The sale of a membership interest in the tax equity financing arrangements (TEFs) represents the sale of an equity interest in a structure that is considered in substance real estate. Under existing guidance for real estate financings, the membership interests in the TEFs we sold to the third-party investors are reflected as a financing obligation in the consolidated balance sheets. We continue to fully consolidate the TEFs' assets and liabilities in the consolidated balance sheets and to report the results of the TEFs' operations in the consolidated statements of income. The presentation reflects revenues and expenses from the TEFs' operations on a fully consolidated basis. We consolidate the TEF's based on being the primary beneficiary for these variable interest entities (VIEs). The liabilities are increased for cash contributed by the third-party investors, interest accrued, and the federal income tax impact to the third-party investors of the allocation of taxable income. Interest is accrued on the balance using the effective interest method and the third-party investors' targeted rate of return. The balance accrued interest at an average rate of 5.4% and 8.5% as of December 31, 2016 and 2015, respectively. The liabilities are reduced by cash distributions to the third-party investors, the allocation of production tax credits to the third-party investors, and the federal income tax impact to the third-party investors of the allocation of taxable losses. This treatment is expected to remain consistent over the terms of the TEFs. The assets and liabilities of these VIEs totaled approximately $1,343 million and $244 million, respectively, at December 31, 2016. As of December 31, 2015 the assets and liabilities of VIEs totaled approximately $1,401 million and $338 million, respectively. At December 31, 2016 and 2015, the assets and liabilities of the VIEs consisted primarily of property, plant and equipment, equity method investments and TEF liabilities. At December 31, 2016 and 2015, equity method investments of VIEs were approximately $161 million and $169 million, respectively.

We consider the following four structures to be TEFs: (1) Aeolus Wind Power II LLC, (2) Aeolus Wind Power III LLC, (3) Aeolus Wind Power IV LLC, and (4) Locust Ridge Wind Farms, LLC, (collectively, Aeolus). We retain a class of membership interest and day-to-day operational and management control of Aeolus, subject to investor approval of certain major decisions. The third-party investors do not receive a lien on any Aeolus assets and have no recourse against us for their upfront cash payments.

Wind power generation is subject to certain favorable tax treatments in the U.S. In order to monetize the tax benefits generated by Aeolus, we have entered into the Aeolus structured institutional partnership investment transactions related to certain wind farms. Under the Aeolus structures, we contribute certain wind assets, relating both to existing wind farms and wind farms that are being placed into operation at the time of the relevant transaction, and other parties invest in the share equity of the Aeolus limited liability holding company. As consideration for their investment, the third parties make either an upfront cash payment or a combination of upfront cash and issuance of fixed and contingent notes.

The third party investors receive a disproportionate amount of the profit or loss, cash distributions and tax benefits resulting from the wind farm energy generation until the investor recovers its investment and achieves a cumulative annual after-tax return. Once this target return is met, the relative sharing of profit or loss, cash distributions and taxable income or loss between the Company and the third party investor flips, with the company taking a disproportionate share of such amounts thereafter. We also have a call option to acquire the third party investors' membership interest within a defined time period after this target return is met.

Our Aeolus interests are not subject to any rights of investors that may restrict our ability to access or use the assets or to settle any existing liabilities associated with the interests.

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

Note 20. Grants, Government Incentives and Deferred Income

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

(Millions)	Government grants	Other deferred income	Total
As of December 31, 2014	$ 1,606	$ 15	$ 1,621
Additions	—	—	—
Recognized in income	(77)	9	(68)
As of December 31, 2015	$ 1,529	$ 24	$ 1,553
Additions	—	—	—
Recognized in income	(68)	(2)	(70)
As of December 31, 2016	$ 1,461	$ 22	$ 1,483

Within deferred income we classify grants we received under Section 1603 of the American Recovery and Reinvestment Act of 2009, where the United States Department of Treasury (DOT) provides eligible parties the option of claiming grants for specified energy property in lieu of tax credits, which we claimed for the majority of our qualifying properties. Deferred income has been recorded for the grant amounts and is amortized as an offset against depreciation expense using the straight-line method over the estimated useful life of the associated property to which the grants apply. We recognize a net deferred tax asset for the book to tax basis differences related to the property for income tax purposes.

We are required to comply with certain terms and conditions applicable to each grant and, if a disqualifying event should occur as specified in the grant's terms and conditions, we are required to repay the grant funds to the DOT. We believe we are in compliance with each grant's terms and conditions as of December 31, 2016 and 2015.

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

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

Note 21. Equity method investments

We have a 50-50 joint venture with Shell Wind Energy, Inc., which owns and operates a 162- megawatt (MW) wind farm located in southeast Colorado (Colorado Wind Ventures LLC), which commenced operations in January 2004. We account for this venture under the equity method of accounting. The carrying amount of this investment was $45 million and $41 million as of December 31, 2016 and 2015, respectively.

We have two 50-50 joint ventures with Horizon Wind Energy, LLC, which own and operate the Flat Rock Windpower LLC and the Flat Rock Wind Power II LLC wind farms located in upstate New York. Flat Rock Wind Power LLC, which commenced operations in January 2006, has a 231-MW capacity. Flat Rock Wind Power II LLC commenced operations in September 2007 and has a 91-MW capacity. We account for the Flat Rock joint ventures under the equity method of accounting. The carrying amount of these investments was $128 million and $143 million for Flat Rock Wind Power LLC, and $64 million and $69 million for Flat Rock Wind Power II LLC, as of December 31, 2016 and 2015, respectively.

Through UI, we are party to a 50-50 joint venture with NRG affiliates in GenConn, which operates two peaking generation plants in Connecticut. The investment in GenConn is being accounted for as an equity investment, the carrying value of which was $128 million and $110 million as of December 31, 2016 and 2015.

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

None of our joint ventures have any contingent liabilities or capital commitments. Distributions received from equity method investments amounted to $20 million, $12 million, and $19 million for the years ended December 31, 2016, 2015, and 2014 respectively, which are reflected as either distributions of earnings or as returns of capital in the operating and investing sections of the consolidated statements of cash flows, respectively. As of December 31, 2016, there was an immaterial amount of undistributed earnings from our equity method investments.

During the year ended December 31, 2016 we completed the sale of our interest in Iroquois Gas Transmission System L.P. (Iroquois) to an unaffiliated third party for proceeds of $53.8 million and an impact to net income of $19.0 million. The carrying value of this equity method investment was $22 million as of December 31, 2015.

Note 22. Other Financial Statements Items

Other income and (expense)

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

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

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

Accounts Receivable

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

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

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

The change in the allowance for bad debts as of December 31, 2016 and 2015 consisted of:

(Millions)	
As of December 31, 2013	**58**
Current period provision	39
Write-off as uncollectible	(48)
As of December 31, 2014	**$ 49**
Current period provision	46
Write-off as uncollectible	(33)
As of December 31, 2015	**$ 62**
Current period provision	48
Write-off as uncollectible	(46)
As of December 31, 2016	**$ 64**

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

Prepayments and Other Current Assets

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

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

Other Non-current Assets

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

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

Other current liabilities

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

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

Note 23. Segment Information

Our segment reporting structure uses our management reporting structure as its foundation to reflect how AVANGRID manages the business internally and is organized by type of business. We report our financial performance based on the following three reportable segments:

- Networks: including all the energy transmission and distribution activities, and any other regulated activity originating in New York and Maine, and regulated electric distribution, electric transmission and gas distribution activities originating in Connecticut and Massachusetts. The Networks reportable segment includes eight rate regulated operating segments. These operating segments generally offer the same services distributed in similar fashions, have the same types of customers, have similar long-term economic characteristics and are subject to similar regulatory requirements, allowing these operations to be aggregated into one reportable segment.
- Renewables: activities relating to renewable energy, mainly wind energy generation and trading related with such activities.
- Gas: including gas trading and storage businesses carried on by the AVANGRID Group

Products and services are sold between reportable segments and affiliate companies at cost. The chief operating decision maker evaluates segment performance based on segment adjusted EBITDA (Earnings Before Interest, Taxes, Depreciation and Amortization) defined as net income adding back income tax expense, depreciation and amortization, impairment of non-current assets and interest expense net of capitalization, and then subtracting other income and earnings from equity method investments per segment. Segment

income, expense, and assets presented in the accompanying tables include all intercompany transactions that are eliminated in the consolidated financial statements.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Note 24. Related Party Transactions

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

Related party transactions for the years ended December 31, 2016, 2015 and 2014, respectively, consisted of:

Years Ended December 31,	2016		2015		2014	
(Millions)	Sales To	Purchases From	Sales To	Purchases From	Sales To	Purchases From
Iberdrola Financiación, S.A.	$ —	$ (2)	—	$ (1)	—	$ (2)
Iberdrola Renovables Energia, S.L.	—	(8)	—	(9)	—	(10)
Iberdrola Canada Energy Services, Ltd	—	(37)	—	(55)	—	(49)
Iberdrola, S.A.	—	(31)	—	(35)	—	(20)
Other	21	(1)	3	(2)	12	(10)

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

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

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

Transactions with our parent company, Iberdrola, relate predominantly to the provision and allocation of corporate services and management fees. Also included within the Purchases From category are charges for credit support relating to guarantees Iberdrola has provided to third parties guaranteeing our performance. All costs that can be specifically allocated, to the extent possible, are charged directly to the company receiving such services. In situations when Iberdrola corporate services are provided to two or more companies of AVANGRID any costs remaining after direct charge are allocated using agreed upon cost allocation methods designed to allocate those costs. We believe that the allocation method used is reasonable.

Transactions with Iberdrola Canada Energy Services predominantly relate to the purchase of gas for ARHI's gas-fired generation facility at Klamath.

There have been no guarantees provided or received for any related party receivables or payables. These balances are unsecured and are typically settled in cash. Interest is not charged on regular business transactions but is charged on outstanding loan balances. There have been no impairments or provisions made against any affiliated balances, other than a $10 million write-off related to an arrangement to purchase turbines from Gamesa, which was recorded in impairment of non-current assets in the consolidated statements of income for the year ended December 31, 2015.

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

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

Note 25. Stock-Based Compensation

Under the Avangrid, Inc. Omnibus Incentive Plan 1,298,683 performance stock units (PSUs) were granted to certain officers and employees of AVANGRID in July 2016. An additional 11,804 PSUs were granted to officers and employees of AVANGRID in December 2016. The PSUs will vest upon achievement of certain performance and market-based metrics related to the 2016 through 2019 plan and will be payable in three equal installments in 2020, 2021 and 2022. As of December 31, 2016, the total number of shares authorized for stock-based compensation plans was 2,500,000.

The fair value of the PSUs on the grant date was $31.80 per share, which is expensed on a straight-line basis over the requisite service period of approximately seven years based on expected achievement. The fair value of the PSUs was determined using valuation techniques to forecast possible future stock prices, applying a weighted average historical stock price volatility of AVANGRID and industry companies, a risk-free rate of interest that is equal, as of the grant date, to the yield of the zero-coupon U.S. Treasury bill and a reduction for the respective dividend yield calculated based on the most recent quarterly dividend payment and the stock price as of the grant date.

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

The total stock-based compensation expense, which is included in operations and maintenance of the consolidated statements of income for the years ended December 31, 2016, 2015 and 2014 was $0.6 million, $6.0 million and $4.8, respectively. The total income tax benefit recognized for stock-based compensation arrangements for the years ended December 31, 2016, 2015 and 2014, was $0.2 million, $2.4 million and $1.9 million, respectively.

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

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

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

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

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

Note 26. Quarterly financial data (unaudited)

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

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

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

The first quarter of 2016 includes a $19.0 million impact to net income from the sale of our interest in Iroquois to an unaffiliated third party for proceeds of $53.8 million. The second quarter of 2016 includes an adjustment of $126 million to unfunded future income tax to reflect the change from a flow through to normalization method following the approval of the proposal by the NYPSC, which was recorded as an increase to income tax expense and an offsetting increase to revenue.

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

Note 27. Subsequent events

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

On February 16, 2017, the board of directors of AVANGRID declared a quarterly dividend of $0.432 per share on its common stock. This dividend is payable on April 3, 2017 to shareholders of record at the close of business on March 10, 2017.

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

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

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

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

See accompanying notes to Schedule I.

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

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

See accompanying notes to Schedule I.

Schedule I – Financial Statements of Parent

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

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

See accompanying notes to Schedule I.

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

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

See accompanying notes to Schedule I.

Note 1. Basis of Presentation

Avangrid, Inc. (AVANGRID), formerly Iberdrola USA, Inc., is a holding company and conducts substantially all of its business through its subsidiaries. Substantially all of its consolidated assets are held by such subsidiaries. Accordingly, its cash flow and its ability to meet its obligations are largely dependent upon the earnings of these subsidiaries and the distribution of other payment of such earnings to in the form of dividends, loans or advances or repayment of loans and advances from it. These condensed financial statements and related footnotes have been prepared in accordance with regulatory statute 210.12-04 of Regulation S-X. These statements should be read in conjunction with the consolidated financial statements and notes thereto of AVANGRID and subsidiaries (AVANGRID Group).

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

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

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

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

Note 2. Acquisition of UIL and Issuance of Common Stock

On December 16, 2015 (acquisition date), UIL Holdings Corporation, a Connecticut corporation (UIL), became a wholly-owned subsidiary of AVANGRID as a result of the merger of Green Merger Sub, Inc., a Connecticut corporation and a wholly-owned subsidiary of AVANGRID (Merger Sub), with UIL, with Merger Sub surviving as a wholly-owned subsidiary of AVANGRID (the acquisition). The acquisition was effected pursuant to the Agreement and Plan of Merger, dated as of February 25, 2015, by and among AVANGRID, Merger Sub, and UIL. Following the completion of the acquisition, Merger Sub was renamed "UIL Holdings Corporation." In connection with the acquisition, AVANGRID issued 309,490,839 shares of its common stock, out of which 252,234,989 shares were issued to Iberdrola through a stock dividend, accounted for as a stock split, with no change to par value, at par value of $0.01 per share, and 57,255,850 shares (including held in trust as treasury stock) were issued to UIL shareowners in addition to payment of $10.50 in cash per each share of the common stock of UIL issued and outstanding at the acquisition date. Following the completion of the acquisition, former UIL shareowners owned 18.5% of the outstanding shares of common stock of AVANGRID and Iberdrola owned the remaining shares.

On April 28, 2016, AVANGRID entered into a repurchase agreement with J.P. Morgan Securities, LLC. (JPM), pursuant to which JPM will, from time to time, acquire, on behalf of AVANGRID, shares of common stock of AVANGRID. The purpose of the stock repurchase program is to allow AVANGRID to maintain the relative ownership percentage of Iberdrola at 81.5%. The stock repurchase program may be suspended or discontinued at any time upon notice. During the year ended December 31, 2016, AVANGRID repurchased 115,831 shares of its common stock in the open market. The total cost of repurchase, including commissions, was $5 million.

On February 16, 2017, the board of directors of AVANGRID declared a quarterly dividend of $0.432 per share on its common stock. This dividend is payable on April 3, 2017 to shareholders of record at the close of business on March 10, 2017.

Note 3. Non-current debt

Supplemental Indenture

On December 19, 2016, AVANGRID, its subsidiary, UIL, and The Bank of New York Mellon, entered into a supplemental indenture, pursuant to which AVANGRID assumed from UIL all the obligations under the indenture dated as of October 7, 2010 between UIL and The Bank of New York Mellon and all obligations relating to $450 million in aggregate principal amount of 4.625% notes due 2020 issued by the predecessor company to UIL in 2010. For the purpose of the supplemental indenture a capital contribution of $483 million was made by AVANGRID to UIL in December 2016.

Note 4. Cash dividends paid by subsidiaries

Cash dividends paid by subsidiaries are as follows:

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

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

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.***

None.

Item 9A. ***Controls and Procedures.***

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our Chief Executive Officer, or CEO, and our Chief Financial Officer, CFO, has evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended, or the Exchange Act), as of the end of the period covered by this Annual Report on Form 10-K. Based on such evaluation, our CEO and CFO have concluded that as of such date, our disclosure controls and procedures were not effective, due to a material weakness in internal control over financial reporting described below.

Report of Management on Internal Control Over Financial Reporting

The management of AVANGRID is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. AVANGRID's internal control system over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles. AVANGRID's internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and

(iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in condition, or that the degree of compliance with the policies or procedures may deteriorate.

AVANGRID's management assessed the effectiveness of AVANGRID's internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) ("COSO") in Internal Control—Integrated Framework. Based upon that assessment and those criteria, management has identified certain deficiencies that rose to the level of a material weakness in controls related to: (1) the accounting for the change in the estimated useful life of certain elements of the wind farms at Renewables and other smaller deficiencies related to documentation of internal controls procedures, and enhancement of review controls at Renewables, (2) the preparation of the consolidated financial statements, specifically the classification and disclosure of financial information, and (3) the measurement and disclosure of income taxes. This material weakness did not result in any restatement of prior-period financial statements.

A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis.

As a result of the material weakness noted above, management concluded that, as of December 31, 2016, our internal control over financial reporting was not effective. We completed additional substantive procedures prior to filing this Annual Report on Form 10-K. Based on these procedures, management believes that our consolidated financial statements included in this Annual Report on Form 10-K have been prepared in accordance with generally accepted accounting principles. Our CEO and CFO have certified that, based on such officer's knowledge, the financial statements, and other financial information included in this Annual Report on Form 10-K, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this Annual Report on Form 10-K. In addition, we have developed a remediation plan for this material weakness, which is described below.

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

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

Changes in Internal Control

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

Remediation Plans and Other Information

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

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

These improvements are targeted at strengthening the Company’s internal control over financial reporting and remediating the material weakness. The Company remains committed to an effective internal control environment and management believes that these actions, and the improvements management expects to achieve as a result, will remediate the material weakness. However, the material weakness in our internal control over financial reporting will not be considered remediated until the controls operate for a sufficient period of time and management has concluded, through testing that these controls operate effectively. We currently plan to have our enhanced review procedures and documentation standards in place and operating in the first quarter of 2017 and expect that the remediation of this material weakness will be completed by December 31, 2017.

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

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance.***

For information regarding our executive officers, see Part I of this Annual Report on Form 10-K. Additional information required by this item is incorporated by reference to our Proxy Statement for the 2017 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2016.

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

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

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.***

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

Item 13. ***Certain Relationships and Related Transactions, and Director Independence.***

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

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

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

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).
4.5	Third Supplemental Indenture, dated as of December 19, 2016, among Avangrid, Inc., UIL Holdings Corporation and The Bank of New York Mellon, as trustee.*
10.1	Shareholder Agreement, dated as of December 16, 2015, by and between Avangrid, Inc. and Iberdrola, S.A. (incorporated herein by reference to Exhibit 4.1 to Form 8-K filed with the Securities and Exchange Commission on December 18, 2015).
10.2	Service Agreement, dated January 1, 2014, between Iberdrola USA, Inc. Management Corporation and Avangrid, Inc. (formerly Iberdrola USA, Inc.) (incorporated herein by reference to Exhibit 10.2 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.3	Second Amended and Restated Five-Year Revolving Credit Agreement, dated as of May 30, 2012, among Avangrid, Inc. (formerly Iberdrola USA, Inc.), as Borrower, The Several Lenders from Time to Time Parties Hereto, Citibank N.A., as Administrative Agent, and Sovereign Bank, N.A. and TD Bank N.A., as Syndication Agents (incorporated herein by reference to Exhibit 10.5 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.4	First Amendment to the Second Amended and Restated Five-Year Revolving Credit Agreement, dated as of May 7, 2013, among Avangrid, Inc. (formerly Iberdrola USA, Inc.), Citibank N.A. and the other parties named therein (incorporated herein by reference to Exhibit 10.6 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.5	Second Amendment to the Second Amended and Restated Five-Year Revolving Credit Agreement, dated as of November 25, 2013, among Avangrid, Inc. (formerly Iberdrola USA, Inc.), Citibank, N.A., and other parties named therein (incorporated herein by reference to Exhibit 10.7 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.6	Third Amendment to the Second Amended and Restated Five-Year Revolving Credit Agreement, dated as of April 1, 2015, among Avangrid, Inc. (formerly Iberdrola USA, Inc.), Citibank, N.A. and the other parties named therein (incorporated herein by reference to Exhibit 10.8 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).

Exhibit Number	Exhibit Description
10.7	Five-Year Revolving Credit Agreement, dated July 15, 2011, among New York State Electric & Gas Corporation, Central Maine Power Company and Rochester Gas and Electric as Borrowers, the Lenders, JPMorgan Chase Bank N.A., as Administrative Agent, Bank of America, N.A., as Syndication Agent, Banco Bilbao Vizcaya Argentaria S.A., New York Branch, Sovereign Bank, TD Bank, N.A., The Bank of New York Mellon, and Union Bank, N.A. as Co-Documentation Agents, and J.P. Morgan Securities LLC, and Merrill Lynch, Pierce, Fenner & Smith Incorporated as Joint Lead Arrangers and Joint Bookrunners (incorporated herein by reference to Exhibit 10.9 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.8	Amendment to Revolving Credit Agreement, dated July 28, 2011, among New York State Electric & Gas Corporation, Rochester Gas & Electric Corporation, Central Maine Power Company, the Lenders and JPMorgan Chase Bank, N.A. as Administrative Agent (incorporated herein by reference to Exhibit 10.10 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.9	First Amendment and Extension Agreement, dated July 18, 2013, among New York State Electric & Gas Corporation, Rochester Gas and Electric Corporation, Central Maine Power Company, the Lenders, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., as Syndication Agent, and Banco Bilbao Vizcaya Argentaria S.A., New York Branch, Sovereign Bank (Santander Group), TD Bank, N.A., The Bank of New York Mellon and Union Bank, N.A., as Co-Documentation Agents (incorporated herein by reference to Exhibit 10.11 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.10	Accession Agreement, dated September 16, 2011, between Iberdrola Renewables Holdings, Inc. and Bank Mendes Gans N.V. (incorporated herein by reference to Exhibit 10.14 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.11	Guarantee and Support Agreement, dated April 3, 2008, between Iberdrola, S.A. and ScottishPower Holdings, Inc. (incorporated herein by reference to Exhibit 10.15 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.12	Amendment No. 1 to Guarantee and Support Agreement, dated May 27, 2010, between Iberdrola, S.A. and Iberdrola Renewables Holdings, Inc. (formerly known as ScottishPower Holdings, Inc.) (incorporated herein by reference to Exhibit 10.16 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.13	English Translation of Regulations for the “2014-2016 Strategic Bonus” for Senior Officers and Officers of Iberdrola, S.A. and Its Group of Companies (incorporated herein by reference to Exhibit 10.19 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015).†
10.14	Provisions to be Applied to U.S. Participants in Relation to the Regulations for the “2014-2016 Strategic Bonus” for Senior Officers and Officers of Iberdrola, S.A. and Its Group of Companies (incorporated herein by reference to Exhibit 10.20 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015). †
10.15	Iberdrola USA Networks, Inc. Annual Incentive Plan, amended and restated January 1, 2014 (incorporated herein by reference to Exhibit 10.21 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015).†
10.16	Iberdrola USA, Inc. Performance Share Plan effective as of January 1, 2009 (incorporated herein by reference to Exhibit 10.22 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015). †

Exhibit Number	Exhibit Description
10.17	Employment Agreement dated October 1, 2010 among Robert Daniel Kump, Iberdrola USA Networks, Inc. (formerly Iberdrola USA, Inc.) and Iberdrola USA Management Corporation (incorporated herein by reference to Exhibit 10.23 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015). †
10.18	Service Contract dated January 16, 2014 between Robert Daniel Kump and Avangrid, Inc. (incorporated herein by reference to Exhibit 10.24 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015). †
10.19	Offer letter dated June 16, 2014 between Pablo Canales Abaitua and Iberdrola USA Management Corporation (incorporated herein by reference to Exhibit 10.25 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015).†
10.20	Employment Agreement dated March 1, 2008 between R. Scott Mahoney and Iberdrola USA Management Corporation (formerly Energy East Management Corporation) (incorporated herein by reference to Exhibit 10.27 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015).†
10.21	Framework Agreement for the Provision of Corporate Services for Iberdrola and the Companies of its Group, and the Declaration of Acceptance, dated July 16, 2015 (incorporated herein by reference to Exhibit 10.28 to Form S-4 filed with the Securities and Exchange Commission on July 17, 2015).
10.22	Equipment Supply Agreement dated December 28, 2014 between Iberdrola Renewables, LLC and Gamesa Wind US, LLC (incorporated herein by reference to Exhibit 10.29 to Form S-4/A filed with the Securities and Exchange Commission on November 6, 2015).
10.23	Agreement and Release dated September 25, 2009 between Robert Daniel Kump and Iberdrola USA Management Corporation (formerly Energy East Management Corporation) (incorporated herein by reference to Exhibit 10.31 to Form S-4/A filed with the Securities and Exchange Commission on September 9, 2015). †
10.24	Form of Indemnification Agreement between Avangrid, Inc. (formerly Iberdrola USA, Inc.) and its directors and officers (incorporated herein by reference to Exhibit 10.32 to Form S-4/A filed with the Securities and Exchange Commission on October 21, 2015).†
10.25	UIL Holdings Corporation 2008 Stock and Incentive Compensation Plan as Amended and Restated May 14, 2013 (incorporated herein by reference to Exhibit 99.1 to Form S-8 filed with the Securities and Exchange Commission on December 16, 2015).†
10.26	UIL Holdings Corporation Deferred Compensation Plan Grandfathered Benefits Provisions, dated August 4, 2008 (incorporated herein by reference to Exhibit 99.2 to Form S-8 filed with the Securities and Exchange Commission on December 16, 2015).†
10.27	UIL Holdings Corporation Deferred Compensation Plan Non-Grandfathered Benefits Provisions, as amended and restated effective dated January 1, 2013 (incorporated herein by reference to Exhibit 99.3 to Form S-8 filed with the Securities and Exchange Commission on December 16, 2015).†
10.28	Employment Agreement, dated as of January 23, 2006, between UIL Holdings Corporation and James P. Torgerson (incorporated herein by reference to Exhibit 10.1 of UIL Holdings Corporation's Current Report on Form 8-K filed with the Securities and Exchange Commission on January 11, 2006).†
10.29	First Amendment, dated August 4, 2008, to Employment Agreement, between UIL Holdings Corporation and James P. Torgerson (incorporated herein by reference to Exhibit 10.26a of UIL Holdings Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).†
10.30	Employment Agreement, dated as of July 8, 2005, between The United Illuminating Company and Richard J. Nicholas (incorporated herein by reference to Exhibit 10.4 of UIL Holdings Corporation's Current Report on Form 8-K filed with the Securities and Exchange Commission on July 11, 2005).†
10.31	First Amendment, dated August 4, 2008, to Employment Agreement, dated as of July 8, 2005, between The United Illuminating Company and Richard J. Nicholas (incorporated herein by reference to Exhibit 10.14a of UIL Holdings Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).†

Exhibit Number	Exhibit Description
10.32	Amended and Restated UIL Holdings Corporation Change In Control Severance Plan II, dated August 4, 2008 (incorporated herein by reference to Exhibit 10.28a of UIL Holdings Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).†
10.33	Employment Agreement, dated as of January 1, 2016, among Avangrid, Inc., Avangrid Service Company and James P. Torgerson (incorporated herein by reference to Exhibit 10.1 to AVANGRID's Current Report on Form 8-K filed with the SEC on April 22, 2016).†
10.34	Amended and Restated Employment Agreement, dated as of June 14, 1999, among Avangrid, Inc. (formerly Energy East Corporation), Central Maine Power Company and Sara J. Burns (incorporated herein by reference to Exhibit 10.2 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016).†
10.35	Employment Agreement, dated as of January 1, 2012, among Central Maine Power Company, Avangrid, Inc. (formerly Iberdrola USA, Inc.) and Sara J. Burns (incorporated herein by reference to Exhibit 10.3 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016).†
10.36	Agreement and Release, dated as of November 25, 2009, between Central Maine Power Company and Sara J. Burns (incorporated herein by reference to Exhibit 10.4 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016).†
10.37	Employment Agreement, dated as of November 24, 2009, among Avangrid, Inc. (formerly Energy East Corporation), Rochester Gas & Electric Corporation, and Mark S. Lynch (incorporated herein by reference to Exhibit 10.5 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016).†
10.38	First Amendment, dated March 31, 2011, to Employment Agreement, dated as of November 24, 2009, among Avangrid, Inc. (formerly Iberdrola USA, Inc.), Rochester Gas & Electric Corporation, and Mark S. Lynch (incorporated herein by reference to Exhibit 10.6 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016).†
10.39	Revolving Credit Agreement, dated April 5, 2016, among Avangrid, Inc., New York State Electric & Gas Corporation, Rochester Gas and Electric Corporation, Central Maine Power Company, The United Illuminating Company, Connecticut Natural Gas Corporation, The Southern Connecticut Gas Company and The Berkshire Gas Company, as Borrowers, the Lenders, JPMorgan Chase Bank N.A., as Administrative Agent, Bank of America, N.A., as Syndication Agent, and J.P. Morgan Chase Bank, N.A, Merrill Lynch, Pierce, Fenner & Smith Incorporated, The Bank of Tokyo-Mitsubishi UFJ, Ltd. and Santander Bank, N.A. as Joint Lead Arrangers and Joint Bookrunners (incorporated herein by reference to Exhibit 10.1 to AVANGRID's Current Report on Form 8-K filed with the SEC on April 5, 2016).
10.40	Commercial Paper/Certificates of Deposit Issuing and Paying Agent Agreement dated May 13, 2016 among Avangrid, Inc., as Issuer, and Bank of America, National Association, as Issuing and paying Agent (incorporated herein by reference to Exhibit 10.1 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
10.41	Form of Commercial Paper Dealer Agreement among Avangrid, Inc., as Issuer, and various Dealers (incorporated herein by reference to Exhibit 10.1 of AVANGRID's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
10.42	Form of Performance Stock Unit Grant Agreement (incorporated herein by reference to Exhibit 10.1 to AVANGRID's Current Report on Form 8-K filed with the SEC on July 19, 2016). †
10.43	Avangrid, Inc. Omnibus Incentive Plan (incorporated herein by reference to Form S-8 filed with the SEC on July 21, 2016).†
10.44	Uncommitted Line of Credit for Standby Letters of Credit Agreement, dated as of December 2, 2016, between Avangrid, Inc. and Crédit Agricole Corporate. *
10.45	Substitution Agreement, dated as of December 19, 2016, between UIL Holdings Corporation and Avangrid, Inc.*
10.46	Employment Agreement, dated March 30, 2004, between The United Illuminating Company and Anthony Marone III (incorporated herein by reference to Exhibit 10.7 to UIL Holdings Corporation's Annual Report on Form 10-K filed with the SEC for the fiscal year ended December 31, 2013). †
10.47	First Amendment, dated November 8, 2004, to Employment Agreement between The United Illuminating Company and Anthony Marone III (incorporated herein by reference to Exhibit 10.7a to UIL Holdings Corporation's Annual Report on Form 10-K filed with the SEC for the fiscal year ended December 31, 2013). †

Exhibit Number	Exhibit Description
10.48	Second Amendment, dated August 4, 2008, to Employment Agreement between The United Illuminating Company and Anthony Marone III (incorporated herein by reference to Exhibit 10.7b to UIL Holdings Corporation's Annual Report on Form 10-K filed with the SEC for the fiscal year ended December 31, 2013). †
10.49	Avangrid, Inc. Executive Annual Incentive Plan (incorporated herein by reference to Exhibit 10.1 to AVANGRID's Current Report on Form 8-K filed with the SEC on February 23, 2017).†
21.1	Significant subsidiaries of the Registrant.*
23.1	Consent of Ernst & Young LLP, independent registered public accounting firm of Avangrid, Inc.*
23.2	Consent of PricewaterhouseCoopers LLP, independent accountants of UIL Holdings Corporation.*
31.1	Chief Executive Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
31.2	Chief Financial Officer Certification Pursuant to Rule 13a-14(a) and 15d-14(a), As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
32	Chief Executive Officer and Chief Financial Officer Certification Pursuant to 18 United States Code Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*
101.INS	XBRL Instance Document.*
101.SCH	XBRL Taxonomy Extension Schema Document.*
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.*
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.*
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.*
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.*

* Filed herewith.
† Compensatory plan or agreement.
0 Confidential treatment has been requested for portions of this document. The omitted portions of this document have been submitted separately to the Securities and Exchange Commission.

The foregoing list of exhibits does not include instruments defining the rights of the holders of certain long-term debt of Avangrid, Inc. and its subsidiaries where the total amount of securities authorized to be issued under the instrument does not exceed ten percent (10%) of the total assets of Avangrid, Inc. and its subsidiaries on a consolidated basis; and Avangrid, Inc. hereby agrees to furnish a copy of each such instrument to the SEC on request.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Avangrid, Inc.

Date: March 10, 2017

By: /s/ James P. Torgerson
James P. Torgerson
Director and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

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

EXHIBIT 4.5

THIRD SUPPLEMENTAL INDENTURE

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

RECITALS

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

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

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

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

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

WHEREAS, UIL is a subsidiary of Avangrid;

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

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

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

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

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

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

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

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

ARTICLE 1

RATIFICATION; DEFINITIONS

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

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

ARTICLE 2

ASSUMPTION OF OBLIGATIONS

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

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

ARTICLE 3

MISCELLANEOUS

Section 3.01. Effective of Supplemental Indenture. This Third Supplemental Indenture is executed and shall be construed as an indenture supplemental to the Indenture and, as provided in the Indenture, this Third Supplemental Indenture forms a part thereof.

Section 3.02. Counterparts. This Third Supplemental Indenture may be executed in any number of counterparts, each of which shall be an original; but such counterparts shall constitute but one and the same instrument.

Section 3.03. Acceptance. The Trustee accepts the Indenture, as supplemented by this Third Supplemental Indenture, and agrees to perform the same upon the terms and conditions set forth therein as so supplemented. The Trustee shall not be responsible in any manner whatsoever for or in respect of the validity or sufficiency of this Third Supplemental Indenture or the due execution hereof by UIL or Avangrid or in respect of the recitals contained herein, all of which are made solely by UIL and Avangrid. In entering into this Third Supplemental Indenture, the Trustee shall be entitled to the benefit of every provision of the Indenture and the 2010 Notes relating to the conduct or affecting the liability or affording protection to the Trustee, whether or not elsewhere herein so provided.

Section 3.04. Successors and Assigns. All covenants and agreements in this Third Supplemental Indenture by Avangrid or the Trustee shall bind their respective successors and assigns, whether so expressed or not.

Section 3.05. Severability. In case any one or more of the provisions contained in this Third Supplemental Indenture shall for any reason be held to be invalid, illegal or unenforceable in any respect, such invalidity, illegality or unenforceability shall not affect any other provisions of this Third Supplemental Indenture, but this Third Supplemental Indenture shall be construed as if such invalid or illegal or unenforceable provision had never been contained herein or therein.

Section 3.06. Governing Law. This Third Supplemental Indenture shall be construed in accordance with and governed by the laws of the State of New York.

Section 3.07. Conflict with Trust Indenture Act. If any provision hereof limits, qualifies or conflicts with another provision hereof which is required to be included in this Third Supplemental Indenture by any of the provisions of the Trust Indenture Act of 1939, as amended, such required provision shall control.

Section 3.08. No Benefit. Nothing in this Third Supplemental Indenture, express or implied, shall give to any Person other than the parties hereto and their successors or assigns, and the Holders of the 2010 Notes, any benefit or legal or equitable rights, remedy or claim under this Third Supplemental Indenture, the Indenture or the 2010 Notes.

Section 3.09. References to Supplemental Indenture. Any and all notices, requests, certificates and other instruments executed and delivered after the execution and delivery of this Third Supplemental Indenture may refer to the Indenture without making specific reference to this Third Supplemental Indenture, but nevertheless all such references shall include this Third Supplemental Indenture unless the context requires otherwise.

[*Signature Page Follows*]

IN WITNESS WHEREOF, the parties hereto have caused this Third Supplemental Indenture to be duly executed, all as of the day and year first above written.

UIL Holdings Corporation

By : /s/ Steven P. Fauzza
Name: Steven P. Fauzza
Title: Vice President, Controller & Treasurer

By : /s/ Leonard Rodriquez
Name: Leonard Rodriquez
Title: General Counsel

Avangrid, Inc.

By : /s/ Howard Coon
Name: Howard Coon
Title: Vice President & Treasurer

By : /s/ Daniel Alcain
Name: Daniel Alcain
Title: Senior Vice President – Controller

The Bank of New York Mellon,
as Trustee

By: /s/ Francine Kincaid
Name: Francine Kincaid
Title: Vice President

[*Signature Page to the Third Supplemental Indenture*]

EXHIBIT 10.44

December 2, 2106

Avangrid, Inc.
70 Farm View Drive
New Gloucester, ME 04260

Attention: Howard Coon, Vice President, Treasurer

Re: Offer, dated as of December 2, 2016 for a U.S.$50,000,000 Uncommitted Line of Credit for Standby Letters of Credit

Ladies and Gentlemen:

1. Introduction:

Crédit Agricole Corporate and Investment Bank ("Issuing Bank") is pleased to offer to negotiate with Avangrid, Inc., a New York corporation ("Account Party"), for the issuance of standby letters of credit, which shall be comprised of performance and financial letters of credit (the "Letters of Credit") on an uncommitted basis on and subject to the terms and conditions hereof and of the other Credit Documents (as defined below); provided, however, that the aggregate amount of the L/C Obligations (as defined below) outstanding at any time hereunder shall not exceed U.S.$50,000,000 (the "Maximum Amount"); and provided, further, that there shall be a sublimit for performance Letters of Credit with a tenor of more than one (1) year up to five (5) years of U.S.$10,000,000. The Letters of Credit issued hereunder shall be utilized by Account Party for general corporate purposes.

Upon execution hereof by Account Party and the satisfaction of the conditions to effectiveness set forth herein, this Agreement shall become effective and shall remain in effect until the earlier of November 30, 2017 and the date of revocation hereof by Issuing Bank in its sole discretion (such earlier date, the "Expiration Date"). Any obligations of Account Party incurred pursuant to this Agreement shall survive its revocation or expiration.

Account Party understands and agrees that (a) Issuing Bank may revoke this Agreement at any time without notice to Account Party and (b) this Agreement is not a commitment by Issuing Bank to issue any Letter of Credit and no commitment fee is being paid. Notwithstanding anything herein contained to the contrary, it is hereby agreed that so long as any Letter of Credit issued pursuant to the terms hereof or any Application (as defined below) remains outstanding, the Events of Default specified herein shall remain effective and shall survive the termination of this Agreement and Issuing Bank shall be entitled to exercise any and all remedies in respect thereof.

2. Definitions:

As used herein and in the other Credit Documents (unless otherwise defined therein), the following terms have the following meanings:

"Account Party": as defined in Section 1.

"Affiliate": means, with respect to any specified Person, any other Person directly or indirectly controlling or controlled by or under direct or indirect common control with such specified Person. For purposes of this definition, "control," when used with respect to any specified Person, means the power to direct the management and policies of such Person, directly or indirectly, whether through the ownership of voting securities, by contract or otherwise. For purposes of this definition, the terms "controlling," "controlled by" and "under common control with" have correlative meanings.

"Agreement": means this Offer for a U.S.$50,000,000 Uncommitted Line of Credit for Standby Letters of Credit, as amended, restated, amended and restated, supplemented, extended or otherwise modified from time to time.

"Anti-Corruption Laws": means any applicable laws, rules, or regulations relating to bribery or corruption, including (a) the United States Foreign Corrupt Practices Act of 1977; (b) the United Kingdom Bribery Act of 2010; and (c) any other similar law, rule or regulation in any applicable jurisdiction currently in force or hereafter enacted.

"Anti-Money Laundering Laws": means any laws or regulations relating to money laundering or terrorist financing in any applicable jurisdiction currently in force or hereafter enacted.

"Application": means an application, in the form attached hereto as Exhibit A or such other form as the Issuing Bank shall from time to time issue, requesting Issuing Bank to open a Letter of Credit. For the avoidance of doubt, to the extent any provision of any Application conflicts with or is otherwise inconsistent with this Agreement, the terms of this Agreement shall supersede any such Application and this Agreement shall govern.

"Base Rate": means as determined by Issuing Bank on a daily basis, the higher of (a) the rate per annum established by Issuing Bank from time to time as the reference rate for short-term commercial loans in U.S. Dollars to domestic corporate borrowers (which Account Party acknowledges is not necessarily Issuing Bank's lowest rate) and (b) the overnight cost of funds of Issuing Bank as determined solely by Issuing Bank plus 1/4 of 1% per annum.

"Board": means the Board of Governors of the Federal Reserve System of the U.S.

"Business Day": means any day, other than a Saturday or Sunday or legal holiday, on which commercial banks generally are open for business in New York, New York .

"Change of Control": means at any time Iberdrola S.A. shall cease to own, directly or indirectly, at least 51 % of the economic and voting interests in Account Party, free and clear of any Lien.

"Code": means the U.S. Internal Revenue Code of 1986, as amended.

"Collateral Account": as defined in Section 9.

"Contingent Obligation": means, as to any Person, any guarantee of payment by such Person of any Indebtedness or other obligation of any other Person, or any agreement to provide financial assurance with respect to the financial condition, or the payment of the obligations of, such other Person which has the effect of assuring or holding harmless any third Person against loss with respect to one or more obligations of such third Person.

"Credit Documents": means this Agreement, and the Applications.

"Currency": means U.S. Dollars and/or any Foreign Currency.

"Default": means any Event of Default or any condition or event which, after the giving of notice, the lapse of time, or both, or any other condition, would become an Event of Default.

"Dollar Equivalent": means, on any date of determination, with respect to an amount denominated in any Foreign Currency, the amount of U.S. Dollars that would be required to purchase such amount of such Foreign Currency on the date two (2) Business Days prior to such date, based upon the spot selling rate at which Issuing Bank offers to sell such Foreign Currency for U.S. Dollars in the London foreign exchange market at approximately 11:00 a.m., London time, for delivery two (2) Business Days later.

"Event of Default": as defined in Section 9.

"Expiration Date": as defined in Section 1.

"FATCA": means Sections 1471 through 1474 of the Code, as of the date of this Agreement (or any amended or successor version), and any current or future regulations or official interpretations thereof.

"Financial Statements": means the income statement, statement of cash flows and balance sheet of Account Party furnished in accordance with Section 8(a)(i).

"Foreign Currency": means at any time any Currency other than U.S. Dollars.

"GAAP": means generally accepted accounting principles in the U.S. consistent with those utilized in preparing the Financial Statements.

"Indebtedness": means with respect to any Person at any date: (a) all indebtedness of such Person for borrowed money or for the deferred purchase price of property or services (other than current trade liabilities incurred in the ordinary course of business and payable in accordance with customary practices), (b) any other indebtedness which is evidenced by a note, bond, debenture or similar instrument, (c) all capital lease obligations of such Person, (d) all obligations of such Person in respect of outstanding letters of credit, acceptances and similar obligations created for the account of such Person, (e) all liabilities secured by any Lien on any property owned by such Person even though such Person has not assumed or otherwise become liable for the payment thereof, (f) all Contingent Obligations of such Person and (g) net liabilities of such Person under interest rate cap agreements, interest rate swap agreements, foreign currency exchange agreements and other hedging agreements or arrangements (calculated on a basis satisfactory to Issuing Bank and in accordance with accepted industry practice). The Indebtedness of any Person shall include any Indebtedness of any partnership in which such Person is the general partner.

"Indemnified Liabilities": as defined in Section 12(b).

"Indemnitee": as defined in Section 12(b).

"ISP": as defined in Section 18(b).

"Issuing Bank": as defined in Section 1.

"L/C Obligations": means at any time, an amount equal to the sum of (a) the aggregate then undrawn and unexpired amount of the then outstanding Letters of Credit and (b) the aggregate amount of drawings under the Letters of Credit for which Issuing Bank has not then been reimbursed pursuant to Section 4.

"Letters of Credit": as defined in Section 1.

"Lien": means any mortgage, pledge, hypothecation, assignment, deposit arrangement, encumbrance, lien (statutory or other), other charge or security interest; or any preference, priority or other agreement or preferential arrangement of any kind or nature whatsoever (including, without limitation, any conditional sale or other title retention agreement or any capital lease obligation having substantially the same economic effect as any of the foregoing).

"Material Adverse Effect": means a material adverse effect on (a) the business, operations, property, condition (financial or otherwise) or prospects of Account Party, (b) the ability of Account Party to perform

its obligations under any Credit Document or (c) the validity or enforceability of (i) any of the Credit Documents or (ii) the rights or remedies of Issuing Bank thereunder.

"Maximum Amount": as defined in Section 1.

"OFAC": means the Office of Foreign Assets Control of the U.S. Department of the Treasury.

"Person": means an individual, partnership, corporation, limited liability company, business trust, joint stock company, trust, unincorporated association, joint venture, governmental authority or other entity of whatever nature.

"Reimbursement Amounts": as defined in Section 4(b).

"Requirement of Law": means as to any Person, the certificate of incorporation and by-laws or other comparable organizational or governing documents of such Person, and any law, treaty, rule, restriction or regulation or determination of an arbitrator or a court or other governmental authority (including, without limitation, any federal, state or local environmental and employee benefit laws and regulations), in each case applicable to or binding upon such Person or any of its property or to which such Person or any of its property is subject.

"Sanctioned Jurisdiction" means any country or territory that is the subject of comprehensive Sanctions broadly restricting or prohibiting dealings with, in or involving such country or territory (currently, Iran, Cuba, Syria, Sudan, North Korea and the Crimea region of Ukraine).

"Sanctioned Person" means any individual or entity (a) identified on a Sanctions List, (b) organized, domiciled or resident in a Sanctioned Jurisdiction, or (c) otherwise the subject or target of any Sanctions, including by reason of ownership or control by one or more individuals or entities described in clauses (a) or (b).

"Sanctions" shall mean any economic or financial sanctions or trade embargoes imposed, administered or enforced by (a) the U.S. (including OFAC and U.S. Department of State), (b) the United Nations Security Council, (c) the European Union or any member state, (d) the United Kingdom (including Her Majesty's Treasury), or (e) any other applicable jurisdiction.

"Sanctions List" shall mean any list of designated individuals or entities that are the subject of Sanctions, including (a) the Specially Designated Nationals and Blocked Persons List maintained by OFAC, (b) the Consolidated United Nation Security Council Sanctions List, (c) the consolidated list of persons, groups and entities subject to EU financial sanctions maintained by the European Union or any member state and (d) the Consolidated List of Financial Sanctions Targets in the United Kingdom maintained by Her Majesty's Treasury.

"SEC": means the Securities and Exchange Commission.

"Subsidiary": means as to any Person, a corporation, partnership or other entity of which shares of stock or other ownership interests having ordinary voting power (other than stock or such other ownership interests having such power only by reason of the happening of a contingency) to elect a majority of the board of directors or other managers of such corporation, partnership or other entity are at the time owned, or the management of which is otherwise controlled, directly or indirectly through one or more intermediaries, or both, by such Person. Unless otherwise qualified, all references to a "Subsidiary" or to "Subsidiaries" in this Agreement shall refer to a Subsidiary or Subsidiaries of Account Party.

"Taxes": as defined in Section 5.

"UCP": as defined in Section 18(b).

"U.S.": means the United States of America.

"U.S. Dollars" or "U.S.$": means the lawful currency of the U.S.

"USA Patriot Act": means the Uniting and Strengthening America by Providing Appropriate Tools Required to Intercept and Obstruct Terrorism Act of 2001 (USA PATRIOT Act, Title III of Pub. L. 107-56 (signed into law October 26, 2001)).

3. Issuance and Terms of Letters of Credit; Fees;

(a) At any time after the date hereof, Account Party may request Issuing Bank to issue a Letter of Credit by issuing a written request to Issuing Bank at its address specified on its signature page hereto, together with an Application therefor, completed to the satisfaction of Issuing Bank (which request and Application must be received by Issuing Bank prior to 10:00 A.M. (New York time) on the proposed date of utilization (which must be a Business Day on or prior to the Expiration Date)). Issuing Bank shall inform Account Party of its decision in its sole discretion to accept or reject such request within three (3) Business Days. If Issuing Bank does not respond within such period of time, the request will be considered to be rejected.

(b) Each Letter of Credit shall (i) be governed by the provisions hereof and of the relevant Application, (ii) be issued in either U.S. Dollars or an Agreed Foreign Currency and in a face amount to be mutually agreed, and (iii) expire on a Business Day (A) no later than twelve (12) months after the date of the issuance in the case of a financial Letter of Credit and (B) no later than five (5) years in the case of a performance Letter of Credit; provided that the aggregate amount of all L/C Obligations outstanding at any time hereunder shall not exceed the Maximum Amount; and provided, further, that the aggregate amount of performance Letters of Credit with a tenor greater than twelve (12) months to be issued hereunder may not exceed U.S.$10,000,000.

(c) Account Party shall pay to Issuing Bank a commission on each individual Letter of Credit at a rate to be agreed upon at issuance of each individual Letter of Credit, quarterly and payable in arrears. In addition, Account Party shall pay to Issuing Bank a non-refundable amendment fee with respect to each amendment to any Letter of Credit in the amount of U.S.$250 payable in advance on the date of such amendment.

(d) With respect to any obligation of Account Party to Issuing Bank under this Agreement payable in any Foreign Currency: (i) Account Party shall indemnify, defend and hold Issuing Bank harmless from all loss arising from any fluctuation in the value of such Foreign Currency from the date such obligation is payable to Issuing Bank by the terms hereof until paid in full; and (ii) upon the failure or inability of Account Party to pay Issuing Bank immediately upon demand the full amount of such obligation in such Foreign Currency, Account Party shall immediately upon Issuing Bank's demand pay to Issuing Bank the Dollar Equivalent of such amount in same day funds which shall be sufficient to fully compensate Issuing Bank for all amounts paid and all changes, costs and expenses incurred by Issuing Bank in acquiring the full amount of such Foreign Currency and Account Party shall pay interest accrued thereon at the highest rate permitted to be charged by Issuing Bank under applicable law, in U.S. Dollars, from the date such obligation is payable to Issuing Bank by the terms hereof until the date of receipt by Issuing Bank of full payment. For purposes of this Agreement the amount of any Letter of Credit denominated in any Foreign Currency shall be deemed to be the Dollar Equivalent of the amount of the Foreign Currency of such Letter of Credit.

4. Reimbursements; Overdue Amounts:

(a) Account Party will reimburse Issuing Bank (in same day funds without set-off, counterclaim or any other deduction of any nature whatsoever and in the Currency of the applicable Letter of Credit), on the date of any drawing under a Letter of Credit, if such drawing is made prior to 11:00 A.M. (New York time), or the next Business Day after the date of such drawing, if such drawing is made on or after 11:00 A.M. (New York time), amounts due in respect of drawings under the Letters of Credit ("Reimbursement Amounts"), and any interest (to the extent permitted by law) and other amounts due hereunder or under any other Credit Document; provided that if the Credit Documents provide for acceptance of a time draft or incurrence of a deferred payment obligation and if Account Party notifies

Issuing Bank of such acceptance or incurrence at least one (1) Business Day in advance of its maturity, reimbursement shall be due sufficiently in advance of its maturity to enable Issuing Bank, as issuer, to arrange for its cover in same day funds to reach the place where it is payable no later than the date of its maturity.

(b) Any amounts that are not paid on the date when due shall bear interest (before as well as after judgment) payable on demand at 2% over the Base Rate from and including the date when such payment was due to, but excluding, the date of receipt of payment.

5. Calculations; Payments; Taxes:

(a) All payments hereunder, including for Reimbursement Amounts and computations of fees and interest shall be made on the basis of a 360-day year for actual days elapsed. Except as required by law, any and all payments by Account Party under the Credit Documents shall be made free and clear of and without reduction or withholding for any and all present or future taxes, levies, deductions, imposts, charges or withholdings, imposed by any governmental authority (all such taxes, levies, deductions, imposts, charges, and withholdings being hereinafter called "Taxes"), excluding (i) franchise taxes, branch profits taxes or taxes imposed on or measured by the overall net income of Issuing Bank, (ii) any U.S. tax that is imposed on amounts payable to Issuing Bank under the law applicable at the time such Issuing Bank acquires an interest in a Letter of Credit (or designates a new lending office), except to the extent Issuing Bank (or its assignor, if any) was entitled, at the time of the designation of a new lending office (or assignment) to receive additional amounts from Account Party with respect to such withholding tax, (iii) taxes attributable to Issuing Bank's failure or inability to comply with Section 5(b), and (iv) any withholding taxes imposed under FATCA.

(b) (i) If Issuing Bank is entitled to an exemption from or reduction of withholding tax with respect to payments made under any Credit Document, Issuing Bank shall deliver to Account Party, at the time or times prescribed by applicable law and reasonably requested by Account Party, such properly completed and executed documentation reasonably requested by Account Party as will permit such payments to be made without withholding or at a reduced rate of withholding. In addition, Issuing Bank, if requested by Account Party, shall deliver such other documentation prescribed by law or reasonably requested by Account Party as will enable Account Party to determine whether or not Issuing Bank is subject to backup withholding or information reporting requirements.

(ii) If Account Party shall be required by law to deduct any Taxes from or in respect of any sum payable under the Credit Documents to Issuing Bank, (A) Account Party shall forthwith pay to Issuing Bank such additional amounts as may be necessary so that after making all required deductions for Taxes Issuing Bank receives an amount equal to the sum it would have received had no such deductions been made and (B) Account Party shall make such deductions and shall pay the full amount deducted to the relevant taxing authority in accordance with applicable law. Account Party shall, provide appropriate documentation, including receipts, evidencing payment by Account Party of any such Taxes. The obligations of Account Party under this Section 5 shall survive the termination of this Agreement, the repayment or reimbursement of all Reimbursement Amounts and all other amounts payable hereunder and under the other Credit Documents.

(iii) Without limiting the generality of the foregoing, if a payment made to Issuing Bank under any Credit Document would be subject to U.S. federal withholding Tax imposed by FATCA if such Issuing Bank were to fail to comply with the applicable reporting requirements of FATCA (including those contained in Section 1471(b) or 1472(b) of the Code, as applicable), such Issuing Bank shall deliver to Account Party at the time or times prescribed by law and at such time or times as reasonably requested by Account Party such documentation prescribed by applicable law (including as prescribed by Section 1471(b)(3)(C)(i) of the Code) and such additional documentation reasonably requested by Account Party as may be necessary for Account Party to comply with its obligations under FATCA and to determine that Issuing Bank has complied with Issuing Bank's obligations under FATCA or to determine the amount to deduct and withhold from such payment. Solely for purposes of this sub-clause (b)(iii), "FATCA" shall include any amendments made to FATCA after the date of this Agreement.

(iv) Issuing Bank agrees that if any form or certification it previously delivered pursuant to this Section 5 becomes obsolete or inaccurate in any respect (other than as a result of expiration), it shall update such form or certification or promptly notify Account Party in writing of its legal inability to do so.

6. Increased Costs:

In the event of the introduction of, or any change in, any applicable law, rule, regulation or official directive (whether or not having the force of law), or in the interpretation or application thereof by any governmental authority after the date hereof which results in an increase in the cost to Issuing Bank of making or maintaining, or which reduces the rate of return on capital of Issuing Bank as a consequence of its obligations with respect to, execution or maintenance of this Agreement or the issuance, maintenance or extension or amendment of any Letter of Credit by reason of reserve (including, without limitation, the imposition of any reserves with respect to "Eurocurrency Liabilities" (as defined in Regulation D of the Board)), liquidity, capital adequacy or similar requirements, or which results in a reduction of amounts otherwise receivable by Issuing Bank from Account Party of principal, interest or other fees and charges hereunder and thereunder by reason of tax (other than tax on the overall net income of Issuing Bank), levy, impost, fee, charge, withholding or similar requirements of any kind, Account Party will pay to Issuing Bank upon demand an amount equal to such actual increased cost or reduction. For clarity, the foregoing sentence shall apply to all requests, rules, guidelines or directives concerning capital adequacy issued in connection with the Dodd-Frank Wall Street Reform and Consumer Protection Act and all requests, rules, guidelines or directives concerning capital adequacy promulgated by the Bank for International Settlements, the Basel Committee on Banking Regulations and Supervisory Practices (or any successor or similar authority) or the U.S. financial regulatory authorities, regardless of the date adopted, issued, promulgated or implemented. If Account Party becomes liable for the payment of any additional amounts pursuant to this Section 6, it may avoid further liability for such additional amounts by: as to each outstanding Letter of Credit, seeking and obtaining replacements therefor from other financial institutions which fully cancel all obligations of Issuing Bank under such Letter of Credit (which shall thereupon be returned promptly to Issuing Bank) and the relevant Application and paying to Issuing Bank in full on the date of replacement all interest, fees and other amounts or charges due relating to such obligations. The obligations of Account Party under this Section 6 shall survive the termination of this Agreement the repayment or reimbursement of all principal and all other amounts payable hereunder and under the other Credit Documents.

7. Representations and Warranties:

Account Party represents and warrants as of the date hereof and as of the date of each Letter of Credit issued, renewed, extended or amended that:

(a) (i) it is a corporation duly organized and validly existing under the laws of the State of New York, (ii) it is in good standing therein, (iii) it is duly qualified to transact business in all jurisdictions where its ownership, lease or operation of property, or conduct of its business requires such qualification, (iv) no consent or authorization of, approval by, notice to, filing with or other act by or in respect of, any governmental authority or any other Person is required in connection with the execution, delivery, performance, validity or enforceability of any of the Credit Documents, and (v) it has the legal right and corporate power and authority to own its assets and properties and enter into, execute, deliver and perform the Credit Documents and all documents, instruments and agreements related thereto and perform the transactions and agreements contemplated thereby;

(b) the execution, delivery and performance of the Credit Documents have been duly authorized by all necessary corporate action;

(c) this Agreement has been, and each of the Credit Documents when delivered hereunder, will have been, duly executed and delivered by it, and this Agreement is, and each of the Credit Documents when delivered hereunder will, constitute the legal, valid and binding obligations of Account Party enforceable in accordance with their respective terms except as enforceability may be limited by applicable bankruptcy, insolvency, reorganization, moratorium or similar laws affecting the

enforcement of creditors' rights generally and by general equitable principles (whether enforcement is sought by proceedings in equity or at law);

(d) it is not in default under any material agreement to which it is a party or by which its businesses, assets or properties are bound, which default would materially adversely affect such Borrower's financial condition and the execution and delivery of, and the performance by it under, the Credit Documents do not and will not, create any Lien on its businesses, properties or assets, contravene, violate or conflict with any material Requirement of Law, nor result in a breach or default under any material agreement to which it is a party or by which its businesses, assets or properties are bound, except for such defaults or breaches that would not have a Material Adverse Effect;

(e) except as disclosed on Schedule 7(e) or in Account Party's annual reports on Form 10-K or quarterly reports on Form 10-Q filed with the SEC, there are no actions, suits or proceedings of any kind pending or threatened against Account Party or its assets or properties which, in any one case or in the aggregate, could reasonably be expected to have a Material Adverse Effect;

(f) it is in compliance with all Requirements of Law except where such non-compliance could not reasonably be expected to have a Material Adverse Effect; provided, however, that where such compliance relates to any Anti-Corruption Laws, Anti-Money Laundering Laws or Sanctions, each of Account Party and its Subsidiaries is in compliance in all respects and subject to no exceptions;

(g) it has filed or caused to be filed all federal, state and local tax returns which are, to its knowledge, required to be filed by it, and has paid or has made provision for the payment of all taxes shown to be due and payable on such returns or on any assessments received by it, other than any taxes or assessments it is contesting in good faith by appropriate proceedings and with respect to which it shall, to the extent required by GAAP, have set aside adequate reserves on its books;

(h) no part of the proceeds of any Letter of Credit will be used for "purchasing" or "carrying" any "margin stock" within the respective meanings of such quoted terms under Regulations T, U and X of the Board or for any purpose, which violates, or which would cause Issuing Bank to violate, the provisions of any such regulations;

(i) it is not subject to regulation under the Investment Company Act of 1940, as amended, or subject to any federal or state statutes or regulations limiting its ability to incur the indebtedness contemplated under, or otherwise affecting the validity or enforceability of, the Credit Documents;

(j) Account Party's obligations hereunder and under any other Credit Document do and, at all times hereafter, shall rank pari passu with all other unsecured and unsubordinated indebtedness of Account Party;

(k) the Financial Statements were prepared in accordance with GAAP consistently applied unless expressly disclosed therein and fairly present the consolidated financial position of the Account Party during the relevant financial year unless expressly disclosed therein to the contrary;

(l) Account Party shall, and shall cause its Subsidiaries to, maintain and enforce policies and procedures designed to promote and achieve compliance by Account Party and its Subsidiaries with applicable Anti-Corruption Laws, Anti-M oney Laundering Laws and Sanctions;

(m) none of Account Party or any of its Subsidiaries or, any of their respective directors, officers or, to Account Party's knowledge, any of their respective Affiliates, agents or employees (i) has conducted their respective businesses or taken any action that would constitute or give rise to a violation of any Anti-Corruption Law or Anti-Money Laundering Law or (ii) is or has been subject to any action, proceeding, litigation, claim or, to Account Party's knowledge, investigation with regard to any actual or alleged violation of any Anti-Corruption Laws or Anti-Money Laundering Laws;

(n) none of Account Party or any of its Subsidiaries or any of their respective directors, officers or, to Account Party's knowledge, any of their respective Affiliates, agents or employees (i) is a Sanctioned Person, (ii) is currently engaging or has engaged in any dealings or transactions with, involving or for the benefit of a Sanctioned Person, or in or involving any Sanctioned Jurisdiction, in each case in violation of applicable Sanctions, or (iii) is subject to any action, proceeding, litigation, claim or, to Account Party's knowledge, investigation with regard to any actual or alleged violation of Sanctions; and

(o) since September 30, 2016, no event, circumstance or change has occurred that has caused, either individually or in the aggregate, a Material Adverse Effect.

8. Covenants:

Until the later of (a) the Expiration Date and (b) the date on which all obligations of Account Party in respect of the Credit Documents are indefeasibly paid in cash in full and all Letters of Credit have expired or been released by the beneficiaries thereof and tendered to Issuing Bank for cancellation, Account Party agrees and covenants with Issuing Bank as follows:

(i) Account Party shall be deemed to have furnished Issuing Bank with its audited annual Financial Statements when its annual report on Form 10-K is filed with the SEC and its quarterly unaudited Financial Statements when its quarterly report on Form 10-Q is filed with the SEC;

(ii) Account Party shall provide prompt written notice of any Default or Event of Default;

(iii) Account Party shall continue to engage in business of the same general type as now conducted by it and preserve, renew and keep in full force and effect its corporate existence and take all reasonable action to maintain all rights, privileges and franchises necessary in the normal conduct of its business and comply with its material contractual obligations;

(iv) Account Party shall not convey, sell, lease, transfer or otherwise dispose of, or create, assume or suffer to exist any Lien on, all or substantially all of its assets (in each case, whether in one transaction or in a series of transactions);

(v) Account Party shall not consolidate with, or merge into, any other Person (unless there is no Change of Control of Account Party and no Default or Event of Default shall have occurred and be continuing or result therefrom);

(vi) Account Party is in compliance, and shall comply with all Requirements of Law (other than those specifically referenced in clauses (vii) through (ix) below) except where the failure to so comply could not reasonably be expected to have a Material Adverse Effect;

(vii) Account Party's obligations hereunder and under the other Credit Documents shall rank pari passu with all other unsecured and unsubordinated indebtedness of Account Party;

(viii) Account Party shall, and shall cause its Subsidiaries to, continue to maintain and enforce policies and procedures designed to promote and achieve compliance by Account Party and its Subsidiaries with applicable Anti-Corruption Laws, Anti-Money Laundering Laws and Sanctions;

(ix) Account Party shall not, directly or indirectly, (A) use any part of the proceeds of the Letters of Credit, or otherwise make available such proceeds to any Person in any manner that would constitute or give rise to a violation of Sanctions by any party hereto or (B) fund all or part of any repayment or reimbursement of the obligations hereunder out of proceeds derived from any transaction or activity involving a Sanctioned Person or Sanctioned Jurisdiction; and

(x) Account Party shall not, directly or indirectly, use any part of the proceeds of the Letters of Credit for any payments to any governmental official or employee, political party, official of a political party, candidate for political office, or anyone else acting in an official capacity, in order to obtain,

retain or direct business or obtain any improper advantage, in each case in violation of Anti-Corruption Law.

9. Events of Default:

The occurrence of any one or more of the following events shall constitute an "Event of Default" under the Credit Documents:

(a) if Account Party shall (i) fail to reimburse any Reimbursement Amount when due and payable or (ii) fail to pay interest or any other amounts due under the Credit Documents within five (5) days of the date on which such payment of interest or other amount was due and payable;

(b) if Account Party shall fail to perform any of its obligations for the payment of any Indebtedness (i) under its $1,500,000,000 Revolving Credit Agreement dated as of April 5, 2016, as amended, with JPMorgan Chase Bank, N.A., as Administrative Agent, et al., or (ii) in the aggregate amount of more than U.S.$50,000,000 (other than Indebtedness described in subsection 9(a)) when due (whether at scheduled maturity or upon acceleration, demand or otherwise) or if Account Party shall default under any agreement or instrument relating to such Indebtedness or any other event shall occur and continue after any grace period applicable thereto, if the effect of such default or event is to accelerate, or permit the acceleration of, the maturity of such Indebtedness;

(c) if Account Party shall:

(i) commence a voluntary case or other proceeding seeking liquidation, reorganization or other relief with respect to itself or its debts under any bankruptcy, insolvency or other similar law now or hereafter in effect or seeking the appointment of a trustee, receiver, liquidator, custodian or other similar official of it or any material part of its property, or shall consent to any such relief or to the appointment of or taking possession by any such official in an involuntary case or other proceeding commenced against it, or shall make a general assignment for the benefit of creditors, or shall fail generally to pay its debts as they become due, or shall take any action to authorize any of the foregoing; or

(ii) suffer the commencement of an involuntary case or other proceeding seeking liquidation, reorganization or other relief with respect to itself or its debts under any bankruptcy, insolvency or other similar law now or hereafter in effect or seeking the appointment of a trustee, receiver, liquidator, custodian or other similar official of it or any material part of its property, and such involuntary case or other proceeding shall not be controverted by appropriate proceedings within thirty (30) days of the commencement thereof or shall remain undismissed or undischarged for a period of sixty (60) days; or suffer the entry of an order for relief or be adjudicated a bankrupt or insolvent under the bankruptcy, insolvency or similar laws of any competent jurisdiction;

(d) if any representation, warranty or statement made by Account Party in any Credit Document or in any certificate or statement furnished pursuant to, or in connection with, any Credit Document shall prove to have been incorrect, misleading or incomplete in any material respect when made or deemed made;

(e) if Account Party shall fail to perform or observe in any material respect any term, covenant or agreement on its part to be performed or observed pursuant to any Credit Document (other than those covered by subsection 9(a)) and such failure shall continue unremedied for thirty (30) days after the earlier of (i) an officer of Account Party obtaining knowledge thereof and (ii) receipt by Account Party of written notice thereof from Issuing Bank;

(f) if one or more judgments or decrees shall be entered against Account Party or any of its Subsidiaries involving in the aggregate for all such Persons a liability (not paid or fully covered by insurance) of U.S.$50,000,000 or more and all such judgments and decrees shall not have been vacated, discharged, stayed or bonded pending appeal within sixty (60) days from the entry thereof;

(g) if an event shall occur with respect to Account Party which, in the reasonable judgment of Issuing Bank, has or is likely to have a Material Adverse Effect; or

(h) if a Change of Control or any material alteration of the structure or organization of Account Party, including without limitation, as a result of a leveraged buyout, recapitalization, merger or consolidation shall occur.

Upon the occurrence of any Event of Default (other than any Event of Default specified in subsection 9(c) in respect of Account Party), Issuing Bank may, by written notice to Account Party, declare this Agreement canceled and/or declare all amounts outstanding under this Agreement (including, without limitation, all amounts of L/C Obligations, whether or not the beneficiaries of the then outstanding Letters of Credit shall have presented the documents required thereunder) to be immediately due and payable in full, whereupon this Agreement shall be canceled and/or such amounts shall become immediately due and payable; provided, however, that upon the occurrence of any Event of Default specified in subsection 9(c) in respect of Account Party, this Agreement automatically shall be canceled and all amounts outstanding under this Agreement (including, without limitation, all amounts of L/C Obligations, whether or not the beneficiaries of the then outstanding Letters of Credit shall have presented the documents required thereunder) automatically shall become immediately due and payable in full, in each case without notice, presentment, demand, protest or other action of any kind, all of which are hereby expressly waived by Account Party.

With respect to any Letters of Credit with respect to which presentment for honor shall not have occurred at the time of an acceleration pursuant to the immediately preceding paragraph, Account Party shall at such time deposit in a cash collateral account on Issuing Bank's books, within Issuing Bank's sole dominion and control, designated by Issuing Bank and over which Issuing Bank shall have exclusive right of withdrawal (the "Collateral Account"), an amount (in the Currency of such Letter of Credit; provided that upon the failure or inability of Account Party for any reason to so effect such payment in the required Currency, Account Party shall be obliged to perform in accordance with Section 3(e)) equal to the aggregate then undrawn and unexpired amount of such Letters of Credit. The Collateral Account (and any and all funds and investments held therein) shall be held in the name of, and subject to the sole dominion and control of, Issuing Bank, as cash collateral for the reimbursement obligations of Account Party in the event of any drawing under the Letters of Credit. Any and all amounts held in the Collateral Account shall be applied by Issuing Bank to satisfy Account Party's L/C Obligations for which Issuing Bank has not been reimbursed, and any unused portion of such amounts after the Letters of Credit shall have expired and all L/C Obligations shall have been satisfied, shall be applied to repay other obligations of Account Party under this Agreement and the other Credit Documents. Except as expressly provided in this Section 9, notice, presentment, demand, protest and any other action of any kind are hereby expressly waived by Account Party.

Account Party hereby grants to Issuing Bank a security interest in, and right of set-off against, any and all funds and investments held in the Collateral Account from time to time and any instrument evidencing the foregoing to secure the obligations of Account Party hereunder in respect of the Letters of Credit, any and all reimbursement obligations arising in connection therewith and other obligations under this Agreement and the other Credit Documents.

Issuing Bank shall have the rights, powers and remedies of a secured party under the Uniform Commercial Code as in effect from time to time in the State of New York with respect to the funds and investments held in the Collateral Account from time to time. Account Party shall take such actions from time to time as Issuing Bank may reasonably request to perfect and preserve the security interests provided for in this Agreement.

Issuing Bank shall release all funds and investments held in the Collateral Account to, or upon the order of, Account Party (or as a court of competent jurisdiction may otherwise direct) upon the later to occur of the date that (i) this Agreement and the other Credit Documents terminate and (ii) all obligations of Account Party under the Letters of Credit and all L/C Obligations are satisfied and indefeasibly paid in full and such Letters of Credit have been canceled or expired and all amounts drawn thereunder have been reimbursed in full.

The rights and remedies of Issuing Bank under this Agreement are in addition to, and not in substitution of, the rights and remedies Issuing Bank is entitled to exercise at law, in equity and under the other Credit Documents.

10. Effectiveness of Agreement; Conditions Precedent:

(a) The effectiveness of this Agreement is subject to receipt by Issuing Bank, in form and substance satisfactory to it, of each of the following:

(i) a copy of this Agreement, duly executed by Issuing Bank and Account Party;

(ii) a customary certificate duly executed by an authorized officer of Account Party, attaching (A) a copy of the articles of incorporation or comparable organizational document duly certified by the Secretary of State of the State of New York as of a recent date; (B) a copy of the by-laws or comparable organizational document of Account Party, duly certified by an authorized officer of Account Party as being in full force and effect; (C) a copy of Account Party's resolutions certified by an authorized officer of Account Party authorizing Account Party to enter into the transactions contemplated by the Credit Documents to which Account Party is a party, including, without limitation, requesting the issuance of Letters of Credit as contemplated hereunder from Issuing Bank in the aggregate amount contemplated hereunder, and evidencing the authority of the officer(s) named therein to sign the Credit Documents and such other documents on behalf of Account Party as Issuing Bank shall require; (D) a certificate of incumbency and specimen signatures of the authorized signers of the Credit Documents issued by the secretary or assistant secretary of Account Party; and (E) a certificate of good standing duly certified by the Secretary of State of the State of New York;

(iii) a customary certificate duly executed by an authorized officer of Account Party, certifying as to (A) the truth in all respects of the representations and warranties contained in this Agreement and the other Credit Documents as though made on and as of the date of the effectiveness of this Agreement and (B) the absence of any Default or Event of Default; and

(iv) such other documents, instruments or agreements as Issuing Bank shall reasonably request.

(b) An additional condition precedent to the issuance of each Letter of Credit is the receipt by Issuing Bank of a duly executed Application in respect of such Letter of Credit.

(c)Each request to issue, renew, amended or extend a Letter of Credit by Account Party hereunder shall constitute a representation and warranty that (i) each of the representations and warranties made by Account Party contained herein or in any other Credit Document shall be true and correct on and as of the date of such issuance, renewal, amendment or extension as if made on and as of such date and (ii) no Default or Event of Default exists (either immediately before or immediately after giving effect to such issuance, renewal, amendment or extension).

11. Authorization to Debit; Right of Set-Off:

With respect to the payment of amounts due hereunder and under any Letter of Credit, Account Party hereby authorizes Issuing Bank to debit any demand deposit account of Account Party maintained with Issuing Bank for such amount when due. In the event Account Party shall default in the payment of any amount due hereunder, under any Letter of Credit, or under the other Credit Documents, Issuing Bank shall have the right to set off and apply any deposit, general or special, time or demand, provisional or final, at any time held or owing by any branch or office of Crédit Agricole S.A. to, or for the credit of, Account Party.

12. Costs and Expenses; Indemnity; Waiver of Special Damages:

(a) Account Party agrees to pay or reimburse Issuing Bank for all Issuing Bank's charges, costs and expenses (including, without limitation, reasonable fees and disbursements of counsel to Issuing Bank) incurred in connection with (i) the issuance, amendment, renewal or extension of any Letter of Credit or any demand for, or collection of, payment thereunder and (ii) the enforcement, protection or preservation of any rights under this Agreement and the other Credit Documents and any other document prepared in connection therewith.

(b) Account Party agrees to indemnify Issuing Bank and any of its Affiliates and the respective branches, agencies, directors, officers, employees, agents, advisors, partners, trustees and administrators of Issuing Bank and its Affiliates (each such Person being called an "Indemnitee") against, and pay and hold each Indemnitee harmless from, any and all losses, claims, damages and related costs and expenses, including the fees, charges and disbursements of any counsel for any Indemnitee, suffered or incurred by, or asserted against, any Indemnitee however characterized or arising out of, in connection with, or as a result of (i) any delay in paying, stamp, excise and other taxes, if any, which may be payable or determined to be payable in connection with the execution and delivery of, or consummation or administration of, any of the transactions contemplated by, or any amendment, supplement or modification of, or any waiver or consent under or in respect of, any Credit Document and any such other document, (ii) any Letter of Credit or the use of the proceeds therefrom (including any refusal by Issuing Bank to honor a demand for payment under a Letter of Credit if the documents presented in connection with such demand to not strictly comply with the terms of such Letter of Credit) and (iii) any and all other liabilities, obligations, losses, damages, penalties, any actual or prospective actions, claims, litigation, suites, investigation or proceeding (whether sounding in contract, in tort or on any other ground and regardless of whether any Indemnitee is a party thereto), judgments, suits, costs, expenses or disbursements of any kind or nature whatsoever with respect to the execution, delivery, enforcement, performance or administration of, or in any other way arising out of or relating to, any Credit Document or any other documents contemplated by or referred to therein or any action taken or omitted to be taken by any Indemnitee with respect to any of the foregoing (all the foregoing, collectively, the "Indemnified Liabilities"); provided, however, that Account Party shall have no obligation hereunder to any Indemnitee with respect to Indemnified Liabilities arising solely from the gross negligence or willful misconduct of such Indemnitee, as determined by a court of competent jurisdiction in a final, non-appealable judgment.

(c) Neither party hereto shall be liable in any action initiated by one against the other for punitive, special, indirect or consequential damages resulting from or arising out of this Agreement, including, without limitation, loss of profit or business interruptions, however the same may be caused.

All amounts due under this Section 12 shall be payable immediately after demand therefor. Without prejudice to the survival of any other provision hereof, the terms of this Section 12 shall survive the termination of this Agreement and the repayment or reimbursement of all Reimbursement Amounts and all other amounts payable hereunder.

13. Obligations Absolute; Risks:

(a)The obligation of Account Party to reimburse Issuing Bank, its correspondents, any of its branches, agencies or Affiliates for each drawing under each Letter of Credit shall be absolute, unconditional and irrevocable, and shall be paid strictly in accordance with the terms of this Agreement under any and all circumstances and irrespective of, including the following: (i) any form, lack of accuracy, legal effect, validity or enforceability of such Letter of Credit, this Agreement, or any other Credit Document or the authority of any persons signing any Credit Documents; provided such Credit Documents appear on their face to be in order; (ii) the existence of any claim, counterclaim, dispute, set-off, defense or other right that Account Party may have at any time against any beneficiary or any transferee of such Letter of Credit (or any Person for whom any such beneficiary or any such transferee may be acting), Issuing Bank or any other Person, whether in connection with this Agreement, any other Credit Document, the transactions contemplated hereby or by such Letter of Credit or any agreement or instrument relating thereto, or any unrelated transaction; (iii) any draft, demand, certificate or other document presented under such Letter of Credit proving to be forged, fraudulent, invalid or insufficient in any respect or any statement therein being untrue, insufficient or inaccurate in any respect; or any loss, error, interruption,

omission or delay in the transmission, delivery or otherwise of any document required in order to make a drawing under such Letter of Credit; (iv) any payment by Issuing Bank under such Letter of Credit against presentation of a draft or certificate that does not strictly comply with the terms of such Letter of Credit; or any payment made by Issuing Bank under such Letter of Credit to any Person; (v) any act, omission, insolvency or failure in business of any other Person including any branch of Issuing Bank; or (vi) any other event, act or omission, circumstance or happening whatsoever, whether or not similar to any of the foregoing, including any other circumstance that might otherwise constitute a defense available to, or a discharge of, Account Party. For the avoidance of doubt, the occurrence of any of the above contingencies shall not affect or impair Issuing Bank's rights and powers hereunder or the obligations of payments, indemnity or reimbursement of Account Party to Issuing Bank hereunder.

(b)None of Issuing Bank, nor any of its Affiliates nor the respective branches, agencies, directors, officers, employees, agents, advisors, partners, trustees and administrators of Issuing Bank and its Affiliates, shall have any liability or responsibility by reason of or in connection with the issuance or transfer of any Letter of Credit by Issuing Bank or any payment or failure to make any payment thereunder irrespective of any of the circumstances referred to in Section 13(a) above, or any act, error, omission, interruption, loss or delay in transmission or delivery of any draft, notice or other communication under or relating to any Letter of Credit (including any document required to make a drawing thereunder), any error in interpretation of technical terms or any consequence arising from causes beyond the control of Issuing Bank. The parties hereto expressly agree that:

(i) Issuing Bank may accept documents that appear on their face to be in substantial compliance with the terms of a Letter of Credit without responsibility for further investigation, regardless of any notice or information to the contrary, and may make payment upon presentation of documents that appear on their face to be in substantial compliance with the terms of such Letter of Credit;

(ii) Issuing Bank shall have the right, in its sole discretion, to decline to accept such documents and to make such payment if such documents are not in strict compliance with the terms of such Letter of Credit; and

(iii) This Section 13(b) shall establish the standard of care to be exercised by Issuing Bank when determining whether drafts and other documents presented under a Letter of Credit comply with the terms thereof (and the parties hereto hereby waive, to the extent permitted by applicable law, any standard of care inconsistent with the foregoing).

14. Assignments; Successors and Assigns; Pledges to Federal Reserve Bank:

(a) This Agreement shall be binding upon and inure to the benefit of Account Party, Issuing Bank and their respective successors and assigns, except that Account Party may not assign, transfer or delegate any of its rights or obligations under this Agreement without the prior written consent of Issuing Bank (such consent not to be unreasonably withheld or delayed). Issuing Bank may, at any time and from time to time, assign all or any part of its rights and obligations under the Credit Documents subject to the prior written consent of Account Party (such consent not to be unreasonably withheld or delayed); provided that no such consent shall be required (i) during the occurrence and continuance of a Default or an Event of Default or (ii) for any assignment to an Affiliate of Issuing Bank.

(b) Nothing herein shall prohibit Issuing Bank from pledging or assigning this Agreement to any Federal Reserve Bank in accordance with applicable law.

15. Notices:

(a) All notices and other communications provided for herein shall be in writing and shall be delivered by hand or overnight courier service, mailed by certified or registered mail or sent by telecopier or electronic communications (including delivery of a "pdf" by email). Notices and other communications sent by hand or overnight courier service, or mailed by certified or registered mail, shall be deemed to have been given when received; notices and other communications sent by fax or email (or

similar electronic communications) shall be deemed to have been given when sent (except that, if not given during normal business hours for the recipient, shall be deemed to have been given at the opening of business on the next Business Day for the recipient).

(b) Account Party hereby authorized Issuing Bank to accept and process any amendments, transfers, assignments of proceeds, instructions, consents, waivers and all documents relating to any Letter of Credit which are sent to Issuing Bank by electronic transmission, including SWIFT, electronic mail, telex, telecopy, telefax, courier, mail or other computer- generated telecommunications and such electronic communications shall have the same legal effect as if written and shall be binding upon and enforceable against Account Party. Issuing Bank may, but shall not be obligated to, require (a) authentication of such electronic transmission or (b) provision of original documents to Issuing Bank prior to acting on such electronic transmission. Account Party acknowledges and agrees that the privacy and integrity of electronic transmissions cannot be guaranteed to be secure or error free due to the possibility that third parties could intercept, view or alter such electronic transmissions. To the extent that any documents, information or data relating to any Letter of Credit, any Application or any other Credit Document are transmitted electronically, Account Party hereby irrevocably releases Issuing Bank from any loss or liability incurred in connection with the electronic transmission of any such documents, data and information, including any unauthorized interception, alteration or fraudulent generation and transmission of electronic transmissions by third parties.

16. Amendments and Waivers; Execution in Counterparts; Electronic Execution:

(a)Neither this Agreement nor any provision hereof may be waived, amended or modified except pursuant to an agreement or agreements in writing entered into by parties hereto.

(b)This Agreement may be executed in any number of counterparts and by different parties hereto in separate counterparts, each of which when so executed and delivered shall be deemed to be an original and all of which taken together shall constitute but one and the same agreement.

(c)Delivery of an executed counterpart of a signature page to this Agreement by telecopier or electronic communications (inducing delivery of a “pdf” by email) shall be effective as delivery of a manually executed counterpart of this Agreement.

17. No Waiver; Severability; Integration:

The failure or delay by Issuing Bank to exercise any right, power or remedy under this Agreement or any other Credit Document or with respect to the indebtedness evidenced hereby or thereby shall not operate as a waiver thereof, nor shall the exercise of any single or partial right, power or remedy preclude any other or further exercise of the same or any other right, power or remedy. Any provision of this Agreement which is illegal, prohibited or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such illegality, prohibition or unenforceability without invalidating the remaining provisions hereof, and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction. This Agreement and the other Credit Documents constitute the entire agreement and understanding among the parties hereto and supersede any and all prior agreements and understandings, oral or written, relating to the subject matter hereof.

18. Governing Law:

(a) THIS AGREEMENT SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE INTERNAL LAWS OF THE STATE OF NEW YORK.

(b) Each Letter of Credit, each Application and all transactions thereunder shall be subject to and governed by either (a) the Uniform Customs and Practice for Documentary Credits (2007 Revision), International Chamber of Commerce, Publication No. 600 (as the same may be modified or amended, the “UCP”) or (b) the International Standby Practices (ISP98), International Chamber of Commerce, Publication No. 590 (as the same may be modified or amended, the “ISP”) as Issuing Bank shall select in its sole discretion. To the extent not inconsistent with the UCP or the ISP, as the case may

be, each Letter of Credit, each Application and all transactions thereunder shall be governed by and construed in accordance with, the internal laws of the State of New York.

19. Jurisdiction; Venue; Waiver of Jury Trial:

(a) Each of the parties hereto hereby irrevocably and unconditionally submits, for itself and its property, to the exclusive jurisdiction of any New York State or federal court of the U.S. sitting in New York City, whether trial or appellate, in any action or proceeding arising out of, or relating to, this Agreement or any of the other Credit Documents, or for recognition or enforcement of any judgment in respect thereof, and each of the parties hereto hereby irrevocably and unconditionally agrees that all claims in respect of any such action or proceeding may be heard and determined in any such New York State court or, to the extent permitted by law, in such federal court and consents that any such action or proceeding may be brought in such courts and waives to the fullest extent permitted by law any objection that it may now or hereafter have to the venue of any such action or proceeding in any such court or that such action or proceeding was brought in an inconvenient court and agrees not to plead or claim the same. Each of the parties hereto agrees that a final judgment in any such action or proceeding shall be conclusive and may be enforced in other jurisdictions by suit on the judgment or in any other manner provided by law. Nothing in this Agreement shall affect any right that Issuing Bank may otherwise have to bring any action or proceeding relating to this Agreement or any of the other Credit Documents in the courts of any jurisdiction.

(b) **Each of the parties hereto hereby irrevocably waives all right to trial by jury in any action, proceeding or counterclaim arising out of, or relating to, any Credit Document or the actions of Issuing Bank or Account Party in the negotiation, administration, performance or enforcement thereof.**

20. USA Patriot Act Notification:

Issuing Bank hereby notifies Account Party that pursuant to the USA Patriot Act, it is required to obtain, verify and record information that identifies Account Party, including without limitation the name and address of Account Party.

* * *

If the foregoing is acceptable, kindly acknowledge your agreement with the terms and conditions hereof by having one original copy of this Agreement signed by a duly authorized representative of Account Party (pursuant to its resolutions) and returned to Issuing Bank as soon as possible.

[Signature pages follow]

Yours truly,

CRÉDIT AGRICOLE CORPORATE AND INVESTMENT BANK

By:/s/ Ghislain Descamps
Name: Ghislain Descamps
Title: Managing Director

By: /s Louis-Marie Dubois
Name: Louis-Marie Dubois
Title: Vice President

Address for notices:

1301 Avenue of the Americas
New York, New York 10019
Attention: Louis-Marie Dubois, Export and Trade Finance, 18th Floor
Email: etf-us@ca-cib.com

Accepted and Agreed:

AVANGRID, INC.

By: /s/ Howard Coon
Name: Howard Coon
Title: Vice President & Treasurer

By: /s/ Daniel Alcain
Name: Daniel Alcain
Title: Senior Vice President – Controller

Address for notices:

70 Farm View Drive
New Gloucester, Maine 04260
Attention: Howard Coon, Vice President, Treasurer
Email: howard.coon@avangrid.com

EXHIBIT A

APPLICATION AND AGREEMENT FOR
IRREVOCABLE STANDBY LETTER OF CREDIT

To: Crédit Agricole Corporate and Investment Bank ("Crédit Agricole CIB" or "you)
Issuing Office: _____ Date: _____

Application and Agreement for Irrevocable Standby Letter of Credit (this "Application") is hereby made for the issuance by you of your irrevocable standby letter of credit (the "Credit") in conformity with your practices and procedures and, to the extent not inconsistent therewith, in accordance with the following instructions:

(Complete Each Section Fully or Indicate "Not Applicable")

Please send the Credit to the Beneficiary by your customary means as follows:

_____ Directly to the Beneficiary.
_____ Through the Advising Bank specified below.
_____ Through your Correspondent.

Name and address of the "Beneficiary": _____

Name and address of the Advising Bank: _____

Name and address of each "Applicant" to be named as an Account Party: _____

Amount of the Credit: _____

Currency: _____

The Credit shall expire at your counters on: _____

The Credit shall provide for an extension of the expiry date: _____Yes _____No

Automatic Renewal Clause: _____Yes _____No

Cancellation Period (check one): ___30 Days ___90 Days ___120 Days; Other: _____

Amounts under the Credit shall be available as follows: _____

Partial Drawings under the Credit: _____Are permitted. _____Are not permitted.

Special Instructions:

In order to induce you to issue the Credit as provided herein, each Applicant (if more than one) hereby expressly agrees to be bound by this Application and the Offer, dated as of December 2, 2016 for a U.S.$50,000,000 Uncommitted Line of Credit for Standby Letters of Credit, as amended, restated, amended and restated, supplemented, extended or otherwise modified from time to time (the "Offer"). Any capitalized term not defined herein shall have the definition set forth in the Offer.

[Applicant]	[Applicant]
_____	_____
By: _____	By: _____
Name:_____	Name:_____
Title: _____	Title: _____
Address:	Address:

_____

For Office Use Only

No. of Credit: _____ Approved by: _____

EXHIBIT 10.45

SUBSTITUTION AGREEMENT

This SUBSTITUTION AGREEMENT, dated as of December 19, 2016 (the “Agreement”), is entered into by and between UIL HOLDINGS CORPORATION, a corporation duly organized and existing under the laws of the State of Connecticut (“UIL”) and AVANGRID, INC., a corporation duly organized and existing under the laws of the State of New York (“Avangrid”).

RECITALS

WHEREAS, the predecessor company to UIL, UIL Holdings Corporation (“predecessor UIL”) and The Bank of New York Mellon, a corporation organized under the laws of the State of New York authorized to conduct a banking business, as Trustee (“Trustee”), entered into an Indenture dated as of October 7, 2010 (the “Base Indenture” and, as amended and supplemented to the date hereof, the “Indenture”) to provide for the issuance of predecessor UIL’s unsecured senior debt securities to be issued from time to time in one or more series as might be determined by predecessor UIL under the Indenture;

WHEREAS, predecessor UIL and the Trustee have heretofore executed and delivered the First Supplemental Indenture, dated as of October 7, 2010, pursuant to which predecessor UIL issued its 4.625% Notes due 2020, in the aggregate principal amount of $450,000,000 (the “2010 Notes”);

WHEREAS, on December 15, 2015, predecessor UIL merged with and into UIL, a wholly-owned subsidiary of Avangrid.

WHEREAS, UIL, predecessor UIL and the Trustee have heretofore entered into a Second Supplemental Indenture, pursuant to which UIL assumed all of the obligations of predecessor UIL under the Indenture and the 2010 Notes;

WHEREAS, UIL, Avangrid and the Trustee intend to execute a Third Supplemental Indenture (the “Third Supplemental Indenture”) pursuant to which Avangrid will be substituted for UIL as issuer of the 2010 Notes and assume all of the obligations and perform every covenant in the Indenture (including every supplemental indenture) (collectively, the “Obligations”); and

WHEREAS, upon assumption of the Obligations by Avangrid, UIL shall be relieved of all obligations and covenants under the Indenture;

NOW THEREFORE: in consideration of the premises and the covenants and agreements provided for herein, and for other good and valuable consideration the receipt of which is hereby acknowledged, UIL and Avangrid mutually covenant and agree as follows:

SECTION I. *Payments by UIL*

UIL shall transfer, on December 19, 2016 (the “Transfer Date”), (i) to such account as shall be designated by Avangrid to UIL, an amount equal to $ in respect of the market value of the aggregate outstanding principal amount of the 2010 Notes (the "Principal Payment") plus (ii) $ in respect of the aggregate interest accrued under the 2010 Notes from and including the relevant last interest payment date up to but excluding the Transfer Date (“Interest Payment”).

SECTION 2. Assumption of Obligations by Avangrid

Upon receipt of the Principal Payment and the Interest Payment on the Transfer Date, Avangrid shall assume all of the Obligations arising out of the execution of the Third Supplemental Indenture, and UIL shall be simultaneously discharged from such obligations.

SECTION 3. *Effect of Headings.*

The Article and Section headings herein are for convenience only and shall not affect the construction hereof.

SECTION 4. *Successors and Assigns.*

All covenants and agreements in this Agreement by Avangrid shall bind its successors and assigns, whether so expressed or not.

SECTION 5. *Counterparts.*

This Agreement may be executed in any number of counterparts, each of which shall be deemed to be an original, but all such counterparts shall together constitute but one and the same instrument.

SECTION 6. *Governing Law.*

This Agreement shall be governed by and construed in accordance with the laws of New York.

IN WITNESS WHEREOF, the parties hereto have caused this Substitution Agreement to be duly executed as of the day and year first written above.

UIL Holdings Corporation

By: /s/ Steven P Fauzza
Name: Steven P Fauzza
Title: Vice President, Controller & Treasurer

By: /s/ Leonard Rodriquez
Name: Leonard Rodriquez
Title: General Counsel

Avangrid, Inc.

By:/s/ Howard Coon
Name: Howard Coon
Title: Vice President & Treasurer

By: /s/ Daniel Alcain
Name: Daniel Alcain
Title: Senior Vice President – Controller

EXHIBIT 21.1

LIST OF SUBSIDIARIES OF Avangrid, Inc.

Name of Subsidiary	State or Jurisdiction of Incorporation Or Organization
Avangrid Networks, Inc.(1)*	Maine
New York State Electric & Gas Corporation(2)	New York
Rochester Gas and Electric Corporation (2)	New York
Central Maine Power Company(2)	Maine
Maine Natural Gas Corporation(2)	Maine
UIL Holdings Corporation.(2)	Connecticut
The United Illuminating Company(5)	Connecticut
The Southern Connecticut Gas Company(5)	Connecticut
Connecticut Natural Gas Corporation(5)	Connecticut
The Berkshire Gas Company(5)	Massachusetts
Avangrid Renewables Holdings, Inc.(1)*	Delaware
Avangrid Renewables, LLC(3)	Oregon
Enstor Gas, LLC(3)*	Delaware
Enstor Energy Services, LLC(4)	Delaware
Enstor, Inc.(4)	Oregon

(1) Subsidiary of Avangrid, Inc.
(2) Subsidiary of Avangrid Networks, Inc.
(3) Subsidiary of Avangrid Renewables Holdings, Inc.
(4) Subsidiary of Enstor Gas, LLC
(5) Subsidiary of UIL Holdings Corporation

* Holding Company

EXHIBIT 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-8 No. 333-212616) pertaining to Avangrid, Inc.'s common stock to be available for issuance under the Avangrid, Inc. Omnibus Incentive Plan, and

(2) Registration Statement (Form S-8 No. 333-208571) pertaining to Avangrid, Inc.'s common stock to be available for issuance under the UIL Holdings Corporation 2008 Stock and Incentive Compensation Plan and the UIL Holdings Corporation Deferred Compensation Plan;

of our reports dated March 10, 2017, with respect to the consolidated financial statements and schedule and the effectiveness of internal control over financial reporting of Avangrid, Inc. included in this Annual Report (Form 10-K) for the year ended December 31, 2016.

/s/ Ernst & Young LLP

New York, New York
March 10, 2017

EXHIBIT 23.2

Consent of Independent Accountants

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (333-208571) of Avangrid, Inc. of our report dated April 1, 2016 relating to the consolidated balance sheet of UIL Holdings Corporation, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Boston, MA
March 10, 2017

EXHIBIT 31.1

CERTIFICATION

I, James P. Torgerson, certify that:

1. I have reviewed this annual report on Form 10-K of Avangrid, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 10, 2017

/s/ James P. Torgerson
James P. Torgerson
Director and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Richard J. Nicholas, certify that:

1. I have reviewed this annual report on Form 10-K of Avangrid, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 10, 2017

/s/ Richard J. Nicholas
Richard J. Nicholas
Chief Financial Officer

EXHIBIT 32

CERTIFICATION OF CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER
Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

Pursuant to 18 U.S.C. 1350, the undersigned, James P. Torgerson and Richard J. Nicholas, the Chief Executive Officer and Chief Financial Officer, respectively, of Avangrid, Inc. (the "issuer"), do each hereby certify that the report on Form 10-K to which this certification is attached as an exhibit (the "report") fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)) and that information contained in the report fairly presents, in all material respects, the financial condition and results of operations of the issuer.

/s/ James P. Torgerson
James P. Torgerson
Director and Chief Executive Officer
Avangrid, Inc.
March 10, 2017

/s/ Richard J. Nicholas
Richard J. Nicholas
Chief Financial Officer
Avangrid, Inc.
March 10, 2017

OCS-A 0501 MASS USA

VINEYARD WIND

Vineyard Wind

Attachment 5.6-2

AR Accounts (2015)

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)**	**4911** **(Primary Standard Industrial Classification Code Number)**	**14-1798693** **(I.R.S. Employer Identification No.)**
157 Church Street **New Haven, Connecticut** **(Address of principal executive offices)**		**06506** **(Zip Code)**

Telephone: (207) 688-6363
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $0.01 par value per share par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer	☐	Accelerated filer	☐
Non-accelerated filer	☒ (Do not check if a smaller reporting company)	Smaller reporting company	☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

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

GLOSSARY OF TERMS AND ABBREVIATIONS	1
CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS	5
PART I	6
Item 1. *Business*	6
Item 1A. *Risk Factors*	25
Item 1B. *Unresolved Staff Comments.*	40
Item 2. *Properties.*	40
Item 3. *Legal Proceedings.*	40
Item 4. *Mine Safety Disclosures.*	43
Executive Officers of AVANGRID	44
PART II	46
Item 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.*	46
Item 6. *Selected Financial Data*	47
Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*	48
Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*	77
Item 8. *Financial Statements and Supplementary Data*	80
Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.*	168
Item 9A. *Controls and Procedures.*	168
Item 9B. *Other information.*	168
PART III	169
Item 10. *Directors, Executive Officers and Corporate Governance.*	169
Item 11. *Executive Compensation.*	169
Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.*	169
Item 13. *Certain Relationships and Related Transactions, and Director Independence.*	169
Item 14. *Principal Accounting Fees and Services.*	169
Part IV	170
Item 15. *Exhibits and Financial Statement Schedules.*	170
SIGNATURES	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 Tariiff
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

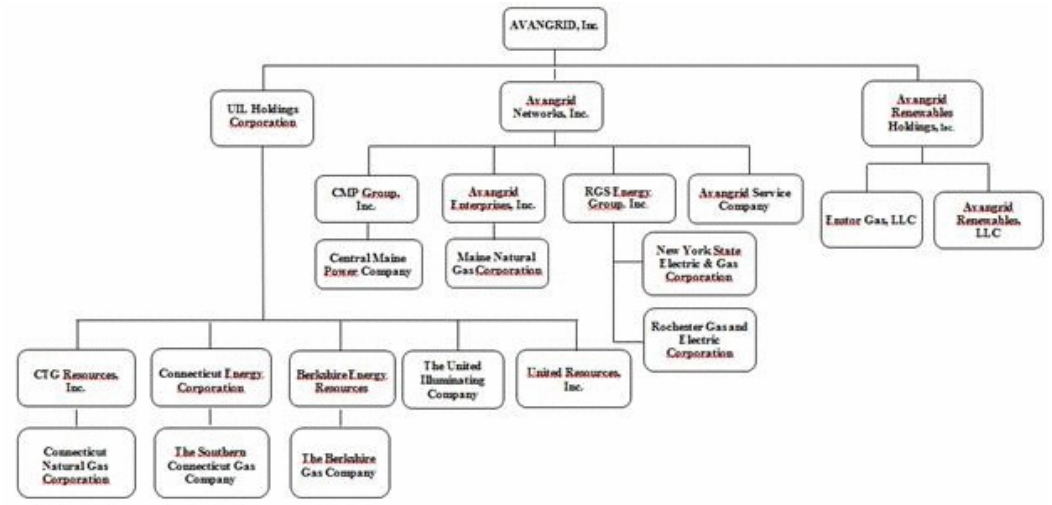
AVANGRID, Inc., or AVANGRID, formerly Iberdrola USA, Inc., is a New York corporation headquartered in New Gloucester, Maine. We are a direct, majority owned subsidiary of Iberdrola, S.A., a corporation (*sociedad anónima*) organized under the laws of Spain, one of the world's leading energy companies. 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) December 31, 2015	Electricity Customers December 31, 2015	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
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
		(in millions)	
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	3,669	3,859	3,977
CMP Dist	714	739	781
CMP Trans	1,252	1,467	1,472
MNG	47	64	60
Subtotal Maine	2,013	2,270	2,313
UI Dist	760	823	942
UI Trans	500	500	508
SCG	468	461	477
CNG	396	382	396
Subtotal Connecticut	2,124	2,166	2,323
Berkshire	70	72	91
Total	$ 7,876	$ 8,367	$ 8,704

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			3,105	5,643

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 EPAct 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 EPAct 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 EPAct 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 EPAct 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 HLPSA. PHMSA, through the NGPSA and HLPSA, regulates the design, installation, testing, construction, operation, maintenance, repair, inspection, replacement and management of interstate and certain intrastate natural gas pipeline facilities. PHMSA has also developed regulations that require transportation pipeline operators to implement integrity management programs to comprehensively evaluate certain high risk areas along Gas' natural gas pipelines and take additional measures to protect natural gas pipeline segments located in highly populated areas.

Gas' natural gas storage operations are also regulated by the EPA, and equivalent state environmental agencies, with respect to the environmental effects of its operations, including air and water quality control, solid and hazardous waste disposal, greenhouse gas emissions, noise and limitations on land use.

Global Climate Change and Greenhouse Gas Emission Issues

Global climate change and greenhouse gas emission issues continue to receive an increased focus from state governments and the federal government. In November 2010, 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 NYPSC, the MPUC, the New York State Department of Environmental Conservation, the Maine Department of Environmental Protection, the PURA, the CSC, the DEEP, and the DPU. These regulatory agencies cover a wide range of business activities, including, among other items, the retail and wholesale rates for electric energy, capacity and ancillary services, and for the transmission and distribution of these products, the costs charged to Networks' customers through tariffs including cost recovery clauses, the terms and conditions of Networks' services, procurement of electricity for Networks' customers, issuances of securities, the provision of services by affiliates and the allocation of those service costs, certain accounting matters, and certain aspects of the siting, construction and transmission and distribution systems. 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 EPAct 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 EPAct 2005 and the Dodd-Frank Act, our businesses are subject to enhanced FERC and CFTC statutory authority to monitor certain segments of the physical and financial energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of the electricity and gas markets. Under these laws, 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 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 the we have a material weakness or significant deficiency in our internal control over financial reporting, could cause investors to lose confidence in the accuracy and completeness of our financial reports, a decline in the market price of our common stock, or subject us to sanctions or investigations by the NYSE, the SEC or other regulatory authorities. Failure to remedy any material weakness or significant deficiency in our internal control over financial reporting, or to implement or maintain other effective control systems required of public companies, could also restrict our future access to the capital markets and reduce or eliminate the trading market for our common stock. Further, as a result of becoming a public company, we have incurred and will continue to incur higher legal, accounting and other expenses than we did as a private company, and these expenses may increase even more in the future.

Item 1B. ***Unresolved Staff Comments.***

None

Item 2. ***Properties.***

We have included descriptions of the location and general character of our principal physical operating properties by segment in "Item 1. *Business*", which is incorporated herein by reference. The principal offices of AVANGRID and Networks are located in New Gloucester, Maine Rochester, New York and New Haven and Orange, Connecticut. Renewables' headquarters is located in Portland, Oregon, while Gas is principally located in Houston, Texas. In addition, AVANGRID and its subsidiaries have various administrative offices located throughout the United States. AVANGRID leases part of its administrative and local offices.

The following table sets forth the principal properties of AVANGRID, by location, type, lease or ownership and size as of December 31, 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 Burkhartsmeyer	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 Burkhartsmeyer. Mr. Burkhartsmeyer was appointed Chief Executive Officer of Renewables in April 2015. Mr. Burkhartsmeyer previously served as Senior Vice President of Finance of ARHI from July 2012 until March 2015 and as Vice President of Strategy, Planning and Market Fundamentals at Renewables from July 2006 until June 2012, both subsidiaries of AVANGRID. He also served as Managing Director of Corporate Strategy of Scottish Power between June 2004 and September 2005. Mr. Burkhartsmeyer earned a B.A. from the University of Montana and a M.B.A. from the University of Oregon.

Sara J. Burns. Ms. Burns was appointed President and Chief Executive Officer of CMP in 2005. She has served as President of CMP since 1998. Ms. Burns is the Chairman of the Board of Directors of Maine & Company and serves on the Board of Directors of the Mitchell Institute and the Maine State Chamber of Commerce. She holds a B.A. in Political Science and Government from Colby College.

Sheila Duncan. Ms. Duncan was appointed Senior Vice President – Human Resources & Corporate Administration of AVANGRID on December 17, 2015. She previously served as Human Resources and Shared Services Director of Scottish Power from March 2009 until December 2015. 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 Adminstration, 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, Controller and Chief Accounting Officer, Treasurer and Secretary. Mr. Kump also previously held a number of positions at NYSEG from 1986 to 1997, including Senior Accountant-External Financial Reporting, Director-Investor Relations, Director-Financial Services, and Treasurer. Mr. Kump earned a B.A. in accounting from Binghamton University and is a C.P.A. in New York.

Mark S. Lynch. Mr. Lynch was appointed President of NYSEG and 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.

PARTII

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.

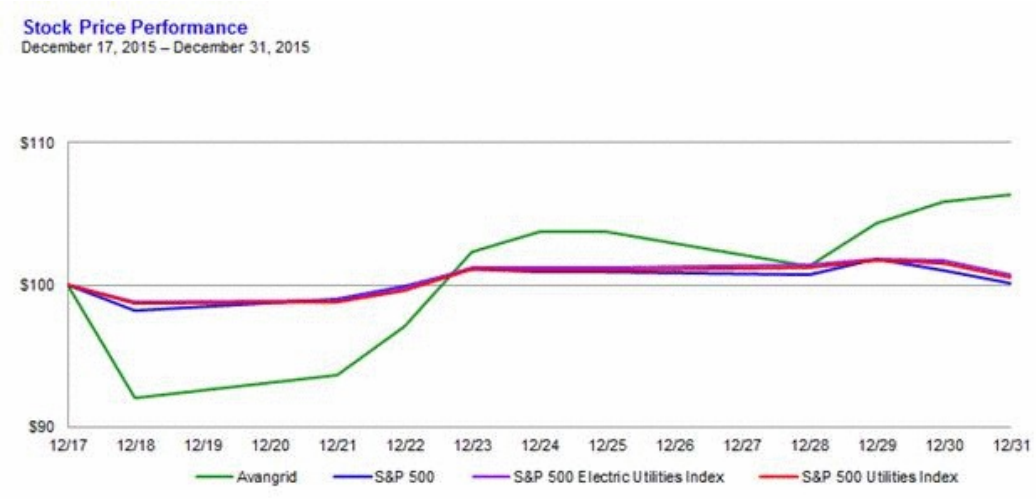
Dividends

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 shareowner 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.



	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.

	Year Ended December 31, (millions, except per share data)				
Consolidated and Combined Statements of Operations 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)				
As of December 31,	**2015**	**2014**	**2013**	**2012**	**2011**
(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	2013	2012	2011
			(millions)		
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 EBTIDA 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:

	May 1, 2016		May 1, 2017		May 1, 2018	
Utility	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %
NYSEG Electric	$ 29.6	4.10%	$ 29.9	4.10%	$ 30.3	4.10%
NYSEG Gas	13.1	7.30%	13.9	7.30%	14.8	7.30%
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	Gas	Other(1)
			(in millions)		
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)
			(in millions)		
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)
			(in millions)		
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	Gas	Other(1)
			(in millions)		
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 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
		(in millions)	
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	$ 1,126	$ 1,001	$ 974

(1) MPRP refers to the Maine Power Reliability Program.

Renewables' capital expenditures for the years set forth below were as follows:

	2013	2014	2015
		(in millions)	
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	$ 30	$ 293	$ 77

(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

Ginna 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
				(in millions)			
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 2015the 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):

		Impact on 2015 Pension Expense Increase (Decrease)	
	Change in Assumption	Pension Benefits	Post Retirement
		(in millions)	
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
		(in millions)	
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

	AVANGRID, Inc. Stockholders							
(Millions, except for number of shares)	Number of shares (*)	Common stock	Additional paid-in capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Noncontro-lling Interests	Total Equity
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.

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).

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.

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.

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.

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.

(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.

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.

(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

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.

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

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.

(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).

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

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.

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

purpose only and are not necessarily indicative of what the actual results of operations of the combined company would have been if the acquisition had occurred at the beginning of the period presented, nor are they indicative of future results of operations:

	Year Ended December 31,	
(millions)	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.

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.

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

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.

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:

	May 1, 2016		May 1, 2017		May 1, 2018	
Utility	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %
NYSEG Electric	$ 29.6	4.10%	$ 29.9	4.10%	$ 30.3	4.10%
NYSEG Gas	13.1	7.30%	13.9	7.30%	14.8	7.30%
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.

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.

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.

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

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.

Current and non-current regulatory assets as of December 31, 2015 and 2014 consisted of:

As of December 31,	2015	2014
(Millions)		
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.

"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.

Current and non-current regulatory liabilities as of December 31, 2015 and 2014 consisted of:

As of December 31,	2015	2014
(Millions)		
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.

"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.

Note 7. Goodwill and Intangible assets

Goodwill by reportable segment as of December 31, 2015 and 2014 consisted of:

As of December 31,	2015	2014
(Millions)		
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.

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.

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.

Note 8. Property, Plant and Equipment

Property, plant and equipment as of December 31, 2015 consisted of:

As of December 31, 2015	Regulated	Nonregulated	Total
(Millions)			
Electric generation, distribution, transmission and other	$ 11,506	$ 10,058	$ 21,564
Natural gas transportation, distribution and other	2,673	651	3,324
Other common operating property	817	40	857
Total Property, Plant and Equipment in Service (a)	**14,996**	**10,749**	**25,745**
Total accumulated depreciation (b)	(3,727)	(2,645)	(6,372)
Total Net Property, Plant and Equipment in Service	**11,269**	**8,104**	**19,373**
Construction work in progress	1,094	244	1,338
Total Property, Plant and Equipment	**$ 12,363**	**$ 8,348**	**$ 20,711**

(a) Includes capitalized leases of $178 million primarily related to electric generation, distribution, transmission and other.
(b) Includes accumulated amortization of capitalized leases of $53 million.

Property, plant and equipment as of December 31, 2014 consisted of:

As of December 31, 2014	Regulated	Nonregulated	Total
(Millions)			
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.

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,		2015		2014	
(Millions)	Maturity Dates	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%.

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.

(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

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)**

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.	Variability Max.	Variability 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.

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.

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,	2015	2014
(Millions)		
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

The location and amounts of derivatives designated as hedging instruments associated with Networks activities as of December 31, 2015 and 2014 consisted of:

	Asset Derivatives		Liability Derivatives	
(Millions)	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,	(Loss) Recognized in OCI on Derivatives	Location of (Loss) Reclassified from Accumulated OCI into Income	(Loss) Reclassified from Accumulated OCI into Income
(Millions)	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.

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,	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	
(Millions)						
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,	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	
(Millions)						
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.

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,	2015	2014
(MWh/Dth in Millions)		
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,	2015	2014
(Millions)		
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,	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		Net Amount
				Financial Instruments	Cash Collateral Pledged	
(Millions)						
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,	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	
(Millions)						
2015						
Derivatives	$ (307)	$ 221	$ (86)	$ 36	$ 4	$ (46)
2014						
Derivatives	(724)	620	(104)	66	1	(37)

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:

	Asset Derivatives		Liability Derivatives	
(Millions)	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 Effective Portion (a)	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.

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. Derivate 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.

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 and ownership 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

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

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

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)	Purchases				Sales			
As of December 31,	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**

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.

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 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.

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**

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.

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.

Obligations and funded status of Networks and ARHI as of December 31, 2015 and 2014 consisted of:

As of December 31,	Pension Benefits 2015	Pension Benefits 2014	Postretirement Benefits 2015	Postretirement Benefits 2014
(Millions)				
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,	Pension Benefits 2015	Pension Benefits 2014	Postretirement Benefits 2015	Postretirement Benefits 2014
(Millions)				
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.

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:

	Pension Benefits			Postretirement Benefits		
Years Ended December 31,	**2015**	**2014**	**2013**	**2015**	**2014**	**2013**
(Millions)						
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:

	Pension Benefits			Postretirement Benefits		
Years Ended December 31,	**2015**	**2014**	**2013**	**2015**	**2014**	**2013**
(Millions)						
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.

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:

	Projected Benefit Obligation Exceeds Fair Value of Plan Assets		Accumulated Benefit Obligation Exceeds Fair Value of Plan Assets	
As of December 31,	**2015**	**2014**	**2015**	**2014**
(Millions)				
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, 2015consisted of:

	Pension Benefits
As of December 31,	**2015**
(Millions)	
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)	Pension Benefits			Postretirement Benefits		
As of December 31,	**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)**

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:

	For the period from December 17, 2015 to December 31, 2015	
	Pension Benefits	Other Postretirement Benefits
(Millions)		
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)	Pension Benefits			Postretirement Benefits		
As of December 31,	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	Pension Benefits	Postretirement Benefits
(Millions)		
Estimated net loss	$ 123	$ 7
Estimated prior service cost (benefit)	2	(9)

Amounts expected to be amortized from OCI into net periodic benefit cost for the year ending December 31, 2016 consisted of:

Year Ended December 31, 2016	Pension Benefits	Postretirement Benefits
(Millions)		
Estimated net loss	$ 1	$ —
Estimated prior service cost (benefit)	—	—

We expect that no pension benefit or postretirement benefit plan assets will be returned to us during the year ending December 31, 2016.

The weighted-average assumptions used to determine benefit obligations for Networks and ARHI as of December 31, 2015 and 2014 consisted of:

	Pension Benefits		Postretirement Benefits	
As of December 31,	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:

	Pension Benefits	Other Postretirement Benefits
As of December 31,	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:

	Pension Benefits			Postretirement Benefits		
Years Ended December 31,	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%	—	—	—

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.

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

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		Fair Value Measurements		
(Millions)	Total	Level 1	Level 2	Level 3
Asset Category				
Cash and cash equivalents	$ 57	$ 3	$ 54	$ —
U.S. government securities	171	171	—	—
Common stocks	314	314	—	—
Registered investment companies	114	114	—	—
Corporate bonds	324	—	324	—
Preferred stocks	5	—	5	—
Common collective trusts	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		Fair Value Measurements		
(Millions)	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.

- 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.

The fair value of other postretirement benefits plan assets, by asset category, as of December 31, 2015 consisted of:

As of December 31, 2015		Fair Value Measurements		
(Millions)	Total	Level 1	Level 2	Level 3
Asset Category				
Money market funds	$ 4	$ 4	$ —	$ —
Mutual funds, fixed	36	36	—	—
Government and corporate bonds	2	—	2	—
Mutual funds, equity	46	46	—	—
Common stocks	24	24	—	—
Mutual funds, other	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		Fair Value Measurements		
(Millions)	Total	Level 1	Level 2	Level 3
Asset Category				
Money market funds	$ 4	$ 4	$ —	$ —
Mutual funds, fixed	36	36	—	—
Government and corporate bonds	2	—	2	—
Mutual funds, equity	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.

	Fair Value Measurements			
December 31, 2015	Level 1	Level 2	Level 3	Total
(Millions)				
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.

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.

Accumulated OCI (Loss)

Accumulated OCI for the years ended December 31, 2015, 2014 and 2013 consisted of:

Accumulated Other Comprehensive Income (Loss) (Millions)	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
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.

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
(Millions, except for number of shares and per share data)			
Numerator:			
Net income (loss) attributable to AVANGRID	$ 267	$ 424	$ (51)
Denominator:			
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
Earnings per share attributable to AVANGRID			
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.

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.

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.

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

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	$ 20,126	$ 10,685	$ 1,265	$ (1,333)	$ 30,743

(a) Does not represent a segment. It mainly includes Corporate and intercompany eliminations.

Included in revenue-external for the year ended December 31, 2015 are: $2,779 million from regulated electric operations, $605 million from regulated gas operations and $2 million from other operations of Networks; $1,051 million from renewable energy generation of Renewables; $21 million from gas storage services and $(92) million from gas trading operations of Gas.

Segment information as of and for the year ended December 31, 2014 consisted of:

For the year ended December 31, 2014 (Millions)	Networks	Renewables	Gas	Other(a)	AVANGRID Consolidated
Revenue - external	$ 3,396	$ 1,180	$ 12	$ 6	$ 4,594
Revenue - intersegment	1	9	72	(82)	—
Impairment of noncurrent assets	—	24	—	1	25
Depreciation and amortization	275	332	22	—	629
Operating income (loss) from continuing operations	616	257	16	(4)	885
Adjusted EBITDA	891	613	38	(3)	1,539
Earnings from equity method investments	—	2	—	10	12
Capital expenditures	775	250	5	—	1,030
As of December 31, 2014					
Property, plant and equipment	8,389	8,219	525	—	17,133
Equity method investments	—	262	—	—	262
Total assets	$ 12,858	$ 12,328	$ 1,393	$ (2,417)	$ 24,162

(a) Does not represent a segment. It mainly includes Corporate and intercompany eliminations.

Included in revenue-external for the year ended December 31, 2014 are: $2,726 million from regulated electric operations, $668 million from regulated gas operations and $2 million from other operations of Networks; $1,180 million from renewable energy generation of Renewables; $8 million from gas storage services and $4 million from gas trading operations of Gas.

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.

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,	2015		2014		2013	
(Millions)	Sales To	Purchases From	Sales To	Purchases From	Sales To	Purchases From
Iberdrola Financiación, S.A.	—	$ (1)	—	$ (2)	—	$ (2)
Iberdrola Renovables Energia, 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,	2015		2014	
(Millions)	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.

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:

(Millions, except per share data)	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
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

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,	2015	2014	2013
(In millions)			
AVANGRID Networks	$ 59	$ 200	$ 110
AVANGRID Renewables	750	—	—
Other AVANGRID subsidiaries	302	—	12
	$ 1,111	$ 200	$ 122

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
/s/ James P. Torgerson James P. Torgerson	Director and Chief Executive Officer (Principal Executive Officer)	April 1, 2016
/s/ Richard J. Nicholas Richard J. Nicholas	Chief Financial Officer (Principal Financial Officer)	April 1, 2016
/s/ Daniel Alcain Daniel Alcain	Controller (Principal Accounting Officer)	April 1, 2016
/s/ Ignacio Sánchez Galán Ignacio Sánchez Galán	Chairman of the Board	April 1, 2016
/s/ John E. Baldacci John E. Baldacci	Director	April 1, 2016
/s/ Pedro Azagra Blázquez Pedro Azagra Blázquez	Director	April 1, 2016
/s/ Arnold L. Chase Arnold L. Chase	Director	April 1, 2016
/s/ Alfredo Elías Ayub Alfredo Elías Ayub	Director	April 1, 2016
/s/ Carol Lynn Folt Carol Lynn Folt	Director	April 1, 2016
/s/ John L. Lahey John L. Lahey	Director	April 1, 2016
/s/ Santiago Martinez Garrido Santiago Martinez Garrido	Director	April 1, 2016
/s/ Juan Carlos Rebollo Liceaga Juan Carlos Rebollo Liceaga	Director	April 1, 2016
/s/ José Sainz Armada José Sainz Armada	Director	April 1, 2016
/s/ Alan D. Solomont Alan D. Solomont	Director	April 1, 2016

EXHIBIT 21.1

LIST OF SUBSIDIARIES OF AVANGRID, INC.

Name of Subsidiary	State or Jurisdiction of Incorporation Or Organization
Avangrid Networks, Inc.(1)*	Maine
New York State Electric 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

EXHIBIT 23.1

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

EXHIBIT 23.2

Consent of Independent Accountants

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (333-208571) of Avangrid, Inc. of our report dated April 1, 2016 relating to the consolidated balance sheet of UIL Holdings Corporation, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Boston, MA
April 1, 2016

EXHIBIT 31.1

CERTIFICATION

I, James P. Torgerson, certify that:

1. I have reviewed this annual report on Form 10-K of Avangrid, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 1, 2016

/s/ James P. Torgerson
James P. Torgerson
Director and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Richard J. Nicholas, certify that:

1. I have reviewed this annual report on Form 10-K of Avangrid, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) 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

EXHIBIT 32.1

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

OCS-A 0501 MASS USA

VINEYARD WIND

Vineyard Wind

Attachment 5.6-3

IB US Accounts (2014)

CONSOLIDATED FINANCIAL STATEMENTS

Iberdrola USA, Inc. and Subsidiaries
(A Wholly Owned Subsidiary of IBERDROLA, S.A.)
Years Ended December 31, 2014 and 2013
With Report of Independent Auditors on 2014

Iberdrola USA, Inc. and Subsidiaries
(A Wholly Owned Subsidiary of IBERDROLA, S.A.)

Consolidated Financial Statements

Years Ended December 31, 2014 and 2013

Contents

Report of Independent Auditors 1

Consolidated Financial Statements

Consolidated Statements of Financial Position 2
Consolidated Statements of Profit or Loss and Other Comprehensive Income 4
Consolidated Statements of Changes in Equity 5
Consolidated Statements of Cash Flows 6
Notes to Consolidated Financial Statements 7

Building a better working world

Ernst & Young LLP
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Report of Independent Auditors

To the Shareholder and Board of Directors of Iberdrola USA, Inc.

We have audited the accompanying consolidated financial statements of Iberdrola USA, Inc. and subsidiaries, which comprise the consolidated statement of financial position as of December 31, 2014, and the related consolidated statements of profit or loss and other comprehensive income, changes in equity and cash flows for the year then ended, and the related notes to the consolidated financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in conformity with International Financial Reporting Standards; this includes the design, implementation and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free of material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Iberdrola USA, Inc. and subsidiaries at December 31, 2014, and the consolidated results of their operations and their cash flows for the year then ended in conformity with International Financial Reporting Standards.

Ernst + Young LLP

February 19, 2015

A member firm of Ernst & Young Global Limited

Iberdrola USA, Inc. and Subsidiaries
(A Wholly Owned Subsidiary of IBERDROLA, S.A.)

Consolidated Statements of Financial Position

	Notes	December 31, 2014	December 31, 2013 *	Pro Forma January 1, 2013 *
(In Thousands)				
Assets				
Noncurrent assets:				
Intangible assets		**$1,187,294**	**$1,198,004**	**$1,284,266**
Goodwill	8	981,645	981,645	1,000,030
Other intangible assets	8	205,649	216,359	284,236
Property, plant, and equipment	9	**17,397,410**	**17,051,676**	**17,042,517**
Investments in joint arrangements	28	**178,652**	**191,121**	**199,802**
Financial assets		**196,221**	**251,519**	**232,885**
Other noncurrent financial investments		108,917	205,488	201,730
Derivative financial instruments	10	87,304	46,031	31,155
Other noncurrent receivables		**3,600**	**28,942**	**29,374**
Deferred tax assets	20	**2,389,361**	**2,041,847**	**1,874,537**
Total noncurrent assets		**21,352,538**	**20,763,109**	**20,663,381**
Current assets:				
Inventories	11	**229,873**	**297,977**	**293,752**
Current trade and other receivables	12	**854,585**	**875,381**	**924,741**
Current financial assets		**270,309**	**335,900**	**306,873**
Other financial investments		141,149	239,113	223,588
Derivative financial instruments	10	129,160	96,787	83,285
Income tax and other taxes receivables	21	**190,540**	**152,982**	**202,677**
Cash and cash equivalents	13	**463,901**	**201,313**	**41,296**
Total current assets		**2,009,208**	**1,863,553**	**1,769,339**
TOTAL ASSETS		**$23,361,746**	**$22,626,662**	**$22,432,720**

See accompanying notes.

*Consolidated Statements of Financial Position at December 31, 2013 and January 1, 2013 are presented for comparative purposes only.

Iberdrola USA, Inc. and Subsidiaries
(A Wholly Owned Subsidiary of IBERDROLA, S.A.)

Consolidated Statements of Financial Position

	Notes	December 31, 2014	December 31, 2013 *	Pro Forma January 1, 2013 *
(In Thousands)				
Equity and liabilities				
Shareholder's equity		**$10,508,073**	**$10,295,473**	**$9,043,740**
Share capital and premium	14	9,280,101	9,280,101	8,573,415
Other reserves		1,227,972	1,015,372	470,325
Non-controlling interests		**75,101**	**81,282**	**87,684**
Total equity		**10,583,174**	**10,376,755**	**9,131,424**
Capital instruments with debt-like characteristics	15	**343,615**	**454,129**	**629,857**
Noncurrent liabilities:				
Deferred income	16	**1,967,758**	**2,006,324**	**2,070,077**
Provisions		**1,777,991**	**1,456,408**	**1,734,046**
Provisions for pensions and similar obligations	17	819,123	434,374	722,879
Other provisions	18	958,868	1,022,034	1,011,167
Other financial liabilities		**2,485,233**	**2,654,120**	**2,512,556**
Other financial debts	19	2,446,686	2,625,030	2,456,799
Derivative financial instruments	10	38,547	29,090	55,757
Other noncurrent liabilities		**60,392**	**102,366**	**442,128**
Deferred tax liabilities	20	**4,539,689**	**4,075,929**	**3,744,568**
Total noncurrent liabilities		**10,831,063**	**10,295,147**	**10,503,375**
Current liabilities:				
Other provisions	18	**36,633**	**31,156**	**41,405**
Other financial liabilities		**293,154**	**229,626**	**573,281**
Other financial debts	19	190,421	77,921	475,205
Derivative financial instruments	10	102,733	151,705	98,076
Trade and other payables		**1,274,107**	**1,239,849**	**1,553,378**
Trade payables	22	693,643	898,229	848,525
Current tax liabilities and other tax payables	21	186,938	154,907	184,375
Other current liabilities		393,526	186,713	520,478
Total current liabilities		**1,603,894**	**1,500,631**	**2,168,064**
TOTAL EQUITY AND LIABILITIES		**$23,361,746**	**$22,626,662**	**$22,432,720**

See accompanying notes.

*Consolidated Statements of Financial Position at December 31, 2013 and January 1, 2013 are presented for comparative purposes only.

Iberdrola USA, Inc. and Subsidiaries
(A Wholly Owned Subsidiary of IBERDROLA, S.A.)

Consolidated Statements of Profit or Loss and Other Comprehensive Income

For The Years Ended December 31,	Notes	December 31, 2014	Pro Forma December 31, 2013 *
(In Thousands)			
Revenues		$4,349,813	$4,176,590
Cost of sales		(1,341,669)	(1,232,698)
Gross margin		**3,008,144**	**2,943,892**
Operating costs		(1,025,989)	(1,129,724)
Other operating income		53,612	35,410
		(972,377)	**(1,094,314)**
Taxes other than income tax		(365,954)	(351,239)
		(1,338,331)	**(1,445,553)**
Depreciation, amortization, and provisions	25	(723,939)	(896,885)
Income from operations		**945,874**	**601,454**
Share of profit of joint operations	28	6,219	304
Finance income	26	36,603	41,813
Finance costs	27	(216,081)	(264,209)
Results on disposal of noncurrent assets		(2,164)	(3,208)
Income before Income Tax		**770,451**	**376,154**
Income tax	20	(324,104)	(87,869)
Net Income		**446,347**	**288,285**
Non-controlling interests		**(100)**	**(1,562)**
Net income attributable to equity holders of the parent		**$446,247**	**$286,723**
Other comprehensive income			
Other comprehensive income to be reclassified to profit or loss in subsequent periods:			
Gross movement of cash-flow hedges		$84,920	($5,422)
Other comprehensive income not to be reclassified to profit or loss in subsequent periods:			
(Loss) income on revaluation of defined benefit plans		(467,063)	374,990
Income tax on OCI movements		153,397	(147,155)
Other comprehensive (loss) income for the year, net of tax		**(228,746)**	**222,413**
Total comprehensive income attributable to equity holders of the Parent		**$217,501**	**$509,136**

See accompanying notes

*The Consolidated Statements of Profit or Loss and Other Comprehensive Income at December 31, 2013 are presented for comparative purposes only.

Iberdrola USA, Inc. and Subsidiaries
(A Wholly Owned Subsidiary of IBERDROLA, S.A.)

Consolidated Statements of Changes in Equity

	Share Capital & Premium (Note 14)	Retained Earnings	Hedge Revaluation Reserve (Note 14)	Other Reserves	Total	Non-Controlling Interests (Note15)	Total Equity
(In Thousands)							
Balance at January 1, 2013 * pro forma	**8,573,415**	**$1,248,383**	**($103,918)**	**($674,140)**	**$9,043,740**	**$87,684**	**$9,131,424**
Net Income for the year	-	286,723	-	-	286,723	1,562	288,285
Other comprehensive income/(loss)	-	-	(3,710)	226,123	222,413	-	222,413
Total comprehensive income	**-**	**286,723**	**(3,710)**	**226,123**	**509,136**	**1,562**	**510,698**
Issue of share capital	706,686	-	-	33,285	739,971	-	739,971
Transfer of net assets from parent	-	-	-	2,626	2,626	-	2,626
Acquisition of non-controlling interests	-	-	-	-	-	(7,964)	(7,964)
Balance at December 31, 2013 *	**9,280,101**	**1,535,106**	**(107,628)**	**(412,106)**	**10,295,473**	**81,282**	**10,376,755**
Net Income for the year	-	446,247	-	-	446,247	100	446,347
Other comprehensive income/(loss)	-	-	52,498	(281,244)	(228,746)	-	(228,746)
Total comprehensive income	**-**	**446,247**	**52,498**	**(281,244)**	**217,501**	**100**	**217,601**
Transfer of net assets from parent	-	-	-	(4,901)	(4,901)	-	(4,901)
Acquisition of non-controlling interests	-	-	-	-	-	(6,281)	(6,281)
Balance at December 31, 2014	**$9,280,101**	**$1,981,353**	**(55,130)**	**($698,251)**	**$10,508,073**	**$75,101**	**$10,583,174**

See accompanying notes.

*The Consolidated Statements of Changes in Equity at December 31, 2013 and January 1, 2013 are presented for comparative purposes only.

Iberdrola USA, Inc. and Subsidiaries
(A Wholly Owned Subsidiary of IBERDROLA, S.A.)
Consolidated Statements of Cash Flows

For The Years Ended December 31,	Notes	December 31, 2014	Pro Forma December 31, 2013 *
(Thousands)			
Operating activities			
Net Income		$446,347	$288,285
Adjustments to reconcile net income to net cash provided by operating activities			
Realized gain on derivative contracts		(28,241)	(6,837)
Depreciation and amortization	8,9,16	725,436	668,829
Investment in joint arrangements		38,270	31,944
Impairments and write-downs	8, 9	80,738	278,535
Pension	17	40,069	65,250
Pension contribution	17	(68,669)	(39,356)
Deferred taxes and investment tax credits		202,190	44,796
Change in provision	18	(48,540)	(2,731)
Working capital and other adjustments:			
Change in trade and other assets		163,450	78,286
Change in inventories		68,135	(4,225)
Amounts due to/from affiliates, net		(32,185)	780
Change in trade and other payables, accruals and provisions		(92,616)	50,793
Change in tax receivable/payables		3,493	23,472
Income tax (paid) received		(21,824)	104
Other		(18,344)	(16,068)
Net cash flows provided by operating activities		**1,457,709**	**1,461,857**
Investing activities			
Capital expenditures	9	(1,184,736)	(1,025,321)
Grants and contributions in aid of construction	16	70,502	73,738
Proceeds from sale of assets		30,537	1,898
Purchase of intangible assets	8	(2,498)	(2,437)
Net cash flows used in investing activities		**(1,086,195)**	**(952,122)**
Financing activities			
Capital contributions from parent		-	153,000
Changes in borrowings from affiliates		199,130	16,830
Change in Aeolus debt	15	(110,378)	(134,793)
Repayment of long-term debt and related interest	19	(176,793)	(499,514)
Financial lease	19	(21,271)	81,850
Interest paid		(7,973)	(26,339)
Long-term debt issuances		-	225,000
Notes payable three months or less, net	19	8,359	(165,752)
Net cash flows used in financing activities		**(108,926)**	**(349,718)**
Change in cash and cash equivalents		262,588	160,017
Cash and cash equivalents at the beginning of the year	13	201,313	41,296
Cash and cash equivalents at the end of the year	13	**$463,901**	**$201,313**

See accompanying notes

*The Consolidated Statements of Cash Flows at December 31, 2013 are presented for comparative purposes only.

Notes to Consolidated Financial Statements

December 31, 2014

1. Company Information

Iberdrola USA, Inc. (IUSA, the company, we, our, us), is a wholly-owned subsidiary of Iberdrola, S.A. (IBERDROLA), a corporation organized under the laws of the Kingdom of Spain. On November 20, 2013, IUSA was reorganized to become the parent company of Iberdrola Renewables Holding, Inc. (IRHI), Iberdrola USA Networks, Inc. (Networks), and Iberdrola USA Group, LLC. (IUSA Group).

IUSA transferred its investments in CMP Group, Inc. (CMP Group) and RGS Energy Group, Inc. (RGS) to Networks at the time of the reorganization, as well as its investment in Iberdrola USA Management Corporation, a company providing management services for the utilities. Also transferred to Networks were Iberdrola USA Enterprises, a holding company that owned two small natural gas companies - Maine Natural Gas and New Hampshire Gas, and equity investments in a gas storage and a gas marketing company held directly by IUSA. In accordance with the predecessor values method, Networks recognized the assets and liabilities of the entities transferred to it from IUSA using the values recorded in IUSA's consolidated financial statements. IUSA retained other assets and liabilities it held directly including goodwill, tax assets and liabilities attributable to IUSA according to the tax sharing agreement, and debt obligations. IUSA also retained its investment in IUSA Group which is a holding company of small unregulated entities.

Networks is a public utility holding company operating under the Public Utility Holding Company Act of 2005. Networks is a super-regional energy services and delivery company with operations in New York and Maine. Its wholly-owned subsidiaries, and their principal operating utility companies, include: CMP Group – Central Maine Power Company (CMP), and RGS – New York State Electric & Gas Corporation (NYSEG) and Rochester Gas and Electric Corporation (RG&E).

IRHI is a holding company for Iberdrola Renewables, LLC and its subsidiaries (collectively, IRL); Iberdrola Energy Holdings and its subsidiaries (collectively, IEH), and Scottish Power Group Holdings Company and its subsidiaries (collectively, SPGHC, and collectively with IRL and IEH, IRHI). IRL is an unregulated energy business that develops, acquires, manages, and operates thermal and renewable energy generation resources and engages in origination and marketing of wholesale electricity. IEH is an unregulated energy business focusing on natural gas and provides, through its subsidiaries, the marketing of wholesale gas, energy management services, and hub services. SPGHC includes its wholly-owned subsidiary, Scottish Power Financial Services, Inc., which is an unregulated financial services business.

Management has authorized the statements for issuance on February 19, 2014, with the company's board being expected to approve these financials, without adjustment, at its next meeting. IUSA is a privately-owned company, incorporated and domiciled in the United States. The registered office is located at 99 Washington Avenue, One Commerce Plaza, Suite 2018, Albany, New York 12210.

2. Basis of Presentation

Applicable Accounting Standards

The company's 2014 and 2013 consolidated financial statements were prepared in accordance with International Financial Reporting Standards (hereinafter, IFRS) as issued by the International Accounting Standards Board (IASB).

These consolidated financial statements have been prepared on a historical cost basis, except for equity investments and derivative financial instruments, which are measured at fair value. The consolidated financial statements are presented in United States dollars (USD), and all values are rounded to the nearest thousands, except when otherwise indicated.

In accounting for the reorganization of IUSA over IRHI we followed the predecessor values method for the common control entities, the accounting policy elected by our parent for comparable transactions, rather than the acquisition method. The predecessor values method requires the financial statements to be prepared using predecessor book values without any step up to fair value.

Basis of Consolidation

The consolidated financial statements comprise the financial statements of the company and its subsidiaries as at December 31, 2014. The subsidiaries over which the company exercises control are fully consolidated. The company considers that it has control over a company when it has the power to apply its financial and operating policies so as to obtain benefits from its activities. Entities that the company manages jointly with other companies are evaluated under IFRS 11, *Joint Arrangements*, and consolidated accordingly. When necessary, adjustments are made to the financial statements of subsidiaries to bring their accounting policies in line with the company's accounting policies.

The operations of the company are consolidated in accordance with the following basic principles:

1. On acquisition, the assets, liabilities and contingent liabilities of a subsidiary are recognized at fair value. Any excess of the subsidiary's acquisition cost over the market value of its assets and liabilities is recognized as goodwill, as it corresponds to assets that cannot be separately identified and measured. The results of the subsidiaries acquired or disposed of during the year are included in the consolidated statement of profit or loss and other comprehensive income from the effective date of acquisition or until the effective date of disposal.

2. The current year result of accounting for investments using the equity method is classified under other reserves and share of profit (loss) of joint operations in the consolidated statement of financial position and in the consolidated statement of profit or loss and other comprehensive income, respectively.

3. The interest of non-controlling shareholders is presented under equity – of non-controlling interests on the liability side of the consolidated statement of financial position and non-controlling interests in the consolidated statement of profit or loss and other comprehensive income.

4. All balances and transactions between the fully and proportionately consolidated companies have been eliminated on consolidation.

3. Industry regulation

Electricity and natural gas distribution

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 United States 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 the company's 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 for 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 (effects of extreme weather conditions, environmental factors, regulatory and accounting changes, treatment of vulnerable customers, etc.) that are offset in the tariff process. Any New York revenues that allow a utility to exceed target returns (usually because of better-than-expected cost efficiency) are generally shared between the utility and its customers, resulting in future tariff reductions.

Each of the five Networks supply companies must comply with regulatory procedures that differ in form but in all cases conform to the basic framework outlined above. As a general rule, tariff reviews cover various years and provide for a reasonable ROE, protection and automatic adjustments for exceptional costs incurred and efficiency incentives.

Maine

CMP Distribution rate stipulation

On May 1, 2013, CMP submitted its required distribution rate request with the Maine Public Utilities Commission (MPUC). After a 14-month review process, on July 3, 2014, 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 revenue 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 events exceed $3.5 million. CMP and customers share storm costs that exceed a certain balance on a 50/50 basis, with CMP's exposure limited to $3.0 million annually.

CMP will make 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 will make a filing by March 1, 2015, and can include a request for a separate rate recovery mechanism.

- The rate stipulation does not have a pre-determined 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.

Transmission – FERC ROE proceeding

CMP'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, as well as return of and on investment in assets. The FERC provided a base ROE of 11.14% and additional incentive adders applicable to assets based upon vintage, voltage and other factors.

Complaint I - In September 2011 the Massachusetts Attorney general filed a complaint with the FERC that the ROE was too high and should be lowered by 1.94%, to a value of 9.2%. CMP is a member of the New England Transmission Owners. On October 16, 2014, the FERC commission issued an order in the ROE case which concluded:

- The base ROE is set at 10.57% effective October 16, 2014.
- There is an ROE cap on incentive returns of 11.74%, also effective October 16, 2014.

- The long-term growth rate used in the two-step DCF analysis should be GDP and is 4.39% in this proceeding. This aspect of their decision results from the paper hearing that FERC initiated in its June 2014 decision in this case.
- CMP must provide refunds for the period October 2011 through December 2012 with a base ROE of 10.57% and an ROE cap on incentives of 11.74%.

Complaint II – Filed December 27, 2012. On June 19, 2014 the Commission issued an order setting this case for settlement and hearing and set a refund effective date of December 27, 2012.

- The parties entered settlement negotiations which ended in late October 2014 when the parties where unable to reach agreement
- FERC has set a schedule for this case that calls for hearings in June 2015. The order estimates a decision by April 30, 2016 (subsequently revised to September 2016).
- On July 6, 2013, the FERC Administrative Law Judge issued its Final Decision (recommendation) determining that the current base ROE should be adjusted because it no longer meets Federal Power Act standards. He recommended a refund period from October 1, 2011, to December 31, 2012, be established based on a ROE of 10.6%, subject to the FERC approval.

Complaint III – Filed August 2014, reiterates the same position in Complaint II

CMP reserved for refunds in 2013 and 2014 under U.S. GAAP. The 2013 reserve was $6.6 million associated with Complaint I. In 2014, CMP recorded an additional reserve of $29.9 million associated with Complaints I, II, and III. Because these refunds will be passed on to ratepayers through rates applied to future sales, the reserves are not reflected in these statements which are prepared in accordance with IFRS.

New York (NYSEG) and RG&E Rate Plans:

On September 16, 2010, the New York Public Service Commission (NYPSC) approved a new rate plan for electric and natural gas service provided by NYSEG and RG&E effective August 26, 2010, through December 31, 2013. The rate plans contain continuation provisions beyond 2013 if NYSEG and RG&E do not request new rates to go into effect and the current base rates will stay in place.

The revenue requirements were based on a 10% allowed ROE applied to an equity ratio of 48%. If annual earnings exceed the allowed return, a tiered Earnings Sharing Mechanism (ESM) will capture a portion of the excess for the benefit of ratepayers. The ESM is subject to specified downward adjustments if NYSEG and RG&E fail to meet certain reliability and customer service measures. Key components of the rate plan include electric reliability performance mechanisms, natural gas safety performance measures, customer service quality metrics and targets, and electric distribution vegetation management programs that establish threshold performance targets. There will be downward revenue adjustments if the NYSEG and RG&E fail to meet the targets. The 2010 rate plans established Revenue Decoupling Mechanisms (RDM), intended to remove company disincentives to promote increased energy efficiency. Under the 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 (excesses) between billed revenues and allowed revenues will be accrued for future recovery (refund).

Reforming Energy Vision (REV):

In April 2014, the NYPSC commenced a proceeding entitled REV which is an initiative to reform New York State's energy industry and regulatory practices. The 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. The Track 1 of this initiative involves a collaborative process to examine the role of distribution utilities in enabling market-based deployment of distributed energy resources to promote load management and greater system efficiency, including peak load reductions. NYSEG and RG&E are participating in the initiative with other New York utilities as well as providing their unique perspective. NYPSC Staff is currently conducting public statement hearings across the state of New York regarding REV.

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.

The Track 2 (Regulatory reform) undertaken in parallel with the first track, examines changes in current regulatory, tariff, and market designs and incentive structures to better align utility interests with achieving the Commission's policy objectives. The NYPSC Staff straw proposal is anticipated in the second quarter 2015. New York utilities will also be addressing related regulatory issues in their individual rate cases.

New York Transco

Affiliates of National Grid, Central Hudson, NYSEG and RG&E, together with an affiliate of Consolidated Edison and Orange and Rockland Utilities, are part of a new organization, New York Transco LLC. 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.

New York Transco members are requesting regulatory approval for a group of transmission projects expected to cost $1.7 billion funded through debt and equity. NYSEG and RG&E allocated equity contribution (20%) 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.

The NY Transco filed with FERC in early December 2014. The filing requests a formula base ROE of 10.6%, plus 150 basis points ROE incentives. The filing also requests recognition of construction work in process, abandoned plant, regulatory asset for pre-commercial costs and 60% equity for five years. Various parties, including the NYPSC, have protested the filing with FERC. The company anticipates a FERC decision in 2015.

Electricity generation from renewable energy resources

In the United States, numerous state governments and the federal government have adopted measures and implemented numerous regulations designed to foster the development of electricity production from renewable resources. State programs have generally come in the form of 1) Renewable Portfolio Standards (RPSs) that usually require utilities to generate or purchase a minimum amount of renewable electricity and 2) tax incentives. To date, the federal government has primarily supported renewable energy development through tax credits to production and investment as well as accelerated tax depreciation.

Twenty-nine states and the District of Columbia have adopted mandatory RPS requirements, which vary across the states but will generally range from 15%-33% of generation by 2025. The requirements are typically implemented through a system of tradable renewable energy certificates that verify that a kilowatt hours (kWh) of electricity has been generated from a renewable resource. In 2014, several state legislatures debated whether to repeal or roll back significantly their RPS requirements and Ohio enacted legislation to freeze the its RPS program until 2017.

Most states also offer a variety of tax incentives to promote investment in renewable energy resources. For instance, Washington and Colorado, among other states, exempt the sale and use of renewable energy equipment from taxation, which reduces development costs substantially. Several states reduce property tax requirements on renewable generation facilities through enterprise zones or similar designations, while Minnesota has substituted a fixed-rate production tax in lieu of property taxes. Other states, such as Texas, boost the construction of electrical infrastructure (Competitive Renewable Energy Zones) to ease the transportation of renewable electricity towards load location.

In 1992 the United States Congress (Congress) enacted legislation that established a Production Tax Credit (PTC) of $15 per megawatt hour (MWh) (adjusted for inflation) for the production of electricity from wind power facilities with 10-year duration. This program has been renewed on several occasions and has been expanded to include the production of electricity from several additional renewable resources, including biomass, geothermal, municipal solid waste and hydroelectric power. Separately, in 2005 Congress established a 30% investment tax credit (ITC) for solar power projects. That investment credit is currently applicable to all solar projects placed in service prior to 1 January 2017. The PTC, which is currently valued at $23 per MWh, was most recently modified and extended by one year and will apply to those projects that started construction before 2015. These qualifying facilities may also elect to take a 30% ITC in lieu of the PTC. The purpose of the PTC and the ITC is to make electricity production from renewable resources more competitive relative to fossil fuel and nuclear power facilities.

In addition to the PTC and ITC, renewable energy facilities are eligible for accelerated five-year tax depreciation on their investments. This program, which is known as the Modified Accelerated Cost Recovery System does not have an expiration date. As a result of legislation enacted in 2008, 2009, 2013 and 2014, many facilities placed in service between 2008 and 2014 qualified for bonus depreciation, which allowed a 50% depreciation deduction in the year a facility was placed in service.

With respect to interstate transmission grids, the FERC has adopted a series of requirements on transmission operators to improve access and reduce costs for variable generation such as wind and solar power. Adoption of FERC Order 764 is driving changes in scheduling practices and other activities that will increase forecasting accuracy and reduce needed reserves, resulting in lower technology integration costs.

Regulatory assets and liabilities

Under IFRS regulatory assets (liabilities) which represent amounts to be recovered from (returned to) customers in future rates are generally not allowed, as they are under U. S. GAAP, as such they have been eliminated with a corresponding charge to reserves.

4. Summary of Significant Accounting Policies

The following are the significant accounting policies applied by the company in preparing its consolidated financial statements:

a) Revenue Recognition

Revenue is recognized to the extent that it is probable that the economic benefits will flow to the company and the revenue can be reliably measured regardless of when the payment is being made. Revenue is measured at the fair value of the consideration received or receivable, taking into account contractually defined terms of payment and excluding taxes or duty. The company assesses its revenue arrangements against specific criteria in order to determine if it is acting as an agent. The company has concluded that is acting as a principal in all of its revenue arrangements. Revenue from the sale of goods is recognized when the significant risks and rewards of ownership of the goods have passed to the buyer, usually on delivery of the goods.

The company recognizes revenue from sales of wholesale energy and natural gas when persuasive evidence of an arrangement exists, delivery has occurred or the services have been rendered, the sales price is fixed or determinable, and collection of the related receivable is reasonably assured. Title and risk of loss generally pass to the customer at the time of delivery of the services. The company records revenues from the sale of renewable energy certificates and federal energy tax credits attributable to the company's operations are also recorded in revenues when generated and sold to the third parties.

The company provides natural gas storage services to customers. The natural gas remains the property of those customers at all times. Customers pay a two-part rate that includes (i) a fixed fee reserving the right to store natural gas in the company's facilities and (ii) a per-unit rate for

volumes actually injected into/withdrawn from storage. The fixed-fee component of the overall rate is recognized as revenue in the period the service is provided. The company recognizes the per-unit charge as revenue when the volumes are injected into or withdrawn from the company's storage facilities.

Derivative contracts associated with trading activities are marked to market (MtM) through earnings. Both realized and unrealized gains on trading contracts are reflected in revenue, unless hedge accounting is elected, at which point the changes in the unrealized asset or liability moves to hedge revaluation reserves within equity. Derivative contracts associated with non-trading activities are also MtM through earnings. Unrealized gains and losses on non-trading contracts are recorded as cost of sales for purchase contracts and revenue for power and natural gas sales contracts, unless hedge accounting is elected. Realized gains and losses on non-trading contracts are reported on a net basis to the extent they are physically settled as either revenue or cost of sales.

The company evaluates its power purchase agreements (PPAs) to determine whether the arrangements contain a lease as specified in International Financial Reporting Interpretations Committee (IFRIC) 4, *Determining Whether an Arrangement Contains a Lease* (IFRIC 4). In cases where operating-lease treatment is necessary, there is no difference in revenue recognition over the life of the contract as compared to accounting for the contract as a power sale. In cases where finance-lease treatment is necessary, the timing of revenue and expense recognition is affected. Additionally, a portion of the revenue representing interest income from the financing component of the lease receivable is reflected as interest income over the life of the contract.

The company recognizes utility revenues upon delivery of energy and energy-related products and services to its customers.

Pursuant to a Maine state 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 independent system operator or similar entity. CMP generally sells all of its power entitlements under its nonutility generator and other purchase power contracts to unrelated third parties under bilateral contracts. If the MPUC does not approve the terms of bilateral contracts, it can direct CMP to sell power entitlements that it receives from those contracts on the spot market through ISO-NE.

NYSEG and RG&E enter into power purchase and sales transactions with the New York Independent System Operator (NYISO). When NYSEG and RG&E sell electricity from owned generation to the NYISO, and subsequently repurchase electricity from the NYISO to serve their customers, the transactions are recorded on a net basis in our consolidated statement of profit or loss and other comprehensive income. NYSEG and RG&E net their purchase and sale transactions with the NYISO on an hourly basis.

b) Cost of Sales

The company records the cost of purchased power and natural gas for hedging, balancing, and optimization activities and for resale to its utility customers is recorded in the consolidated statement of profit or loss and other comprehensive income, as cost of sales. The company records the cost of natural gas purchased for consumption in its generation projects as cost of sales. Trading activities including certain risk management, balancing, and optimization activities are presented net, within revenues.

c) Joint Arrangements

A joint arrangement exists whereby the parties that have joint control of the arrangement have rights to the net assets of the joint venture. IFRS 11 classifies joint arrangements into two types:

Joint Operations – whereby the parties that have joint control of the arrangement have rights to their share of the assets and liabilities relating to the arrangement. A joint operator shall consolidate its share of assets, liabilities, revenues, and expenses based on the company's interest in the ownership in the same sections of the consolidated financial statements as its own.

Joint Ventures – whereby the parties that have joint control of the arrangement have rights to the net assets of the arrangement. A joint venturer shall recognize an investment and account for that investment using the equity method in accordance with International Accounting Standard (IAS) 28, *Investments in Associates and Joint Ventures.*

Under the equity method, the investment is initially recognized at cost, and then adjusted to recognize changes in the company's share of net assets since the acquisition date. The share of profit or loss of the joint venture is shown outside operating profit and represents profit or loss after tax and non-controlling interests.

After application of the equity method, the company determines whether it is necessary to recognize an impairment loss on its investment in its joint venture. At each reporting date, the company determines whether there is objective evidence that the investment in the joint venture is impaired. If there is such evidence, the company calculates the amount of impairment as the difference between the recoverable amount of the joint venture and its carrying value, then recognizes the loss as 'Share of profit of joint operations' in the consolidated statement of profit or loss and other comprehensive income.

Upon loss of joint control over the joint venture, the company measures and recognizes any retained investment at its fair value. Any difference between the carrying amount of the joint venture upon loss of joint control and the fair value of the retained investment and proceeds from disposal is recognized in profit or loss.

d) Goodwill

Goodwill represents future economic benefits arising from other assets acquired in a business combination that are not individually identified and separately recognized. Goodwill is measured at acquisition cost. Goodwill is not amortized, although it is reviewed annually for impairment or when impairment indicators exist.

Goodwill is initially measured at cost, being the excess of the aggregate of the consideration transferred and the amount recognized for non-controlling interest over the fair value of the net identifiable assets acquired and liabilities assumed. If this consideration is lower than the fair value of the net identifiable assets acquired, the difference is recognized in profit and loss.

e) Intangible Assets

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 accumulated impairment losses. The useful lives of intangible assets are assessed as either finite or indefinite.

Intangible assets with finite lives are amortized over the useful economic life, which ranges from 4 to 40 years, and assessed for impairment whenever there is an indication that the intangible asset may be impaired. The amortization period and the amortization method for an intangible asset with a finite useful life are reviewed at least at the end of each reporting period. Changes in the expected useful life or the expected pattern of consumption of future economic benefits embodied in the asset are considered to modify the amortization period or method, as appropriate, and are treated as changes in accounting estimates. The amortization expense on intangible assets with finite lives is recognized in the consolidated statement of profit or loss and other comprehensive income as the expense category that is consistent with the function of the intangible assets.

Indefinite life intangible assets are not subject to amortization and are instead tested for impairment on an annual basis or when impairment indicators exist. The assessment of indefinite life is reviewed annually to determine whether the indefinite life continues to be supportable. If not, the change in useful life from indefinite to finite is made on a prospective basis.

<u>Other Intangible Assets</u>

Other Intangible Assets include a valuation for the underground gas storage rights that the company has in relation to its operating gas storage facilities. In addition, it also includes wind farm projects in the development phase that meet the requirements under IAS 38, *Intangible Assets*, as they are separable and susceptible to individual sale and are carried at cost. The company transfers these assets to Property, plant, and equipment in the consolidated statement of financial position when construction of each wind farm commences. Intangible assets not yet

available for use are not amortized, but are tested for impairment annually, either individually or at the cash-generating unit (CGU) level.

f) Property, Plant, and Equipment

Property, plant, and equipment are stated at cost of acquisition. In cases where the company is required to dismantle installations or to recondition the site on which they are located, the present value of such costs is added to the carrying amount of the asset, with a charge to provisions – other provisions in the consolidated statement of financial position.

The company transfers property, plant, and equipment under construction to property, plant, and equipment in use at the date of substantial completion.

The costs of expansion or improvements leading to increased productivity or capacity or to a lengthening of the useful lives of the assets are capitalized.

Replacements of complete items are recorded as additions to property, plant, and equipment, and the items replaced are derecognized. As a result of this, the company records its spare parts inventory within property, plant, and equipment.

The company periodically reviews its estimates of this present value and increases or reduces the carrying amount of its renewable generation and gas storage assets on the basis of the results obtained.

Development and construction of wind and solar generation facilities are carried out in various stages. Project costs are expensed during early-stage development activities. Once certain development milestones are achieved and it is more likely than not that the company can obtain future economic benefits from a project, salaries/wages for persons directly involved in the project, engineering, permits, licenses, meteorology, and insurance costs are capitalized. 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. Owned gas storage facilities contain injected gas that is not routinely cycled but, instead, serves the function of maintaining the necessary pressure to allow efficient operation of the facility. This gas is divided into the categories of recoverable cushion gas and unrecoverable cushion gas, based on an engineering analysis of whether the gas can be economically removed from the gas storage facility at any point during its life. The portion of the cushion gas that is determined to be unrecoverable is considered to be a permanent part of the gas storage facility itself and therefore part of property, plant, and equipment. Unrecoverable cushion gas is carried at historical cost and is depreciated over the gas storage facility's estimated useful life.

Gains or losses arising on the disposal of items of property, plant, and equipment are calculated as the difference between the amount received on the sale and the carrying amount of the asset disposed of.

Borrowing costs directly attributable to the acquisition or construction of qualifying assets are capitalized within property, plant and equipment. Capitalization of borrowing costs commences when the activities to prepare the asset for its intended use are undertaken and continue to be capitalized until the asset is placed in service. All other borrowing costs are recognized as an expense in profit or loss when incurred.

g) Depreciation of Property, Plant, and Equipment in Use

The cost of property, plant, and equipment in use is depreciated on a straight-line basis, less any material residual value. The company's main asset categories are depreciated over the following estimated useful lives:

	Average Years of Estimated Useful Life
Computer software	3-10
Combined cycle plants	30-35
Hydroelectric power stations	40-90
Wind power stations	25
Gas storage	25-40
Transport facilities	33-75
Distribution facilities	15-80
Counters and measuring device	20-41
Buildings	20-60
Operations offices	5-32

For information on the depreciation expense, please see Note 25.

h) Nonfinancial Assets Impairment

The company annually reviews the carrying amounts of its nonfinancial assets to determine whether there is any indication that those assets have suffered an impairment loss. If such indication exists, the recoverable amount of the asset is estimated in order to determine the extent of the impairment loss necessary. For this purpose, in the case of assets that, taken individually, do not generate cash flows, the company estimates the recoverable amount of the CGU to which it belongs.

The recoverable amount is the higher of fair value less costs to sell and value in use, which is taken to be the present value of the estimated future cash flows. The assumptions used in assessing value in use include: discount rates, growth rates, terminal values and expected changes in selling prices and direct costs. The discount rates reflect the time value of money and the risks specific to each CGU. The growth rates and the changes in prices and direct costs are based on contractual commitments that have already been signed, information in the public domain, sector forecasts, and the experience of the company.

If the recoverable amount of an asset or CGU is less than its carrying amount, an impairment loss is recognized for the difference with a charge to depreciation, amortization, and provisions in the consolidated statement of profit or loss and other comprehensive income. Impairment losses recognized for an asset or CGU can potentially be reversed, except in the case of goodwill. In such cases the carrying amount cannot exceed the original carrying amount recognized. In the case of goodwill and other intangible assets that have not come into use or that have an indefinite useful life, the company performs the recoverability analysis systematically every year, except when there are signs of impairment, in which case a recoverability analysis is performed immediately.

Essentially all of Networks nonfinancial assets are allowed a return pursuant to applicable regulation and are therefore not subject to annual impairment analysis. In the event that these assets were no longer allowed to earn a return, an impairment analysis would be performed.

For information related to noncurrent asset impairment losses, please see Note 25.

i) Financial Instruments

Financial assets

The company measures its current and noncurrent financial assets in accordance with the criteria described below:

1. Financial assets classified at fair value through the profit or loss. Assets included in this category are stated at fair value in the consolidated statement of financial position, and changes in fair value are recognized as finance costs or finance income in the consolidated statement of profit or loss and other comprehensive income, as appropriate.

   The company includes in this category the derivative financial instruments that do not satisfy the conditions necessary for hedge accounting based on the requirements established for this purpose in IAS 39, *Financial Instruments: Recognition and Measurement* (IAS 39).

2. Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. These are initially recognized at fair value and are subsequently measured at amortized cost using the effective interest rate method. The majority of trade and other receivables, due to their short maturity, are deemed to be at fair value, after adjusting for recoverability. Certain utility receivables, due to regulatory requirements, are expected to be recovered over extended periods of time. These are adjusted to fair value by discounting, after adjusting for recoverability.

3. Held-to-maturity investments are non-derivative assets with fixed or determinable payments and fixed maturities that the company has the intention and ability to hold to the date of maturity. These assets are measured at amortized cost.

4. Available-for-sale financial assets are the other financial assets that do not fall into any of the aforementioned three categories and correspond in almost all cases to equity instruments. These investments are also recognized in the consolidated statement of financial position at fair value at year-end, which, in the case of companies that are not publicly listed, is obtained using a range of methods such as comparable company transactions or, if there is sufficient information, by discounting the expected cash flows.

Changes in fair value are recognized with a charge or credit, as appropriate, to the hedge revaluation reserve in the consolidated statement of changes in equity until the disposal or impairment of these assets at which time the cumulative balance of this heading is recognized in full in the consolidated statement of profit or loss and other comprehensive income.

The company determines the most appropriate classification for each asset on acquisition and reviews the classification at each year-end date.

The company recognizes financial assets purchases and sales on the date of the transaction.

Cash and cash equivalents

Cash and cash equivalents include cash, bank accounts, and other highly liquid short-term investments that can be converted to cash quickly.

Financial liabilities and equity instruments

Financial liabilities are classified on the basis of the nature of their issue. The company's financial liabilities include trade and other payables, loans and borrowings (including any bank overdrafts), financial guarantee contracts, and derivative financial instruments. The company classifies as an equity instrument any contract that evidences a residual interest in the assets of the company.

Capital instruments with debt-like characteristics

The company has undertaken several structured institutional partnership investment transactions that bring in external partners as non-controlling shareholders of certain of its wind farms in exchange for cash and other financial assets.

The main characteristics of these transactions are as follows:

- Regardless of the equity stake taken by the non-controlling shareholders, the company retains ownership and management control of the wind farms; accordingly, they are fully consolidated in these financial statements.

- The non-controlling shareholders have the right to a substantial portion of the profits and tax credits generated by these wind farms up to the return level established at the beginning of the contract.

- The non-controlling shareholders remain shareholders of the wind farms until they achieve the stipulated returns.

- Once these returns have been obtained, the non-controlling shareholders lose their entitlement to hold capital in the wind farms, simultaneously renouncing their claim on the profits and tax credits generated.

- Whether or not the non-controlling shareholders of the company obtain the agreed-upon returns depends on the economic performance of the wind farms. Although the company is bound to operate and maintain these facilities in an efficient manner and to obtain the appropriate insurance policies, it is not obliged to deliver cash to the non-controlling shareholders over and above the aforementioned profits and tax credits.

Following an analysis of the economic substance of these agreements, the company classifies the consideration received at the outset of the transaction under capital instruments with debt-like characteristics in the consolidated statement of financial position. Subsequently, this consideration is measured at amortized cost.

Debentures, bonds, and bank borrowings

Loans, debentures and similar items are recorded initially at the amount received, net of transaction costs. In subsequent periods, all of these financial liabilities are measured at amortized cost, using the effective interest rate method, except for hedged transactions, which are measured using the method described below in this same note. Obligations under finance leases are recognized at the present value of the lease payments under other financial debts in the consolidated statement of financial position.

Trade and other payables

Trade payables are created by ordinary operations. As with trade receivables, the carrying value is taken to be the same as fair value.

Contracts to buy or sell nonfinancial items

The company performs a detailed analysis of all its contracts to buy or sell nonfinancial items to ensure they are classified correctly for accounting purposes.

Contracts that are settled net in cash or in another financial asset are classified as derivatives and are recognized and measured as described in this note, except for contracts entered into and held for the purpose of the receipt or delivery of a nonfinancial item in accordance with the company's purchase, sale, or usage requirements. Contracts to buy or sell nonfinancial items

which are designated as own use contracts, to which the treatment described in the IAS 39 does not apply, are recognized as the company receives or delivers the rights or obligations originating there under.

In the specific case of short-term contracts to buy or sell electricity and gas concluded on certain highly liquid markets, the company adopts the following accounting treatment:

- The company classifies as own use contracts only those contracts to buy or sell electricity or gas that reflect its best estimate of the actual purchase requirements of the company.

- All contracts entered into with the intention of realizing short-term gains on fluctuations in the market price of electricity or gas, as well as those that do not correspond to the situations described in the preceding point, are considered derivatives and are therefore recognized at their fair value in the consolidated statement of financial position.

Derivative Financial Instruments and Hedge Accounting

Financial derivatives are initially recognized at acquisition cost in the consolidated statement of financial position, and the required value adjustments are subsequently made to reflect their fair value at all times. Gains and losses arising from these changes are recognized in the consolidated statement of profit or loss unless the derivative has been designated as a hedge. The company primarily uses cash flow hedges, where the risk hedged is the variation in cash flows attributable to a specific risk associated with an asset or liability or a likely transaction, or to exchange rate risk in a firm commitment.

Each time a hedge transaction is entered into, the company contemporaneously documents the transaction to be treated under hedge accounting. This documentation includes its identification as a hedge instrument, the item hedged, the nature of the risk the hedge is designed to cover, and the way the effectiveness of the hedge is to be measured. In addition, hedges are reviewed periodically to ensure they are highly effective (between 80% and 125%).

The accounting treatment for cash flow hedges is as follows:

- Changes in the fair value of the hedging derivative are recognized, in respect of the ineffective portion of the hedges, in the consolidated statement of profit or loss, while the effective portion is recognized under hedge revaluation reserve in the consolidated statement of changes in equity. The cumulative gain or loss recognized is transferred to the relevant caption within the consolidated statement of profit or loss as the hedged item affects net profit or loss or in the year in which the item is disposed.

- If a hedge of a forecasted transaction results in the recognition of a nonfinancial asset or a liability, its balance is taken into account in the initial measurement of the assets or liabilities arising from the hedged transaction.

- If a hedge of a forecasted transaction results in the recognition of a financial asset or liability, this balance is recognized in the hedge revaluation reserve until the hedged item affects the consolidated statement of profit or loss.

- If a forecasted transaction does not result in recognition of an asset or a liability, the amounts credited or charged to hedge revaluation reserve in the consolidated statement of changes in equity will be recognized in the consolidated statement of profit or loss in the same period in which the hedge transaction is realized.

- When hedge accounting is discontinued, the cumulative amount at that date recognized under hedge revaluation reserve is retained until the hedged transaction occurs, at which time the gain or loss on the transaction will be adjusted. If a hedged transaction is no longer expected to occur, the gain or loss recognized under the aforementioned heading is transferred to the consolidated statement of profit or loss.

Derivatives embedded in other financial instruments are recognized separately when the company considers that their characteristics are not closely related to the financial instruments in which they are embedded and so long as the entire contract is not already and entirely carried at fair value through profit or loss, registering changes in fair value with the gain or loss recognized in the consolidated statement of profit or loss.

The fair value of the derivative financial instruments is calculated as follows:

- Derivatives quoted on an organized market are calculated at market price at year-end.

- Derivatives not traded on an organized market, the company uses assumptions based on market conditions at year-end. The fair value of contracts to trade nonfinancial items falling under the scope of IAS 39 is calculated on the basis of the best estimate of future price curves for the underlying nonfinancial items at year-end using, wherever possible, prices established on futures markets.

Derecognition of financial assets and liabilities

A financial asset is derecognized when:

- The rights to receive cash flows from the asset have expired.

- The company retains the rights to receive cash flows from the asset but has assumed an obligation to pay them in full to a third party and has transferred substantially all the asset's benefits and risks or does not retain them substantially.

- The company has transferred its rights to receive cash flows from the asset and either has transferred substantially all the risks and rewards of the asset or has neither transferred nor retained substantially all risks and rewards of the asset but has transferred control of the asset.

Financial liabilities are derecognized when the obligation under the liability is discharged, cancelled or expires.

j) Inventories

The company, through its gas trading operations, owns natural gas that is stored in both its own and third-party underground storage facilities. This gas is recorded as inventory. It also owns natural gas for sale to its utility natural gas customers. This gas is also included in inventory. Injections of inventory into storage are priced at the market price at the time of injection, and withdrawals of working gas from storage are priced at the weighted-average price in storage.

The company, through its gas storage operations, owns natural gas in its owned underground storage facilities classified as either inventory or as cushion gas. The component that is inventory represents the portion of gas in the company's gas storage facilities available for routine injection and withdrawal to meet demand and also optimization opportunities within the next fiscal year. The component that is cushion gas represents the gas required to maintain pressure levels for normal operating purposes and is included in property, plant, and equipment.

k) Deferred Income

The company includes the following items as deferred income:

Government grants

Income recognized under various state or federal programs of the United States, received in relation to investment expenditures made by the company, is recognized under deferred income as a liability in the consolidated statement of financial position when the related investments have been made and when the company has submitted a recognized formal application for the grant.

All capital grants are recognized in the profit and loss under depreciation, amortization and provisions on the consolidated statement of profit or loss and other comprehensive income as the facilities are depreciated, thereby offsetting the depreciation expense.

Contributions in Aid of Construction (CIAC)

Income recognized as a result of payments received from customers in relation to investment expenditures made by the company or resulting from contributions of property to the company, is recognized under deferred income as a liability in the consolidated statement of financial position when the related investments have been made.

All CIAC funds are recognized in the profit and loss under other income on the consolidated statement of profit or loss as the related facilities are depreciated, thereby offsetting the amount recorded to depreciation expense.

Other deferred income

As outlined previously under Revenue Recognition, the company on occasion receives payments from transactions in advance of the resulting obligations arising from the transaction. It is the policy of the company to defer such revenues and amortize them to the consolidated statement of profit or loss and other comprehensive income consistent with the obligations.

l) Post-Employment and Other Employee Benefits

The company sponsors defined benefit pension plans that cover the majority of the company's employees. The company also provides health care and life insurance benefits through various post-retirement plans for eligible retirees.

The company evaluates its actuarial assumptions on an annual basis and considers changes based upon market conditions and other factors. All of the company's qualified defined benefit plans are funded in amounts calculated by independent actuaries based on actuarial assumptions proposed by management. The company uses a December 31 measurement date for its benefits plans.

The company commissions independent actuarial studies using the projected unit credit method to measure the obligation accrued at year-end, and recognizes the positive or negative actuarial differences as other reserves in the consolidated statement of financial position, when they arise. The provision recognized in this respect represents the present value of the defined benefit obligation reduced by the fair value of the related plans' assets. The fair value of the assets move with market gains and losses, company contributions, and withdrawals made by the company to pay benefits.

m) Provisions

The company has obligations relating to its electricity generation facilities that will incur decommissioning costs, and as a result it records this as a decommissioning provision (or liability).

The estimated present value of these costs is capitalized with a credit to provisions at the beginning of the useful life of the related asset. This estimate is subject to annual revision so that the provision reflects the present value of the full amount of the estimated future costs.

Any change in the provision as a result of unwinding of discounting is recognized in finance costs in the consolidated statement of profit or loss and other comprehensive income.

Additionally, from time to time the company may be required to recognize provisions to cover present obligations, whether these be legal or constructive, which arise as a result of past events, provided that it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. In such cases, a provision is recognized when the liability or obligation arises, with a

charge to the relevant heading in the consolidated statement of profit or loss and other comprehensive income depending upon the nature of the obligation, for the present value of the provision when the effect of discounting the value of the obligation to present value is material.

The change in the provision due to its discounting each year is recognized under finance costs in the consolidated statement of profit or loss and other comprehensive income.

The company also records as a provision the present value of the anticipated costs to remediate certain hazardous substances at sites where gas was manufactured in the past. The anticipated costs of remediation as requirements of various state and federal environmental regulatory agencies change and as more information is obtained about the extent of remediation required. The estimate used is the best estimate, when available, or a midpoint of the range if no best estimate is available. Changes in the provisions due to either a change in the anticipated costs or changes in the discount rate are recorded in operating costs on the consolidated statement of profit or loss and other comprehensive income.

n) Income Tax

Income tax is accounted for using the liability method, which consists of determining deferred tax assets and liabilities on the basis of the carrying amounts of assets and liabilities for financial reporting purposes and their tax base, using the tax rates that can objectively be expected to be in force when the assets or liabilities are realized or settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the reporting date. Deferred tax assets and liabilities arising as a result of direct charges or credits to equity are also accounted for with a charge or credit to equity.

The company recognizes deferred tax assets as long as future taxable profits are expected against which said assets can be recovered and that it is probable they will be realized. Deferred tax assets that do not meet this criteria are not recognized by the company.

Significant judgment is required in determining income tax provisions and evaluating tax positions. The company's tax positions are evaluated under a more-likely-than-not recognition threshold and measurement analysis before they are recognized for consolidated financial statement reporting.

Uncertain tax positions have been classified as noncurrent unless expected to be paid within one year. The company's policy is to recognize interest and penalties on uncertain tax positions as interest expense.

o) Current vs. Non-Current Classification

The company presents assets and liabilities in the consolidated statement of financial position based on current/noncurrent classification. An asset is current when one of the following:

- Expected to be realized or intended to be sold or consumed in the normal operating cycle
- Held primarily for the purpose of trading
- Expected to be realized within 12 months after the reporting period
- Cash or cash equivalent unless restricted from being exchanged or used to settle a liability for at least 12 months after the reporting period

All other assets are classified as noncurrent.

A liability is current when one of the following applies:

- It is expected to be settled in the normal operating cycle.
- It is held primarily for the purpose of trading.
- It is due to be settled within 12 months after the reporting period.
- There is no unconditional right to defer the settlement of the liability for at least 12 months after the reporting period.

The company classifies all other liabilities as noncurrent.

Deferred tax assets and liabilities are classified as noncurrent assets and liabilities.

5. First Time Adoption of IFRS

These financial statements for the year ended December 31, 2014 are the first the company has issued under IFRS. The company did not issue a set of comparable financial statements for the period ended December 31, 2013 (the company was reorganized in November 2013). As such we are unable to provide a reconciliation to any previously issued financial statements.

The company has prepared financial statements that comply with IFRS applicable for periods ending on or after December 31, 2014, together with the comparative period data as at and for the year ended December 31, 2013, as described in the basis of presentation and summary of

significant accounting policies. In preparing these financial statements, the company's opening statement of financial position was prepared as at January 1, 2013, the company's date of transition to IFRS.

IRHI previously issued financial statements prepared in accordance with IFRS for the year ended December 31, 2013.

Networks previously issued financial statements prepared in accordance with U.S. generally accepted accounting principles (GAAP) for the year ended December 31, 2013. The primary items that affected the Networks shareholder as a result of the transition to IFRS are as follows:

IFRS 3, *Business Combinations,* has not been applied to acquisitions of subsidiaries, which are considered businesses for IFRS, or of interests in associates and joint ventures that occurred before January 1, 2013. Use of this exemption means that the historical carrying amounts of assets and liabilities, that are required to be recognized under IFRS, is their deemed cost at the date of the acquisition. After the date of the acquisition, measurement is in accordance with IFRS. Assets and liabilities that do not qualify for recognition under IFRS are excluded from the opening IFRS statement of financial position. The company did not recognize or exclude any previously recognized amounts as a result of IFRS recognition requirements.

IFRS 1 also requires that the historical carrying amount of goodwill must be used in the opening IFRS statement of financial position (apart from adjustments for goodwill impairment and recognition or derecognition of intangible assets).

The company has applied the transitional provision in IFRIC 4, *Determining Whether an Arrangement Contains a Lease*, and has assessed all arrangements based upon the conditions in place as at the date of transition.

The company has adopted IFRS later than its parent and has measured its assets and liabilities at amounts as determined by IFRS 1.

Networks has elected to use the value of its property, plant and equipment as of January 1, 2013, as its deemed cost. The costs allowed in the regulatory process are based on historical cost, including capitalized financing costs, staff costs and overheads, and reduced by depreciation, because the costs are allowed to be recovered in rates.

Regulatory assets and liabilities - Under IFRS regulatory assets (liabilities) that represent amounts to be recovered from (returned to) customers in future rates are generally not allowed, as they are under U. S. GAAP, as such they have been eliminated with a corresponding charge to reserves. The net amount of regulatory assets eliminated from the U.S. GAAP statements, net of regulatory liabilities, were $1.1 billion at December 31, 2014, $0.9 billion at December 31, 2013, and $1.1 billion at January 1, 2013. We did not elect to apply the provisions of IFRS 14 Regulatory Deferral Accounts and therefore did not recognize any regulatory deferral accounts previously recognized under U.S. GAAP. See also Note 3.

Post-retirement benefits – Post-retirement benefits accounting under U.S. GAAP and IFRS are broadly similar, however, the attribution method used to accrue post-retirement medical benefits is different, resulting in a provision that is $32 million lower for IFRS as of January 1, 2013.

Provision for environmental remediation costs – Under U.S. GAAP environmental remediation costs are recorded at the low end of the range if no best estimate is available. Under IFRS the midpoint of the range is used if no best estimate is available. As a result, the provision was $99 million higher on the IFRS consolidated statement of financial position as of January 1, 2013.

The three items above create the principal differences on the statement of profit and loss and other comprehensive income between U.S. GAAP and IFRS. Under U.S. GAAP certain costs may be deferred if they will be allowed in future rates, therefore the timing of expenses will be different under IFRS. In 2013 the net effect of changes in regulatory assets and liabilities on the statement of profit and loss and other comprehensive income was $13 million of additional operating expenses. Under U.S. GAAP any change in the provision for environmental remediation costs is deferred as a regulatory asset or liability. Under IFRS they are recorded in the statement of profit and loss and other comprehensive income. The additional environmental expense recorded under IFRS was $66 million in 2013.

In addition to the different attribution period for post-retirement medical benefits, there are other differences between U.S. GAAP and IFRS that affect the statement of profit and loss related to pensions and post-retirement medical benefits. Under U.S. GAAP actuarial gains and losses are amortized into income, whereas under IFRS all gains and losses are taken directly to equity and are not amortized to profit and loss. In addition, the expected return on plan assets is different than the discount rate under U.S. GAAP whereas, as required by IAS 19, the expected return is equal to the discount rate, resulting in a different return on assets, which is included in the total pension and post-retirement benefit cost. The net effect of all of these items was the U.S. GAAP expense was $15 million lower than the IFRS expense in 2013.

There is no significant difference in cash flows between U.S. GAAP and IFRS as cash flows from operations, investing and financing would generally be the same.

Networks has elected to use the value of its property, plant and equipment as of January 1, 2013, as its deemed cost. The costs allowed in the regulatory process are based on historical cost, including capitalized financing costs, staff costs and overheads, and reduced by depreciation, because the costs are allowed to be recovered in rates.

6. Financing and Financial Risk Management Policy

The company is exposed to various inherent risks in the industries and markets in which it operates, which could prevent it from achieving its objectives and executing its strategies successfully. The company has an organization and systems that allow the financial risks to

which it is exposed to be identified, measured, and controlled. The financing and financial risk policy identifies the following as the main risk factors faced by the company.

Energy Market Risk

The company faces a number of energy market risk exposures, including fixed price, basis (both location and time), and heat rate risk. Its contracted gas storage exposures are affected by gas price differentials across time. It manages 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). The company hedges this exposure with basis swaps. Its merchant power plants are subject to heat rate risk, which is hedged with fixed price power and fixed price gas and basis positions. The company's merchant wind facilities are subject to fixed price power risk, which is hedged with fixed price power trades. Some of the derivative transactions entered into to manage economic risk are either ineligible for hedge accounting, or we have elected not to use hedge accounting and therefore, are MtM. Because the exposures (e.g., transport, storage, power plant) are accounted for on an accrual basis, timing differences are created between the derivatives and accrual basis earnings, as it pertains to earnings recognition.

Commodity price risk, due to volatility experienced in the wholesale energy markets, is a significant issue for the electric and natural gas utility industries. The company 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. Long-term supply contracts reduce our exposure to market fluctuations.

The company has electricity commodity purchases and sales contracts for both capacity and energy (physical contracts) that have been designated and qualify for the own use exemption in accordance with the accounting requirements concerning derivative instruments and hedging activities.

The company 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 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 other comprehensive income.

Treasury Management (including Liquidity Risk)

IUSA: IUSA's cash management and short-term funding activities are coordinated with its ultimate parent, Iberdrola. IUSA is able, effectively, to borrow from or lend to its parent. IUSA and its subsidiaries use a series of arms-length agreements to provide short term funding to its unregulated subsidiaries, to minimize overall short-term funding costs and to maximize returns

on temporary cash investments. IUSA has the capacity to borrow from third parties through a $300 million revolving credit facility that expires in 2019 and was undrawn at December 31, 2014. IUSA had no other third-party debt at December 31, 2014.

Regulated Utilities: IUSA's 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 regulation from lending to unregulated affiliates. NYSEG, RG&E and CMP each independently access the investment grade debt capital markets for long-term funding and each are borrowers in a joint revolving credit facility in which the aggregate credit limit is $600 million. This facility expires in 2018 and had $586 million of credit available as of December 31, 2014. NYSEG and CMP also have commercial paper programs.

CMP issued $225 million of first mortgage bonds in January 2013 that had been priced in a private transaction in May 2012. The regulated utilities had approximately $2.5 billion of outstanding third-party debt at December 31, 2014.

The company's regulated utilities are subjected by regulation 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 IUSA.

IRHI: IRHI has primarily funded operations through equity contributions from its parent. It has also raised a small percentage of its capital through tax equity partnerships, secured loans and sale-leaseback arrangements. The balance of the outstanding tax equity liability at December 31, 2014 was $344 million and the balance of loans and leases was $87 million.
Treasury risks: IUSA manages its foreign currency exposure in Canadian dollars arising from the trading activities by Iberdrola Energy Services by entering into forward foreign exchange hedges with select banks. IUSA did not utilize interest rate derivatives in 2014.

The company maintains cash and cash equivalents with several high-quality financial institutions and financial service providers where balances may periodically exceed federally insured limits. The company has not experienced any losses related to these balances, and management believes the risk of loss is minimal.

Debt Covenants: In its third-party debt agreements, the borrowers in each case make certain covenants to the lenders, including, in certain agreements, covenants regarding the ratio of indebtedness to total capitalization. The company continually monitors compliance with its covenants and, as of December 31, 2014 and February 19, 2015, is aware of no situation which would constitute an Event of Default or which would cause acceleration of scheduled repayments.

Credit Risk

This risk is defined as the risk that a third party will not fulfill its contractual obligations and, therefore, generate losses for the company.

The company's renewables and gas storage businesses sell their energy products and services to customers in the electric and natural gas industries and to financial institutions. These industry concentrations have the potential to affect overall exposure to credit risk, either positively or negatively, because the customer base may be similarly affected by changes in economic, industry, weather, or other conditions.

The company's credit department, based on guidelines approved by the board of directors, establishes and manages its counterparty credit limits. The company has developed a matrix of unsecured credit thresholds that are dependent on a counterparty's or the counterparty guarantor's applicable credit rating (normally Moody's or S&P). 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, the company employs specific eligibility criteria in determining appropriate limits for each prospective counterparty and supplements this with netting and collateral agreements, including margining, guarantees, letters of credit, and cash deposits, where appropriate.

The company is exposed to both settlement and replacement risk with counterparties. Our credit risk system provides current credit exposure to counterparties on a daily basis.

The company has master netting agreements in place with most of its significant trading counterparties and enters into master netting agreements in an attempt to both mitigate credit exposure and reduce collateral requirements. In general, the agreements allow the aggregation of credit exposure, margin, and set off. As a result, potential credit loss arising from a counterparty default decreases. Beyond these agreements, the company mitigates its risk exposure with other agreements that allow netting, including accounts receivable and accounts payable netting, and other normal credit activities necessary to minimize its overall exposure. The company includes cash collateral deposited with counterparties in current assets and includes cash collateral due to counterparties in current liabilities on the consolidated statement of financial position. For financial statement presentation, we do not 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.

Balances with individual counterparties can fluctuate greatly depending upon the prevailing market conditions. Limits are set for all counterparties, and exposure is monitored proactively. While individual counterparty balances can be large, collateral or guarantees will be in place to mitigate any exposure the company has.

Certain of our agreements 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, it would be in violation of those provisions, and the counterparties to

the agreements could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions.

Networks faces risks regarding the recovery of receivables for delivery service provided to utility customers. Accounts receivable do not bear interest, although late fees may be assessed.

The collection practices for retail customer accounts receivable, including the ability of the company to terminate service for nonpayment, are governed by state regulatory requirements. When a residential customer of a utility company becomes delinquent in making payments, that company's state regulatory commission requires it to allow the customer to enter into a deferred payment arrangement (DPA) to settle the account balance. A DPA allows the account balance to be paid in installments over an extended time by negotiating mutually acceptable payment terms. Generally, the utility company must continue to serve a customer who cannot pay an account balance in full if the customer: pays a reasonable portion of the balance; agrees to pay the balance in installments; and agrees to pay future bills within 30 days until the DPA is paid in full.

At December 31, 2014 and 2013, there was no material credit risk concentration with all counterparties located in the United States.

Sensitivity Analysis

IRHI uses a Monte Carlo Simulation Value-at-Risk (VaR) 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.

IRHI uses a 99% probability level over a five-day holding period, indicating that it can be 99% confident that losses over five days would not exceed that value. Using a simple summation approach across commodities, IRHI's average VaR for 2014 was $12.5 million compared to a 2013 average of $12.3 million. This approach has limitations in that it ignores the extent of correlation between commodity prices and diversification between positions; as a result, VaR is not additive.

As noted above, VaR is a statistical technique and is not intended to be a guarantee of the maximum loss IRHI may incur.

Because all gains or losses on Networks' commodity contracts will ultimately be passed on to retail customers, no sensitivity analysis is performed for Networks.

7. Significant Accounting Assumptions and Estimates, and Judgments.

a) Assumptions and Estimates

The preparation of the company's consolidated financial statements requires management to make judgments, estimates, and assumptions that affect the amounts reported in the consolidated financial statements and the accompanying disclosures. Uncertainty about these assumptions and estimates could result in outcomes that require a material adjustment to the carrying amount of assets or liabilities affected in future periods.

Although these estimates are made on the basis of the best information available at the date on which these consolidated financial statements were prepared, events that take place in the future might make it necessary to change these estimates (upwards or downwards) in coming years. Changes in estimates would be applied prospectively, recognizing the effects of the change in estimates in the related future consolidated financial statements.

The key assumptions and estimates made by the company that have a significant risk of causing a material adjustment in these consolidated financial statements are shown below.

Provisions for Contingencies

The company recognizes provisions to cover present obligations arising from past events. For this purpose, it must assess the outcome of certain procedures of a legal or other nature that are ongoing at the date of authorization for issue of these consolidated financial statements based on the best information available.

Provisions include environmental remediation costs for site remediation resulting from hazardous substances, including the residue of manufacturing gas. The company's estimates of these costs consider applicable legal requirements and the amount of remediation required based on its best understanding of the conditions at the various sites.

Useful Lives

The company's tangible assets operate over prolonged periods of time. The company estimates their useful lives for accounting purposes, taking into account each asset's technical characteristics, the period over which they are expected to generate economic benefits, and applicable legislation in each case.

The useful lives for the utility assets are consistent with the depreciation rates allowed by the applicable regulatory agency, which is determined using historical information and takes into consideration other technical considerations.

Provision for Decommissioning

As the estimate for decommissioning is being made today in anticipation of future costs, there are a number of assumptions and estimates made, such as discount rates, inflation rates, and future costs. The company annually reviews the assumptions and estimates made. Asset

retirement obligations are calculated based on discounting future cash flows using the risk free rate. In accordance with IBERDROLA policy the discount rate is based on treasury bonds with a maturity that matches the payment of the liability. Where the liability is expected to mature after 10 years the company uses the 10 year rate. See Note 18 for further details.

Provision for Pensions and Similar Commitments

At each year-end the company estimates the current actuarial provision required to cover obligations relating to pensions and other similar obligations to its employees. In several cases, it involves the valuation of the assets affected to certain plans. In making these estimates, the company receives advice from independent actuaries.

The cost of the defined benefit pension plan and other post-employment medical benefits and the present value of the pension obligations are determined using actuarial valuations. An actuarial valuation involves making various assumptions that may differ from actual developments in the future. These include the determination of the discount rate, future salary increases, mortality rates, and future pension increases. Due to the complexities involved in the valuation and its long-term nature, a defined benefit obligation is highly sensitive to changes in these assumptions. All assumptions are reviewed at each reporting date.

In determining the appropriate discount rate, management considers the interest rates of corporate bonds consistent with the currencies of the post-employment benefit obligation with at least an AA rating or above, as set by an internationally-acknowledged rating agency, and extrapolated as needed along the yield curve to correspond with the expected term of the defined benefit obligation. The underlying bonds are further reviewed for quality. Those having excessive credit spreads are excluded from the analysis of bonds on which the discount rate is based, on the basis that they do not represent high-quality corporate bonds.

The mortality rate is based on publicly available mortality tables for the United States. Future salary increases and pension increases are based on expected future inflation rates. See Note 17 for further details.

Impairment of Assets

The company, in accordance with applicable accounting standards, tests impairment each year as of September 30th. These impairment tests require estimating the future cash flows of the businesses and the most appropriate discount rate in each case. These estimates of future cash flows include many inputs based upon estimations and predictions of future events. The company believes its estimates in this respect are appropriate and consistent with the current market situation and reflect its investment plans and the best available estimate of its future expense and income. It is, however, possible that changes in some of these future assumptions or estimates could have a material effect on the valuation of the company assets and liabilities. The discount rates, before taxes, used by the company for impairment test purposes on its wind generation and gas storage assets were, 6.0%-6.9% for 2014 and 6.5%-7.84% for 2013 depending upon the assets being evaluated. These discount rates, before taxes, are based on the time value of money or the risk-free rate of that market, plus the specific risks of the asset or risk premium of the asset or business in question.

Although IAS 36, Impairment of Assets, recommends the use of projections to five years for impairment test purposes, the company has decided to use the useful lives, due to the fact that in the generation business there are long-term energy sale contracts in force, and long-term estimated price curves are frequently used in the operating activity (contracts, hedges, etc.).

The projections used in the impairment tests coincide with the best forecast information held by the company or its ultimate parent, IBERDROLA, at the date the tests were carried out and include the investment plan prevailing at that time.

The company also conducts an impairment test as of September 30 of each year for its long-lived intangible assets, which relates to its development projects that have been purchased and assigned purchase price allocation value. During 2014 and 2013, the company impaired certain of these development projects as a result of these tests. See Notes 8 and 25 for further details.

Part of our business relates to the development of new facilities in both renewable energy and gas storage in order to ensure future growth, as a result of which, we have ongoing construction in progress expenditures in the consolidated statement of financial position. In light of this, we have developed a process to periodically review our development projects to ensure that they remain economically viable, based on a variety of factors.

The company conducts an annual impairment test for its goodwill as of September. All remaining goodwill relates to its utility operations. It updates its goodwill impairment test if circumstances occur that would more likely than not reduce the fair value of a CGU below its carrying value. These impairment tests require estimating the future cash flows of the businesses and the most appropriate discount rate. These estimates of future cash flows include many inputs based upon estimations and predictions of future events. The company believes its estimates in this respect are appropriate and consistent with the current market and regulatory situation and reflect its investment plans and the best available estimate of its future expense and income. It is, however, possible that changes in some of these future assumptions or estimates could have a material effect on the valuation of the company's utility assets and liabilities. The discount rates, before taxes, used by Networks for impairment test purposes were 5.26% for 2014 and 5.38% for 2013. These discount rates, before taxes, are based on the time value of money or the risk-free rate of that market, plus the specific risks of the regulated businesses being evaluated.

Other Intangible Assets

The other intangible assets caption on the consolidated statement of financial position includes wind farm projects and gas storage facilities in the development phase. The company estimates that these projects meet the requirements under IAS 38 for them to be capitalized and that the company's future investment plans will include constructing the facilities proposed in these projects. See Note 8 for further details.

Taxes

Uncertainties exist with respect to the interpretation of complex tax regulations, changes in tax laws, and the amount and timing of future taxable income. Given the wide range of business relationships and the long-term nature and complexity of existing contractual agreements, differences arising between the actual results and the assumptions made, or future changes to such assumptions, could necessitate adjustments to future tax income and expense.

Significant judgment is required in determining income tax provisions and evaluating tax positions. The company's tax positions are evaluated under a more-likely-than-not recognition threshold and measurement analysis before they are recognized for consolidated financial statement reporting.

Deferred tax assets are recognized for unused tax losses and tax credits, to the extent that it is probable that taxable profit will be available against which the losses and credits can be utilized. Significant management judgment is required to determine the amount of deferred tax assets that can be recognized, based upon the likely timing and the level of future taxable profits together with future tax planning strategies. See Note 20 for further details.

Unbilled Revenues

Networks' unbilled revenues represent estimates of receivables for energy provided but not yet billed. The estimates are determined based on various assumptions, including current month energy load requirements, billing rates by customer class and delivery loss factors. Changes in those assumptions could significantly affect the estimated amount of unbilled revenues.

Allowance for Doubtful Accounts

The allowance for doubtful accounts is the company's best estimate of the amount of probable credit losses in its existing accounts receivable, determined based on experience for each service region. Each month the operating companies review their allowance for doubtful accounts and past due accounts by age. When an operating company believes that a receivable will not be recovered, it charges off the account balance against the allowance. Changes in assumptions about input factors and customer receivables, which are inherently uncertain and susceptible to change from period to period, could significantly affect the allowance for doubtful accounts estimates.

b) Judgments

The most significant judgments made by the company in these consolidated financial statements are as follows:

Consolidation of Entities

The company fully consolidates subsidiaries over which it exercises control, unless they are considered insignificant to the fair presentation of the company. Control in this context is evidenced when the company has the power to govern the financial and operating policies so as to obtain benefits from its activities.

As described in Note 28, the company is party to both joint arrangements and also structured institutional partnership investment arrangements.

The company is party to three joint arrangements where it owns 50% and one other partner holds the remaining 50% of each wind farm facility. In light of the requirements of IFRS 11, the company has reviewed the operations of these facilities and the significant contracts of these entities and has held meetings with the other partners to review these findings. From these reviews it was agreed that one would be classified as a joint operation (with a 50% proportional consolidation) and the other two would be classified as joint ventures (with 50% equity investment accounting).See Note 28 for further details.

The structured institutional partnership investment arrangements – shown under capital instruments with debt-like characteristics in the consolidated statement of financial position refer to structures where a variety of third-party institutional investors invest in the equity of a holding company that owns wind farm facilities. In return the investors receive profit/loss, cash distributions, and tax benefits resulting from the wind farm energy generation. In each of these cases a non-controlling (5%–10%) stake is offered, and the company retains total control of the operations of the facilities. Accordingly, these arrangements are consolidated 100% with the investors share shown as non-controlling interests in the equity section of the consolidated statement of financial position. See Note 15 for further details.

Fair Value of Financial Instruments

When the fair value of financial assets and financial liabilities recorded in the consolidated statement of financial position cannot be derived from active markets, their fair value is determined using valuation techniques, including the discounted cash flow model. The inputs to these models are taken from observable markets where possible, but where this is not feasible, a degree of judgment is required in establishing fair values. The judgments include considerations of inputs such as liquidity risk credit risk and volatility. Changes in assumptions about these factors could affect the reported fair value of financial instruments. See Note 10 for further details.

8. Intangible Assets

The changes during 2014 and 2013 in intangible assets accounts and in the related accumulated amortization and provisions were as follows:

(In Thousands)	Goodwill	Gas Storage Rights	Computer Software	Other Intangible Assets	Total
Cost					
Balance at January 1, 2013 Pro Forma	**$1,000,030**	**$241,982**	**$57,189**	**$88,036**	**$1,387,237**
Additions	-	-	1,796	-	1,796
Capitalized staff costs	-	-	641	-	641
Disposals	-	-	(9,257)	(1)	(9,258)
Transfers/reclasses	-	-	1,926	(26,857)	(24,931)
Impairments	(18,385)	-	-	(39,891)	(58,276)
Balance at December 31, 2013	**981,645**	**241,982**	**52,295**	**21,287**	**1,297,209**
Additions	-	-	-	-	-
Capitalized staff costs	-	-	2,498	-	2,498
Disposals	-	-	-	(1)	(1)
Transfers/reclasses	-	-	-	(30)	(30)
Impairments	-	-	-	(1,558)	(1,558)
Balance at December 31, 2014	**$981,645**	**$241,982**	**$54,793**	**$19,698**	**$1,298,118**
Amortization and provisions					
Balance at January 1, 2013 Pro Forma	-	**($39,783)**	**($43,920)**	**($19,268)**	**($102,971)**
Charge for the year	-	(6,398)	(8,608)	(882)	(15,888)
Disposals	-	-	9,257	-	9,257
Transfers/reclasses	-	-	(239)	10,636	10,397
Balance at December 31, 2013	**-**	**(46,181)**	**(43,510)**	**(9,514)**	**(99,205)**
Charge for the year	-	(6,398)	(4,531)	(690)	(11,619)
Disposals	-	-	-	-	-
Transfers/reclasses	-	-	-	-	-
Balance at December 31, 2014	**-**	**($52,579)**	**($48,041)**	**($10,204)**	**($110,824)**
Net book value					
At January 1, 2013	**$1,000,030**	**$202,199**	**$13,269**	**$68,768**	**$1,284,266**
At December 31, 2013	**$981,645**	**$195,801**	**$8,785**	**$11,773**	**$1,198,004**
At December 31, 2014	**$981,645**	**$189,403**	**$6,752**	**$9,494**	**$1,187,294**

Total accumulated impairments of goodwill as of December 31, 2014, and December 31, 2013 were $18.4 million. There were no accumulated impairments of goodwill as of January 1, 2013. See Note 25.

Fully amortized intangible assets in use at December 31, 2014, and 2013, amounted to $48.1 million and $31.3 million, respectively.

As of December 31, 2014 and 2013, there were no significant restrictions on the ownership of intangible assets.

Over time, the company's renewables group has purchased development projects from third parties and has assigned purchase price allocation values accordingly, which are accounted for as indefinite life intangible assets. These project values are transferred to tangible assets as the projects are completed. The company conducts impairment tests on these assets annually. See Note 7.

The amount of indefinite life and in-progress intangible assets, on a value-in-use basis, at December 31, 2014, and 2013, amounted to $6.1 million and $7.7 million, respectively, with the reduction arising due to the impairments in the year. See Note 25.

Amortization and impairment expenses are shown in the depreciation, amortization, and provisions line of the consolidated statement of profit or loss and other comprehensive income. For further details, see Note 25.

9. Property, Plant, and Equipment

The changes during 2014 and 2013 in property, plant, and equipment accounts and in the related accumulated depreciation and provisions were as follows:

	Land and Buildings	Construction in Progress	Plant and Equipment	Other	Total
(In Thousands)					
Cost					
Balance at January 1, 2013 Pro Forma	**$249,790**	**$1,512,606**	**$19,768,132**	**$1,143,829**	**$22,674,357**
Additions	2,297	521,530	452,392	49,102	1,025,321
Disposals	(1,346)	(38,266)	(191,415)	(26,629)	(257,656)
Transfers/reclasses	975	(474,914)	470,079	26,221	22,361
Impairments	(4,500)	(190,225)	-	-	(194,725)
Balance at December 31, 2013	**247,216**	**1,330,731**	**20,499,188**	**1,192,523**	**23,269,658**
Additions	5,332	679,017	451,932	48,455	1,184,736
Disposals	(862)	(35,998)	(151,648)	(117,008)	(305,516)
Transfers/reclasses	31,337	(421,247)	372,671	17,237	(2)
Impairments	-	(15,408)	-	-	(15,408)
Balance at December 31, 2014	**$283,023**	**$1,537,095**	**$21,172,143**	**$1,141,207**	**$24,133,468**
Depreciation and provisions					
Balance at January 1, 2013 Pro Forma	**($63,557)**	-	**($4,968,425)**	**($599,858)**	**($5,631,840)**
Charge for the year	(3,179)	-	(613,391)	(68,868)	(685,438)
Disposals	380	-	85,997	25,350	111,727
Transfers/reclasses	2,714	-	(12,520)	(2,625)	(12,431)
Balance at December 31, 2013	**(63,642)**	-	**(5,508,339)**	**(646,001)**	**(6,217,982)**
Charge for the year	(2,127)	-	(655,573)	(57,986)	(715,686)
Disposals	628	-	118,552	79,002	198,182
Transfers/reclasses	-	-	2,436	(3,008)	(572)
Balance at December 31, 2014	**($65,141)**	-	**($6,042,924)**	**($627,993)**	**($6,736,058)**
Net Book Value					
At January 1, 2013	**$186,233**	**$1,512,606**	**$14,799,707**	**$543,971**	**$17,042,517**
At December 31, 2013	**$183,574**	**$1,330,731**	**$14,990,849**	**$546,522**	**$17,051,676**
At December 31, 2014	**$217,882**	**$1,537,095**	**$15,129,219**	**$513,214**	**$17,397,410**

The fully depreciated items of property, plant, and equipment in use amounted to $273 million at December 31, 2014 and 2013. Amounts with restrictions on title were $57.6 million in 2014 and $63.5 million in 2013. The value of compensation or recoveries from third parties was $1.8 million in 2014 and $5.9 million in 2013.

At December 31, 2014, the company had property, plant, and equipment purchase commitments amounting to $168 million.

Depreciation and impairment expenses are shown in the depreciation, amortization, and provisions line of the consolidated statement of profit or loss and other comprehensive income. For further details, see Note 25.

Additionally, the cost of acquisition includes the following items:

- Borrowing costs relating to funding incurred during the construction period only, by applying the average effective interest rate to the average cumulative investment qualifying for capitalization. The average capitalization rates used were 1.54% to 7.2% in 2014 and 7.0% in 2013. In 2014 and 2013, we capitalized to property, plant, and equipment, borrowing costs of $19 million and $3.9 million respectively, with a credit to Finance income in the consolidated statement of profit or loss and other comprehensive income.

  Staff costs relating directly or indirectly to construction-in-progress. The amounts capitalized in this respect were $61.4 million in 2014 and $43.9 million in 2013.

10. Measurement of Financial Instruments

The comparison between carrying amount and fair value of the company's financial instruments at December 31, is as follows:

December 31, 2014	Carrying Amount	Fair Value	Level 1	Level 2	Level 3
(In Thousands)					
Securities portfolio (available for sale)	**$24,390**	**$24,390**	**$1,389**	**-**	**$23,001**
Financial assets					
Derivative financial instruments-Power	$77,682	$77,682	-	$47,810	$29,872
Derivative financial instruments-Gas	$138,782	$138,782	$299	$90,629	$47,854
	$216,464	**$216,464**	**$299**	**$138,439**	**$77,726**
Financial liabilities					
Derivative financial instruments-Power	($36,158)	($36,158)	($28,420)	($7,633)	($105)
Derivative financial instruments-Gas	(101,802)	(101,802)	(6,686)	(66,169)	(28,947)
Derivative financial instruments-Other	(3,320)	(3,320)	-	-	(3,320)
	($141,280)	**($141,280)**	**($35,106)**	**($73,802)**	**($32,372)**

There have been no transfers between Level 1 and Level 2 during the periods reported.

December 31, 2013	Carrying Amount	Fair Value	Level 1	Level 2	Level 3
(In Thousands)					
Securities portfolio (available for sale)	**$44,674**	**$44,674**	**$44,674**	**-**	**-**
Financial assets					
Derivative financial instruments-Power	$71,347	$71,347	$3,126	$29,174	$39,047
Derivative financial instruments-Gas	71,471	71,471	1,018	21,322	49,131
	$142,818	**$142,818**	**$4,144**	**$50,496**	**$88,178**
Financial liabilities					
Derivative financial instruments-Power	($27,623)	($27,623)	($1,184)	($1,888)	($24,551)
Derivative financial instruments-Gas	(152,625)	(152,625)	(7,232)	(129,347)	(16,046)
Derivative financial instruments-Other	(547)	(547)	-	-	(547)
	($180,795)	**($180,795)**	**($8,416)**	**($131,235)**	**($41,144)**

There have been no transfers between Level 1 and Level 2 during the periods reported.

Reconciliation of Level 3 Fair Value items	
In Thousands	
December 31, 2013	**$47,035**
Gains for the period recognized in Revenues	7,910
Losses for the period recognized in Revenues	(952)
Total gains or losses for the period recognized in Revenues	**6,958**
Gains recognized in Hedge Revaluation Reserve	2,192
Losses recognized in Hedge Revaluation Reserve	(3,781)
Total gains or losses recognized in Hedge Revaluation Reserve	**(1,589)**
Purchases	**9,979**
Settlements	**(25,840)**
Transfers into Level 3	23,001
Transfers out of Level 3 (moved into 'liquid' period)	8,811
Transfers	**31,812**
December 31, 2014	**$68,355**

December 31, 2014	Current Asset	Noncurrent Asset	Current Liability	Noncurrent Liability
(In Thousands)				
Financial assets and liabilities subject to offsetting:				
Gross amounts recognized	$707,877	$134,113	($681,490)	($85,316)
Amounts of offsetting	(578,717)	(46,809)	578,757	46,769
Net amounts presented in the statement of financial position	**$129,160**	**$87,304**	**($102,733)**	**($38,547)**
Related amounts not set off in the statement of financial position:				
Financial instruments	($55,939)	($10,012)	$55,901	$10,051
Cash collateral	(49,521)	(14,974)	28,741	9,383
Balance as at December 31, 2014	**$23,700**	**$62,318**	**($18,091)**	**($19,113)**

The fair value of these financial instruments has been calculated described in under Note 3.

The company measures financial instruments, such as derivatives at fair value at each balance sheet date. 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 at 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 either in 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 nonfinancial 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.

The company uses valuation techniques that are appropriate in the circumstances and for which sufficient data is available to measure fair value, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs. All assets and liabilities for which fair value is measured or disclosed in the consolidated financial statements are categorized within the fair value hierarchy, described as follows, based on the lowest level of input that is significant to the fair value measurement as a whole:

- Level 1 –Consist of exchange-traded transactions such as the New York Mercantile Exchange (NYMEX) with quoted market prices in active markets for identical products.

- Level 2 – Consist of transactions with delivery periods of two years or less that trade in active markets and are valued with or derived from observable market data for identical or similar products (e.g., over-the-counter NYMEX, foreign exchange swaps, fixed price physical, basis and index trades). Monthly data points will be included in this category provided they fall within the bid/ask data provided by brokers for seasonal strips and

quarterly quotes. Trader marks that fall outside of a 5% threshold of the average broker marks and fall outside of the widest bid/ask spreads will be adjusted to reflect the broker quotes. Any position that is initially classified as Level 2 will be evaluated before and after the provision of credit reserves with incremental value changes of 10% or more classified as Level 3. To be included in this category, market data, or a derivative thereof, must be available for the entire term of the trade.

- Level 3 – Consist of transactions 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 (e.g., tolling arrangements with historical volatilities, park and loan arrangements that include the value of expired legs, transactions with significant credit adjustments). The valuation premise in this category will be based on market participant assumptions.

For assets and liabilities that are recognized in the consolidated financial statements on a recurring basis, the company determines 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.

Level 3 Fair Value Measurement

The table below illustrates the significant sources of unobservable inputs used in the fair value measurement of the company's Level 3 derivatives. It represents the variability in prices for those transactions that fall into the illiquid period, 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	Mark to market	Observable and extrapolated forward gas & power prices not all of which can be corroborated by market data for identical or similar products	NYMEX ($/MMBtu)	$ 4.33	$ 5.47	$ 3.34
				SP15 ($/MWh)	$ 43.27	$ 59.12	$ 30.04
				Mid C ($/MWh)	$ 36.16	$ 56.28	$ 12.62
				Cinergy ($/MWh)	$ 37.41	$ 68.65	$ 21.17

The company's 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.

A sensitivity analysis was performed around the Level 3 gas and power positions to changes in the valuations inputs noted above and it was 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.

The company maintains a formal Risk Management Policy and Procedures manual that sets out the requirements for maintaining the models used in calculating fair value, with requirements to maintain documentation describing the detailed methodologies and tools used to construct the assumptions, forward curves, and key parameters used in the valuation models. These detailed documents provide all necessary information and data necessary to independently value any transaction.

The company maintains full documentation describing the models, forward curves, and other parameters used in valuation models. Descriptions of valuation models and pricing data are maintained and documented by the Structuring and Market Analysis group and the Mid Office. Summaries of valuation models developed are maintained and documented by the Structuring and Market Analysis group.

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 Mid 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. Description 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 30 years.

11. Inventories

The detail of inventories in the consolidated statements of financial position is as follows:

	December 31, 2014	December 31, 2013	Pro Forma January 1, 2013
(In Thousands)			
Gas inventory	$228,157	$285,408	$279,459
Other Inventory	1,716	12,569	14,293
	$229,873	**$297,977**	**$293,752**

The company expensed $2.1 billion of inventory during the year ended December 31, 2014, and $2.0 billion for the year ended December 31, 2013. IRHI's gas inventory relates to proprietary trading and it is required to be netted off within revenues and is not expensed under cost of sales in the consolidated statement of profit or loss and other comprehensive income. Inventory used for sale to utility customers is expensed to cost of sales.

The company recorded a provision at December 31, 2014, to record the difference between its cost of gas inventory and spot prices. This reduction in inventory value is more than offset by the contracted cash flows of the forward hedges under which this inventory has been sold. The cash flows to be realized from the forward hedges exceeds the inventory expense by more than the original provision and as such the provision for the change in inventory value was offset by the revaluation reserves in the consolidated statements of financial position.

At December 31, 2014, the company has contractual commitments to purchase 506 billion cubic feet of gas in future years. This amount is gross of any sales commitments and excludes financial transactions where gas does not physically move.

12. Current Trade and Other Receivables

The detail of current trade and other receivables in the consolidated statements of financial position is as follows:

	December 31, 2014	December 31, 2013	Pro Forma January 1, 2013
(In Thousands)			
Trade receivables	$863,040	$912,373	$969,602
Receivables from associates	50,170	22,641	14,985
Other receivables	(36)	45	(3,204)
Bad debt provision	(58,589)	(59,678)	(56,642)
	$854,585	**$875,381**	**$924,741**

The breakdown of the trade receivables is as follows:

	December 31, 2014	December 31, 2013	Pro Forma January 1, 2013
(In Thousands)			
Neither past due nor impaired	$699,516	$721,681	$824,287
up to 90 days	47,005	51,366	52,878
90-180 days	47,680	59,146	26,898
More than 180 days	68,839	80,180	65,539
	$863,040	**$912,373**	**$969,602**

The amounts included do not bear any interest under this caption in the consolidated statement of financial position, although Network's utility subsidiary may charge late fees.

Accounts receivable includes amounts due under DPAs. A DPA allows the account balance to be paid in installments over an extended period of time, which generally exceeds one year, by negotiating mutually acceptable payment terms. Generally, the utility company must continue to serve a customer who cannot pay an account balance in full if the customer: pays a reasonable portion of the balance; agrees to pay the balance in installments; and agrees to pay future bills within 30 days until the DPA is paid in full. DPA receivable balances, net of the applicable reserve, at December 31, 2014, and December 31, 2013, were $40.1 million and $51.1 million, respectively.

The variations in the bad debt provision in 2013 and 2014 were as follows:

	December 31, 2014	December 31, 2013
(In Thousands)		
Beginning Balances	$59,678	$56,642
Provision	47,759	38,064
Utilization of provisions	(43,467)	(33,548)
Transfers	(5,381)	(1,480)
Ending Balance	**$58,589**	**$59,678**

The bad debt provision relates entirely to gas and electricity consumers.

13. Cash and Cash Equivalents

The detail of cash and cash equivalents in the consolidated statement of financial position is as follows:

	December 31, 2014	December 31, 2013	Pro Forma January 1, 2013
(In Thousands)			
Cash and cash equivalents	$455,609	$191,697	$10,448
Short-term deposits	8,292	9,616	30,848
	$463,901	**$201,313**	**$41,296**

This heading includes short-term deposits that mature within a period of less than three months and bear market rates. These accounts have no restrictions on cash withdrawals. The company has no overdraft amounts at December 31, 2014 and 2013.

The company is free to move its cash balances across those entities that it owns, without restriction. For the 50/50 joint arrangements, approval of the other owner is necessary to withdraw any cash balances.

14. Equity

Share Capital

The company's ending share capital and premium at December 31, 2013, was $9.3 billion, representing 243 shares with a nominal value of $0.01. The company has 243 ordinary shares authorized, but has no treasury shares or convertible preference shares.

During 2013, IRHI issued 498 new shares to its parent, IFUL, in return for $800 million of new equity, $153 million in cash and the remainder in the form of loan notes. As a result, at December 31, 2013, IRHI's ending share capital was $8.6 billion, representing 6,786 shares with a nominal value of $0.01. Due to the transfer of ownership of IRHI, as mentioned in Note 1, all of IRHI's shares are held by its parent, IUSA. IRHI has 10,000 ordinary shares authorized, but has no treasury shares or convertible preference shares.

Capital Management

The company's capital management is controlled on a group basis by its ultimate parent, IBERDROLA. At this time, IBERDROLA's credit ratings are Baa1 granted by Moody's and BBB granted by Standard & Poor's.

Hedge Revaluation Reserve

The change in this reserve arising from valuation adjustments to derivatives designated as cash flow hedges at December 31, 2014, and 2013, is as follows:

(In Thousands)	**Commodity Derivatives**
Balance at January 1, 2013 Pro Forma	**$(103,918)**
Change in fair value	(36,881)
Amounts allocated to income and others	31,459
Income tax effect	1,712
Balance at December 31, 2013	**$(107,628)**
Change in fair value	17,699
Amounts allocated to income and others	67,221
Income tax effect	(32,422)
Balance at December 31, 2014	**$(55,130)**

The commodity hedges are expected to mature within, and reverse to the consolidated statements of profit or loss and other comprehensive income, over the years 2015 – 2017. During the year ended December 31, 2014, the company recognized $2.6 million of income as compared to $0.2 million of expense in 2013 in relation to hedge ineffectiveness. The IRHI trading activities are recorded to revenues in the consolidated statement of profit or loss.

The commodity hedges are expected to mature within, and reverse to the consolidated statements of profit or loss and other comprehensive income, over the years 2015 – 2017.

15. Capital Instruments With Debt-Like Characteristics

The detail of the consolidated statements of financial position at December 31, 2014 and 2013 is as follows:

(In Thousands)

Balance at January 1, 2013 Pro Forma	**$629,857**
Finance costs accrued during the year	38,890
Payments	(125,500)
Amortization	(40,936)
Repurchases	(48,182)
Balance at December 31, 2013	**454,129**
Finance costs accrued during the year	34,653
Payments	(118,897)
Amortization	(26,270)
Balance at December 31, 2014	**$343,615**

The balance in Capital Instruments with Debt-like Characteristics of the consolidated statements of financial position at December 31, 2014, accrues interest at an average rate of 7.2% compared to 6.1% at December 31, 2013.

Wind power generation is subject to certain favorable tax treatments within the U.S. In order to monetize the tax benefits generated by the company's wind farms, the company has entered into structured institutional partnership investment transactions related to certain wind farms located throughout the U.S. There are five such structures: Aeolus Wind Power I LLC, Aeolus Wind Power IV LLC and Locust Ridge Wind Farms LLC (collectively, Aeolus). Under the Aeolus structures, the company contributes 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 pay the company a specified amount of up-front cash and enter into fixed and/or contingent notes.

Under each Aeolus structure, for a specified period of time the third-party investors receive a disproportionate amount of the profit/loss, cash distributions, and tax benefits resulting from the wind farm energy generation. For Aeolus wind farm structures in place at December 31, 2014 and 2013, the disproportionate returns of the investors represented a percentage of the cash flows and tax benefits from the Aeolus wind farm operations during the preferential return period, which continues until the investor entitled to the preferential return recovers its investment and achieves a cumulative annual after-tax return. The company cannot estimate the preferential return period for Aeolus wind farm structures in place at December 31, 2014 and 2013, because the length of the preferential return period depends on estimated future cash flows as well as projected tax benefits. At the end of the specified period, the majority of the profit/loss, cash distributions, and tax benefits, if any, flip back to the company. In all of the Aeolus structures, the company retains a class of membership interests and day-to-day operational and management control of the wind farms, subject to investor approval of certain

major decisions. The institutional investors do not receive a lien on any wind farm assets and have no recourse against the company for the upfront cash payments.

During 2014 the investor returns on the Aeolus I structure successfully met the investor requirements, causing the structure to flip back, with the investor and company each retaining returns appropriate to their investment. From that point forward, the investor interest is now being recorded as a 10% non-controlling interest, with a commensurate share of the returns of the portfolio.

The effects of the Aeolus transactions are accounted for as follows in the company's consolidated financial statements:

Fixed notes – Fixed notes receivable are unsecured and are reflected in current or noncurrent other financial investments, depending on the fixed note maturities. Principal and interest payments are due on a quarterly basis. Interest accrued on the fixed notes receivable is credited to finance income in the period earned.

Contingent notes – Contingent notes are credited to revenue when they are earned, payment is considered virtually certain, and the asset is no longer regarded as contingent. The contingent notes receivable have fixed interest rates and maturity dates, with principal and interest payments due on a quarterly basis. As the payments are received quarterly, a small receivable balance, shown under current trade and other receivables, is the only balance recognized in the consolidated statement of financial position.

Capital instruments with debt-like characteristics – The sale of a membership interest in the Aeolus structures 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 Aeolus structures that were sold by the company to the third-party investors are reflected as a financing obligation on the consolidated statement of financial position. The company continues to fully consolidate the Aeolus wind farms' assets and liabilities on the consolidated statement of financial position and to report the results of the operations of the wind farms in the consolidated statement of profit or loss and other comprehensive income. The presentation reflects revenues and expenses from the Aeolus wind farms' operations on a gross basis. The balances are increased for cash contributed by the third-party investors, interest accrued, and by 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 balances 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 Aeolus structures. The portion of this balance expected to mature within one year is $123.6 million for 2014, compared to $118.2 million in 2013.

Income tax expense – The federal income tax affect of the difference between depreciation for financial reporting, which is recognized on a straight-line basis, and the accelerated depreciation

used for tax purposes, is accounted for as a long-term deferred liability due to the investors with an offsetting adjustment to interest expense. The adjustment normalizes the impact on interest expense of the accelerated tax depreciation used for tax purposes.

Revenue – Amounts related to the PTCs on the electricity generated from the wind farms are credited to revenue in the period associated with the related generation from the wind farms.

Finance income – Interest is accrued on the fixed and contingent note receivables and credited to finance income in the period earned.

Finance expense – Interest is accrued on the outstanding balance of the capital instruments with debt-like characteristics using the effective interest method.

Non-controlling interests – A non-controlling interest based on the estimated value that the third party investor will have after the flip date is recorded in the consolidated statement of financial position on the closing date of the Aeolus transactions.

One of the Aeolus transactions provides the investor class of share equity with a contingent put option in case a specified event takes place as defined in the Aeolus agreements. If the put option were exercised, the company would be obliged to buy the third-party investor's member interest. All Aeolus transactions provide the company with a call option to acquire the third-party investor's member interest upon the occurrence of a specified event as defined in the Aeolus agreements. Such an event did occur in 2013, and the company exercised its option to repurchase a portion of the holding of one of the third-party investors.

The company's interests in the wind farms are not subject to any protective rights of non-controlling interests which may restrict the company's ability to access or use the assets or settle any existing liabilities associated with the interests. Summarized financial information as it relates to these structures with non-controlling interests is as follows:

	Aeolus Wind Power I, LLC	Aeolus Wind Power II, LLC	Aeolus Wind Power III, LLC	Aeolus Wind Power IV, LLC	Locust Ridge Wind Farms, LLC
Non-controlling ownership (%)	10%	5%	5%	5%	5%
Non-controlling voting rights (%)	45%	25%	25%	25%	53.7%
2014 Summarized Financial Information					
(In Thousands)					
Current assets	$1,644	$5,302	$4,472	$11,023	$898
Noncurrent assets	$109,003	$507,470	$339,811	$681,259	$36,346
Current liabilities	$(1,519)	$(3,410)	$(3,054)	$(4,913)	$(1,317)
Noncurrent liabilities	$(19,771)	$(39,503)	$(26,078)	$(49,007)	$(2,693)
Revenue	$14,357	$51,029	$43,250	$95,342	$4,598
(Loss) or Profit	$(1,322)	$12,206	$12,026	$29,832	$1,048
Total comprehensive (loss) income	$(1,322)	$12,206	$12,026	$29,832	$1,048
Dividends/distributions paid to non-controlling interest	$2,886	$26,830	$24,367	$63,288	$1,854

16. Deferred Income

The detail of deferred income in the consolidated statement of financial position as of December 31, 2014, and 2013, is as follows:

	Government Grants	Other Deferred Income	Total
(In Thousands)			
Balance at January 1, 2013 Pro Forma	**$1,849,205**	**$220,872**	**$2,070,077**
Additions	31,094	42,644	73,738
Disposals	(33,579)	-	(33,579)
Allocated to statement of Profit or Loss and	-	-	-
Other Comprehensive Income	(82,183)	(21,729)	(103,912)
Balance at December 31, 2013	**$1,764,537**	**$241,787**	**$2,006,324**
Additions	-	70,502	70,502
Disposals	(3,347)	-	(3,347)
Allocated to statement of Profit or Loss and	-	-	-
Other Comprehensive Income	(82,153)	(23,568)	(105,721)
Balance at December 31, 2014	**$1,679,037**	**$288,721**	**$1,967,758**

Within the government grants heading, the company classifies grants received under Section 1603 of the American Recovery and Reinvestment Act of 2009, where the United States Department of the Treasury (DOT) provided eligible parties the option of claiming grants for specified energy property in lieu of tax credits, which the company claimed for the majority of its qualifying properties. Deferred income has been recorded for the amount of the grants 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.

The company is required to comply with certain terms and conditions applicable to each grant. If a disqualifying event should occur, as specified in the grant's terms and conditions, the company is required to repay the grant funds to the DOT. At December 31, 2014, the company continues to believe that it is in compliance with each grant's terms and conditions.

Other deferred income relates predominantly to gas a storage transaction, where revenue is recognized as services are provided. See the revenue recognition section within Note 4 for further details.

Networks periodically receives CIACs or conveyed assets when it constructs and owns property for the benefit of its customers. These contributions are recorded as deferred income and amortized as other income on the consolidated statement of profit or loss and other comprehensive income.

17. Provisions for Pensions and Similar Obligations

The detail of pensions and similar obligations in the consolidated statements of financial position is as follows:

	December 31, 2014	December 31, 2013
(In Thousands)		
Networks Pension Benefits	($508,577)	($124,482)
Networks Postretirement Benefits	(268,302)	(220,048)
IRHI Retirement and SERP	(18,424)	(11,958)
IRHI Postretirement Health and	(24,322)	(25,247)
	($819,625)	**($381,735)**

Each year the company estimates through independent actuarial studies the payment amount for pensions and similar commitments in the year ahead. This amount is recorded as a current liability in the consolidated statement of financial position.

Defined benefit and other non-current benefits

The employees of Networks are included in various defined benefit pension plans (Qualified Pension Plans and Non Qualified Pension Plans) and postretirement benefits plans (Post Retirement Health Insurance and Long-Term Disability).

Networks has funded noncontributory defined benefit pension plans that cover substantially all employees. For most employees, generally those hired before 2002, the plans provide defined benefits based on years of service and final average salary. 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 it would freeze the benefits for all non-union employees covered under the cash balance plans. Their earned balances would continue to accrue interest, but would no longer be increased by a percentage of earnings. In place of the pension benefit for those employees, 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 also has other postretirement health care benefit plans covering substantially all employees. The health care plans are contributory with participants' contributions adjusted annually.

During 2014, Networks gave current retirees an option to accept a lump sum payment in settlement of future pension payments. As a result, and based on the option selected by eligible retirees, Networks paid $118 million and recognized a prior service credit of $14 million, which is included in normal cost.

The Company also sponsors defined contribution plans for certain eligible employees in Rabbi Trusts. The assets associated with this deferred compensation plan approximated $36 million as of December 31, 2014 and $39 million as of December 31, 2013.

Funding for the Qualified Pension Plan is determined periodically within the requirements of the Employee Retirement Income Security Act (ERISA) and applicable Internal Revenue Service guidelines. Networks plans to contribute $0.8 million to the Pension Benefits Plans in 2015.

The most significant data for the Networks plans are as follows:

	December 31, 2014		December 31, 2013	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
(In Thousands)				
Present value of obligation	($2,605,818)	($396,167)	($2,301,985)	($348,079)
Fair value of plan assets	2,097,241	127,865	2,177,503	128,031
Net asset / (net provision)	**($508,577)**	**($268,302)**	**($124,482)**	**($220,048)**
Amounts recognized in the Consolidated statement of financial position:				
Other non-current financial investment	-	-	$52,651	-
Provision for pensions and similar commitments	($508,577)	($268,302)	(177,133)	($220,048)
Net asset / (net provision)	**($508,577)**	**($268,302)**	**($124,482)**	**($220,048)**

The former employees of Scottish Power that now form part of the workforce of the company, most of them belonging to the workforce of IRHI, are members of various post-employment plans (Supplemental Executive Retirement Plan (SERP), and Iberdrola Renewables Retirement Plan).

The SERP Plan is a special retirement benefit for qualifying executives and subject to CEO approval.

The Retirement Plan is for eligible employees hired prior to January, 2008 based on participant's age, service, and five years average pay at the time of freeze date of April 30, 2011.

The plans are fully funded for purposes of minimum funding under the Employee Retirement Income Security Act (ERISA) and therefore there were no required cash contributions for 2013 and 2014.

The Postretirement Health and Welfare Plan is for eligible retirees, employees hired prior to January 1, 2008. Health and life insurance rates are based on age and service points at the time of retirement.

There are no plans for IRHI to make contributions in 2015 to the Retirement and SERP Plans or the Postretirement Health and Welfare Plan.

The most significant data for the IRHI plans are as follows:

	December 31, 2014		December 31, 2013	
	Retirement SERP	Postretirement Health & Welfare	Retirement SERP	Postretirement Health & Welfare
(In Thousands)				
Present value of obligation	($64,071)	($25,656)	($57,069)	($26,749)
Fair value of plan assets	45,647	1,334	45,111	1,502
Net asset / (net provision)	**($18,424)**	**($24,322)**	**($11,958)**	**($25,247)**
Amounts recognized in the Consolidated statement of financial position:				
Provision for pensions and similar commitments	(18,424)	(24,322)	(11,958)	(25,247)
Net asset / (net provision)	**($18,424)**	**($24,322)**	**($11,958)**	**($25,247)**

The movement in the present value of the obligations is as follows:

	Networks		IRHI	
	Pension Benefits	Postretirement Benefits	Retirement and SERP	Postretirement Health and Welfare
(In Thousands)				
Present value of obligation at January 1, 2013 Pro Forma	**($2,598,652)**	**($397,345)**	**($73,795)**	**($19,103)**
Normal cost	(37,279)	(6,719)	-	(737)
Finance cost	(103,166)	(15,273)	(1,004)	(683)
Actuarial deviations credited to reserves	224,409	40,338	9,732	(6,569)
Payments	212,703	30,920	7,998	343
Present value of obligation at December 31, 2013	**(2,301,985)**	**(348,079)**	**(57,069)**	**(26,749)**
Normal cost	(14,954)	(6,880)	-	(1,361)
Finance cost	(108,774)	(15,992)	(2,715)	(1,348)
Actuarial deviations credited to reserves	(454,006)	(63,296)	(8,627)	3,349
Payments	273,901	38,080	4,340	453
Present value of obligation at December 31, 2014	**($2,605,818)**	**($396,167)**	**($64,071)**	**($25,656)**

Of the $517 million actuarial loss incurred by Networks' benefit plans in 2014, $331 million resulted from a decrease in the discount rate and $159 million resulted from the adoption of the new mortality tables. Of the $265 million actuarial gain incurred by Networks' benefit plans in 2013, $238 million resulted from an increase in the discount rate.

The movement in the fair value of the plan assets is as follows:

(In Thousands)	Networks		IRHI	
	Pension Benefits	Postretirement Benefits	Retirement and SERP	Postretirement Health and Welfare
Fair value at January 1, 2013 Pro Forma	**$2,196,573**	**$118,449**	**$47,740**	**$2,029**
Estimated revaluation	87,134	4,659	5,041	159
Actuarial deviations credited to reserves	95,659	7,923	-	-
Contributions	8,052	35,274	-	-
Payments and other	(209,915)	(38,274)	(7,670)	(686)
Fair value at December 31, 2013	**$2,177,503**	**$128,031**	**$45,111**	**$1,502**
Estimated revaluation	103,343	6,273	4,330	285
Actuarial deviations credited to reserves	55,636	(2,368)	1	-
Company contributions	31,306	32,911	-	-
Payments	(270,547)	(36,982)	(3,795)	(453)
Fair value at 31 December 2014	**$2,097,241**	**$127,865**	**$45,647**	**$1,334**

The main categories of plan assets, as a percentage of total plan assets at the close of each year, are shown in the table below:

	Equity securities	Fixed-income securities	Other
December 31, 2014			
Retirement Plan	**34%**	**36%**	**30%**
Retiree Benefits Plan	**53%**	**31%**	**16%**
December 31, 2013			
Pension Plans	**44%**	**35%**	**21%**
Postretirement Welfare Plans	**60%**	**29%**	**11%**

The assets associated with these plans include neither financial instruments issued by the Iberdrola Group, IUSA, IRHI or Networks, nor tangible nor intangible assets.

The main assumptions used in the actuarial studies undertaken to determine the provision required at December 31, 2014, and 2013, in connection with these plans were as follows:

	2014			
	Discount rate	***CPI/Wage Inflation***	***Health insurance cost***	***Survivorship tables***
Networks	**3.80%**	2.20% / Age-linked wage growth and Union/Non Union	**Based on the year RX: 2014** 7.75%/7.25%; (pre 65/post 65) year 2027: 4.50%	RP-2014 fully generational projection
IRHI	**3.90%**	**2.20% -0.00%**	**Based on the year RX: 2014:** 7.50%; year 2027: 4.50%	RP-2014 fully generational, MP-2014

	2013			
	Discount rate	***CPI/Wage Inflation***	***Health insurance cost***	***Survivorship tables***
Networks	4.90%	2.40% / Age-linked wage growth and Union/Non Union	**Based on the year RX: 2013:** 8.00%/7.50%; (pre 65/post 65) year 2027: 4.50%	RP-2000 fully generational projection
IRHI	5.00%	2.40%-0.00%	**Based on the year RX: 2013:** 7.75%; year 2025: 4.75%	RP-2000 [Combined] fully generational projection

The sensitivity of the present value of the obligation of these commitments to changes in the discount rate, wage increase and health cost at December 31, 2014 is as follows:

Increase/decrease (basis points)	*Effect on present value of the obligation*
	(In Thousands)
Discount rate	
+10	$2,996
-10	$3,038
Wage increase	
+10	$3,006
-10	$2,998
Health cost	
+25	$390
-25	$387

The following payments are expected to be made in future years out of the defined benefit plan obligations:

	Networks Pension Benefits	**IRHI Retirement and SERP**
(In Thousands)		
Within the next 12 months (next annual reporting period)	$150,010	$4,074
Between 2 and 5 years	623,373	16,101
Between 5 and 10 years	786,853	20,107
Beyond 10 years	2,811,895	54,055
Total expected payments	**$4,372,131**	**$94,337**

Defined contribution plans

The company has defined contribution plans defined as 401(k). The annual contributions made through these plans amounted to $19.8 million for 2014 and $14.5 million for 2013. Those amounts are recognized under Staff costs in the consolidated statement of profit or loss and other Comprehensive Income.

18. Other Provisions

The detail of other provisions in the liability section of the consolidated statements of financial position is as follows:

	Decommissioning	Environmental	Other Provisions	Total
(In Thousands)				
Balances at Jan 1, 2013 Pro Forma	**$609,574**	**$285,139**	**$157,859**	**$1,052,572**
Additions	-	113,525	5,548	**119,073**
Utilized during year	(4,913)	(22,087)	(9,273)	**(36,273)**
Discount unwind and changes in discount note	(85,530)	-	-	**(85,530)**
Transfers	(4,992)	-	8,340	**3,348**
Balance at December 31, 2013	**514,139**	**376,577**	**162,474**	**1,053,190**
Additions	-	14,225	1,946	**16,171**
Utilized during year	(54,960)	(23,972)	(26)	**(78,958)**
Discount unwind and changes in discount note	17,854	-	45	**17,899**
Transfers	800	-	(13,601)	**(12,801)**
Balance at December 31, 2014	**$477,833**	**$366,830**	**$150,838**	**$995,501**

Decommissioning provisions are intended to meet the costs for dismantling and restoration work at operational facilities that the company has committed to carry out. None of these liabilities mature within the next five years.

The estimated years in which the company expects it will have to meet the payments relating to the provisions included in this caption of the consolidated statement of financial position at December 31, 2014, are as follows:

(In Thousands)	
2015	$(36,633)
2016	(37,644)
2017	(36,087)
2018	(30,970)
2019 and thereafter	(854,167)
	$(995,501)

Within other provisions, the company records provisions for responsibilities arising from litigation and similar disputes. Such items are determined on a case-by-case basis.

19. Bank borrowings and other financial liabilities

The detail of the bank borrowings pending of amortization at December 31, 2014 and 2013 and the repayment schedules are as follows:

			Borrowings at December 31, 2014						
			Current Maturity	Non-Current Maturity					
	Balance at December 31, 2014	Balance at December 31, 2013	2015	2016	2017	2018	2019	2020 and subsequent years	Total noncurrent
(In Thousands)									
Finance leases	$79,599	$100,870	$13,404	$6,352	$3,481	$2,900	$3,699	$49,763	$66,195
Debentures and bonds	2,506,608	2,561,609	134,840	181,033	201,183	1,183	301,183	1,687,186	$2,371,768
Notes	12,859	4,500	4,136	8,723	-	-	-	-	8,723
Other financing transactions	4,030	1,726	4,030	-	-	-	-	-	-
Unpaid accrued interest	34,011	34,246	34,011	-	-	-	-	-	-
	$2,637,107	$2,702,951	$190,421	$196,108	$204,664	$4,083	$304,882	$1,736,949	$2,446,686

The foregoing loan balances correspond to amounts drawn down and not repaid at December 31, 2014 and 2013. At December 31, 2014 and 2013, the company had undrawn loans and credit facilities amounting to $886 million and $874 million, respectively, maturing between 2018 and 2019.

Bond issues:

The most significant financing transactions performed by the company in 2013 were as follows:

In January, CMP collected the second tranche of the mortgage-backed bond issue signed in May 2012 amounting to $225 million at an interest rate of 4.4% and maturing in 30 years.

At the date of preparation of these consolidated financial statements, neither IUSA nor any of its material subsidiaries are in breach of their financial commitments or of any kind of obligation that could trigger the early redemption of their financial undertakings.

The company's average cost of debt in 2014 and 2013 was 4.9%.

Fair Market Value of Debt: The estimated fair value of financial liabilities at December 31, 2014 and 2013 amounted to $3,001 million and $3,036 million, respectively. The market value was determined by discounting the future cash flows at market interest rates. The interest rate curve used to make this calculation takes into account the risks associated with the electricity industry and the credit ratings of the borrowers in each case. The sensitivity of the aforementioned fair value to interest rate fluctuations is as follows:

December 31,	2014		2013	
	Interest Rate Fluctuation		Interest Rate Fluctuation	
(Thousands)	+0.25%	-0.25%	+0.25%	-0.25%
Change in the value of borrowings	-$55,326	+$55,655	-$53,884	+$55,808

20. Deferred Taxes and Income Tax Expense

The difference between the tax charge allocated to 2014 and 2013, and the tax payable for those years, recorded under deferred tax assets and deferred tax liabilities in the consolidated statements of financial position at December 31, 2014 and 2013, arose as a result of the temporary differences relating to the difference between the carrying amount of certain assets and liabilities and their tax bases. The main differences are the following:

- Temporary differences arising from the accelerated depreciation taken for tax purposes compared to the depreciation reported in the financial accounts.

- Temporary differences arising from the basis differences between book reporting and tax reporting on certain joint ventures and partnerships.

- Temporary differences arising from the measurement of assets and liabilities related to derivatives and assets that were measured at their market value for which differences between the tax base and carrying amount is not deductible for tax purposes.

- Temporary differences arising from the timing of the deductibility of certain employee benefits for tax purposes.

The detail of current and deferred income tax expense is summarized as follows:

December 31,	**2014**	**Pro Forma 2013**
(In Thousands)		
Current tax (benefit) expense:		
Current tax expense (benefit) from current period operations	$11,922	$46,888
Current tax (benefit)expense relating to adjustments recognized in the current period for tax of prior periods	7,922	(47,309)
Current tax (benefit) expense relating to current year accruals to tax reserves	1,947	(16,646)
Deferred tax (benefit) expense:		
Deferred tax (benefit) expense relating to origination and reversal of temporary differences	296,782	87,656
Deferred tax (benefit) expense relating to adjustments recognized in the current period for tax of prior periods	3,828	14,786
Deferred tax (benefit) expense relating to the write-down of temporary items recognized in a prior period	1,703	2,494
Total income tax expense	**$324,104**	**$87,869**

The Deferred tax expense relating to origination and reversal of temporary differences above includes impacts associated with the enactment of a Unitary Tax regime in New York State effective for tax years beginning after December 31, 2014 and the reduction in the New York State tax rate from 7.1% to 6.5% for tax years beginning after December 31, 2015.

The impact associated with the enactment of the Unitary Tax regime in New York State was an increase to deferred tax expense of $42 million, net of the federal offset. The impact of the reduction in the New York State tax rate was a decrease to deferred income taxes of $14 million, net of the federal offset.

The difference between the U.S. federal statutory rate of 35% and the effective income tax rate is reconciled as follows:

December 31,	2014	Pro Forma 2013
(In Thousands)		
Profit before taxes	$769,033	$374,776
Nondeductible expenses	1,418	1,378
Adjusted accounting profit	**$770,451**	**$376,154**
Expected income tax at the federal statutory rate	$269,658	$131,654
State taxes, net of federal benefit,	88,704	(15,224)
Tax reserves and related interest	1,946	(4,010)
Prior year adjustments	(9,986)	9,808
Write-down of deferred tax items	342	2,540
Aeolus permanent differences	(18,330)	(22,815)
Amortization of investment tax credit	(12,465)	(12,871)
Tax credits	(9,091)	(7,470)
Other	13,326	6,257
Income tax expense	**$324,104**	**$87,869**
Effective tax rate	**42.1%**	**23.4%**

The detail of the movements in deferred tax assets and deferred tax liabilities in the consolidated statements of financial position is as follows:

	Pro Forma January 1, 2013	Charge (Credit) to Consolidated Statement of Comprehensive Income	Charge (Credit) to Hedge Revaluation Reserve	Other	December 31, 2013	Charge (Credit) to Consolidated Statement of Comprehensive Income	Charge (Credit) to Hedge Revaluation Reserve	Other	December 31, 2014
Deferred tax assets									
Employee benefits	**$275,419**	$(71,805)	-	$(29,431)	**$174,183**	$5,833	-	$184,719	**$364,735**
Impairments	**1,781**	54,349	-	-	**56,130**	(467)	-	-	**55,663**
Derivative contracts	**55,017**	6,523	$1,939	(6,628)	**56,851**	(21,050)	$13,353	5,910	**55,064**
Net operating loss and tax credit carryforwards	**1,066,072**	365,775	-	17,790	**1,449,637**	160,705	-	(41,898)	**1,568,444**
Other deferred tax assets	**476,248**	(86,143)	-	(85,059)	**305,046**	46,773	-	(6,364)	**345,455**
	$1,874,537	$268,699	$1,939	$(103,328)	**$2,041,847**	$191,794	$13,353	$142,367	**$2,389,361**
Deferred tax liabilities									
Property, plant, and equipment	**$2,767,294**	$304,304	-	$22,002	**$3,093,600**	$319,333	-	$(38,323)	**$3,374,610**
Leveraged leases	**7,205**	(2,975)	-	-	**4,230**	(4,230)	-	-	-
Derivative contracts	**387**	-	$226	-	**613**	31,781	$45,775	(7,979)	**70,190**
Joint ventures and partnerships	**881,591**	70,540	-	(58,112)	**894,019**	97,502	-	(70,676)	**920,845**
Other deferred tax liabilities	**88,091**	1,766	-	(6,390)	**83,467**	49,721	-	40,856	**174,044**
	$3,744,568	$373,635	$226	$(42,500)	**$4,075,929**	$494,107	$45,775	$(76,122)	**$4,539,689**

The company has established, and periodically reviews, a tax reserve recorded on its consolidated statement of financial position to provide for probable adverse outcomes in tax proceedings and for tax assets for which realization is virtually certain. The current year accruals for tax liabilities are primarily attributable to the reversal of $8 million of previously accrued interest related to the settlement of the IUSA, without IRHI, 2006 – 2009 IRS audit.

During 2012, the Internal Revenue Service concluded its examination of the IRHI for 2008–2010 tax years, the results of which were reviewed by the Joint Committee on Taxation of the United States Congress and approved April 1, 2013. All federal tax returns filed by IHRI from the period ended March 31, 2004 to December 31, 2009, are closed for adjustment. Generally, the adjustment period for the individual states the company filed in is at least as long as the federal period.

On December 29, 2014, the Joint Committee on Taxation approved the examination of Iberdrola IUSA, without IRHI, for the 1998-2009 tax years. The results of these audits, net of reserves already provided, were immaterial. All New York and Maine state returns, which were filed without IRHI, are closed through 2011.

At December 31, 2014, the company had federal tax net operating losses of $3.2 billion, federal renewable energy credits, federal R&D tax credits and other federal credits of $304 million, state tax net operating losses of varying values in several jurisdictions and miscellaneous state tax credits of $17 million available to carry forward and reduce future income tax liabilities. The tax value of the state net operating losses is $118 million. The company has determined that the reversal of federal temporary differences as of December 31, 2014, provides ample future taxable income to utilize all of the federal net operating losses and federal tax credits. For state purposes, the company utilized a combination of the reversing state timing differences and a projected additional taxable income for its regulated companies in determining that $109 million of the gross $135 million state income tax benefits will be utilized. The inclusion of additional taxable income for the regulated companies is appropriate based on the guaranteed rate of returns on rate base that these companies are allowed. The net operating losses begin to expire in 2025, while the federal tax credits begin to expire in 2024.

21. Tax Receivables and Payables

The detail of current tax receivables and current tax liabilities and other tax payments is as follows:

	December 31, 2014	December 31, 2013	Pro Forma January 1, 2013
(In Thousands)			
Income tax receivable	$186,774	$136,246	$202,677
Property and sales tax receivable	3,766	16,736	-
	$190,540	**$152,982**	**$202,677**

	2014	2013	2012
(In Thousands)			
Income tax payable	$136,509	$96,912	$148,291
Accrued property tax	46,863	50,747	30,928
Other tax payables	3,566	7,248	5,156
	$186,938	**$154,907**	**$184,375**

Amounts included in income tax payable include tax reserves.

22. Trade Payables

The detail of trade payables in the consolidated statements of financial position is as follows:

	December 31, 2014	December 31, 2013	Pro Forma January 1, 2013
(In Thousands)			
Suppliers	$517,063	$666,812	$719,210
Rendering of services creditors	157,803	193,306	106,060
Suppliers, group and associated companies	(2,432)	8,022	-
Creditors, group and associated companies	19,864	23,836	13,919
Advances from customers	1,345	6,253	9,336
Trade payables	**$693,643**	**$898,229**	**$848,525**

The majority of these payables do not bear interest.

23. Staff Costs

Staff costs are included within the operating costs heading in the consolidated statement of profit or loss and other comprehensive income. The details of 2014 and 2013 are as follows:

	December 31, 2014	Pro Forma December 31, 2013
(In Thousands)		
Wages and salaries	($483,397)	($472,842)
Retirement and other benefits	(141,903)	(145,493)
	(625,300)	(618,335)
Capitalized staff costs:		
Intangible assets	-	641
Property, plant and equipment	152,248	152,206
	($473,052)	**($465,488)**

The compensation of the key management personnel during the periods was as follows:

	December 31, 2014	Pro Forma December 31, 2013
(In Thousands)		
Short-term employee benefits	$2,434	$2,187
Post-employment pension & medical benefits	211	192
Share-based payments	535	89
	$3,180	**$2,468**

These amounts were expensed and appear within operating costs on the consolidated statement of profit or loss and other comprehensive income.

24. Leases

The heading operating costs in the consolidated statements of profit or loss and other comprehensive income for 2014 and 2013, includes $48.7 million and $67.6 million, respectively, relating to operating leases arising from operational facilities, office building leases, and vehicle and equipment leases. Of those amounts, $20.4 million and $20.6 million, respectively, related to contingent payments, which are predominantly linked to electricity generation at the respective facilities.

The contracts for leasing most of the land on which wind farm facilities are located have various renewal and termination clauses. The payments detailed in the table below relate to the period of the remaining useful life of the facilities and are on a discounted basis due to their maturity.

In April 2013 the company concluded a sale and subsequent lease-back transaction on one of its operating facilities for an initial cash receipt of $110 million. Under the terms of the agreement the company will simultaneously sell and then lease back the facility over a 15-year period, with an option to repurchase the facility at year 10. During the lease period, the company will continue to maintain and operate the entire facility. The company accounted for this as a finance sale-leaseback transaction, under which a lease payable liability is created, 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 through June 2017 in order to maintain necessary system reliability. 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 interface and comply with scheduling deadlines and requirements for maintaining the Facility and the RSS units as eligible energy and capacity providers, as well as

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 also be entitled to a share of any capacity and energy revenues earned by Cayuga. The company accounts for the arrangement as an operating lease. The net expense incurred in 2014 was $19.8 million.

At December 31, 2014, the company concluded the sale for $19.6 million of its 10% undivided interest in Unit 1 of the Springerville power plant to Tucson Electric Power, which it previously accounted for as a lease. This amount was recorded tin 'Other Operating Income' in the company's consolidated statements of profit or loss and other comprehensive income.

The detail of the total future minimum lease payments at December 31, 2014 are set out in the table below.

	Operating Lease	Finance Leases	Total
(In Thousands)			
2015	$23,848	$13,404	$37,252
2016-2019	$88,838	$16,434	$105,272
2020 and thereafter	$225,654	$49,761	$275,415

25. Depreciation, Amortization, and Provisions

The detail in the consolidated statements of profit or loss and comprehensive income for 2014 and 2013 is as follows:

	December 31, 2014	Pro Forma December 31, 2013
(In Thousands)		
Tangible assets depreciation charge	($715,686)	($685,438)
Intangible assets amortization charge	(12,250)	(16,339)
Grants related to assets	84,735	83,427
Impairments and write-downs - tangible	(15,408)	(194,725)
Impairments and write-downs - intangible	(1,558)	(58,276)
Impariments and write-downs - other	(63,772)	(25,534)
	($723,939)	**($896,885)**

The depreciation expense represents straight-line expense over the remaining life of the asset, as described in Notes 4 and 7 and in accordance with the asset lives shown in the accounting policy under Note 4g. For further details of the grants related to assets depreciation offset, see Note 16.

During the year ended December 31, 2014, the company impaired or wrote off $76.3 million of development projects. The comparable amount for the year ended December 31, 2013, was $286.1 million as a result of impairment of certain gas storage development projects. Impairments and write-downs – other are mostly related to accounts receivable. Some of these projects could become economic in the future if conditions change, and if so, the impairments would be reversed.

26. Finance Income

The detail of finance income in the consolidated statements of profit or loss and other comprehensive income for 2014 and 2013 is as follows:

(In Thousands)	**December 31, 2014**	**Pro Forma December 31, 2013**
Income from affiliates	$74	$22,634
Income from investments and other instruments	10,145	10,181
Capitalized finance costs	22,109	4,197
Exchange gains	1,845	3,045
Other interest and finance income	2,430	1,756
	$36,603	**$41,813**

27. Finance Costs

The detail of finance costs in the consolidated statements of profit or loss and other comprehensive income for 2014 and 2013 is as follows:

(In Thousands)	**December 31, 2014**	**Pro Forma December 31, 2013**
Expense from affiliates	($1,499)	($7,950)
Expense on borrowings	(150,100)	(169,373)
Provision discounting unwind	(21,808)	(34,845)
Equity instruments	(35,415)	(34,605)
Exchange gains	(1,499)	(2,702)
Other interest and finance expense	(5,760)	(14,734)
	($216,081)	**($264,209)**

28. Interests in Joint Arrangements

As outlined previously, the company is party to several joint arrangements.

The company owns 50% of the Flat Rock Windpower LLC and Flat Rock Windpower II LLC projects (together, Flat Rock). The Flat Rock projects are two wind farms jointly owned and operated with Horizon Wind Energy LLC. Both projects are located in Lewis County, New York. Due to the way these facilities operate, they are classified as joint ventures and accordingly, the company's 50% share of Flat Rock is accounted for as an equity investment.

The company also owns 50% of Colorado Wind Ventures LLC in conjunction with Shell WindEnergy Inc. Colorado Wind Ventures LLC owns a wind farm project in Prowers County, Colorado, which both partners then own and operate. The form of the operations and contracts for this arrangement allow this project to be proportionally consolidated on a 50% basis.

Because both the Flat Rock and Colorado Wind Ventures LLC entities prepare their accounts under U.S. GAAP, the company has adjusted their balances and presented the summarized financial information below. The respective balances are as follows:

	Flatrock	Flatrock II	Equity Total	Colorado
(In Thousands)				
December 31, 2014				
Non-current assets	$273,485	$105,251	$378,736	$115,267
Current Assets	5,313	1,055	6,368	5,008
Cash and cash equivalents (included above)	*3,065*	*648*	*3,713*	*3,428*
Non-current liabilities	(19,740)	(7,639)	(27,379)	(30,051)
Non-current financial liabilities (included above)	-	-	*(145)*	*(17,446)*
Current liabilities	(276)	(145)	(421)	(9,082)
Current financial liabilities (included above)	-	-	-	*(8,272)*
Equity	($258,782)	($98,522)	($357,304)	($81,142)
Equity ownership interest	50%	50%	50%	
Carrying amount of investment	$129,391	$49,261	$178,652	
Revenue	($42,445)	($11,211)	($53,656)	($18,020)
Depreciation amortization and provisions	$16,131	$5,930	$22,061	$12,701
Financial Income	($4)	($1)	($5)	-
Financial expense	$488	$190	$678	$1,678
Income tax expense	$0	$0	$0	$0
Profit (loss) from continuing operation	($11,841)	($597)	($12,438)	$3,932
Other Comprehensive income	$0	$0	$0	$0
Total comprehensive income	($11,841)	($597)	($12,438)	$3,932
Total comprehensive income attributable to the Company	($5,920)	($299)	($6,219)	$1,966

	Flatrock	Flatrock II	Equity Total	Colorado
(In Thousands)				
December 31, 2013				
Non-current assets	$289,752	$111,558	$401,310	$127,121
Current Assets	8,949	2,020	10,969	4,773
Cash and cash equivalents (included above)	*4,191*	*1,282*	5,473	*1,870*
			-	
Non-current liabilities	(21,391)	(8,309)	(29,700)	(40,714)
Non-current financial liabilities (included above)	-	-	-	*27,300*
Current liabilities	(204)	(133)	(337)	(9,270)
Current financial liabilities (included above)	-	-	-	*(7,465)*
Equity	($277,106)	($105,136)	($382,242)	($81,910)
Equity ownership interest	50%	50%	50%	
Carrying amount of investment	$138,553	$52,568	$191,121	
Revenue	($33,474)	($7,887)	($41,361)	($18,949)
Depreciation amortization and provisions	$15,786	$5,830	$21,616	$12,078
Financial Income	($5)	($1)	($6)	-
Financial expense	$26	$10	$36	$2,725
Profit (loss) from continuing operation	($3,153)	$2,545	($608)	$4,966
Total comprehensive income	($3,153)	$2,545	($608)	$4,966
Total comprehensive income attributable to the Company	($1,576)	$1,272	($304)	$2,483

	Flatrock	Flatrock II	Equity Total	Colorado
(In Thousands)				
January 1, 2013 Pro Forma				
Non-current assets	$286,759	$110,111	$396,870	$125,754
Current Assets	5,340	1,496	6,836	3,380
Cash and cash equivalents (included above)	*2,790*	*825*	*3,615*	*1,462*
Non-current liabilities	(2,637)	(1,026)	(3,663)	(37,443)
Non-current financial liabilities (included above)	-	-	-	*(34,765)*
Current liabilities	(349)	(90)	(439)	(15,903)
Current financial liabilities (included above)	-	-	-	*(14,304)*
Equity	($289,113)	($110,491)	($399,604)	($75,788)
Equity ownership interest	50%	50%	50%	
Carrying amount of investment	$144,556	$55,246	$199,802	

None of the joint ventures had any contingent liabilities or capital commitments.

For information regarding subsidiaries with non-controlling interest, please see Note 15.

29. Guarantee Commitments to Third Parties and Other Contingent Liabilities

The company and its subsidiaries are, at times, required to provide bank or corporate guarantees in the normal course of business. These include the following guarantees provided to market operators to enable the company and its subsidiaries to participate in the energy markets:

Market Guarantee – Guarantees given to cover risks of buying and trading electricity and gas with the company or its subsidiaries.

Performance Guarantees – Guarantees to secure fulfillment of obligations, resulting from the exercise of its business activities, of the company or its subsidiary entities.

Management does not believe that the company will be required to perform under these guarantees and as such has not recognized any liability related to them.

IRHI has executed a guaranty and support agreement from IBERDROLA, which obligates IBERDROLA to provide any necessary financial support to the company to allow it to meet payment obligations on indebtedness that it may incur or for claims made against the company pursuant to its obligations as a guarantor to its subsidiaries.

In order to continue to develop and grow, the company has future commitments to purchase property, plant, and equipment. As at December 31, 2014 and 2013, those amounts were $168.3 million and $570.0 million, respectively.

The company is party to various legal and out-of-court disputes arising as part of its normal activities.

FirstEnergy: NYSEG sued FirstEnergy under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) to recover environmental clean-up costs at 16 former manufactured gas sites. (Liability was based upon FirstEnergy's status as successor to Associated Gas & Electric Company (AGECO), a utility holding conglomerate that unlawfully dominated operations at the plants from approximately 1906-1942.) In July 2011, the Court issued a decision and order in NYSEG's favor. Based upon past and future clean-up costs at the 16 sites in dispute, FirstEnergy will be required to pay NYSEG approximately US $60 million if the decision is upheld on appeal. FirstEnergy appealed the decision to the Second Circuit Court of Appeals o. 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.

On September 11, 2014 the Second Circuit Court of Appeals affirmed the District Court's decision in NYSEG's favor, but modified it 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 expense at nine MPG sites. Because the District Court's original damage award for incurred costs was based upon 2009 figures, FirstEnergy now owes NYSEG an additional damages payment of approximately $16 million for clean-up costs incurred while the appeal was pending.

In addition to the $16 million, excluding interest, in damages incurred through 2014, FirstEnergy would be liable for a share of future costs. Based on current projections, the future costs would be $27 million. At the present time both of these amounts are being treated as contingent assets and have not been recorded as either a receivable or a decrease to the environmental provision.

30. Related-Party Transactions

The following table provides the total amount of transactions that have been entered into with related parties for the relevant financial year.

December 31, (In Thousands)	Year	Sales to	Purchases From	Owed by	Owed to
Iberdrola Renovables Engergia, S.L.	2014	(157)	9,798	-	-
	2013	(49)	10,227	-	-
CNE Energy Services Group, Inc. USA Services	2014	(26,593)	-	-	-
	2013	-	-	-	-
Iberdrola Renewables	2014	-	11,718	-	-
	2013	-	11,242	-	-
		-	-	-	-
Iberdrola Spain	2014	(236)	25,597	107	(497)
	2013	(4,441)	29,059	2,182	(1,725)
ICES	2014	(590)	49,217	1,330	-
	2013	(1,781)	74,844	11,643	(8,662)
					-
Gamesa Corporation Tecnologica SA	2014	-	-	32,942	(222,775)
	2013	-	-	6,044	(25,018)
					-
Iberdrola I.I. S.A. U. Inc.	2014	-	-	-	(10,744)
	2013	(25,891)	-	411	(9,108)
					-
Iberdrola Ing, E.E.U.U, Inc.	2014	-	-	11,091	(14,605)
	2013	-	-	8,346	(9,377)
SP LTD	2014	-	-	-	-
	2013	-	6,426	-	-
Other	2014	(12,104)	5,668	1,502	(1,300)
	2013	(11,733)	5,705	4,060	(2,276)

Transactions with Iberdrola Canada Energy Services are predominantly in relation to the purchase of gas for IRHI's gas-fired generation facility at Klamath.

Transactions with the company's ultimate parent, IBERDROLA, relate predominantly to recharges of corporate services/management fees. Also included within the purchases category are charges for credit support, relating to parent company guarantees that IBERDROLA has provided to third parties to guarantee the performance of the company.

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 loan balances outstanding. There have been no impairments or provisions made against any affiliated balances.

31. New and Amended Accounting Standards and Interpretations

New and amended standards and interpretations adopted:

IFRIC 21 Levies

IFRIC 21 provides guidance for when an entity recognizes a liability for a levy imposed by a government that is within the scope of IAS 37 *Provisions, Contingent Liabilities and Contingent Assets.* The liability is recognized when the activity that triggers payment, as identified by the relevant legislation, occurs. For a levy that is triggered upon reaching a minimum threshold, IFRIC 21 clarifies that no liability should be recognized before the specified minimum threshold is reached. IFRIC 21 is effective for annual periods beginning on or after January 1, 2014, and retrospective application is required. IUSA began applying IFRIC 21 as of January 1, 2014, and, as required, has accounted for the change in accounting policy retrospectively in accordance with IAS 8, *Accounting Policies, Changes in Accounting Estimates and Errors.*

The impact of the adoption of IFRIC 21 was not material to the company's financial statements.

New and amended standards and interpretations issued but not yet adopted:

The standards and interpretations that are issued, but not yet effective, up to the date of issuance of the company's financial statements are disclosed below. The company intends to adopt these standards, as applicable, when they become effective.

IFRS 9 Financial Instruments

IFRS 9, as previously issued, reflected the first phase of the IASB's work on the replacement of IAS 39 and applied to classification and measurement of financial assets and financial liabilities as defined in IAS 39. The standard was initially effective for annual periods beginning on or after January 1, 2013, but Amendments to IFRS 9, Mandatory Effective Date of IFRS 9 and Transition Disclosures, issued in December 2011, moved the mandatory effective date to January 1, 2015. The final version of IFRS 9, issued in July 2014, combines classification and

measurement, the expected credit loss impairment model, and hedge accounting, and will eventually replace IAS 39 and all previous versions of IFRS 9. An entity will base its measurement of financial assets at amortized cost, fair value through profit or loss, or fair value through other comprehensive income, on the entity's business model for managing the financial assets and the financial asset's contractual cash flow characteristics. Except for 'own credit risk' requirements, the classification and measurement of financial liabilities is unchanged from existing requirements. Application of the final version of IFRS 9 is required for annual periods beginning on or after January 1, 2018, with earlier application permitted. The application of IFRS 9 will have an effect on the classification and measurement of the company's financial assets but not on its financial liabilities. The company will quantify the effect in conjunction with the other phases.

IFRS 11 Joint Arrangements – Amendments to IFRS 11 – Accounting for Acquisitions of Interests in Joint Operations

The amendments add new guidance to IFRS 11 on accounting for the acquisition of an interest (initial and additional) in a joint operation that constitutes a business, as defined in IFRS 3, *Business Combinations*. The amendments are effective for annual periods beginning on or after January 1, 2016, with prospective application required and earlier application permitted. The company expects the effects of the amendments will not be material to its financial statements.

IFRS 14 Regulatory Deferral Accounts

IFRS 14 represents an interim standard as an additional phase of the Rate-regulated Activities project. It allows entities that adopt IFRS to continue to recognize regulatory deferral accounts in accordance with their previous GAAP (as defined in IFRS 1 *First-time Adoption of International Financial Reporting Standards*, i.e., the basis of accounting that a first-time adopter used immediately before adopting IFRS). The standard allows those entities to avoid making major changes in accounting policy on transition to IFRS until guidance can be developed through the comprehensive project. It requires the effect of rate regulation to be presented separately from other items. This interim standard does not imply the IASB is anticipating the outcome of the comprehensive rate-regulated activities project. IFRS 14 can be applied in an entity's first annual IFRS financial statements for periods beginning on or after January 1, 2016, with earlier application permitted. The company has decided not to apply IFRS 14.

IFRS 15 Revenue from Contracts with Customers

IFRS 15 is primarily principles-based guidance that provides a framework intended to improve financial reporting of revenue and improve comparability of revenue reporting in financial statements. The standard replaces all existing IFRS revenue requirements. 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, to be achieved by applying the following five steps: 1) Identify the contract(s) with a customer; 2) Identify the performance obligations in the contract; 3) Determine

the transaction price; 4) Allocate the transaction price to the performance obligations in the contract; and 5) Recognize revenue when (or as) the entity satisfies a performance obligation. The standard also enhances disclosures about revenue, provides guidance for transactions not previously addressed comprehensively and improves guidance for multiple-element arrangements. Application of IFRS 15 is required for annual periods beginning on or after January 1, 2017, with earlier application permitted. The company has not yet determined the effect that the adoption of the standard will have on its financial statements.

IAS 16 Property, Plant and Equipment and IAS 38 intangible Assets – Amendments to IAS 16 and IAS 38 – Clarification of Acceptable Methods of Depreciation and Amortization

The amendments to IAS 16 and IAS 38 are to ensure that preparers do not use revenue-based methods to calculate charges for the depreciation or amortization of items of property, plant and equipment. A revenue-based method reflects a pattern of economic benefits being generated from the asset, rather than the expected pattern of consumption of the future economic benefits embodied in the asset. The amendments are effective for annual periods beginning on or after January 1, 2016, with prospective application required and earlier application permitted. The company expects the amendments will not have a material effect on its financial statements.

Disclosure Initiative – Amendments to IAS 1

The amendments to IAS 1 are part of a package of several projects aimed at improving disclosure of financial information and represent narrow-focus clarifying amendments to address some concerns about existing presentation and disclosure requirements and ensure entities are able to use judgment when preparing their financial statements. The amendments are designed to encourage companies to apply professional judgment in determining what information to disclose in their financial statements, including determining where and in what order information is presented. For example, the amendments clarify that materiality applies to the whole of financial statements and that the inclusion of immaterial information can inhibit the usefulness of financial disclosures. The amendments are effective for annual periods beginning on or after January 1, 2016, with earlier application permitted and prospective or retrospective application required as specified. The company expects the amendments will not have a material effect on its financial statements.

32. Subsequent Events

The company has performed a review of subsequent events through February 19, 2015, which is the date these financial statements were available to be issued, and the financial statements reflect events occurring from January 1, 2015 through such date. Through the date of this review, one subsequent event was identified relating to CMP's issuance of first mortgage bonds in January of 2015 that were priced in October of 2014 for $150 million.

OCS-A 0501 MASS USA

VINEYARD WIND

Vineyard Wind

Attachment 5.6-4

Iberdrola SA Accounts (2016)

IBERDROLA

Integrated Report february / 2017

- Comfort for homes
- Sustainability for the future
- Competitiveness for companies
- Innovation for infrastructure

Our goal is to offer a reliable, high-quality, and environmentally-friendly energy supply, in order to:

- Improve the well-being of people.
- Drive the economic and social development of the communities in which we are present.
- Create sustainable value for our shareholders, employees, customers, suppliers, and society in general.

Mission
We create value in a sustainable way and we are commited to social dividend.

Vision
We want to be a global energy leader and create a better future for people with the support of our human team.

Values
The twelve values inspire and guide the Group's strategy and all of its actions.

IBERDROLA

Utility of the future

Whitelee wind farm,
Scotland / UK

© Chris James

Iberdrola's Public Information

Iberdrola makes all of its public information available to our shareholders, employees, customers, suppliers, and society in general to provide reliable and relevant information regarding the Company's performance and its strategic lines for the coming years.

Annual information

Integrated Report
Prepared based on the recommendations of the International Integrated Reporting Council (IIRC).

Financial Report
Prepared according to international financial reporting standards and externally audited.

Corporate Governance Report
Prepared according to the form provided by the National Securities Market Commission of Spain.

Sustainability Report
Prepared according to the Global Reporting Initiative (GRI) guidelines and externally assured.

Activities Report of the Board of Directors and of the Committees thereof
Prepared according to Iberdrola internal standards.

Director Remuneration Report
Prepared according to the form provided by the National Securities Market Commission of Spain.

Report on Compliance with Legal Provisions on the Separation of Regulated Activities
Prepared according to Iberdrola internal standards.

Report on Related-Party Transactions with Directors and Significant Shareholders
Prepared according to Iberdrola internal standards.

Report on the Application of the Shareholder Engagement Policy and the Policy regarding Communication and Contacts with Shareholders, Institutional Investors, and Proxy Advisors.
Prepared according to Iberdrola internal standards.

Report on the Independence of the Auditor in relation to the audit report for financial year 2016.
Prepared according to Iberdrola internal standards.

Additional information

Quarterly Results Report
IBE Watch Fact Sheet
Quarterly Shareholder Bulletin
Innovation Report
Environmental Footprint Report
Biodiversity Report
Greenhouse Gas Report

Information on the corporate website www.iberdrola.com

About Us
Corporate Governance
Sustainability
Shareholders and Investors
Suppliers
People and Talent
Press Room

Access the annual reports for financial year 2016 and supplementary documentation regarding the Iberdrola Group by scanning the corresponding QR code using your smart phone or tablet:

⦿ This icon refers to related information. It also gives information on other specific reports where more information of interest can be accessed.

Integrated Report

IBERDROLA

February 2017

Contents

1. Iberdrola Today

Letter from the Chairman & CEO 6

1.1 Iberdrola Today 10

1.2 Company Performance 11

1.3 Key Figures 12

1.4 Presence by Areas of Activity 14

2. Business Model and Strategy

2.1 The Future of Energy 26

2.2 Business Model 28

2.3 Iberdrola, a Different Company 31

2.4 Asset Management 32

2.5 Value Chain 34

2.6 Strategic Foundations 36

2.7 Capital/Business Relationship 39

2.8 Comparative Results and Awards 40

3. Iberdrola's Primary Businesses

3.1 Regulatory Environment 44

3.2 Networks 47

3.3 Wholesale and Retail 51

3.4 Renewables 55

3.5 The Cost of Supply 58

4. Our Assets

4.1 Financial Capital 62

4.2 Manufactured Capital 64

4.3 Intellectual Capital 66

4.4 Human Capital 68

4.5 Natural Capital 70

4.6 Social and Relationship Capital 72

5. A Framework of Trust

5.1 Corporate Governance Model 78

5.2 Three Lines of Defence 84

5.3 Risks 86

5.4 Ethics and Social Responsibility 90

6. About this Report

6.1 About this Report 94

Notes:
- The company Iberdrola, S.A., parent company of the Iberdrola Group, is referred to as "Iberdrola" or the "Company" in this report. Iberdrola (as parent company) and the group of subsidiaries over which Iberdrola has the power of control or joint control is also referred to as the "Iberdrola Group" or the "Group".
- The figures included in this translation follow the customary English convention, with figures in thousands separated by a comma (,) and decimals indicated by a full stop (.).
- €M: millions of euros; $M: millions of dollars.

Letter from the Chairman & CEO

Ignacio S. Galán
Chairman & CEO of Iberdrola
© Adrián Ruiz

"In the coming years, Iberdrola will intensify its wager on the solutions required by the energy transition and which have made the company the utility of the future".

I am pleased to present to you Iberdrola's Integrated Report, in which you can find extensive and detailed information regarding the Group's performance, the strategic foundations on which the company addresses its future, and the most significant aspects of its performance.

In the energy scenario within which Iberdrola will be acting in the coming years, notable progress has been made towards the achievement of a more sustainable energy model following the entry into force of the Paris Climate Summit Agreement on 4 November, only eleven months after it was signed.

This swiftness of action, which stands in contrast with the almost eight years that the Kyoto Protocol took to come to fruition, reveals the firm commitment of the international community to reduce the emissions causing climate change and to limit the increase in temperature to less than 2 degrees by the end of the century as compared to the levels of the pre- industrial era, leaving the door open for an improvement of this goal to 1.5 degrees.

This commitment was ratified at the latest Climate Summit, held in Marrakesh, through the establishment of the agenda and the instruments needed to implement the Paris Agreement over the next two years and the preparation of working programmes on key issues in order to facilitate compliance therewith.

Meanwhile, the European Commission has affirmed its goal of a 40% reduction in CO_2 emissions by 2030 and its intention for the European Union to lead the energy transition through its "Clean Energy for All Europeans" package of proposals.

In this context, and given the technological potential of our industry to contribute to decarbonisation thanks to renewable energy, increased electrification of the economy is indispensable to honour the international commitments concerning emissions and at the same time respond to the strong growth in global energy demand.

In the coming years, Iberdrola will intensify its firm wager on the solutions required by the energy transition and which have made the company the utility of the future: more renewable energies, increased storage capacity, more and smarter grids, and growing digitisation to offer new and better services to our customers.

2016-2020: accelerating growth

In February 2017, Iberdrola updated its *Outlook 2016-2020*, which was presented a year ago, following its decision to increase investments to 25,000 million euros during the period in view of the company's financial strength to take advantage of new

opportunities for growth, primarily for the development of renewable energy projects in the United States.

Following its unique model, which combines geographic diversification with a focus on activities linked to the energy transition, the Company will allocate 91% of investment to the expansion and digitisation of networks, renewable energy, and regulated generation, which areas will contribute 81% of the Group's Ebitda. By currency, the investments will be split amongst dollars (48%), pounds (29%), euros (20%), and other (3%), and will go mainly to countries with an A rating.

Iberdrola will add 8,200 MW of new capacity to its generation pool through 2020, such that the Group's overall capacity will exceed 50,000 MW (with more than 29,000 MW of renewable energy), growing 12% from year- end 2015.

During the 2016-2020 period, the Company expects to obtain annual average growth in after-tax profits of approximately 7.5% (which will come mainly from countries with an A rating), up to approximately 3,500 million euros.

At the same time, we will continue to maintain financial strength, increase the return on investments, and improve operational efficiency thanks to advances in automation and digitisation in all businesses and processes.

Iberdrola will thus offer its shareholders growing remuneration in line with its results, with a pay-out of between 65% and 75%, such that a range of between 0.37 and 0.40 euro per share could be reached by 2020, with a floor of 0.31 euro per share in any case. We will also maintain the flexible dividend formula, and the current number of outstanding shares will remain stable.

Impact on society

The expansion of this strategic coverage will allow us to continue generating a positive economic and social impact on all of the regions in which we have a presence, contributing to their progress and to the well-being of their citizens. According to a study by PwC,[1] for each euro obtained in profits, Iberdrola contributes 11.1 euros to the GDP of the countries in which it does business.

We will thus continue to act as a major driving force through procurement contracts (which came to more than 9,800 million euros in 2016, thus exceeding the record figure for the prior year) and through our commitment to maintaining and creating stable and quality jobs, as shown by the addition of more than 2,600 people to our workforce only last year. Overall, Iberdrola provides direct, indirect, and induced employment to 288,000 people throughout the world, thanks to its investments and operations.[1]

"The expansion of our strategic coverage will allow us to continue generating a positive economic and social impact on all of the regions in which we have a presence".

Our unwavering commitment to the training of the company's personnel (we currently provide three times more hours of training per employee per year than the average of European companies[1]) will be boosted by the activities of the Iberdrola Campus in Madrid, which, with a built-up area of 45,000 square metres and 540 seats in classrooms and workshops, has already become a leading centre for corporate training. We will also continue to improve the management of our human resources by promoting the reconciliation of working and family life, gender equality, and job security.

Iberdrola will also strengthen its commitment to clean energies and to protection of the environmental, by increasing its production capacity with renewable technologies over the next years and by reaffirming its goal to reach a 50% reduction in emissions by 2030 as compared to 2007 levels.

The development of our sustainable business model will allow us to remain at the top of the main indices in this field, such as the Dow Jones Sustainability Index (on which we are the only European electric utility to have been included for seventeen years), FTSE4Good, and CDP Climate Change.

Furthermore, our efforts in the area of R&D (to which we allocated 211 million euros in 2016) will be focused on sustainability, the promotion of renewable energy, and the exploitation of the opportunities offered by digitisation and automation for the development of new products and services. We thus expect to continue to be at the forefront among the most innovating electric utilities, Iberdrola now being the fourth largest electric company in the world by volume of investment.[1]

As part of our commitment to society, the Foundations of the Iberdrola Group will continue with their programmes in the areas of training and research (primarily through the International Scholarship Programme), the protection of biodiversity and the promotion of art and culture, and cooperation and solidarity with the most vulnerable groups.

In the coming years, we will also move forward with the "Electricity for All" programme, which in 2016 already reached more than two and a half million beneficiaries in emerging or developing countries who have been given access to electric power, the aim being to reach four million beneficiaries by 2020.

In parallel with all of the foregoing, Iberdrola will continue to develop its Corporate Governance System, based on ethical principles, transparency, and leadership in the application of the best international practices on good governance, an area in which the company has become an international leader.

(1) PwC study "Iberdrola's economic, social, and environmental impact on the world" (based on 2015 data).

Wikinger marine wind farm -
Baltic Sea / Germany

© David López Navarro

1.

Iberdrola Today

1.1 Iberdrola Today

Our activities

- Production of electricity from renewable and conventional sources.
- Purchase/sale of electricity and gas on wholesale markets.
- Transmission and distribution of electricity.
- Supply of electricity, gas, and related energy services.
- Other activities, mainly linked to the energy sector.

Presence focused on the Atlantic area

Iberdrola carries out its activities mainly in the five countries of the Atlantic area: Spain, the United Kingdom, the United States, Mexico, and Brazil.

What we are

The process of internationalisation carried out in recent years has led Iberdrola to be one of the leading electric companies, and among the largest utilities in the world by stock market capitalisation. The corporate and governance structure is described in chapter 5.1 of this report and consists of:

- Iberdrola, as a holding company.
- Country subholding companies in the 5 main geographic areas of activity.
- Head of business companies reporting to the country subholding companies.

Iberdrola is one of the leading electric companies in the world.

2016 Data Iberdrola Group

46,925
MW
Installed capacity[1]

142,453
GWh
Net output[1]

229,816
GWh
Electric power distributed[1]

9,884
€M
Procurement awarded

27,723
MW
Renewable installed capacity[1]

34.5
Million users[1]

5,750
€M
Direct tax contribution

30,591
People
Direct employment

288,000
People
Direct, indirect, and induced employment[2]

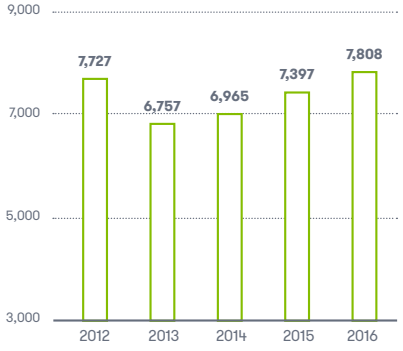
4,264
€M
Investments

(1) Managed magnitudes including 100% Neoenergia.
(2) Data from a Study of Iberdrola's Impact, prepared by PwC, based on 2015 figures.

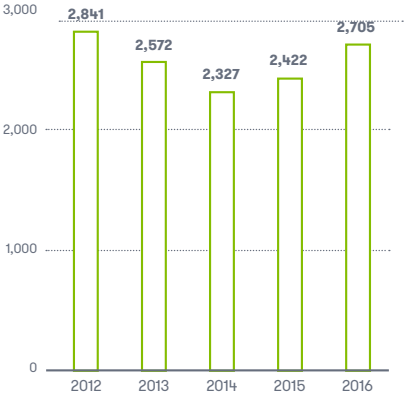
1.2 Company Performance

Revenues (€M)

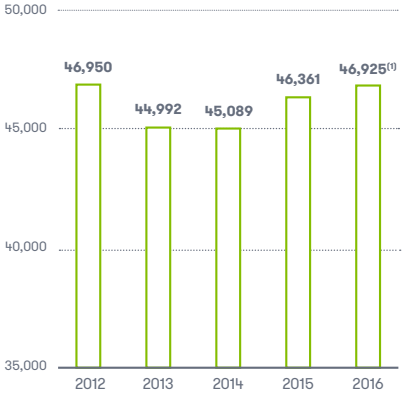
Ebitda (€M)



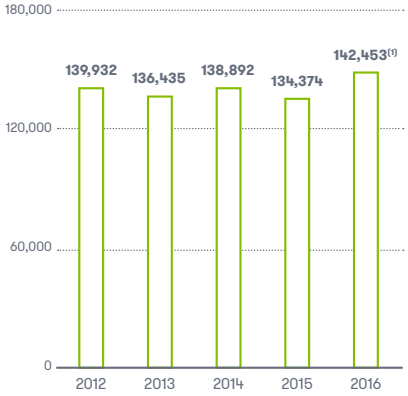
Net Profit (€M)



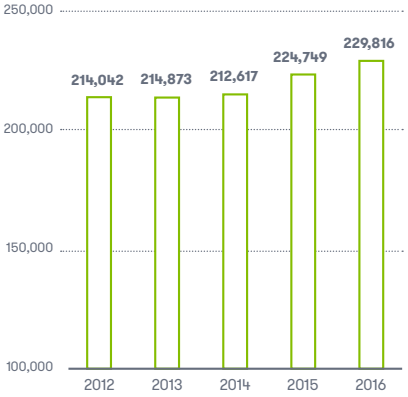
Installed capacity (MW)



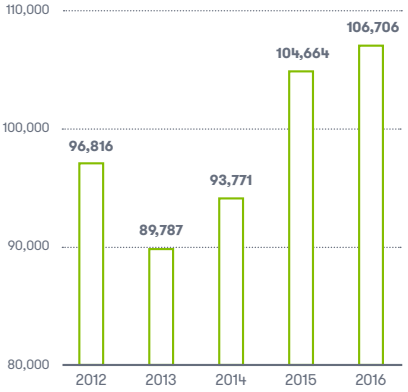
Net output (GWh)



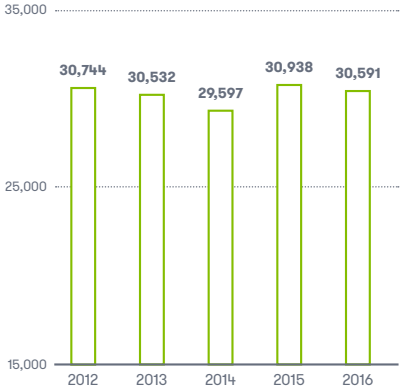
Energy distributed (GWh)(1)



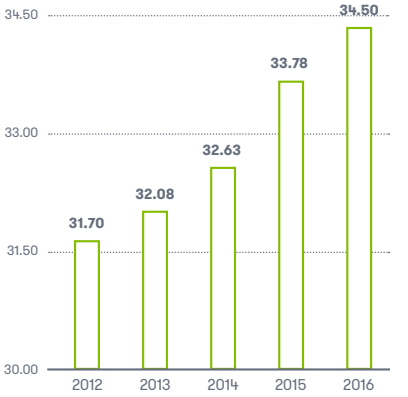
Assets (€M)



Employees



Users (millions)



(1) Managed magnitudes including 100% Neoenergia.
* Note: Due to legal requirements, Iberdrola has applied International Financial Reporting Standard IFRS-11 to the financial information for the financial years 2013 to 2016, which aspect should be taken into account in evaluating the historical performance of the Company.

1.3 Key Figures

Financial performance (€M)	2012	2013	2014	2015	2016	Δ annual average 2012-16	Δ 2015-2016
Revenues	34,201.2	31,077.1	30,032.3	31,418.7	29,215.4	-3.9%	-7.0%
Consolidated Gross Margin	12,578.1	11,781.9	12,179.5	12,842.7	12,916.2	0.7%	0.6%
Consolidated Ebitda	7,726.6	6,756.9	6,964.5	7,397.4	7,807.7	0.3%	5.5%
Ebitda - Networks (Regulated)	3,773.7	3,346.5	3,534.7	3,628.0	4,081.7	2.0%	12.5%
Spain	1,348.3	1,450.3	1,438.5	1,456.8	1,603.1	4.4%	10.0%
United Kingdom	937.3	939.0	1,024.8	1,138.0	976.2	1.0%	-14.2%
United States	660.2	718.2	772.0	780.5	1,269.6	17.8%	62.7%
Brazil	827.9	239.0	299.4	252.7	232.8	-27.2%	-7.9%
Ebitda - Wholesale and Retail (Liberalised)	2,355.2	1,986.6	2,292.2	2,323.1	2,253.3	-1.1%	-3.0%
Spain	1,605.4	1,341.2	1,517.6	1,504.6	1,520.5	-1.3%	1.1%
United Kingdom	360.6	320.4	456.6	421.7	293.6	-5.0%	-30.4%
United States	9.1	-22.6	-32.0	-58.4	6.1	-9.5%	–
Mexico and Brazil(1)	380.1	347.6	350.0	455.2	433.1	3.3%	-4.9%
Ebitda - Renewables	1,620.3	1,501.1	1,326.0	1,647.2	1,500.2	-1.9%	-8.9%
Spain	804.3	668.4	420.6	473.2	497.4	-11.3%	5.1%
United Kingdom	168.1	231.8	265.2	438.1	267.0	12.3%	-39.1%
United States	412.2	448.0	495.3	570.9	563.6	8.1%	-1.3%
Mexico	37.2	34.1	38.2	43.1	52.0	8.7%	20.6%
Brazil	11.3	9.1	33.0	26.9	24.9	21.8%	-7.4%
Rest of World	187.2	109.7	73.7	95.0	95.3	-15.5%	0.3%
Ebitda - other businesses	44.3	0.5	-17.0	-10.5	-111.3	–	–
Ebitda - Corporation and adjustments	-66.9	-77.8	-171.4	-190.4	83.8	–	–
Amortisation charge, provisions, and other	-3,349.7	-4,537.5	-3,023.6	-3,568.1	-3,253.7	0.7%	8.8%
Operating profit (EBIT)	4,376.9	2,219.5	3,940.9	3,829.3	4,554.0	1.0%	18.9%
Financial result	-1,100.3	-1,277.9	-1,122.4	-1,023.1	-903.4	4.8%	11.7%
Results from companies accounted for using the equity method	-187.5	205.0	135.4	55.3	48.7	–	-11.9%
Gains on non-current assets	-13.9	-10.4	247.9	125.1	48.2	–	-61.5%
Profit before Tax (PBT)	3,075.1	1,136.1	3,201.8	2,986.6	3,747.5	5.1%	25.5%
Corporate tax	-206.5	1,466.7	-837.1	-527.1	-904.6	-44.7%	-71.6%
Non-controlling interests	-27.9	-31.0	-38.2	-38.0	-137.9	-49.1%	-262.9%
Net attributable profit	2,840.7	2,571.8	2,326.5	2,421.6	2,705.0	-1.2%	11.7%
Total assets	96,816.4	89,786.8	93,771.4	104,664.1	106,706.2	2.5%	2.0%
Equity	34,084.8	35,288.6	35,790.5	40,956.1	40,687.4	4.5%	-0.7%
Net investments	3,259.0	3,053.0	2,848.0	3,223.0	4,264.3	7.0%	32.3%
Funds from operations (FFO)	6,196.0	5,619.0	5,459.0	5,906.7	6,310.8	0.5%	6.8%
Net financial debt	30,324.4	26,836.3	25,618.4	28,067.1	29,414.0	-0.8%	4.8%

Financial ratios	2012	2013	2014	2015	2016	Δ annual average 2012-16	Δ 2015-2016
Ebitda - outside eurozone (%)	51.0	49.5	54.0	56.0	54.0	1.4%	-3.6%
Ebitda margin (Ebitda/revenue) (%)	22.6	21.7	23.2	23.5	26.7	4.3%	13.5%
Net profit margin (Net profit/ Revenues) (%)	8.3	8.3	7.7	7.7	9.3	2.8%	20.1%
NOE/Gross margin (%)	30.1	29.4	29.8	29.8	27.7	-2.1%	-7.3%
Net financial debt/ebitda (multiple)	3.92	3.97	3.68	3.79	3.77	-1.0%	-0.6%
Financial leverage (%)	47.1	43.2	41.7	40.7	42.0	-2.8%	3.2%
Funds from operations (FFO)/ Net financial debt (NFD)	20.4	20.8	21.3	21.0	21.5	1.3%	1.9%
Retained cash flow (RCF/NFD) (%)	17.2	17.5	17.4	18.7	19.1	2.6%	2.0%
Return on equity (ROE) (%)	8.3	7.5	6.7	6.3	7.3	-3.2%	15.9%

Stock market performance	2012	2013	2014	2015	2016	Δ annual average 2012-16	Δ 2015-2016
Stock market capitalisation (€M)	25,753	28,922	35,756	41,506	39,661	11.4%	-4.4%
Number of shares at year-end (millions)	6,139	6,240	6,388	6,337	6,362	0.9%	0.4%
Share price (€)	4.20	4.63	5.60	6.55	6.23	10.4%	-4.8%
Earnings per share (EPS)	0.45	0.41	0.36	0.37	0.42	-1.7%	14.4%
Dividend per share (DPS)	0.340	0.310	0.275	0.276	0.286	-4.2%	3.6%
Dividend yield (%)	8.13	6.65	4.91	4.21	4.59	-13.3%	9.0%
Total dividend (including payment in kind) (€M)	2,093	1,922	1,716	1,732	1,966	-1.6%	13.5%
Payout ratio (%)	65.4	65.5	73.8	71.5	72.7	2.7%	1.7%
Price/net earnings per share (PER)	9.31	11.25	15.37	17.17	14.66	12.0%	-14.6%

- Sustainability Report
- Quarterly Results Report
- Consolidated Annual Financial Statements

(1) These figures only include Mexico until 2015. The 2015 and 2016 figures include the value for Mexico and Brazil.
* Note: Due to legal requirements, Iberdrola has applied International Financial Reporting Standard IFRS-11 to the financial information for financial years 2013 to 2016, which aspect should be taken into account in evaluating the historical performance of the Company.

Operating performance	2012	2013	2014	2015	2016	Δ annual average 2012-16	Δ 2015-2016
Installed capacity (MW)	46,950	44,992	45,089	46,361	46,925[1]	-0.9%	-2.4%
Net output (GWh)	139,932	136,435	138,892	134,374	142,453[1]	-0.5%	2.2%
Electric power distributed (GWh)[1]	214,042	214,873	212,617	224,749	229,816	1.8%	2.3%

Environmental performance	2012	2013	2014	2015	2016	Δ annual average 2012-16	Δ 2015-2016
Emission-free installed capacity (%)	59.4	61.2	61.9	63.0	65.9	2.6%	4.6%
Emission-free production (%)	51.9	54.6	56.8	52.5	57.1	2.4%	8.8%
Specific CO_2 emissions (t/GWh)	264	226	212	225	176	-9.6%	-21.8%
Fuel consumption (M Tep)	19,236	18,968	18,849	19,001	17,734	-2.0%	-6.7%
Environmental investments (€M)	1,062.4	1,015.7	1,100.9	1,014.2	2,262.2	20.8%	123.1%
Environmental expenses (€M)	723.3	686.4	635.7	669.2	527.1	-7.6%	-21.2%
Energy produced under certified environmental management systems (%)	85.2	84.4	87.0	84.2	84.0	-0.4%	-0.2%
Water use/overall production (m^3/GWh)	699	976	509	533	586	-4.3%	9.9%
Direct CO_2 emissions. Scope 1 (kt)	35,461	31,846	30,217	31,752	25,194	-8.2%	-20.7%
Indirect CO_2 emissions. Scope 2 (kt)	2,122	997	1,544	963	817	-21.2%	-15.2%
CO_2 avoided due to efficiency initiatives (kt)	24,014	18,480	21,459	19,269	16,461	-9.0%	14.6%
SO_2 emissions (t/GWh)	0.366	0.217	0.154	0.125	0.051	-38.9%	-59.2%
NO_x emissions (t/GWh)	0.334	0.262	0.236	0.230	0.144	-19.0%	-37.4%

- Sustainability Report
- Quarterly Results Report
- Consolidated Annual Financial Statements

Social performance	2012	2013	2014	2015	2016	Δ annual average 2012-16	Δ 2015-2016
Users (millions)	31.7	32.1	32.6	33.8	34.5	2.1%	2.0%
Electrical power	28.1	28.5	29.0	29.7	30.4	2.0%	2.4%
Spain	10.9	10.9	10.9	10.9	11.0	0.1%	0.5%
United Kingdom	3.5	3.5	3.5	3.5	3.5	0.1%	0.6%
United States	1.8	1.8	1.8	2.2	2.5	8.5%	13.2%
Latin America	11.9	12.4	12.8	13.1	13.4	3.0%	2.3%
Gas	3.6	3.6	3.6	4.1	4.1	3.3%	-0.2%
Spain	0.8	0.8	0.8	0.9	0.9	4.1%	5.6%
United Kingdom	2.2	2.2	2.2	2.2	2.1	-0.8%	-2.7%
United States	0.6	0.6	0.6	1.0	1.0	13.6%	0.0%
Number of employees	30,744	30,532	29,597	30,938	30,591	-0.1%	-1.1%
Permanent contracts (%)	98.0	98.5	98.5	98.4	98.7	0.2%	0.3%
Employees with collective bargaining agreement (%)	79.8	79.4	79.0	76.6	76.9	-0.9%	0.4%
Employee turnover (%)	10.6	6.6	8.6	7.0	7.3	-8.9%	4.3%
Diversity (men/women)	76/24	76/24	77/23	76/24	76/24	–	–
Ratio between basic entry level wage and local minimum wage (%)	151	154	161	153	154	0.6%	0.9%
Injury rate (IR)	0.34	0.46	0.39	0.28	0.35	0.7%	25.0%
Hours of training (millions of hours)	1.12	1.2	1.0	0.9	1.3	3.8%	44.4%
Hours of training per employee (h)	44.2	44.7	38.7	38.6	46.0	1.0%	19.2%
Funds for social development (€M)	51.7	91.7	65.0	46.0	61.5	4.4%	33.7%
Contributions to society (€M)	37.7	31.6	34.0	38.0	43.7	3.8%	15.0%
Rural electrification programmes (€M)	14	60	31	8	17.8	6.2%	122.5%
Investments in R&D (€M)	145	159	170	200	211	9.8%	5.5%
General procurement (€M invoiced)2	4,830	4,359	4,599	5,093	6,415	7.4%	26.0%
Procurement from qualified suppliers (%)	84	87	92	94	89	1.5%	-5.3%
Number of suppliers with social responsibility standards	1,233	1,202	1,326	1,536	1,667	7.8%	8.5%
Procurement in sensitive countries per ILO (%)	8.9	12.0	10.7	10.8	8.2	-2.1%	-24.2%
Procurement from local suppliers (%)	90	86	87	85	84	-1.7%	-1.2%

(1) Managed magnitudes including 100% Neoenergia.
(2) Supplies in the amount of 9,884 million euros were awarded during 2016.

1.4 Presence by Areas of Activity

Iberdrola in Spain

Largest energy company
Δ 2016 / 2015
GDP +3.0%
Electricity demand +0.7%

Primary brands

IBERDROLA ESPAÑA
Spain subholding company

IBERDROLA ESPAÑA Renovables
Renewables business

IBERDROLA ESPAÑA Redes
IBERDROLA DISTRIBUCIÓN ELÉCTRICA
Networks business

IBERDROLA ESPAÑA Generación
IBERDROLA
Wholesale and retail business

IBERDROLA Inmobiliaria
Real Estate

IBERDROLA Ingeniería y Construcción
Engineering

Fundación IBERDROLA ESPAÑA
Foundation

2016 data

26,162
MW
Installed capacity

15,819
MW
Renewable installed capacity

62,784
GWh
Net output

267,576
Km
Power lines

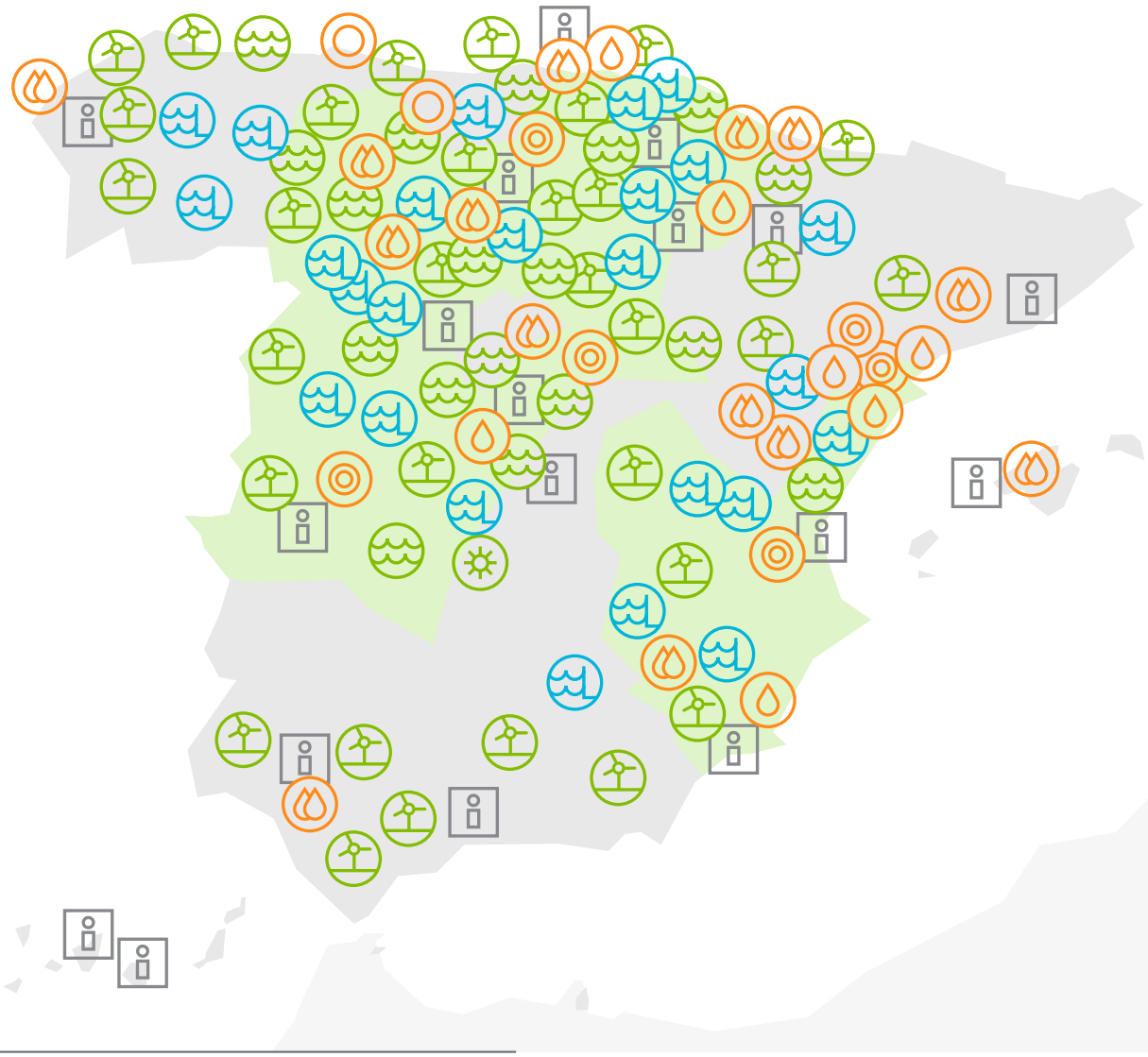
92,308
GWh
Electric power distributed

11.8
Million users

10,395
Employees

649
€M
Investments

3,454
€M
Direct tax contribution



Primary facilities

195
Windfarms
5,751 MW

89
Minihydro power plants
303 MW

1
Solar thermal plant
50 MW

8
Combined cycle gas plants
5,695 MW

20
Cogeneration plants
364 MW

6
Nuclear plants
3,410 MW

2
Thermal plants
874 MW

79
Hydro power plants
9,715 MW

Offices

Area of influence

Electricity distribution

Iberdrola in the United Kingdom

Largest wind producer
3rd-largest network company
Δ 2016 / 2015
GDP +1.8%
Electricity demand –1.3%

Primary brands

SCOTTISHPOWER
United Kingdom subholding company

SCOTTISHPOWER RENEWABLES
Renewables businesses

SP ENERGY NETWORKS
Networks business

SCOTTISHPOWER Generation
SCOTTISHPOWER
Wholesale and retail business

IBERDROLA Engineering & Construction
Engineering

Foundation SCOTTISHPOWER
Foundation

2016 data

4,537
MW
Installed capacity

2,568
MW
Renewable installed capacity

13,748
GWh
Net output

108,818
Km
Power lines

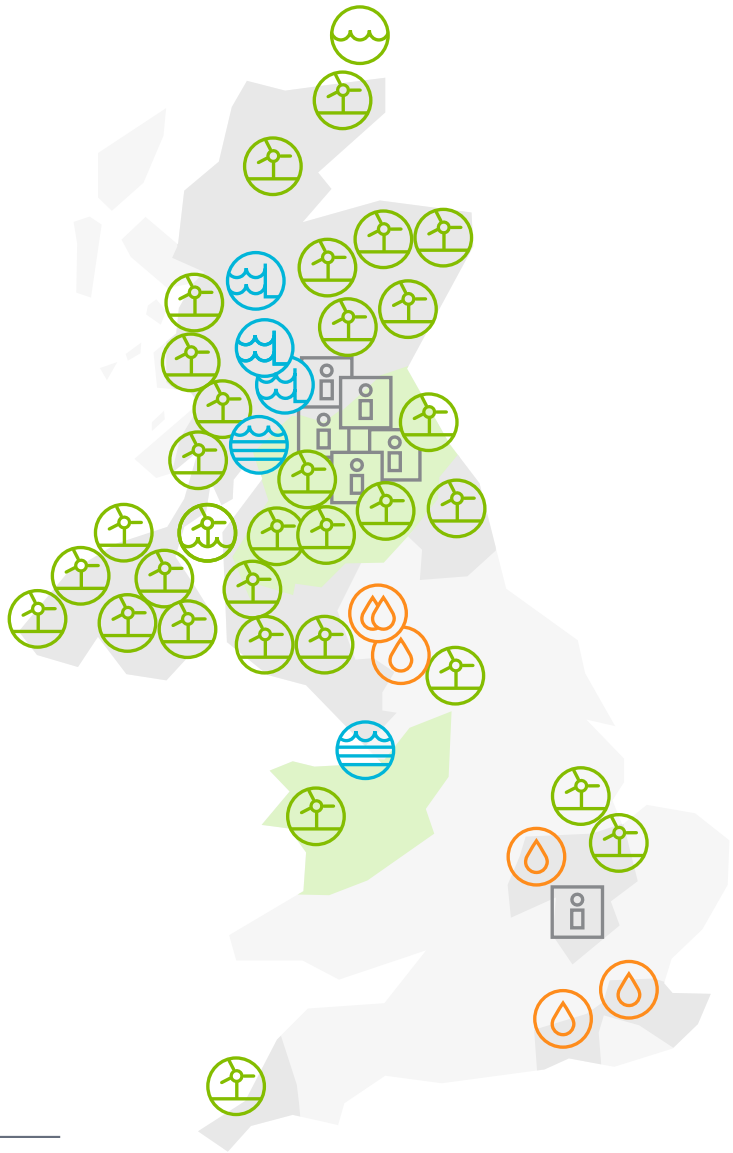
35,704
GWh
Electric power distributed

5.6
Million users

6,373
Employees

1,740
€M
Investments

536
€M
Direct tax contribution



Primary facilities

32
Windfarms
1,811 MW

1
Offshore windfarm
194 MW

1
Cogeneration plant
1 MW

4
Combined cycle gas plants
1,967 MW

3
Hydro power plants
563 MW

1
Underwater power line
425 Km

Offices

Area of influence

Electricity distribution

Iberdrola in the United States

Second-largest wind producer
Electricity and gas distributor in New York, Maine, Connecticut, and Massachusetts
Δ 2016 / 2015
GDP +1.9%
Electricity demand –1.3%

Primary brands

AVANGRID
United States subholding company

AVANGRID RENEWABLES, ENSTOR
Renewables business

IBERDROLA Energy Projects
Engineering

AVANGRID Networks, CENTRAL MAINE POWER, MAINE NATURAL GAS, NYSEG, RG&E, UI, SCG, CNG, BERKSHIRE GAS
Regulated networks business and sale of electricity and gas

Foundation AVANGRID
Foundation

2016 data

6,875
MW
Installed capacity

6,033
MW
Renewable installed capacity

17,912
GWh
Net output

130,791
Km
Power lines

39,079
GWh
Electric power distributed

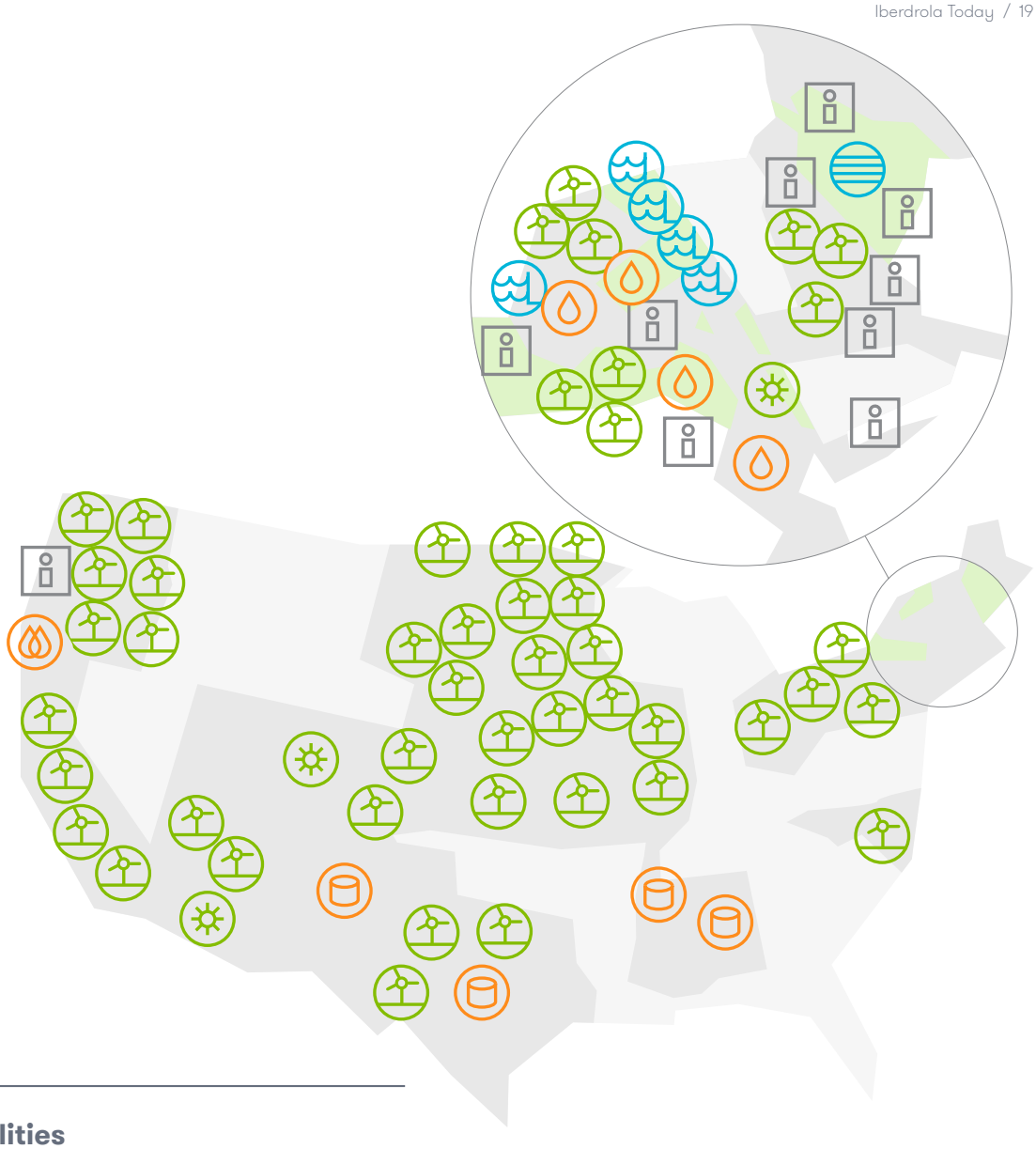
3.5
Million users

6,849
Employees

1,492
€M
Investments

864
€M
Direct tax contribution

2.4
BCM
Gas storage capacity



Primary facilities

55
Windfarms
5,855 MW

2
Photovoltaic energy
50 MW

1
Cogeneration plant
636 MW

4
Gas storage facilities

4
Combined cycle gas plants
209 MW

9
Hydro power plants
118 MW

1
Power transmission line
United States-Canada / 708 Km

Offices

Area of influence

Electricity distribution

Iberdrola in Mexico

Largest private electricity producer
Δ 2016 / 2015
GDP +2.3%
Electricity demand +3.2%

Primary brands

IBERDROLA MÉXICO
Mexico subholding company

IBERDROLA MÉXICO Renovables
Renewables business

IBERDROLA MÉXICO Generación
Wholesale generation business

IBERDROLA Ingeniería y Construcción
Engineering

2016 data

5,804
MW
Installed capacity

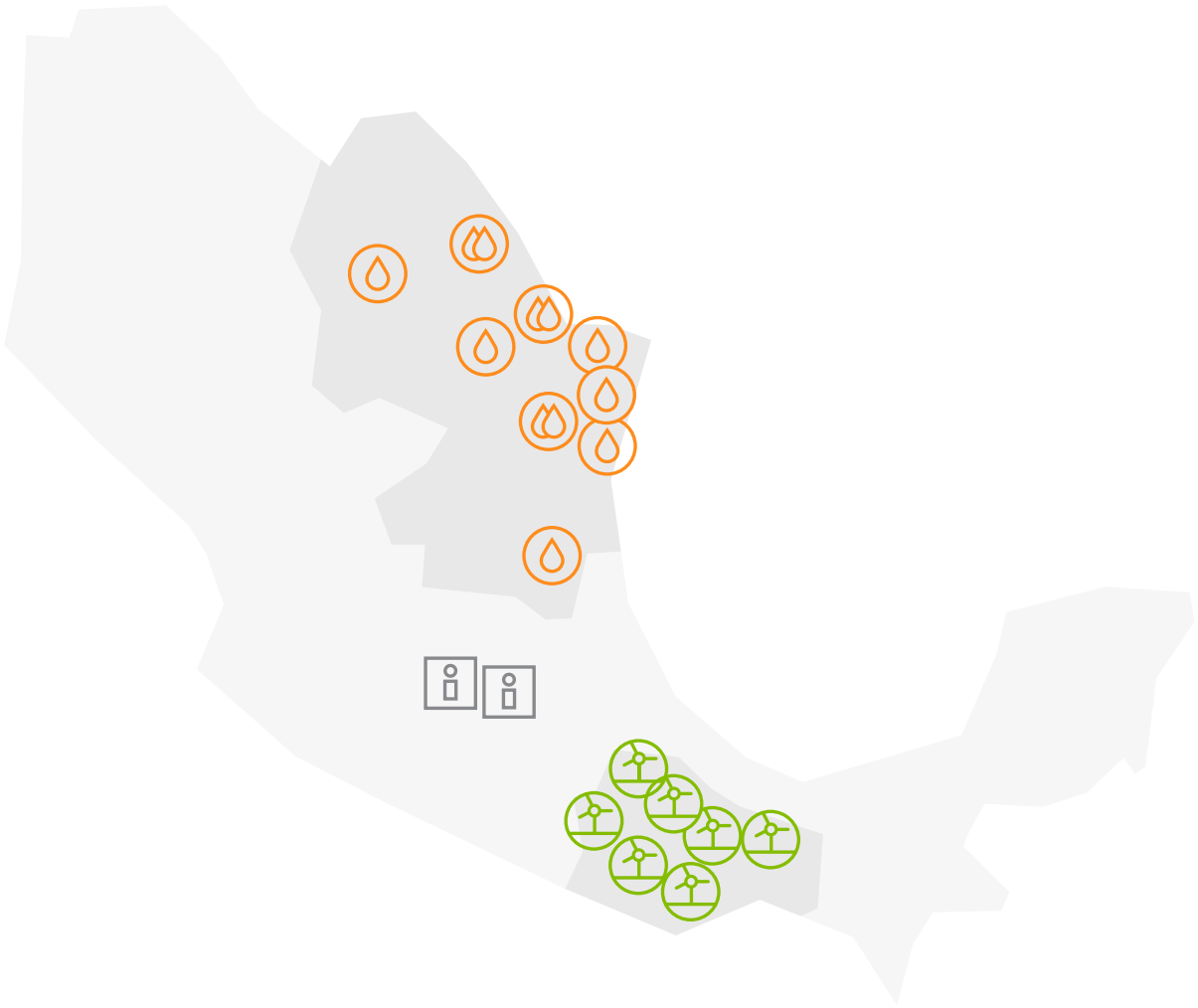
367
MW
Renewable installed capacity

37,569
GWh
Net output

874
Employees

358
€M
Investments

209
€M
Direct tax contribution



Primary facilities

7
Windfarms
367 MW

3
Cogeneration plants
237 MW

6
Combined cycle gas plants
5,200 MW

Offices

Area of influence

Iberdrola in Brazil

Largest distributor in Brazil by number of customers
Δ 2016 / 2015
GDP –3.5%
Electricity demand –0.9%

Primary brands

ELEKTRO
Brazil subholding company

Instituto ELEKTRO

IBERDROLA Ingeniería y Construcción
Engineering

2016 data

2,926
MW
Installed capacity(1)

2,315
MW
Renewable installed capacity(1)

9,003
GWh
Net output(1)

592,717
Km
Power lines(1)

62,726
GWh
Electric power distributed(1)

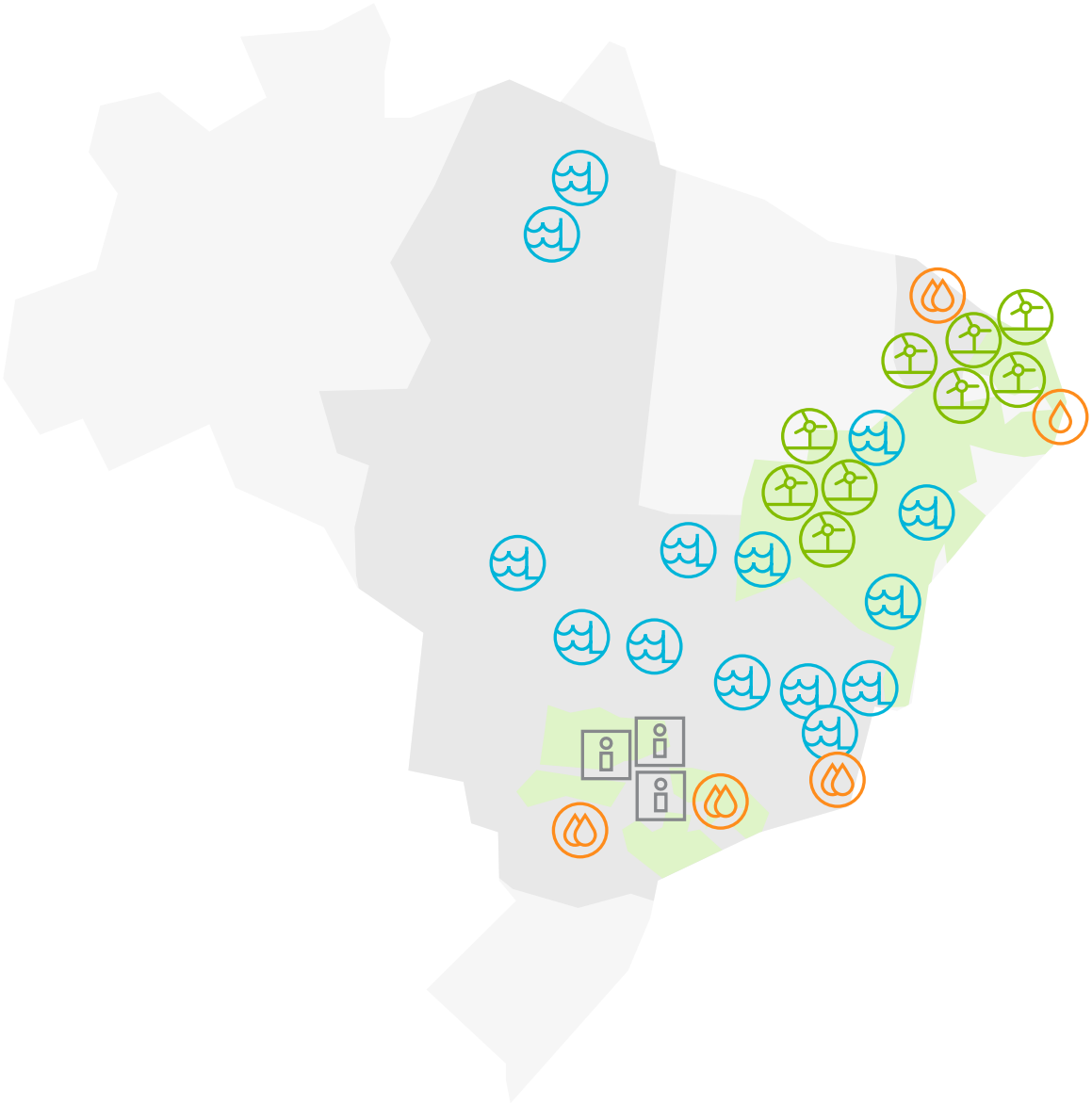
13.4
Million users(1)

3,742
Employees

81
€M
Investments

593
€M
Direct tax contribution

(1) Managed magnitudes including 100% Neoenergia.



Primary facilities

11 Windfarms
337 MW

4 Cogeneration plants
78 MW

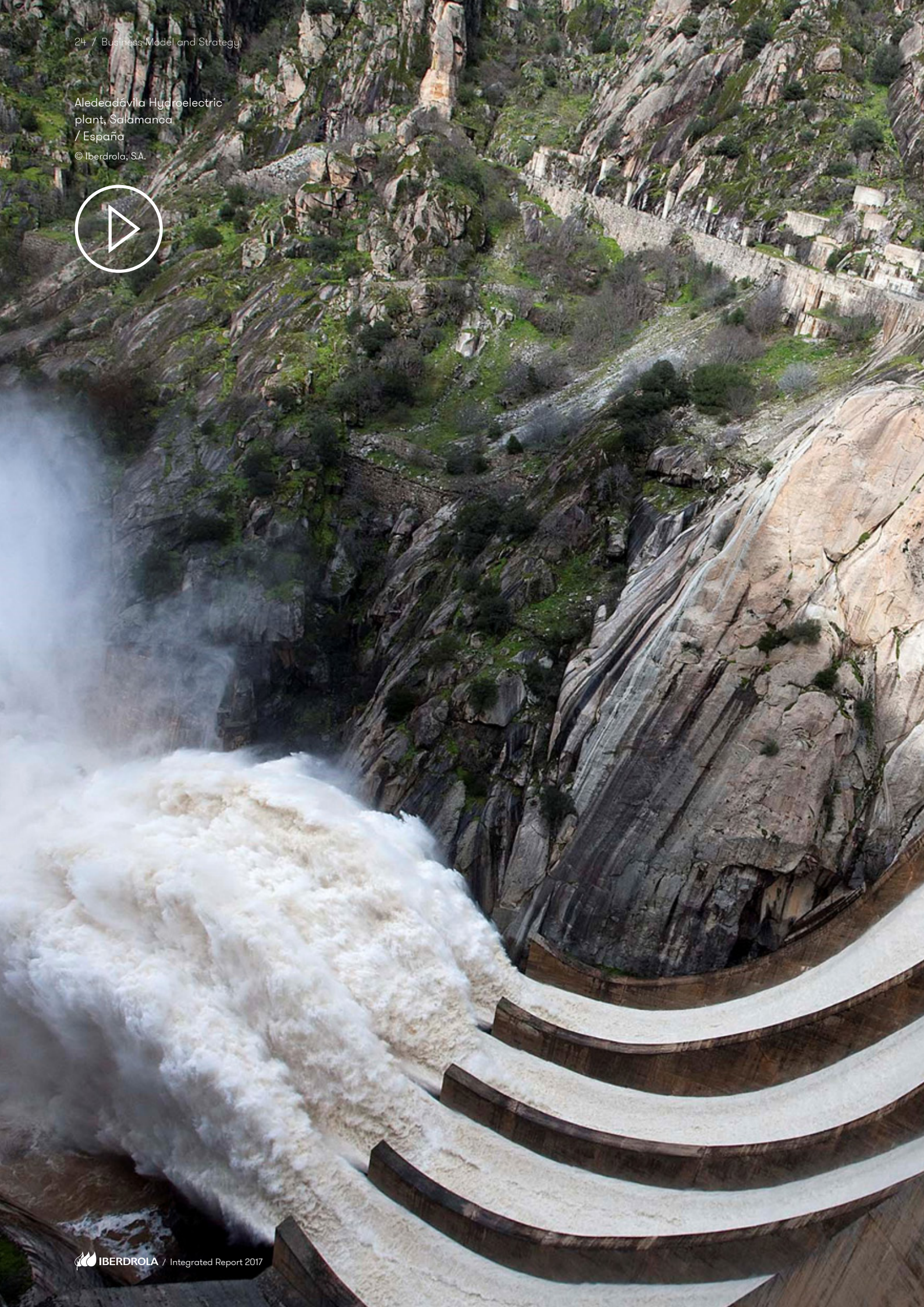
1 Combined cycle gas plant
533 MW

14 Hydro power plants
1,978 MW

Offices

Area of influence

Electricity distribution



Aledeadávila Hydroelectric plant, Salamanca / España

© Iberdrola, S.A.

2.

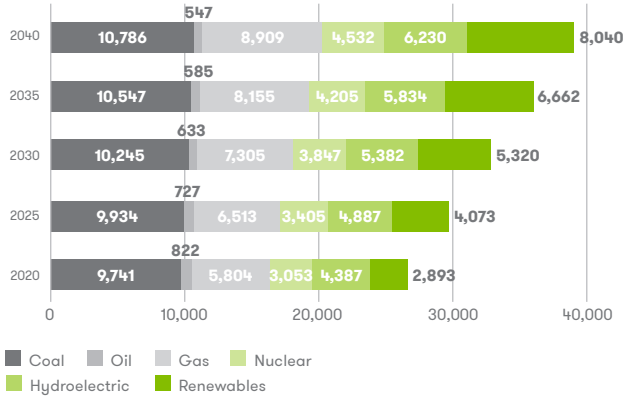
Business Model and Strategy

2.1 The Future of Energy

Opportunities for continued growth

The energy sector presents strong opportunities for growth over the long term.

Electricity production by type of source (TWh)



Source: World Energy Outlook 2016 – International Energy Agency

"Meeting the emissions targets will only be possible by massively electrifying the economy, through more clean energies, especially hydroelectric, wind and solar power, more storage capacity, and more and smarter distribution networks"

Ignacio Galán, at the WORLD ECONOMIC FORUM 2017

The electric industry, according to *World Energy Outlook 2016*

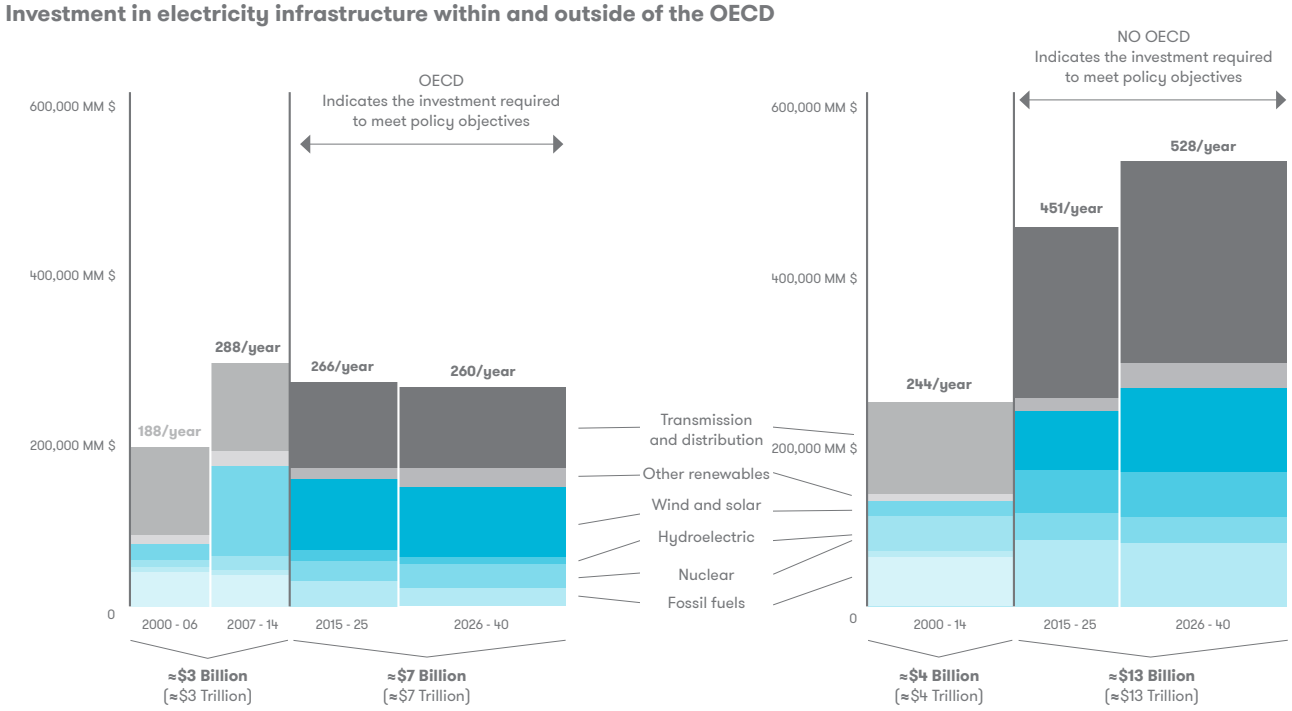
The Paris Agreement on climate change (COP21) will transform the global energy system in the coming decades.

The electricity sector is the focus of many of the Paris commitments. Almost 60% of all new electric generation capacity to be installed through 2040 will come from renewable sources. It is also estimated that by 2040 most renewable generation will be competitive without needing any kind of subsidy.

Another important factor in the near future will be the strengthening of the electric distribution grids, to facilitate better integration of renewable technologies, and ensuring the availability of sufficient backup capacity.

It will also be interesting to have the ability to store energy and to improve energy efficiency in all industries and energy-using processes.

Investment in electricity infrastructure within and outside of the OECD



Source: The Future of Electricity Report, World Economic Forum 2016

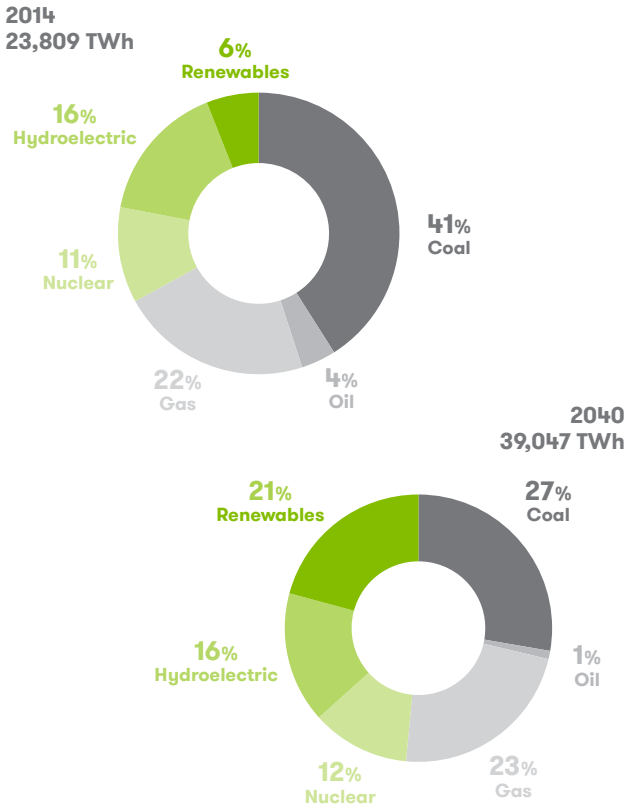
Evolution of demand[1], [2]

The prospects set out in *International Energy Outlook 2016* regarding the use of energy continue to show an increase in energy demand over the next three decades, driven mainly by non-OECD countries, whose strong long-term economic growth translates into a growing demand for energy.

The EU Roadmap forecasts that electricity will at least double its share in final energy demand to 36-39% in 2050, which would contribute to a reduction in carbon emissions in heating systems and in the transport sector.

The energy sector is launching measures to reduce CO_2 emissions, showing its commitment to reach the goals set out in the Paris Agreement on climate change.

Growth in global electricity production (TWh)[3]



Sources: (1) *World Energy Outlook 2016* - IEA; (2) *Energy Roadmap 2050 of the European Parliament*; (3) *World Energy Outlook 2016* - IEA

Trends in production and use of electricity

Sectoral[4], [5], [6]

- The European Union has a significant challenge in meeting its commitments on climate and energy established for 2020, 2030, and 2050. The energy sector knows that supplying energy with lower CO_2 emissions is not an option, but rather a necessity.
- Rapid development of electricity output with renewable sources will mean lower manufacturing costs: an additional reduction in the average cost of photovoltaic solar energy and onshore wind energy is expected from now through 2040.
- Unsustainable pressure on natural resources. A world economy four times larger than today is projected to use 80% more energy in 2050.

Technological[4], [5], [7]

- Rapid implementation of technologies with low variable costs, like most renewable energies, increases the possibility of sustainable periods of low wholesale electricity prices.
- Intelligent technologies applied to networks and remote management will allow for more active participation of demand and thus strengthen the role of the consumer in the energy market.
- Urban/technological lifestyles require more electricity. The growing middle class, the increase in income, and the larger amount of electric appliances will contribute to a doubling of electricity demand through 2060.
- Electricity storage, as a still-embryonic technological possibility, can open up new vistas for the operation and management of power systems.

Consumption[4], [6]

- 1.2 billion people, or 17% of the global population, currently lack access to electricity, and 2.7 billion people, or 38% of the global population, put their health at risk by resorting to the traditional use of solid biomass for cooking.
- Over the next 25 years, it will be necessary to reduce emissions by almost half in order to halt climate change, with the difficulty that if consumption stays on its current pace, it will have increased by approximately 45%. "*To solve this equation, we will need a huge energy transformation that can increase efficiency and substantially alter the energy mix with a higher contribution of low carbon sources*" (Ignacio Galán).
- The development of new uses and applications for electricity may result in new markets and opportunities.

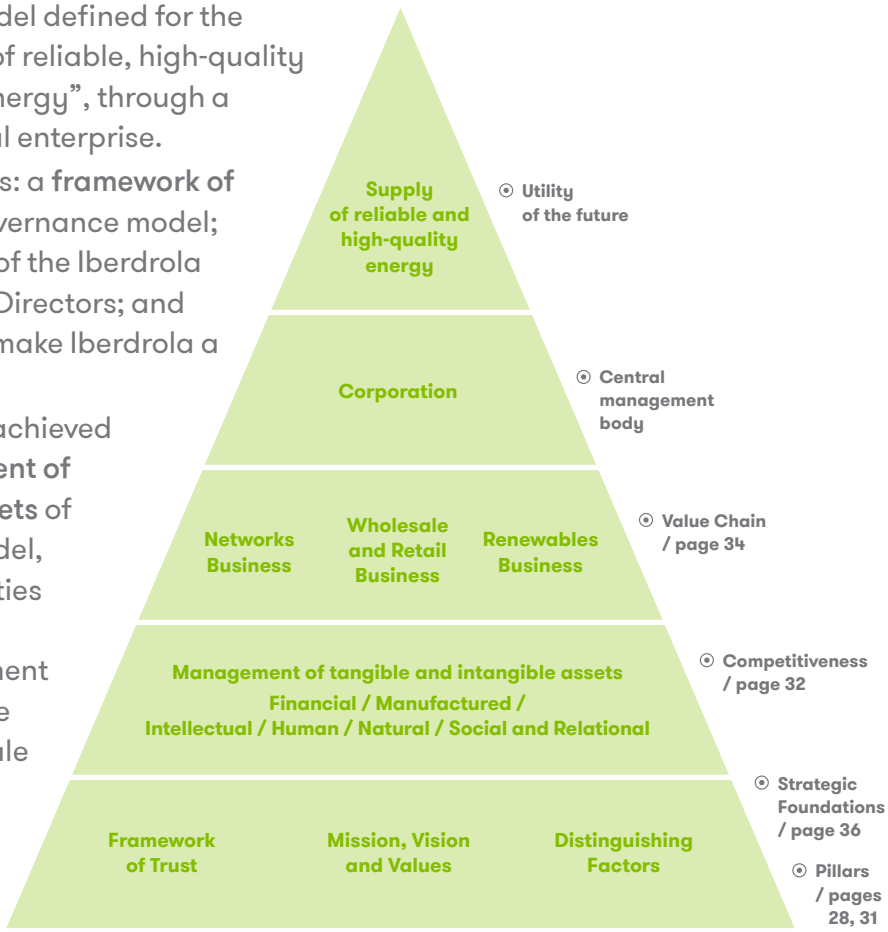
Sources: (4) *World Energy Outlook 2016* - IEA; (5) *Energy today in Spain, 15 key issues for the next legislature* - Club Español de la Energía; (6) *World Energy Outlook 2014* - IEA; (7) *World Energy Scenarios 2016* – World Energy Council

2.2 Business Model

The purpose of the business model defined for the Iberdrola Group is the "supply of reliable, high-quality and environmentally-friendly energy", through a sustainable, long-term industrial enterprise.

The model is built on three pillars: a **framework of trust** based on an advanced governance model; the **Mission, Vision, and Values** of the Iberdrola Group defined by the Board of Directors; and the **distinguishing factors** that make Iberdrola a different company.

The model's competitiveness is achieved through **responsible management of the tangible and intangible assets** of the Company. To apply this model, Iberdrola has defined the activities in which it seeks to be an active player, structuring its management into three global businesses: The Networks Business, the Wholesale and Retail Business, and the Renewables Business, with a Corporation as the Group's central management unit.



Framework of trust

To ensure the sustainability of its business model, Iberdrola has implemented:

- A Corporate Governance System consistent with best international practices.
- Corporate ethics, internalised by the management units and the organisation as a whole.
- Social responsibility policies, with a view to meeting the expectations of Stakeholders.
- An advanced risk control system, to maintain an optimal "risk/opportunity" balance, taking advantage of opportunities and mitigating risks.

Corporate Governance Model / page 78

Mission, Vision, and Values

"We want to be the leading multinational group in the energy sector at the forefront of a better future, sustainably creating value with a quality service for people...".

This Vision is based on twelve Values:

- Sustainable creation of value
- Ethical principles
- Good corporate governance and transparency
- Development of our workforce
- Social commitment
- Sense of belonging
- Safety and reliability
- Quality
- Innovation
- Respect for the environment
- Customer focus
- Institutional loyalty

Ethics and Social Responsibility / page 90

Iberdrola wants to be a responsible and sustainable company, serving society and people

The Company has been leading with a history of growth and foresight...

Vision 2001	**The world requires more, cleaner, and more sustainable energy**	
+		
Strategy	• **Renewable energy** • **Regulated businesses** • **Countries with high ratings**	• **Financial strength** • **Sustainable dividend**
+		
Execution	• **Operational efficiency** • **Balance sheet management** • **Customer focus**	• **Personnel management** • **Supplier management** • **Technological innovation**
+		
Values	• **Effort** • **Ability** • **Honesty** • **Loyalty**	• **Team spirit** • **Social commitment** • **Corporate governance**
=		
Results	**European electric utility with highest increase in stock market capitalisation over the 2001-2016 period: 229%**	

... with a very positive impact on society

Iberdrola generates a number of very significant economic, social, and environmental impacts on the countries in which it does business. The most significant are[1]:

- Annual generation of more than **€27,000 million in Gross Domestic Product** (GDP) in the countries in which it operates.
- Annual contribution of more than **€4,400 million in investments**, for the capital formation of the world economy.
- Investment of more than **€2,300 million in "green generation"** (2013-15), entailing:
  - Installed **green capacity** (hydroelectric and renewable) constituting **55%** of all of Iberdrola's installed capacity.
  - Avoidance of the emission of more than **57 million tonnes of CO_2**.
- Creation of close to **300,000 jobs** throughout the world (direct, indirect, and induced employment).
- Investments of more than **€100 million in rural electrification programmes** in Brazil (2013-15), and facilitating access to electricity for more than **1.4 million people in developing countries** (2014-15).

(1) Data from a Study of Iberdrola's Impact, prepared by PwC, based on 2015 figures.

Iberdrola's strategy is perfectly aligned with the Sustainable Development Goals (SDGs)

Iberdrola is fully committed to the Sustainable Development Goals defined by the United Nations for the 2015-2030 period. The are 17 global goals intended to transform our world, ending poverty, fighting against inequality and injustice, and confronting climate change. They affect both developing and developed countries, and also all types of organisations and institutions, including companies.

Iberdrola has incorporated the Sustainable Development Goals (SDGs) into its business strategy and its *Sustainability Policy*.

The Company has prioritised the various SDGs based on type of activity, defining 3 levels of contribution:

Main focus

Goal	2020
▲ Access to electricity	4 million people

Goal	2020	2030	2050
▼ CO_2	30%	50%	Neutral

Direct contribution

Indirect contribution

Iberdrola has set ambitious challenges relating to the Goals selected as its principal Focus:

- **Goal 13 *Climate action***: Achieve a 30% reduction in the intensity of CO_2 emissions by 2020 compared to those in 2007; a 50% reduction in emissions intensity by 2030; and be carbon neutral by 2050.

  At year-end 2016, Iberdrola's emissions intensity was 34% lower than the European average, and 66% of its installed capacity is emission-free.
- **Goal 7 *Affordable and clean energy***: By 2020, bring electricity to 4 million people who today lack access to this energy source.

  By year-end 2016, we had contributed to 2.5 million people benefiting from access to electricity through projects carried out in various countries of Latin America and Africa.

2.3 Iberdrola, a Different Company

Iberdrola's Primary Businesses / page 43

Focus on basic and regulated businesses

Approximately 75% of Ebitda comes from regulated businesses or long-term contracts.

Presence by Areas of Activity / page 14

International diversification

Approximately 55% of earnings are generated outside of Spain.

Natural Capital / page 70

Commitment to clean and competitive energies

- Generation and production of largely emissions-free electricity.
- Large portfolio of offshore wind generation projects and wave and tidal power projects.
- Clear goals for reducing emissions.

Operational efficiency

An energy model based on clean energy, networks, and digitisation has allowed our Company to be 30% more efficient than the average for the industry in Europe.

Iberdrola's Primary Businesses / page 43

Financial strength and solidity of the Group

- Strengthening of the balance sheet due to growth in Ebitda and FFO, which allows for continued strength in solvency ratio levels.
- Liquidity position that covers financial needs for more than 18 months under a stress scenario.

Financial capital / page 62

Global, committed, and qualified workforce

- Stable and high-quality jobs, with high level of training.
- Health and safety as values: "accident reduction" goal.
- The companies of the Group have been recognised: In Spain for their Reputation (*Merco*) and in Brazil as the best company to work for in Latin America (*Great Place to Work*).

Human Capital / page 68

2.4 Management of Tangible and Intangible Assets

	Financial capital / page 62	Manufactured Capital / page 64	Intellectual Capital / page 66
	Financial capital	Manufactured capital	Intellectual capital
What is it?	Financial resources that the Company already has or obtains through financing.	Tangible assets or goods used by the Company to carry out its business activities.	Intangible, knowledge-based assets.
Management Approach	Create value for shareholders through sustainable growth.	Offer a competitive supply of energy in a safe and reliable environment.	Consider innovation as a strategic element of the Company.
Significant aspects	• Balanced growth. • Sound financial structure. • Operational efficiency. • Sustainable results and dividends.	• Power generation assets. • Power transmission and distribution assets. • Other assets.	• Promotion of R&D. • Efficiency and new products and services. • Disruptive technology and business models.

The Iberdrola Group holds valuable assets for the development of its business model. The strategy defined by the Company transforms these assets to create value for all its Stakeholders.

Human Capital / page 68	Natural Capital / page 70	Social and Relational Capital / page 72
Human capital	Natural capital	Social and relationship capital
Employee knowledge, skills, experience and motivation.	Natural resources affected by the Company's activities.	Ability to share, relate, and collaborate with its Stakeholders, promoting community development and well-being.
Guarantee the availability of a committed and qualified workforce.	Ensure sustainable use of natural resources and contribute to combating climate change.	Promote relations of trust with Stakeholders, improving the quality of life of people in areas where the Group has a presence.
• Global human resources management. • Goal of "accident reduction". • Talent management. • Diversity, equal opportunity, and reconciliation.	• Environmental management. • Preservation of biodiversity. • Prevention of pollution. • Operating excellence and energy efficiency. • Waste management.	• Stakeholder relations. • Community support and electricity access programmes. • Foundations of the Iberdrola Group. • Corporate reputation. • Brand management. • Informational transparency.

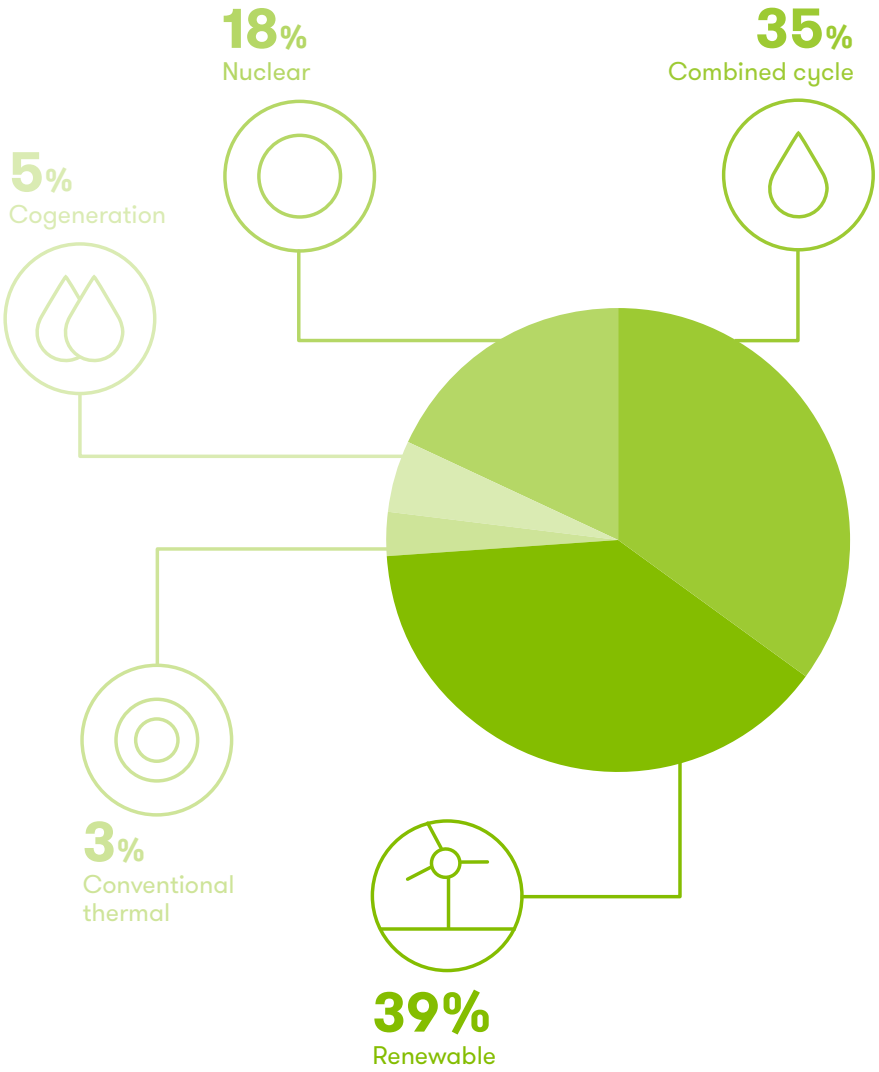
2.5 Value Chain

Power generation
Electricity production through the construction, operation, and maintenance of generating plants, and purchase/sale of energy on wholesale markets.

Power transmission and distribution
Construction, operation, and maintenance of electrical lines, substations, transformer centres, and other infrastructure, to transfer electrical power from production centres to the end user.

Generating plants*

* % of 2016 net output



Electric grids*

* At 31 December 2016

Overhead lines

4,000
High and medium voltage transformer substations

30,491 km
of transmission lines

875,140 km
of distribution lines

Retail sale of energy

Supply to end users of energy and additional products and services.

Underground lines

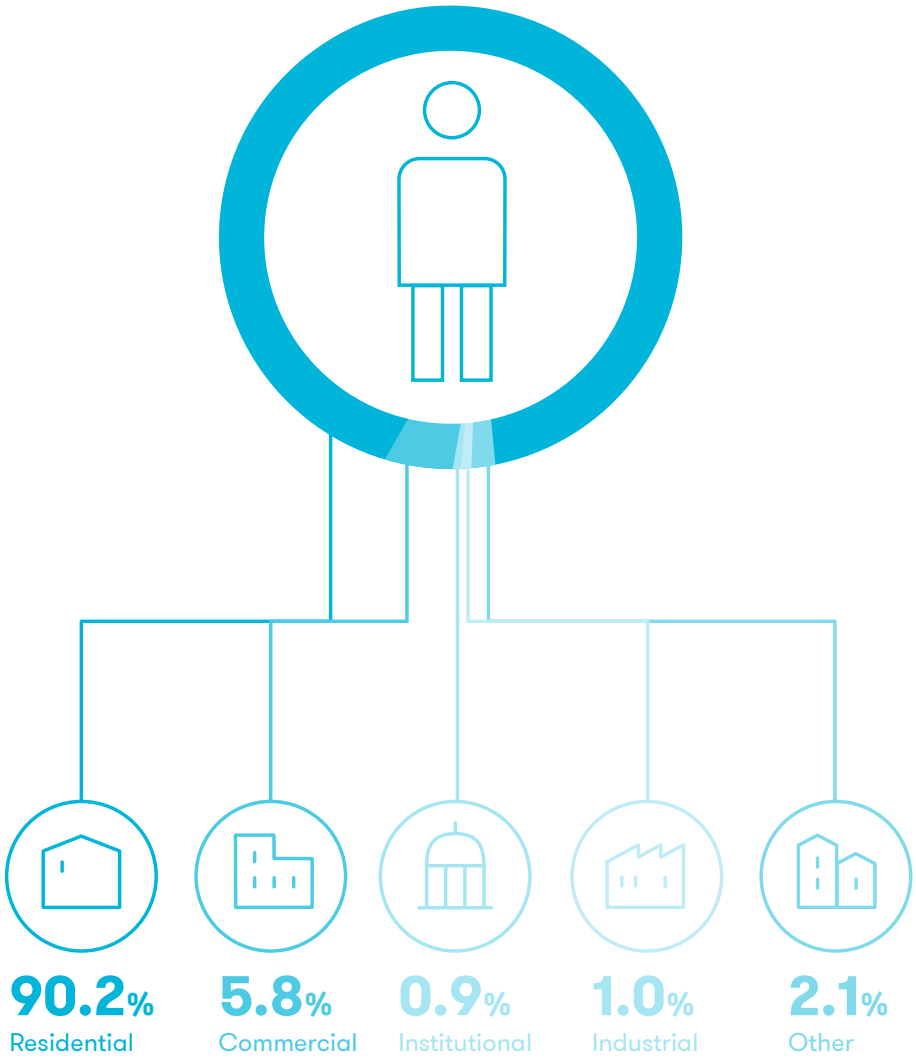
1.4 million
Medium to low voltage distribution transformers

986 km
of transmission lines

193.285 km
of distribution lines

Users*

* % by sector at 31 December 2016



2.6 Strategic Foundations for 2016-2020

Market conditions

The global energy markets are showing a certain amount of volatility, which is a reflection of geopolitical factors affecting the oil- and gas-producing countries. Our update of the scenario for the 2016-2020 period compared to prior forecasts is maintenance of prices in Spain and an increase in electricity prices in the United Kingdom, explained by an increase in the price of gas. We expect a relatively flat scenario over the full period. The diversification of businesses and countries will allow the Company to develop a strategy of growth and value creation that conforms to this environment.

Challenges and opportunities

Challenges

- Decarbonisation in the energy sector. Demand for cleaner and more sustainable energy.
- Management of a scenario of constant prices for energy in the medium term.
- Attainment of higher efficiency levels in all businesses.
- Regulatory management in all businesses, with special emphasis on transmission and distribution businesses, and in the development of the single market in Europe.
- Implementation of an investment plan focused on growth in the businesses of regulated networks, renewables, and long-term contracted generation.

Opportunities

- Balanced business model focused on regulated activities and renewable generation.
- Significant experience in the development and construction of network and emission-free generation projects.
- International diversification with a presence in countries with stable and predictable regulatory frameworks that require investment in the electricity and gas sectors.
- High quality of assets.
- Proven management capacity, culture of efficiency, and results.
- Culture of innovation to implement digitisation in relation to customers and the development of new products and services.

Growth vectors 2016-2020

Investments

- United States: the Company, through Avangrid, will continue with new onshore wind developments, taking advantage of the extension of tax credits to 2020. It is also facing growth in the area of distribution networks as well as in transmission.
- Mexico: it will consolidate its position as the largest private power generator in Mexico, through new plants under long-term contract with the Federal Electricity Commission (*Comisión Federal de Electricidad*) (CFE), and also taking advantage of the opportunities arising from the liberalisation of the sector.
- United Kingdom: Iberdrola continues with its growth phase in the power transmission and distribution businesses and with the start-up of onshore and offshore renewable energy projects. Offshore wind will gain significance beginning in 2018.
- Brazil: strengthened growth in renewables, maintaining its position as largest electricity distributor by number of customers.
- Spain: maintenance and improvement of facilities. Growth in smart grids.

Operational efficiency

- In all areas of activity, with a plan to save €1,300 million over the period.

The Future of Energy / page 26

.... expanding the geographic diversification of the Company in countries with an A rating, and increasing its presence in regulated businesses with low risk and the generation of recurring cash flows.

Strategic pillars

Iberdrola's strategy for 2016-2020 will remain focused on balanced growth, ensuring its financial strength and the sustainability of its dividend policy, the growth of which will be linked to growth in results.

New investments will be concentrated in countries with high credit ratings (A rating), and in businesses that are preferably regulated or under long-term contract, thus improving the profile of the Company.

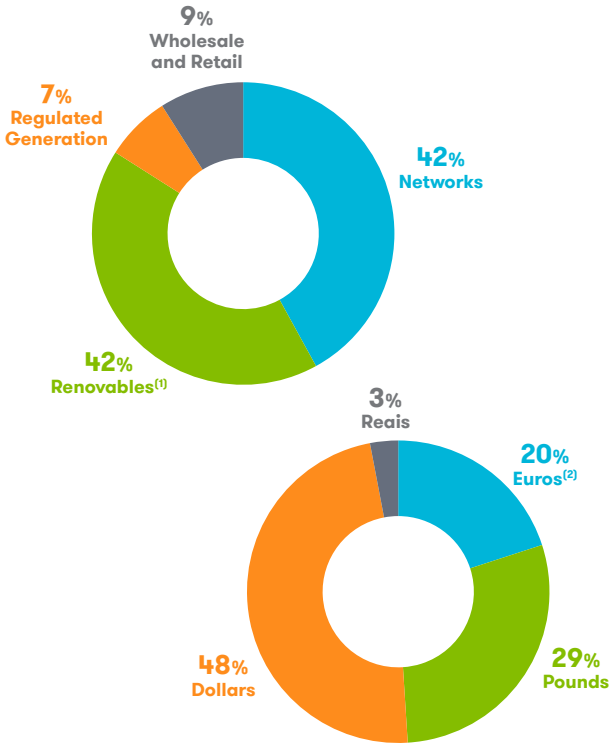
1. Balanced growth

- Investments focused on businesses and countries with stable and predictable regulatory frameworks, 71% in countries with a credit rating of A.
- Net investment increases €1,000 million over the plan presented in 2016, to €25,000 million, due to higher growth in renewable generation in the United States.
- Of total investments during the period, 75% are focused on growth and the rest on maintenance.
- Electric power transmission and distribution networks will account for 42% of net investments. Of the overall amount, 42% will be dedicated to renewable energy and 7% to regulated wholesale generation. 9% of the total will be invested in the Wholesale and Retail business.
- The regulated businesses (networks, renewables, and regulated generation) will account for 90% of all planned investments.
- Geographically, Iberdrola will concentrate the bulk of its growth in the international area. By currency, 48% will be invested in dollars, 29% in pounds Sterling, 20%[2] in the Euro zone, and 3% in Brazilian reais.

From 2016 to 2020, investments will be focused on countries with an A rating and in regulated businesses or those under long-term contracts.

Financial Capital / page 62

Investment by business and currency 2016-2020



(1) Includes hydroelectric
(2) Includes offshore windfarm in Germany: Wikinger

2. Financial strength

The Company obtained solid results in financial year 2016, thanks to the good performance of the businesses and a reduction in costs. Ebitda reached €7,808 million, increasing 5.5%, although it would have grown 8.2% excluding the exchange rate effect (depreciation of the pound). Net profit grew 11.7% to €2,705 million. The efficient operation of operating assets, together with the above-described investment plan, will lead to sustainable growth in the Company's results, with an estimated average annual increase of approximately 7.5% over the 2016-2020 period.

The profile of the Company's businesses, together with a balanced investment plan, will allow for sustained growth in Ebitda and Net profit of approximately 6% and 7.5%, respectively...

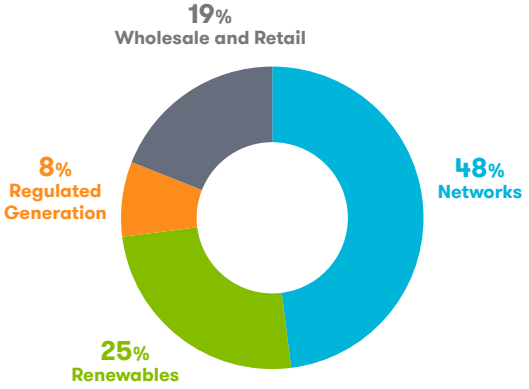
- Average annual funds from operations (FFO) in the amount of €7,100 million will amply exceed investments, which will reach an annual average of €5,100 million. By business, cash flow generation from Wholesale and Retail and from Networks will be significantly greater than investments, while Renewables will invest a number somewhat higher than its cash flow generation.
- Maintenance of the current financial model to provide subsidiaries with an optimal capital structure giving appropriate financial signals and which is consistent with an investment grade rating, while respecting current guidelines for structural subordination.
- Optimisation of liquidity position (around €8,000 - 9,000 million) to current market conditions in order to improve financial costs, maintaining 18 months of coverage even during stress scenarios.
- Maintenance of the strong 2016 solvency ratios through 2018, after which they will substantially improve, thanks to increase in Ebitda and FFO.

...resulting in the Company proposing a sustainable shareholder remuneration policy linked to the growth in results.

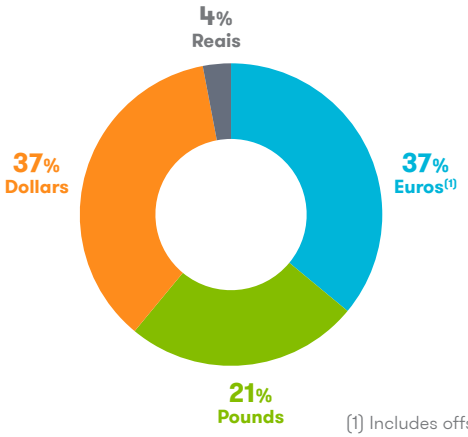
3. Sustainable dividend

- Thanks to the strength of the results obtained, the Company has announced a proposal to immediately increase the annual divided to 0.31 euro per share with a charge to financial year 2016. This amount is also set as the minimum dividend for future years.
- In the coming years, shareholder remuneration will grow in line with the increase in results, converging towards a payout ratio between 65% and 75%. Taking into account this range and the forecast growth in net profit, the dividend would be between 0.37 and 0.40 euro per share by 2020.

Ebitda by business (forecast to 2020)



Ebitda by currency (forecast to 2020)



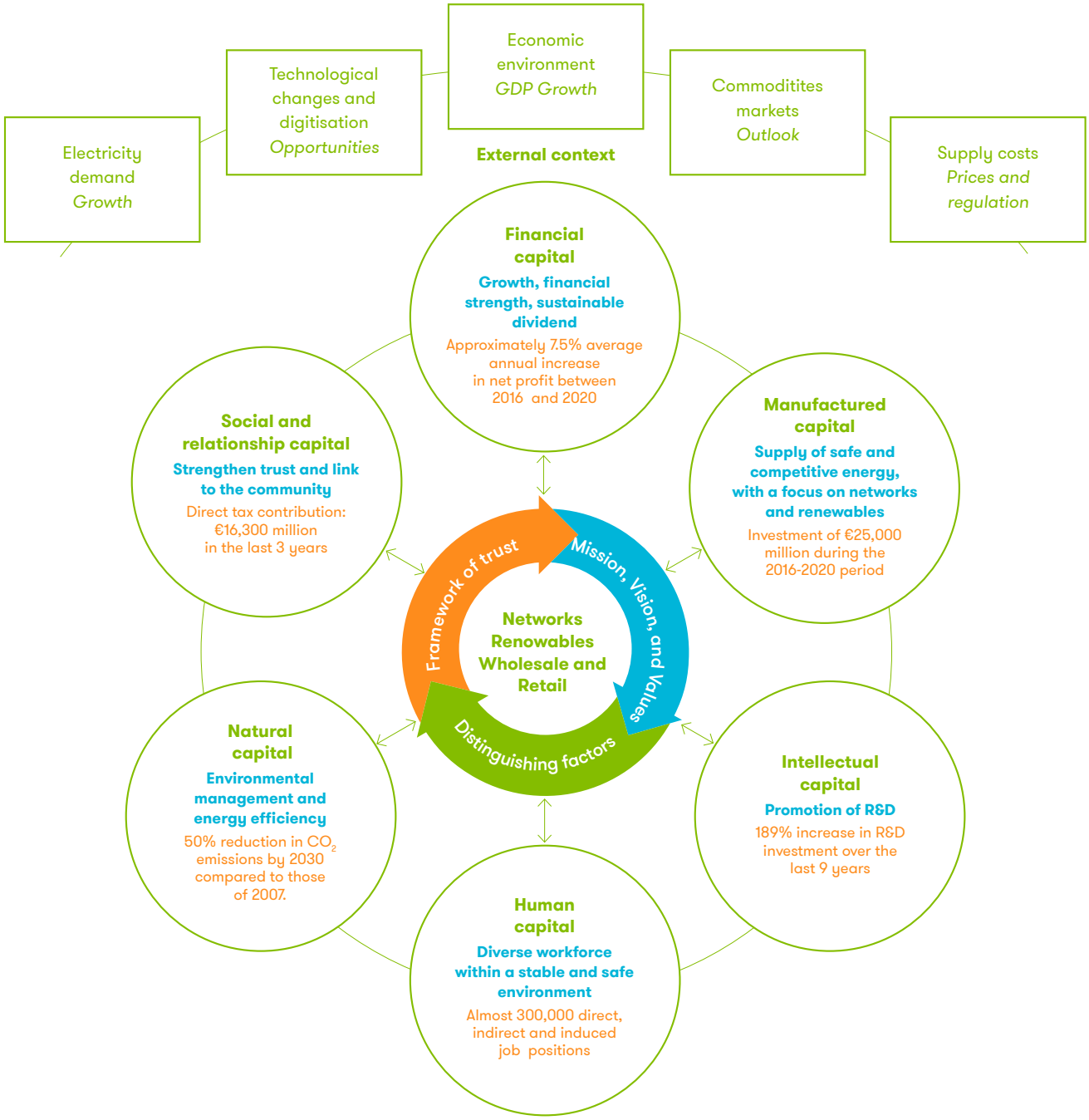
(1) Includes offshore windfarm in Germany: Wikinger

2.7. Capital/Business Relationship

The value created by the business strategy and model of Iberdrola over time translates into an increase in its capital, which in turn feeds back into a cycle of value creation, efficiently inter-relating the operations of the businesses and the capital of the Company.

The chart below shows for each Chapter its strategic focus and quantifies an aspiration or achievement of the Company in this area.

This process creates shared value for both Iberdrola and for its Stakeholders, and constitutes a main vector for achieving the Company's goal to offer a reliable, high-quality, and environmentally-friendly energy supply.



2.8 Comparative Results and Awards

Comparative analysis*

Comparative economic/financial variables 2016

Growth in Ebitda

ACGR (%)	Average comparables	Iberdrola
31-Dec.-06 / 31-Dec.-16	1.3%**	7.2%

Growth in capitalisation

Total growth (%)	Average comparables	Iberdrola
31-Dec.-06 / 31-Dec.-16	-54.2%	32.8%

Iberdrola held 5th place among comparable companies in terms of stock market capitalisation for the last 10 years. It is now in second place.

Share price

Total growth (%)	Average comparables	Eurostoxx Utilities	Iberdrola
31-Dec.-06 / 31-Dec.-16	-70.1%	-52.4%	-24.7%

* Comparable companies analysed: Engie, EDF, E.On, Enel, RWE.
ACGR: Annual Compound Growth Rate, i.e. weighted average annual growth.
** For Engie, Enel, E.ON, and RWE, the 2016 Ebitda figures are the estimates published by Bloomberg, due to the lack of final closing figures on the date of preparation of this document. In addition, for Engie, the 2006 figure is for GDF (prior to the merger of GDF and Suez SA).

Comparative performance of total shareholder return

Profitability (%)	Average comparables	Eurostoxx Utilities	Iberdrola
31-Dec.-06 / 31-Dec.-16	-37.0%	-16.6%	11.3%

Iberdrola's performance

Over the last 10 years, Iberdrola has more than tripled its assets, tripled its revenues, doubled its Ebitda and increased its net profit by 60% and shareholder remuneration by 30%, while maintaining its financial strength.

Iberdrola	31-Dec.-06	31-Dec.-16	Multiple
Assets (€M)	33,061	106,706	3.2x
Revenues (€M)	11,017	29,215	2.7x
Ebitda (€M)	3,890	7,808	2.0x
Net Profit (€M)	1,660	2,705	1.6x
Dividends[1] (€/share)	0.22	0.28	1.3x
Net Debt/Ebitda	3.7	3.8	1.0x

(1) Not including the bonus for attending the General Shareholders' Meeting.

Ignacio Galán at the offices of the Iberdrola Tower / Bilbao

External awards

For the Company:

- Best Corporate Governance in Spain (World Finance): 2015, 2014, and 2012.
- Best Corporate Governance among European Utilities (Ethical Boardroom): 2016, 2015, and 2014.
- World's Most Ethical Company Index (Ethisphere Institute): 2016, 2015, and 2014.
- Leading Ibex 35 company in the tax transparency ranking 2015, from *Fundación Compromiso y Transparencia*.

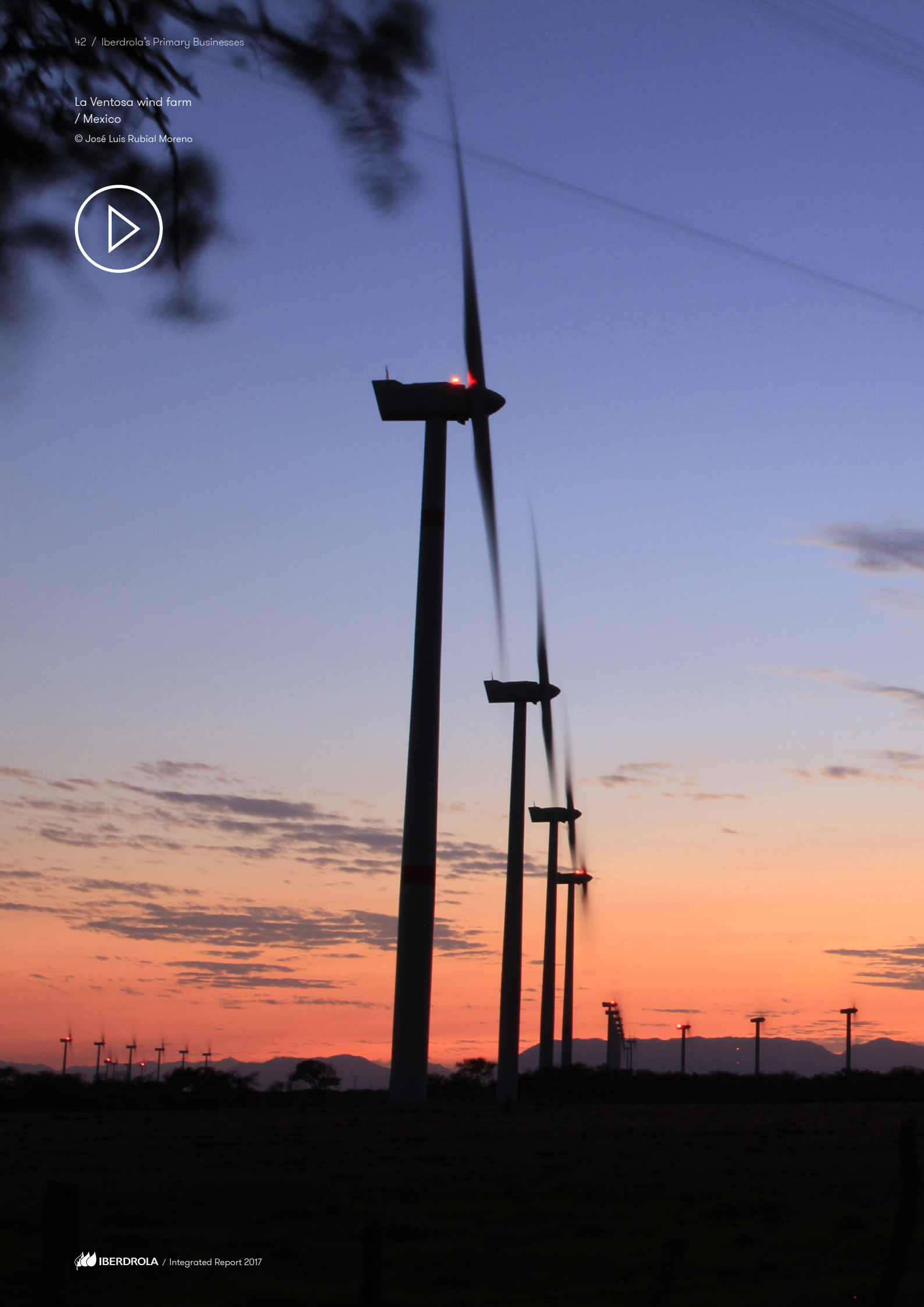
Other Awards / page 91

For the chairman & CEO:

- Best European Utility CEO (Institutional Investor Research): 2016, 2015, 2014, 2013, and 2011.
- Commander of the Most Excellent Order of the British Empire: 2014.
- Honorary Doctorate from the Universities of Salamanca (2011), Strathclyde (2013), and Edinburgh (2011).

For other members of the Company:

- Best European Utility CFO (Institutional Investor Research): 2016, 2015, 2014, and 2012.
- Best European Utility Investor Relations (Institutional Investor Research): 2016, 2015, 2014, 2013, 2012, and 2011.



La Ventosa wind farm
/ Mexico

© José Luis Rubial Moreno

3.

Iberdrola's Primary Businesses

Regulation is a key factor in the sustainability of Iberdrola's activities.
Energy policies must set clear and predictable goals in order to attract the investment needed to guarantee a safe, competitive, and sustainable supply, developing to the maximum its potential as a source of growth and employment.

3.1 Regulatory Environment

European Union

- The Climate Change Conference (COP21) agreements reached during the Paris Summit in 2015 were ratified in 2016, before the commencement of the Marrakesh Summit. These agreements entail a multilateral commitment to implement measures to reduce emissions in order to limit the increase in temperature to a maximum of 2°C. These measures will foster investment and must be supported by signals incentivising low-carbon technologies. In addition, these costs must be paid in accordance with the "polluting party pays" principle.
- In November 2016, the European Commission (EC) published the "*Clean Energy for All Europeans*" package (also known as the "Winter Package"), the legislative proposals of which, in the words of the EC, have three main goals: putting energy efficiency first, achieving global leadership in renewable energy, and providing a fair deal for consumers.

  Among the more far-reaching measures included in the proposed Directives and Regulations are those concerning the market design reform and the safety of supply framework. Proposals have also been submitted to modify the frameworks for renewables and for energy efficiency, in line with the 2030 goals.
- During 2017, there will be continued steps in connection with the Emissions Market Directive, and preparation of the regulations and directives contained in the "Winter Package" will begin.

Spain

- After the strong tariff deficit during the 2005-2013 period and a slight surplus in 2014 and 2015, the system has reached financial balance. A Ministry Order freezing electricity and gas usage charges for 2017 was published in December 2016.
- The Supreme Court has rendered judgements holding that the funding system for the subsidised rate (*bono social*) is invalid on the grounds that it is discriminatory. The companies funding these amounts (up to now, the parent companies of vertically integrated groups) must be reimbursed for the amounts contributed between 2014 and 2016, with interest.

United Kingdom

- On 23 June 2016, the United Kingdom voted to leave the European Union. Future trade agreements have not yet been determined, but significant changes are expected in the energy regulatory environment in the short term.
- After the referendum, David Cameron resigned and Theresa May was elected Prime Minister; her government stated that the protection of consumer interests is a priority and reiterated its commitment to decarbonising the economy.
- The Competition and Markets Authority (CMA) completed its investigation into the industry in June, and the proposed orders were implemented at the end of 2016. The CMA largely disregarded the concerns about the wholesale market and vertical integration, but recommended Ofgem or the Government adopt remedies in the retail market, such as a temporary limit on prepayment tariffs, a data base to help disconnected customers, and reforms in the SME market.

United States and Canada

- On 8 November 2016 Donald Trump won the elections and Republicans gained control of Congress and the Senate. The states will continue establishing a large part of the regulations affecting Avangrid.
- In 2016 litigation continued forward to determine whether the Environmental Protection Agency (EPA) can implement the *Clean Power Plan* (CPP). Trump has vowed to revoke it. There are various possible scenarios depending on the decision of the U.S. Court of Appeals for the D.C. Circuit regarding the CPP.
- It is expected that PTCs (Production Tax Credits) will be maintained during the Trump administration, as they have the support of Congress. Current laws already provide for their gradual phase-out, and a change therein would have an impact on regulatory security.
- The methodology to replace net metering in the State of New York is now being debated. An order of the Commission is expected in January 2017.

Mexico

- The energy reform encourages private investment in the generation, sale, and supply of electric power. The networks continue to be under state ownership but are open to contracts with private persons. In this context, the first auction of transmission lines is expected to take place in the first half of 2017. The share of clean energy is forecast to increase up to 35% by 2024 with the creation of a clean energy certification system that will determine certain supply obligations.
- The Real-Time and Day-Ahead Markets began to operate in 2016. Two Long-term Auctions were also held, which will add almost 5 GW of new clean generation capacity.

Brazil

- The regulator has launched a Strategic Plan for the improvement of the Brazilian energy industry in order to carry out a revision of the sector, make improvements, and mitigate the risks facing the players involved. This project will continue until the first quarter of 2018.
- Due to the decrease in demand and the migration of customers to the free market, distributors have found themselves to have contracted for an oversupply of energy. The regulatory agency and the ministry have approved various regulations to minimise the effects of the 2016 oversupply.
- A two-part tariff was approved in 2016 with a view to modernising the tariff system.
- The Government has announced a plan to privatise six state-owned distribution companies belonging to Eletrobras; the plan should be completed before the end of 2017. The wave of privatisations began in 2016 with the auction sale of the distributor CELG.
- 2016 saw a modification in the model defining the maximum contract income by public auction for concessions of transmission lines. The main change was the method for calculation of the WACC,[1] which has been set at 9.67%. This measure increases the profitability of transmission concessions and makes auctions more appealing.

(1) WACC: Weighted Average Cost of Capital.

Work on distribution line
/ Spain

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3.2 Networks

Regulatory environment of the business

Spain

- After the approval of unit costs in December 2015, 2016 was the first year of the first regulatory period, which will end in December 2019.
- The remuneration of Iberdrola Distribución Eléctrica for 2016 was set at €1,664 million. This remuneration will increase each year based on the investments made.

United States

- The new tariff conditions for the NYSEG and RG&E (New York) gas and electricity businesses came into effect in July 2016. They will be in force for three years.
- A new three-year tariff agreement will come into effect for the electricity distribution company UI (Connecticut) in January 2017.
- In Maine, a 10-year tariff agreement for the gas distributor MNG came into effect, and the agreement for the electricity distributor CMP was extended for an additional year.
- The tariff conditions for the gas distributors CNG and SCG (Connecticut) and BCG (Massachusetts) will remain the same in 2017.

United Kingdom

- Ofgem has revised the investment scenario contemplated for the mid-period RIIO-T1, with no impact on the transmission projects of ScottishPower Transmission Ltd. (SPT) agreed in 2013 and which will end in 2021.
- Distributors ScottishPower Distribution Ltd. (SPD) and ScottishPower Manweb plc (SPM) carry out their activities during the first regulatory period RIIO-ED1, which will extend through March 2023.

Brazil

- The new tariff agreement for Celpe will come into force in April 2017 and will be in effect for five years.
- The tariff agreements for Coelba and Cosern will remain in effect until April 2018, and that for Elektro until 2019.
- The remuneration for the distribution activities of Elektro, Coelba, Cosern, and Celpe has been adjusted based on inflation in Brazil.

New tariff conditions for UI enter into effect in the State of Connecticut (USA) in 2017.

Objectives, risks, and principal activities

Objectives

- Zero accidents.
- Offer our customers excellent service based on the quality of supply and information regarding the network.
- Maximise efficiency in system operations through operational excellence and the digitisation of our assets.
- Lead the transformation towards more efficient integration of renewable and distributed energy.

Significant risks

- Safety of individuals due to risk of accidents.
- Assuring supply in the face of meteorological effects.
- Technological and cybersecurity risks affecting the security of the facilities and service to our customers.

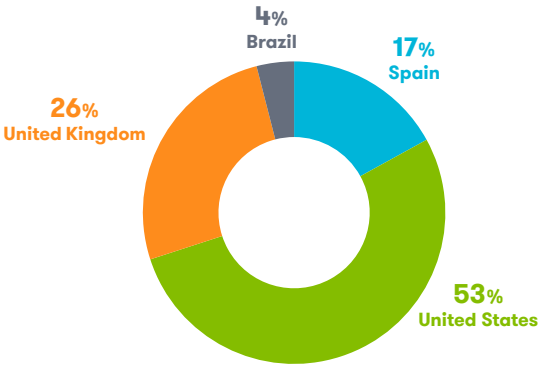
Principal activities 2016

- Spain: continuation of the network digitisation and automation project, with the installation of more than 8.8 million meters (83.5%) and digitisation of 55,500 transformer centres (66%).
- United Kingdom: developing the investment plans contained in RIIO-T1 and RIIO-ED1. Continuation of the Western Link HVDC project, which is expected to be completed in 2017.
- United States: developing the plan for integrating UIL's distributors within Avangrid. All regulatory quality levels have been met. Submission of filing with the regulator to launch smart meters, and creation of a platform for the integration of distributed generation within New York. Launch of Energy Smart Community project in Ithaca.
- Brazil: strengthening the position of Coelba and Celpe in Brazil's quality ranking thanks to Neoenergia's efficiency and supply quality improvement plan. At Elektro, development of facilities to meet demand and connect new customers.

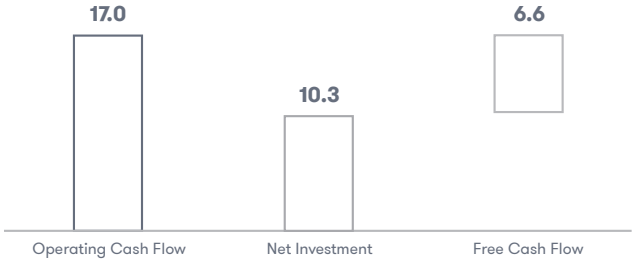
Outlook 2016-2020

- Increased regulatory visibility in all countries, with investments of €10,300 million. 15% increase in RAV* since 2015, which would increase to 22% taking into account 100% of Neoenergia.
- Increase in efficiency: improvement in NOE/MB* by 2 percentage points, with a 41% in Ebitda/Employee.
- Growth in digitisation of the network (€2,600 million in investments during the 2017-2020 period), to increase efficiency and the quality of supply, and to offer new services to customers.
- Opportunities for selective growth in transmission.

Net Investment of €10,300 million between 2016 and 2020, mainly in the United States and the United Kingdom



2016-2020 cash flow generation to finance investments (€ thousands of millions)



* RAV: Regulatory Asset Value; NOE: Net Operating Expenditure; GM: Gross Margin.

Key figures of the Networks Business

		Spain		United Kingdom		United States[1]		Brazil				Total	
								Elektro		Neoenergia[2]			
Item	**Unit**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**
Gross margin	€M	1,952	2,029	1,472	1,267	1,698	2,537	390	328	–	–	**5,512**	**6,160**
Ebitda	€M	1,457	1,603	1,138	976	781	1,270	253	233	–	–	**3,628**	**4,082**
Electric power distributed	GWh	92,685	92,308	36,253	35,704	33,697	39,079	17,448	17,425	44,673	45,301	**224,749**	**229,816**
Users (Electricity)	Millions	10.9	11.0	3.5	3.5	2.2	2.5	2.5	2.6	10.6	10.8	**29.7**	**30.4**
Gas supply	GWh	–	–	–	–	36,196	59,544	–	–	–	–	**36,196**	**59,544**
Users (gas)	Millions	–	–	–	–	1.0	1.0	–	–	–	–	**1.0**	**1.0**
Investments	€M	346	389	847	628	429	752	71	76	–	–	**1,693**	**1,845**
Workforce	No. of people	3,981	3,887	2,934	2,819	5,795	5,734	3,713	3,708	5,101	5,403	**21,524**	**21,548**

International Financial Reporting Standard (IFRS) 11 has been applied to the financial information.
1 UIL included in users and workforce in 2015. Not included in energy supplied.
2 Operational information is deemed to be 100% from Neoenergia.

◉ **Quarterly Results Report**

Customer service, operational efficiency, and digitisation of networks are the strategic pillars of the Networks Business upon which the business rests.

Customer service

- Investment in expansion, renewal of network, and investments in operation and maintenance to improve service quality for our customers.
- Met service quality targets, despite poor meteorological conditions during the last quarter of 2016.
- Implementation of transmission and distribution projects to improve service quality for customers.
- Development of digital customer service channels: improvements in website, apps, social media, etc.

Efficiency

- Increase in operating expenses contained despite strong increase in activity.
- Implementation of best practices throughout the networks companies, mainly in the areas of asset management, processes and technology, control systems, digitisation and automation, and customer service.
- Emphasis on the fight against electricity fraud in Brazil and Spain.
- Containment of increase in late payments in Brazil due to the country's economic crisis.

Digitisation of the network

- Projects to increase the automation of the MV network.
- Expand visibility of the LV network in Spain.
- Deployment of smart meters in Spain and the United States.
- Focus on maximising operational efficiency and improving service quality and providing useful information to customers.
- Improve customer service using new technologies.
- Strengthened measures to protect against cybersecurity risks associated with new grid management technologies.

Dulces Nombres II Combined Cycle gas plant / Mexico

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3.3 Wholesale and Retail

Regulatory environment of the business

Spain

- Royal Decree 469/2016 was approved in November 2016, establishing the methodology for calculation of voluntary prices for small consumers of electric power and the legal rules governing contracting therefor.
- Ministry Order ETU/1948/2016 was approved in December 2016, establishing specific values for the supply costs of leading supply companies to be included in the calculation of the voluntary price for small consumers during the 2014-2018 period. A fixed amount is set in €/kW and per year and a variable amount is set in €/kWh.
- Royal Decree-Law 7/2016 was published in December 2016, governing the mechanism for financing the cost of the subsidised rate (*bono social*) and establishing other measures for the protection of vulnerable consumers of electric power. This Decree-Law provides that the costs of the subsidised rate shall be borne by the parent companies of the groups engaged in the supply of electric power, or by the supplier companies themselves if they are not part of a group, and expands the protection of groups of vulnerable customers by extending the periods before interruption of supply in the event of non-payment and by including new categories of severely vulnerable customers, who will be considered essential supply customers.
- The availability service of the generation facilities has been extended in 2017.

United Kingdom

- The capacity auction 2020/2021 took place in December 2016, with the participation of both existing plants and new projects. A total of 52.4 GW was awarded at a price of £22.50/kW, of which 48.4 GW correspond to existing capacity (generation and interconnections) and 4 GW to new capacity, mainly diesel engines and batteries.
- Based on the plan for implementation of the measures recommended by the CMA[1] in June 2016, Ofgem[2] has proposed limiting the charges for the installation of prepayment meters by court order and prohibiting the billing of more vulnerable customers for the installation. Such limit will be in effect as from April 2017.

Mexico

- There were two long-term auctions in 2016 awarding the proceeds from Power, Capacity and Clean Energy Certificates (*Certificados de Energías Limpias*) (CELs).
- In April 2016, Iberdrola was awarded the Noroeste 887 MW combined cycle plant located in the state of Sinaloa.
- As from August 2016, consumers with demand greater than 1 MW can acquire their energy on the market.

(1) CMA: Competition and Markets Authority
(2) Ofgem: Government regulator for gas and electricity markets

Objectives, risks, and principal activities

Objectives

- Competitive supply and excellence in service to customers.
- Operating excellence, safety, and respect for the environment.
- Risk identification and minimisation.
- Safety and continuous improvement in operating efficiency.
- Analysis of growth opportunities.

Significant risks

- Regulatory uncertainty in the countries in which it operates.
- Operating risks: downtime of facilities and incidents with environmental impact.
- Market risk: uncertainty regarding fuel prices and revenues from the sale of electricity and gas.
- Credit, exchange-rate, and interest-rate risks.
- Technological and cybersecurity risks affecting the security of the facilities or the information of our customers.

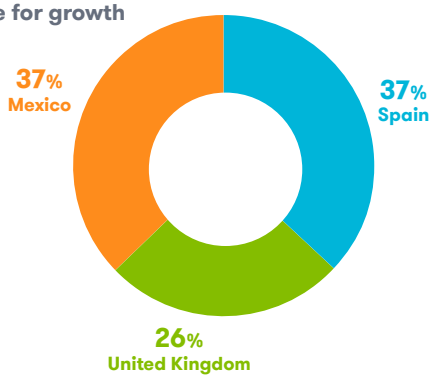
Principal activities 2016

- Spain: ongoing development of products and services adapted to the needs of customers (Customised Plans, Smart Solar, Iberdrola Smart Home, ...).
- United Kingdom: final shut down of the Longannet Coal Plant took place in the month of April. The decrease in variable rates for domestic gas customers (-5.4%) became effective in March 2016. 180,000 smart meters were installed during 2016.
- Mexico: installation of 409 MW (5th unit of Monterrey CCGT (300 MW), Ramos Arizpe cogeneration (53 MW, and repowerings (56 MW)), in addition to 308 MW from the Baja California III CCGT, which entered into operation at the beginning of 2017. 2,761 MW of thermal capacity under construction.
- Brazil: work continues on the construction of the Baixo Iguazu and Belo Monte hydroelectric plants, of which 245 MW and 1,123 MW belong to Iberdrola through Neoenergia, a company in which Iberdrola holds a stake.
- Portugal: continued construction of the Tamega hydro complex, which will have 1,158 MW. As to Customers, there has been a strengthening of the offer to mass segments with the inclusion of gas and new products and services.

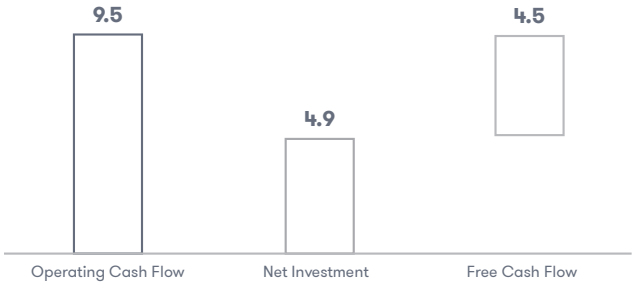
Outlook 2016-2020

- Investments of €4,900 million, mainly to increase installed capacity and to deploy 5.3 million smart meters in the United Kingdom.
- During the period, entry into service of 3,600 MW in Mexico, of which more than 700 MW have already entered into operation and almost 2,800 are under construction.
- In Retail, commitment to digitisation, multiple channels, personalisation of products adapted to the needs of our customers, and service excellence.
- Continuing improvement of operational processes and practices to increase efficiency.

Investment of €4,900 million during the period, of which €3,600 million are for growth



2016-2020 cash flow generation to finance investments (€ thousands of millions)



Key figures of the Wholesale and Retail Business

		Spain		United Kingdom		United States and Canada		Mexico		Total	
Item	**Unit**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**
Gross margin	€M	2,971	3,072	1,306	1,000	-19	48	583	509	**4,842**	**4,629**
Ebitda	€M	1,505	1,521	421	294	-58	6	455	436	**2,323**	**2,253**
Installed capacity	MW	20,081	20,058	4,835	2,531	N/A	N/A	4,976	5,437	**29,892**	**28,026**
Net output (excluding renewables)	GWh	43,616	50,790	14,925	10,650	N/A	N/A	38,128	36,449	**96,669**	**97,889**
Electricity contracts	Millions	10.3	10.3	3.3	3.2	N/A	N/A	N/A	N/A	**13.6**	**13.5**
Gas contracts	Millions	0.9	0.9	2.2	2.1	N/A	N/A	N/A	N/A	**3.1**	**3.0**
Products and services contracts	Millions	4.9	5.0	0.1	0.1	N/A	N/A	N/A	N/A	**5.0**	**5.1**
Total retail contracts	Millions	16.2	16.3	5.5	5.4	N/A	N/A	N/A	N/A	**21.7**	**21.7**
Investments	€M	188	215	94	134	5	6	353	353	**640**	**708**
Workforce	No. people	3,395	3,375	2,491	2,254	108	110	489	582	**6,483**	**6,321**

International Financial Reporting Standard (IFRS) 11 has been applied to the financial information.

◉ **Quarterly Results Report**

The Wholesale and Retail Business is focused on the safety of operations, the loyalty of customers, and growth in Mexico, which will allow for the stability of results and ensure the generation of funds for the Group.

Efficiency
- Optimisation of thermal production.
- Facilitating operations in complementary markets.
- Operating improvements and increase in availability and energetic yield of the thermal facilities in Mexico and Spain.

Prices
- Minimisation of risks through appropriate hedging of all generation, including renewable generation.

Growth
- Mexico: Almost 2,800 MW under development by 2020:
  - Escobedo I CCGT (857 MW).
  - Noroeste CCGT (887 MW).
  - El Carmen CCGT (866 MW).
  - Bajío Cogeneration (50 MW).
  - Altamira Cogeneration (57 MW).
  - Repowering improvements (44 MW).
- United Kingdom: Continued widespread deployment of smart meters that began in 2016, to reach 100% of customers by 2020.

Customers
- Loyalty-building and development of new products and personalised services adapted to the needs of customers.
- Retail development in Mexico pursuant to changes in legal provisions on energy reform.
- In Portugal, leadership in industrial customers, and strong growth in SMEs and residential customers.

Harestanes wind farm,
Scotland / UK

© Chris James

3.4 Renewables

Regulatory environment of the business

Spain

- A proposed Ministry Order was published in December, whereby the specific remuneration for renewables and cogeneration is revised as from 1 January 2017, following the established schedule. In the case of the wind power sector, this will entail increasing the return on investment (ROI) by €212 million, in order to offset the lower existing and expected market prices. It is expected that the final Ministry Order will be published in the first quarter of 2017.
- In 2016 the first auction of renewable capacity took place in Spain, at which 500 MW were awarded in wind-powered capacity and 200 MW in biomass. A new auction of 3,000 MW has been announced to take place in 2017, which will be technologically neutral and subject to controls in order to verify the credibility of the winning projects.

United Kingdom

- In November 2016, the new Government of Theresa May announced the second auction of Contracts for Differences, which is expected to begin in April 2017. Eligible for this auction, with an annual budget of £290 million, will be the less mature technologies: offshore wind, biomass, tidal, and wave, with start-up dates of 2021-22 and 2022-23. The starting price for offshore wind technology is £105/MWh.

The business will engage in sustainable growth, mainly based on onshore and offshore wind investments in the countries most important to the Group.

United States

- Donald Trump's victory in the presidential elections might entail a shift in the policies expected from the White House for the promotion of renewable energy. However, the main federal support comes in the form of tax credits (PTCs), which have already been approved for the coming years.
- The state support systems are stable and independent of the federal system, and it is expected that such stability will be preserved.

Mexico

- Two long-term auctions took place in 2016 for the sale of 20-year Clean Energy Certificates. The contracts deriving from such auctions included the sale of the energy and capacity associated with the projects awarded.
- According to the schedule, a new auction is slated to take place in April 2017.

Brazil

- The macroeconomic situation has entailed a certain change in planning.
- No wind or photovoltaic MW were awarded in 2016, as the December auction was cancelled due to overextension in the sector.
- It is expected that less volume than usual will be awarded in 2017.

Objectives, risks, and principal activities

Objectives

- Safety in operations.
- Efficiency in operations to maximise the profitability of the assets.
- Efficiency in construction costs, with a particular emphasis on offshore wind projects.
- Profitable growth in onshore and offshore wind investments in the countries that are strategic for the Group.

Significant risks

- Competitive auction processes in the markets in which it operates.
- Operational and technological risk.
- Risk of access to evacuation networks and limits on production due to technical restrictions of the networks.
- Open market energy prices.
- Cybersecurity risks with an impact on operations centres of the facilities.

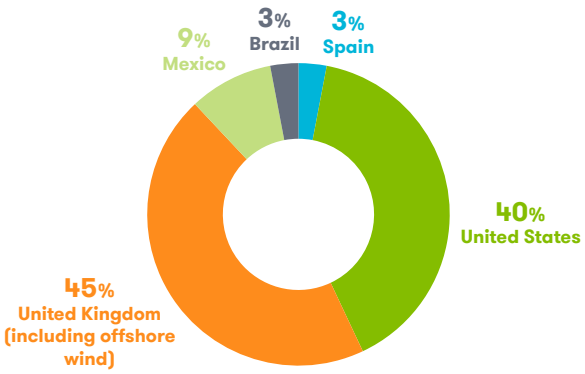
Principal activities 2016

- The year ended with 467 MW of additional capacity: 200 MW in the United States, 183 MW in the United Kingdom, and 84 MW in Brazil.
- There has been a start-up or continued construction of 1,487 MW of onshore wind capacity: 744 MW in the United States, 291 MW in the United Kingdom, 95 MW in Brazil, 32 MW in Spain, and 325 MW in Mexico.
- Construction of photovoltaic solar capacity has commenced in the United States (66 MW) and Mexico (270 MW).
- In offshore wind, there is continued progress on the construction of the 350 MW Wikinger project in the Baltic Sea (Germany). Construction has also commenced on the 714 MW East Anglia I project in the United Kingdom, after being awarded in the 2015 auction.

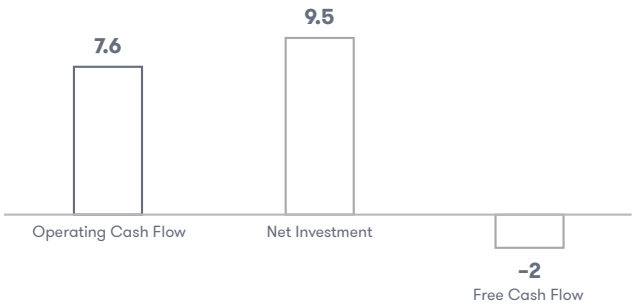
Outlook 2016-2020

- Investments of €9,500 million, mainly to increase installed capacity in the United States, the United Kingdom, and Brazil during the period.
- Start-up of 4,600 MW, of which 467 MW has already been placed into service in 2016 and more than 3,000 MW is already under construction, including two offshore windfarms: Wikinger (350 MW) and East Anglia I (714 MW).
- Continuing operational improvement, with cost savings, optimisation of useful life of the assets, and improvement in the capacity curve.

Investment plan of €9,500 million over the period, of which €8,800 million are for growth



2016-2020 cash flow generation to finance investments (€ thousands of millions)



Key figures of the Renewables Business

		Spain		United Kingdom		United States		Mexico		Brazil		Rest of World		Total	
Item	**Unit**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**
Gross margin	€M	751	764	572	385	822	802	57	69	36	37	123	123	**2,361**	**2,180**
Ebitda	€M	473	497	438	267	571	564	43	52	27	25	95	95	**1,647**	**1,500**
Installed capacity	MW	5,861	5,859	1,615	1,991	5,534	5,742	367	367	187	187	621	621	**14,186**	**14,768**
Output	GWh	11,463	11,554	3,694	3,075	13,868	14,552	738	1,119	441	639	1,371	1,366	**31,576**	**32,305**
Load factor	%	22.3	22.4	26.2	21.0	28.8	29.9	31.5	34.7	39.1	38.8	25.2	25.0	**25.7**	**25.8**
Investments	€M	9.9	19.8	488.8	950.6	69.6	735.4	124.7	4.9	38.4	4.8	3.4	-57.5	**734.8**	**1,658.0**

Notes:
• The figures for the United Kingdom include those of the offshore wind division.
• International Financial Reporting Standard (IFRS) 11 has been applied in the preparation of this table.

◉ **Quarterly Results Report**

The business will focus on the safety of operations and on sustainable growth, mainly based on onshore and offshore wind investments in the countries most important to the Group. Efficiency is a key factor for business sustainability in the medium and long terms. Iberdrola will take technological advances into account and will act on the supply chain to allow for improvement in the coming years.

Load factor
Maximising the load factor of facilities, while minimising down time through operating and maintenance measures, as well as other external factors.

Operation and maintenance costs
Continuous improvement in efficiency through global standardisation and systematisation processes.

Project Portfolio
Development of the portfolio of onshore wind projects in the United Kingdom, the United States, Mexico, and Brazil, and the East Anglia 3 (United Kingdom) and St Brieuc (France) offshore wind projects.

3.5 The Cost of Supply, the Main Factor in the Political and Social Agenda

The cost of electricity supply is taking on a greater role in the political and social agenda. The principal challenge is to reconcile safe and environmentally-friendly supply with the use of renewable energy at prices that are competitive and can be afforded by society as a whole.

In the European Union

- The Agency for the Cooperation of Energy Regulators and the European Commission, in studies on electricity prices published in 2016, confirmed that taxes and components associated with energy and environmental policies have grown the most, reaching half of the bill in countries like Spain, due to the significant renewables effort made by the electric sector. A competitive electricity supply requires the elimination of cost components outside of the service itself, and paying for these costs through general taxes or taxes on all polluting energies.
- The strategy of the Energy Union that commenced in 2015 and that was specified in legislative proposals like the *Clean Energy for All Europeans* (2016) "package" responds to the need to comply with the 2030 environmental agenda (40% reduction in GHG[1] emissions, 27% increase in renewables, and 30% improvement in energy efficiency), monitoring the safety of supply and the competitiveness of the European industry, and allowing prices that are accessible for European citizens.

(1) GHGs: Greenhouse gases

In Spain

- The price of electricity supply in Spain is less than the European average. Less than half the costs of supply are directly related to providing the service. The rest derive from the pursuit of energy policy goals (aid for renewable energy and cogeneration) and social goals (subsidies for electricity in non- mainland territories, recovery of tariff deficits from previous years).
- Iberdrola has established a protocol to ensure energy supply for customers in vulnerable situations, defined as those entitled to subsidised rates (*bono social*) due to being pensioners or all members of a family unit being unemployed, as well as disadvantaged persons identified by the social services. Iberdrola has been collaborating with public authorities and with various institutions and NGOs for this purpose since 2015, signing agreements in order to identify these economically disadvantaged persons. 98.8% of the domestic customers of Iberdrola reside in an area protected by an agreement.

In the United Kingdom

- After the CMA[1] investigation, the debate on prices has focused on higher standard variable tariffs (SVTs): reducing the number of people with SVTs and the disadvantages thereof. Iberdrola has the lowest proportion of SVTs amongst the large suppliers.
- Although the government continues to focus on minimising the costs that it controls, it has maintained capacity auctions, the minimum price of CO_2, and has announced the next auction of Contracts for Difference.

In the United States

- Tariff revisions reflect pressure by regulators to limit returns on capital, while maintaining the investments required to improve the network infrastructure.
- The closure of coal plants and the new regulation developed by the Environmental Protection Agency (EPA) may increase pressure on gas and electricity prices. Shale production might limit this impact.
- Restrictions on transporting natural gas by pipeline in the Northeast could lead to volatility in electricity market prices during periods of extreme weather.
- The development of smart grids, the rapid replenishment of supplies in the face of extreme weather conditions, new EPA regulations, and the integration of new energy sources require major investments, which sometimes conflicts with the goal of reducing final tariffs.
- In 2017, President Trump and the Congress want to focus on comprehensive tax reform, including support for infrastructure and repealing environmental regulations. Trump promised to support oil, gas, and coal, questioned climate science, argued for withdrawing from the Paris Agreement, and opposed a carbon tax. This could affect electricity markets and prices.

(1) CMA: Competition and Markets Authority

In Mexico

- Energy reforms were launched in 2014, with one of the key goals being to improve competition and lower electricity prices for end users.
- With the opening of electrical energy generation to private investment, renewable generation objectives and other measures, such as auctions for the purchase of clean energy certificates, the reform is incentivising competition in order to diversify the energy mix and reduce the costs of generation.

In Brazil

- 2016 was marked by a position of energy overcontracting by the distributors, caused by the reduction in consumption deriving from the economic crisis, consumer migration to the free market without distributors being able to reduce the contracts, and assignment of contracts for a higher-than-necessary amount. The regulatory bodies and government have approved a set of measures to resolve this distributor risk.
- The hydrological situation improved in 2016 in comparison with the previous year, allowing a "green tariff band" structure from April to October, which entails the end customer not paying additional costs for the production of energy.

Iberdrola will support frameworks that expand market deregulation and transparency and that provide incentives for required investments and efficient operations, through tariff structures that give efficient signals to consumers and do not penalise them with costs unrelated to the supply of electricity.

Worker at the Marquesado wind farm, Granada / Spain

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4.

Our Assets

Iberdrola's assets are the basis for the creation of value by the Company, which carries out its activities through the sound management thereof.

In this report, Iberdrola's assets are identified in accordance with the IIRC classification system:

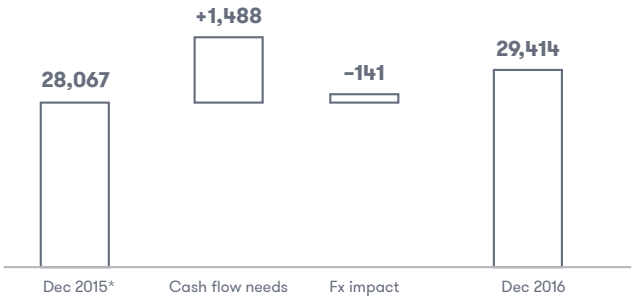
- **Financial capital**
- **Manufactured capital**
- **Intellectual capital**
- **Human capital**
- **Natural capital**
- **Social and relationship capital**

4.1 Financial Capital

	Management approach	Results 2016	Outlook
Balanced growth	The Company has an investment policy consistent with its strategic vision and financial policy. The main goals are: • Ensure a return on capital through projects and investments preferably in regulated businesses, renewable assets, or long-term contracts. • Increase geographic diversification, further balancing the contribution of the countries in which it does business. • Tailor investment levels to the actual needs of each market.	• Total investment of €4,264 million, with almost 90% channelled into regulated businesses. • The United Kingdom was the country absorbing the highest volume of investments, with 46% of the total, followed by Spain with 20%, the United States with 16%, and Mexico with 15% of the amount invested.	• Strict investment criteria based on earnings security, project profitability, and strategic fit. • Selection of businesses and countries with predictable and stable regulation and which have an A credit rating. • Net investment of more than €25,000 million over the 2016-2020 period, of which approximately 90% will be dedicated to regulated businesses, renewables, or long-term contracts. • The United States will be the area with the highest volume of investments, with 38% of the total, followed by the United Kingdom with 34%, Spain with 15%, Mexico with 10%, and Brazil with 3%.
Solid financial structure	• Iberdrola considers financial strength to be one of the strategic cornerstones that allows it to successfully face potential turbulence in the markets and to be in a position to exploit growth opportunities in the countries in which it does business. • The financial policy seeks stabilisation and subsequent improvement in solvency ratios, balancing an increase in debt with the generation of additional cash flow from new investments. • The debt structure is in line with the profile of the business, which is mostly regulated, and the composition thereof reflects the results obtained in the relevant currencies.	• Gross margin of €12,916 million, growing by 0.6%. • Net profit of €2,705 million, an 11.7% increase over the prior year. Recurring net profit was €2,532 million (+12%), as a result of the favourable performance of the businesses. • Cash flow of €6,311 million (+6.8%). • Net financial debt was €29,414 million, increasing €1,347 million since 2015 as a result of early investments in renewable energy, mainly offshore wind, and various extraordinary events (taxes in Spain, Safe Harbor in United States...) • Liquidity of €8,666 million, which covers more than 24 months of financing needs.	• Average annual Ebitda and net profit growth of approximately 6% and 7.5%, respectively, during the 2016-2020 period. • Average annual net investments of approximately €5,100 million, compared to average annual cash flow generation (FFO) of €7,100 million. • As a result of the investment process, increase in net debt to approximately €32,500 million in 2019 and subsequent decrease to €32,200 million by 2020. • With the current investment plan, solvency ratios in 2017 and 2018 are in line with 2016, and will strengthen in 2019 and 2020. • Optimisation of the liquidity position to cover financing needs for 18 months.
Operational efficiency	• The current macroeconomic and regulatory environment requires an additional effort to keep operating costs under control.	• Net operating expenses decrease 4.5% due to cost controls and the closing of the Longannet plant. Excluding the contribution from UIL and the exchange rate effect, the decrease in NOE would have been 6.9%.	• Progressive absorption of the increase in expenses, which will grow less than gross margin during the 2016-2020 period, maintaining an industry-leading position of leadership in cost efficiency.
Sustainable results and dividends	• Iberdrola offers its shareholders an industrial enterprise for the long-term creation of value. The confidence of its shareholders enables Iberdrola to secure the resources needed to move its enterprise forward.	• Shareholder remuneration of 0.286 euro per share, equal to a dividend yield of 4.59%. • Flexible dividend offering tax benefits.	• Increase of dividend to 0.31 euro per share, with a charge to 2016 profits. This amount is established as the minimum figure for future financial years. • Maintenance of the flexible dividend programme. • Target of maintaining the number of shares at 6,240 million, neutralising the capital increases associated with implementation of the flexible dividend programme. • Growing shareholder remuneration, in line with the increase in results, converging on a payout ratio of between 65% and 75%. Taking into account results forecasts, the dividend will be between 0.37 and 0.40 euro per share by 2020.

Create value for the shareholder with sustainable growth

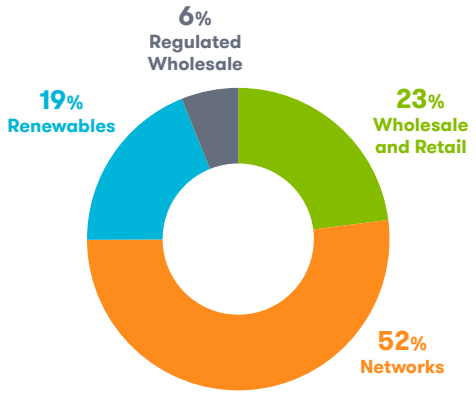
Net Debt (€M)



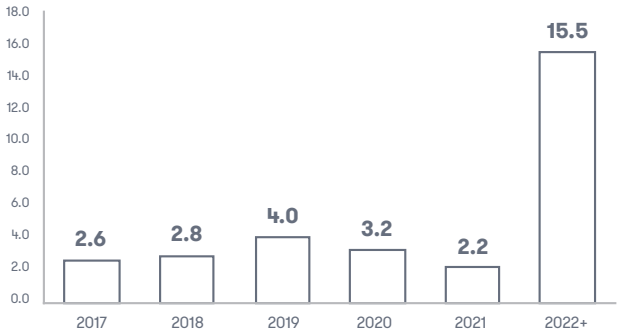
* Pro-forma including UIL.

Adjusted net financial debt at 31 December 2016 increased by €1,347 million to €29,414 million, compared to €28,067 million at 31 December 2015, as a result of €720 million of non-recurring taxes in Spain arising from RDL 2/2016 on measures for reducing the public deficit in Spain and other matters, and due to early investments in renewables and the Safe Harbor in the United States (€328 million), among other reasons.

Ebitda by business 2016

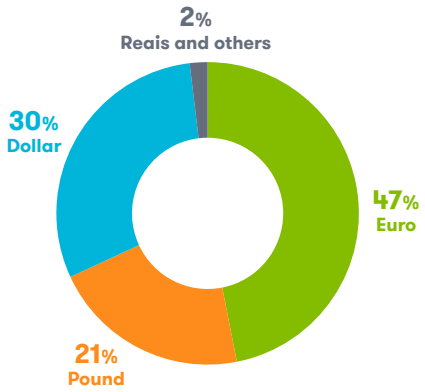


Maturity of financial debt (€M)



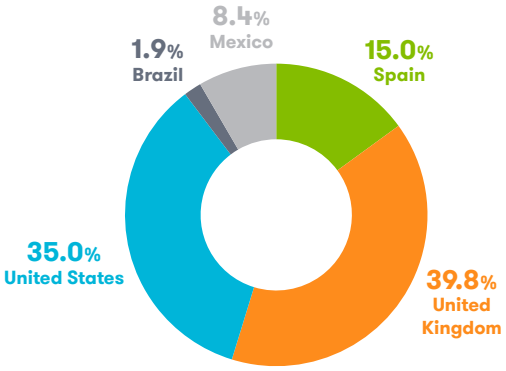
Comfortable maturity profile.

Debt structure by currency in 2016



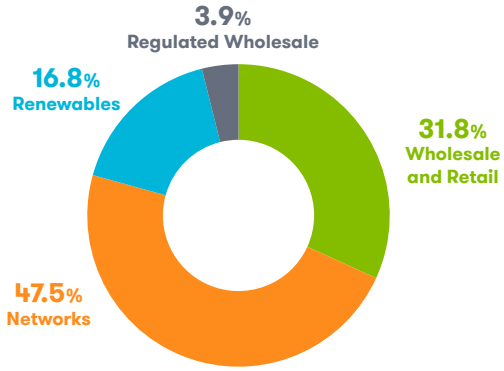
Debt structured by origin of cash flow earned in each currency. Includes derivatives to hedge net investment.

Investment by geographic area 2016



Diversification of investments, with a heavy concentration outside of the euro zone.

Gross margin by business 2016

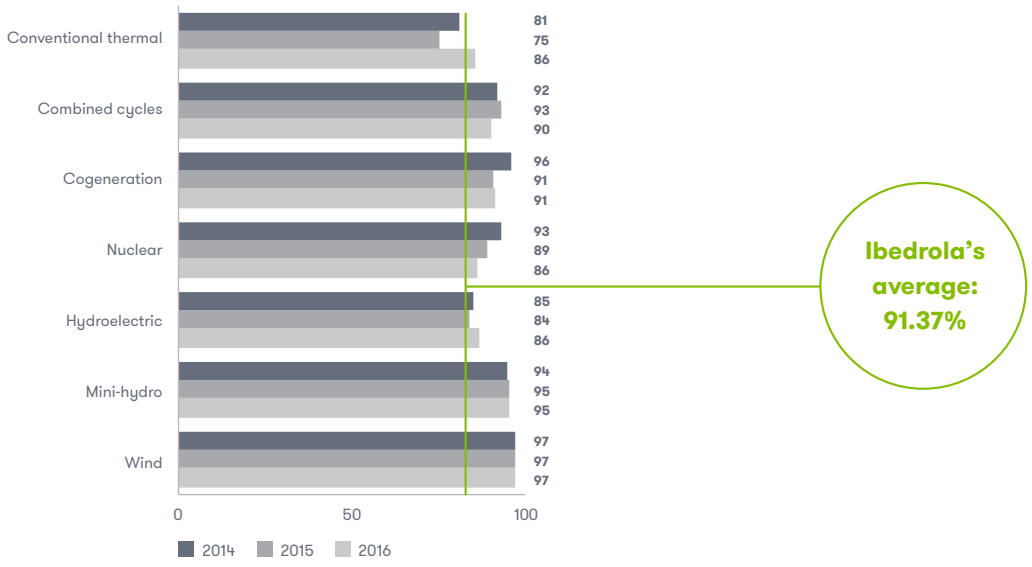


4.2 Manufactured Capital

	Size	Principal activities 2016	Outlook
Electric power generation assets	• Iberdrola's generation assets comprise nearly 300 windfarms, almost 90 hydroelectric power plants (in addition to the mini- hydro plants), 36 thermal power stations using various technologies, 5 of which are nuclear, and other facilities built and operated according to the best available practices.	• ISO 9000 certification has been attained for the operation of windfarms in Spain and the United Kingdom.	• Construction continues on almost 1,700 MW of onshore wind, 336 MW of photovoltaic, and 1,064 MW of offshore wind. • In Mexico, construction will continue on almost 2,700 MW in combined cycle and 100 MW in cogeneration. • In Portugual, there is continued construction of the Tamega hydroelectric complex, with 1,158 MW. • In Brazil, work continues on the construction of the Baixo Iguaçu (350 MW total) and Belo Monte (11,233 MW total) hydroelectric plants, through Neoenergia.
Power transmission and distribution assets	• Iberdrola's electricity transmission and distribution networks comprise over 30,000 km of transmission lines, over 1 million km of distribution lines, roughly 4,000 substations and over 1.4 million transformers, built and operated to supply a high-quality, reliable service.	• In Spain, more than 8.8 million smart meters have been installed (83.5%) and 55,500 transformer centres have been digitised (66%). • In the United Kingdom, work has advanced on the Western Link project (completion expected in 2017). SPEN received the Customer Care Award for its customer service and the Scottish Green Energy Award for innovation. • Elektro was awarded the National Quality and Iberoamerican Quality awards in 2016. • In the United States, Avangrid began the Smart Grid Community Project in Ithaca (NY).	• Significant proposed transmission projects in Maine and New York to permit the connection of renewable generation projects expected by 2020. • Installation of 1.8 million smart meters in New York and automation of the network, putting Avangrid at the forefront of the REV initiative. • Investments in the United Kingdom transmission network, to improve the reliability and quality of supply. • Progress with the digitisation of the network to lead the transformation towards a Distribution System Operator.
Other assets	• Iberdrola manages approximately 690,000 m^2 of offices and work centres throughout the world, with a total of 770 properties, of which 358 are located in Spain, 45 in the United Kingdom, 117 in the United States, 231 in Brazil, and 19 in the rest of the world. These properties, which follow the same corporate criteria in the interior spaces, are designed, built, and operated in accordance with the strictest sustainability and efficiency standards.	• ScottishPower's new corporate headquarters in Glasgow. This is a property with more than 20,000 square meters of offices for more than 1,600 employees. Start-up and the first transfer occurred during the month of December. • Phase I of the Iberdrola Campus began in the month of September. Located in San Agustín de Guadalix, this infrastructure is intended to become the backbone of knowledge and training for the employees of the Group.	• As a culmination to the process of integrating Avangrid, the infrastructure holding its corporate headquarters, located at 180 Marsh Hill Road, Orange, CT, will commence operations during 2017. • During the first half of 2017, it is expected that more than 1,600 employees will be transferred to the Glasgow headquarters, as well as the closing of surplus buildings. • Construction will begin during 2017 on phase II of the Iberdrola Campus, which will include an expansion of training infrastructures and an office complex. Completion is expected during the first half of 2019.

Offer a secure supply of energy that is competitive in price and quality

Average availability factor of Iberdrola's generation facilities

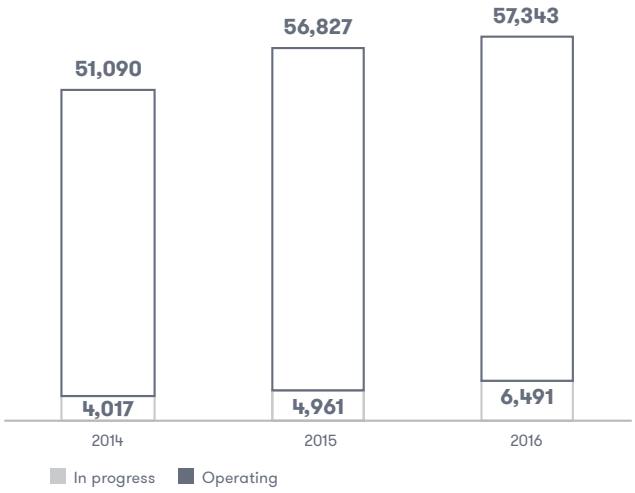


Quality of electricity supply

Average power outage duration		2015	2016
Spain	TIEPI (m)	61.9	54.0
United Kingdom	CML (m)	34.8	33.5
United States	CAIDI (h)	1.89	1.91
Brazil	DEC (h)	18.81	17.23
Power outage frequency		**2015**	**2016**
Spain	NIEPI (number)	1.20	1.04
United Kingdom	CI (ratio)	40.1	42.6
United States	SAIFI (index)	1.21	1.15
Brazil	FEC (frequency)	7.22	7.46

TIEPI: Installed Capacity Equivalent Interrupt Time.
CML: Customer Minutes Lost Per Connected Customer.
CAIDI: Customer Average Interruption Duration Index.
DEC: Equivalent Duration of Interruption by Consumer Unit.
NIEPI: Installed Capacity Equivalent Interrupt Number.
CI: Customer Interruptions Per 100 Connected Customers.
SAIFI: System Average Interruptions Frequency Index.
FEC: Equivalent Frequency of Interruption by Consumer Unit.

Property, plant, and equipment (€M)



4.3 Intellectual Capital

	Management Approach	Principal activities 2016	Outlook
Promotion of R&D	• In anticipation of the energy transition towards a more sustainable model, Iberdrola has made an advance wager on innovative solutions that require greater electrification of the economy: more clean energy, more storage capacity, more and smarter grids, and more digitisation.	• Significant increase in R&D investment: More than €211 million in 2016, a 6% increase over 2015. Being recognised as the most innovative utility in Spain and the third most innovative in Europe, according to the European Commission. • Launch of "Iberdrola Universitas", an initiative that will gather together all of Iberdrola's activities with the academic world. The goals are to promote a university-company transfer of knowledge, the attraction of talent, and contribution to the "social dividend".	• Progress on the R&D Plan 2015-2017. • R&D will continue to be a key factor to successfully achieve a new growth phase of our Company, making it the *utility of the future*, founded on sustainable development, the promotion of renewable energy, and emerging technologies, as engines for the creation of value and social contribution.
Efficiency and new products and services	• Continuous optimisation of our operations, management of the lifecycle of facilities and equipment, reduction in operating and maintenance costs, and decreasing environmental impact. • Development of new and competitive products and services that adapt to an increasingly global market, the main goal of which is to meet the needs of customers.	• New initiatives to improve the customer experience: personalisation of content and offers, delivery of proactive real-time communications, online self-service, Optimum Rate, and Energy Advisor. • New Smart Home products: Consumption Monitor, an electric meter capable of breaking down the consumption of main domestic appliances, and Smart Lamps, smart LED bulbs that can be controlled from a mobile device.	• Our commitment to innovation will continue to be a priority in order to keep Iberdrola at the forefront of developing the new products, services, and business models that are transforming the industry. Finally, we will continue making efforts to offer our customers better and more efficient service and to contribute to sustainable development with our innovative activities.
Disruptive technology and business models	Through the Iberdrola Ventures- Perseo corporate venture capital programme, there has been more than €50 million invested since 2008 in technologies and new disruptive businesses, which ensure the sustainability of the energy model. Lines of activity: • Customer-focused solutions: energy efficiency, demand management, digital solutions, etc. • Distributed energy resources: innovative generation and distributed storage solutions. • Renewable energy: technologies related to renewable generation (solar, wind, offshore wind). • New technologies applied to the operation and maintenance of energy infrastructures: robots, sensors, software, drones, etc.	• Positioning of the company Silicon Valley Stem as the market leader in distributed storage. This start-up offers savings to commercial and industrial customers through a solution behind a meter that includes software (big data and cloud) and batteries. Stem reached 200 installations of distributed storage during 2016. • Growth and development of the Salamancan company Arbórea Intellbird, jointly owned by Perseo and CDTI, which sells drone inspection services for all kinds of energy infrastructure. During 2016, it has inspected more than 600 of the Company's wind turbine blades, preventively detecting anomalies and permitting a reduction in the cost of repairs and improved planning of corrective maintenance.	• Ensure Iberdrola's access to the energy technologies of the future. • Foster entrepreneurship and the development of an innovative entrepreneurial fabric within the energy sector: investment in initiatives with a high social and job creation component. • Establish alliances with key technology providers for Iberdrola (Open Innovation Ventures).

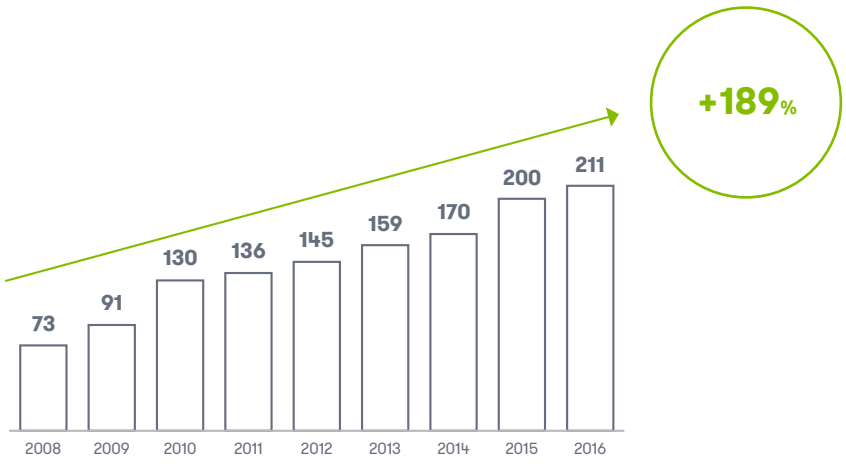
◉ **Innovation Report**

Highlight the value of the Company's intangible assets

Main R&D research projects

Renewable energy	• Projects to improve the efficiency of assets and models for the design of windfarms. Monitoring of the main equipment for early detection of failures or reduced production using artificial intelligence/big data. The area of energy resources includes the *HPC4E* (High Performance Computing for Energy) project, which plans to use computational fluid dynamics (CFD) models in future exascale supercomputers. • The area of offshore wind includes the installation of jacket piling and foundations at the Wikinger offshore windfarm, as well as innovative substation design based on a 6-legged jacket foundation design built in two separate blocks to simplify transport to the site. • Renewable energy integration projects include the exceptional *ESS2Wind* project, which aims to analyse the possible application of battery storage systems associated with windfarms to provide auxiliary services to the system.
Smart grids	• The *iGreenGrid* project for developing specific methods for integrating renewable energy into the electric distribution grids and the *Discern* project for comparing different smart grid solutions to discover the ideal arrangement of architectures were successfully completed. • In the United Kingdom, work continues on the *Visor*, *Angle* and *Fitness* projects to improve the transmission and distribution network, strengthening smart grids.
Clean generation	• The CO_2*Formare* project, the goal of which is to avoid macrofouling in a sustainable manner, reducing environmental impact. The first tests for injecting CO_2 into water have been performed, the results have been satisfactory, and the previously developed CO_2 capture modules will soon be installed at the plant. • The *Prexes* project, which focuses on developing a model for predicting expansion in concrete hydraulic structures.

Investments in R&D (€M)



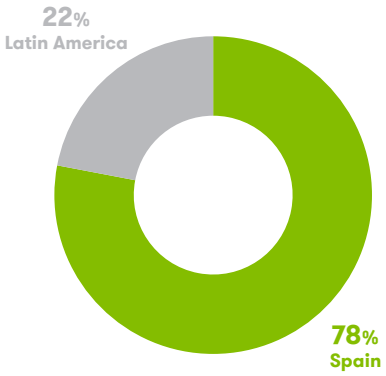
4.4 Human Capital

	Management approach	Principal activities 2016	Outlook
Global human resources management	• Achieve the goals of competitiveness and business efficiency in a climate of social peace, fostering stable, high- quality employment. • Harmonise human resources processes and make inroads with implementing the Iberdrola culture in all countries, respecting specific local conditions.	• Finalisation of the project for integration of the Human Resources Model (OneHR project) at Avangrid. • Management of an appropriate labour relations framework that can be adapted to suit business and social requirements.	• Consolidate the Human Resources function at Avangrid, extending and unifying best practices. • Strengthen the commitment to social responsibility, fostering ethical and responsible behaviour. • Maintain team pride, workforce satisfaction, job commitment, and productivity.
Goal of "accident reduction"	• Prioritise the safety of individuals at the Group's facilities and within its sphere of influence, fostering a progressive reduction in incident rates and improving health and safety conditions. • Replicate throughout the Group the best practices identified in the area of occupational health and safety, fostering a culture of excellence in management and coordinating global preventive activities.	• Attainment and/or maintenance of the OHSAS 18001 certification, and approval of a system of global prevention standards in accordance with the Group's policy. Assessment of level of conformance to global standards. • Monitoring of proactive and reactive indicators among the Group's companies for the global scorecard. • Establishment of goals for the management of occupational health and safety at subcontractors. • Identification and application of best safety practices. Exchange of lessons learnt. Creation of groups to promote safe behaviour.	• Define the global occupational health and safety strategy for the coming years. • Continue with assessment of level of conformance to global standards and the implementation of improvement groups to promote safe behaviour. • Continue developing certifications of the Group in accordance with OHSAS 18001. • Analysis of accident rate and establishment of goals for Group and subcontractor employees. • Global campaigns to raise awareness on certain types of common accidents.
Talent management	• Drive staff qualifications, preparing employees to work in a multicultural environment and making continual efforts to improve their employability. • Develop alternatives to compensate for factors stemming from the ageing of the workforce. • Maintain a team of competent, committed, and motivated professionals, which is key for the sustained success of the business.	• Promotion of job and international mobility within multicultural teams in a global context. • Launch of new Management School programmes. • Expansion of the professional training and development model to all countries. • Identification of the group of high-potential professionals to provide the organisation with professionals will lead the Iberdrola of the future. • Expansion of the process of publishing internal vacancies at the global level.	• Strengthen the talent and leadership development management model at the international level. • Define and implement the Global Development Roadmap for the Iberdrola Group. • Attract the best talent, strengthening excellence in our selection processes. • Integrated talent management of the Company in order to train future leaders, preparing them now to assume larger responsibilities. • Development of the second phase of the Campus project.
Diversity, equal opportunity, and reconciliation	• Guarantee a social model committed to professional excellence and the quality of life of our employees. • Development of labour relations based on equal opportunity, non- discrimination, and respect for diversity. • Create a high-quality labour environment by committing to reconciliation, and promote a position of leadership in these areas in the countries in which it does business similar to that enjoyed in Spain. • Align the Corporate Volunteering Programme with the Sustainable Development Goals defined by the United Nations.	• International cultural exchange programmes. • Corporate Volunteerism Activities focused on improving the quality of life and the integration of vulnerable groups, including the *International Volunteering Day*, the *Involve* international volunteering programme, and the project for improving the electricity situation of several refugee camps in Ethiopia. • Launch of the volunteer project regarding the fight against climate change. Sustainable Development Goals 4 (Quality education) and 13 (Climate action).	• Continue to foster improvements in the quality of people's lives through social-welfare activities in all of the countries in which the Iberdrola Group has a presence, creating a global volunteer community. • Promote the internationalisation of social programmes and strengthen ties among the employees of the Group at the global level. • Contribute to achieving the Sustainable Development Goals defined by the United Nations for the 2015-2030 horizon.

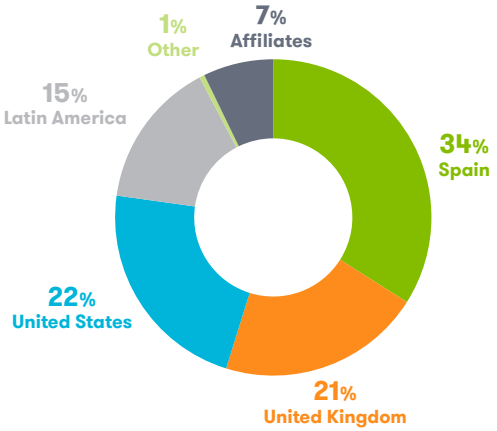
Ensure the availability of a committed, qualified workforce in a safe and stable environment

Growth and geographic diversification of the workforce

2006: 16,155 employees



2016: 30,591 employees



Key Figures / page 12

Social commitment

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Visit by their Majesties the King and Queen of Spain to Iberdrola's headquarters in Madrid for the tenth anniversary of the international Corporate Volunteering programme and the delivery of the Iberdrola Scholarships 2016.

Iberdrola Campus: Finalisation of first phase

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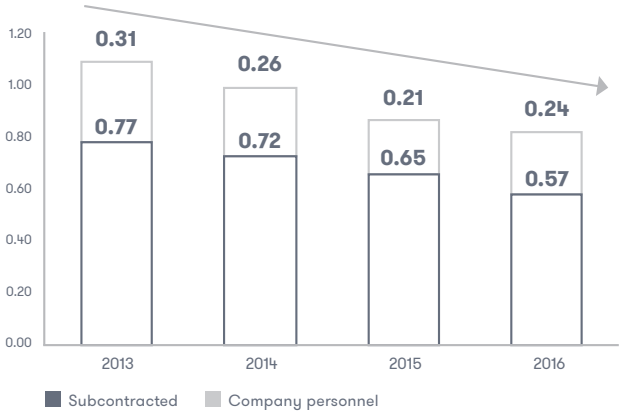
Accident rate (2013-2016): progressive reduction



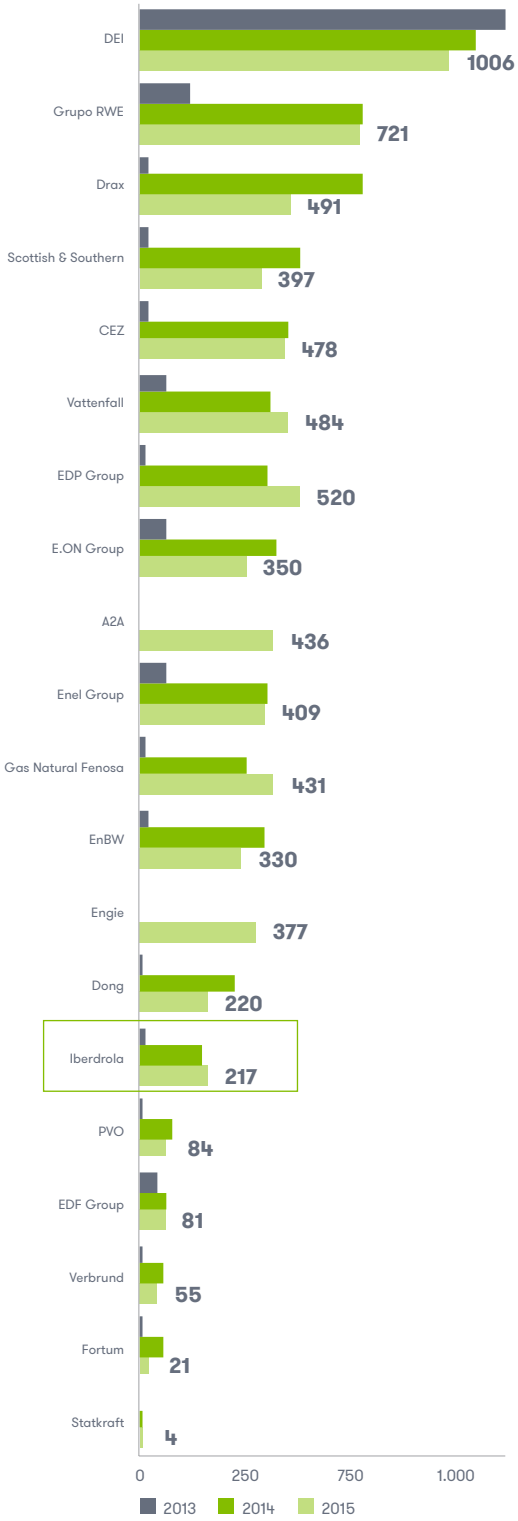
26% in subcontracted personnel and 23% in Company personnel.

4.5 Natural Capital

	Management Approach	Principal activities 2016	Outlook
Environmental management and biodiversity	• Integrate standards for conserving biodiversity when engaging in new projects. • Reduce environmental risks in the operation of existing facilities. • Promote the protection of ecosystems in the surroundings of the facilities. • Strengthen transparent dialogue with Stakeholders in seeking solutions to environmental problems. • Manage environmental compliance by suppliers. • Transparently report on environmental results and activities.	• Sustainable General Shareholders' Meeting 2016: – ISO 20121 certification. – Erronka Garbia Environmental certification. • ISO-TS 14072 Certificate for Corporate Environmental Footprint (CEF) 2015. • Development of Environmental Product Declaration (EPD) for the Kilgallioch windfarm under construction in Scotland. • Energy efficiency project for the facilities of Iberdrola España (conformance to RD 56-2016). • Climate Change Adaptation Report for activities in Spain.	• Adaptation to ISO 14001 2015 standard. • Development of EDP for an offshore windfarm. • Development of a strategic plan for Climate Change Adaptation. • CEF by region. • Environmental Guidelines linked to impacts of the CEF. • Restoration, recovery, improvement, and maintenance of surroundings and habitats.
Prevention of pollution	• Prevent pollution and the emission of greenhouse gases (GHGs) through practices that reduce or eliminate the production of pollutants at source. • Reduce the emissions of non- GHGs into the air. • Gradually replace equipment using substances that reduce the ozone layer. • Promotion of awareness-raising campaigns regarding air quality. • New GHG emissions-free facilities (renewable, wind, hydroelectric, etc.).	• 42% reduction in intensity of CO_2 emissions per kWh produced since 2007. • Thermal emission factor has decreased from 460 g/thermal kWh generated in 2015 to 391 g/kWh generated in 2016. • Increase in emission-free installed capacity to 65.9%. • Closure of Lonnganet coal plant in the United Kingdom. • New commitment to reduce emissions, and active participation in the Marrakesh Climate Conference (Morocco). • Sustainable mobility plan, electric car.	• Achieve a 50% reduction in emissions intensity by the year 2030 in comparison to 2007. • Carbon neutral by 2050. • Develop innovation projects geared towards reducing pollution. • Actively participate in achieving the Sustainable Development Goals approved in September 2015 (goals 6, 7, and 13).
Operating excellence and energy efficiency	• Continuous improvement in operational performance, increase in energy efficiency, increase in energy savings, reduction in consumption of natural resources, etc., all while promoting the use of environmentally-friendly resources.	• Innovative activities in environmental management and control. • Assurance of quality in environmental management. • Efficient management of water consumption.	• Development and promotion of ecodesign initiatives. • Life-cycle and *green purchasing* analysis.
Waste management	• Improve control and management of waste (hazardous and non-hazardous) generated. • Minimise the generation of waste at source. • Maximise the reuse, recycling, and recovery of waste.	• Reuse of waste from thermal coal plants. • Carry out waste minimisation plans, recycling plans, and awareness campaigns aimed at employees.	• Make progress in the optimisation of waste management: circular economy. • Draw up economic/financial analyses of the best waste management strategies.

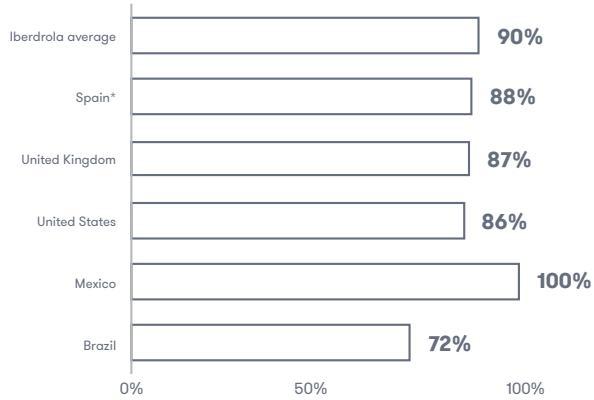
The environmental dimension is a key factor in the concept of sustainability

CO_2 emissions at companies in the sector (Carbon factor in kg of CO_2/MWh)



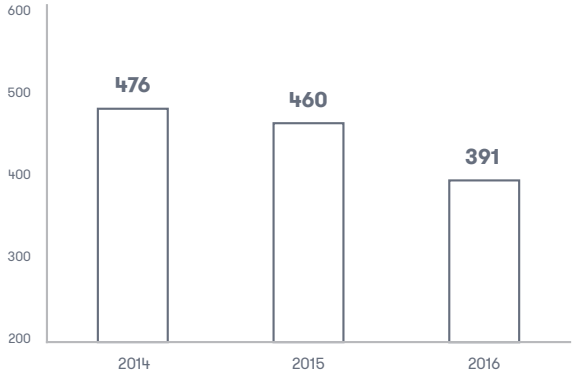
European carbon factor 2015: 311 kg CO_2 /MWh.
Source: "*Facteur carbone européen Comparaison desémissions de CO_2 des principaux électriciens européens*" PwC France. Nov 2016.

Production of Iberdrola plants using local energy sources in the countries in which it operates

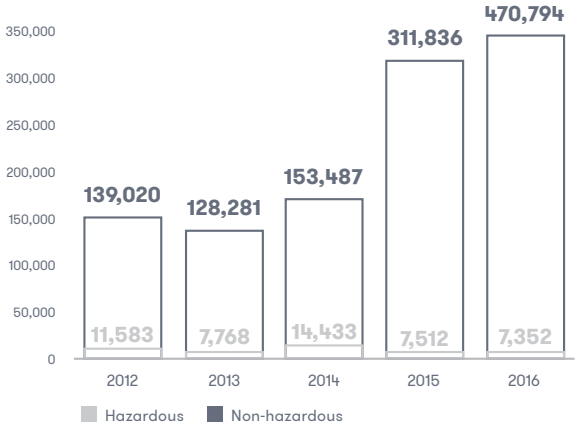


* Nuclear fuel acquired from the Spanish company Enusa is considered a local source.

Intensity of emissions at the thermal plants of the Group (CO_2/MWh)



Volume of recovered, reused, or recycled waste (t)



Key Figures / page 12

4.6 Social and Relationship Capital

Stakeholder relations

Iberdrola wants to engage its Stakeholders in all of its activities and businesses, participating in an ongoing and constructive dialogue with them in order to know their expectations, build strong ties, and thus generate confidence and forge a sense of belonging to an excellent company, of which they feel they are a part.

Management approach

Iberdrola's strategic approach sets great store by its relations with Stakeholders, giving importance to the dual facets of this relationship:

- In terms of social responsibility, meeting their expectations and needs.
- In terms of reputation, managing Stakeholders' perception of the Company.

Principal activities 2016 and Outlook

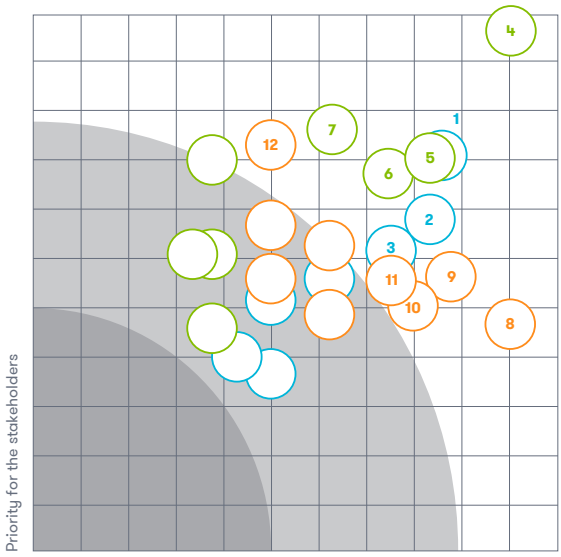
- Approval of a new *Stakeholder Relations Model*, the goals of which are:
  - To further develop the *Stakeholder Relations Policy* approved by the Board of Directors in 2015.
  - To systematise Stakeholder relations throughout the Iberdrola Group.
  - To create a business culture with respect to the significance of dialogue with the Stakeholders.
- Monitoring of the AA1000 standard, in accordance with the principles of inclusiveness, materiality, and responsiveness:
  - Update of the channels of communication with the Stakeholders.
  - Identification of the most significant matters.
  - Balanced and reasonable response thereto.
- New microsite on the Employee Portal (Intranet) to internally disseminate the importance of the dialogue and of the relations with Stakeholders.
- In 2017, implementation of the new *Stakeholder Relations Model* throughout the Iberdrola Group.

A materiality analysis allows for prioritisation of the issues most important to the Company's Stakeholders.

Materiality

A Materiality Study allows for prioritisation of the issues most important to the Iberdrola's Stakeholders. In the *Sustainability Report 2016*, Iberdrola explains the management approaches taken by the Company in regard to these significant issues and the results achieved. The following graph summarises the main issues.

Materiality analysis of the Iberdrola Group



- Economic dimension
- Environmental dimension
- Social dimension

Material issues

1. Business innovation and opportunities
2. Economic performance and fiscal transparency
3. Customer satisfaction
4. Renewable energy development
5. Electricity generation: electricity mix and energy efficiency
6. Strategy in the fight against climate change
7. Electricity and gas supply
8. Human rights
9. Attraction and retention of talent
10. Socioeconomic impact on the community
11. Health and safety of employees and contractors
12. Access to energy for vulnerable customers

Other issues identified

Anti-corruption
Anti-competitive behaviour and monopolistic practices
Public policy
Management of supply chain
Environmental performance: operational efficiency
Management of environmental impact
Management of biodiversity impact
Management of water usage
Labour practices
Development of human capital
Social-welfare action
Physical security of the facilities (community)

Community support and electricity access programmes

Primary programmes

Activities 2016

- Contribution of €44 million to the community in the countries in which Iberdrola operates, measured according to the London Benchmarking Group (LBG) international standard.
- International corporate volunteering programme, offering various volunteering opportunities to employees in Spain, the United Kingdom, the United States, Mexico, and Brazil.
- Entrepreneurial support: over €46 million of procurement from companies in operation for less than 5 years, and €70 million in venture capital for new initiatives with high technological value.
- Programmes and pricing to aid vulnerable groups in Spain, the United Kingdom, the United States, and Brazil.
- Rural electrification programmes in Brazil, to which €18 million has been allocated on a consolidated basis.
- Programmes implemented by the foundations created by Iberdrola in the principal countries in which it operates.
- Development of the *Electricity for All Programme.*

Electricity for Everyone

- The Sustainable Development Goals (SDGs) 2015-2030, approved at the UN Sustainable Development Summit in New York (September 2015), entail the recognition of energy as an engine of sustainable growth.
- The *Electricity for All* programme is Iberdrola's response to this demand to extend universal access to modern forms of energy, with environmentally sustainable, financially affordable, and socially inclusive models. This initiative is focused on sustainable electrification activities in emerging and developing countries.
- Iberdrola has set itself the goal of reaching 4 million beneficiaries of this programme by 2020. At year-end 2016, the programme had reached 2.5 million users.

Economic value distributed (€M)

Item	2015	2016
Procurement from suppliers	5,093	6,415
Payments to providers of capital	1,646	2,692
Payments to government administrations	2,746	2,740
Employee remuneration	2,187	2,260

⊙ Sustainability Report

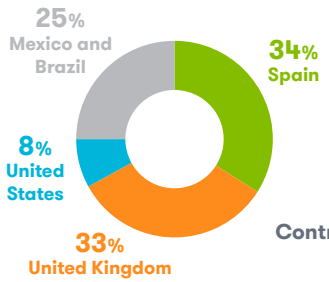
Foundations of the Iberdrola Group

Activities 2016

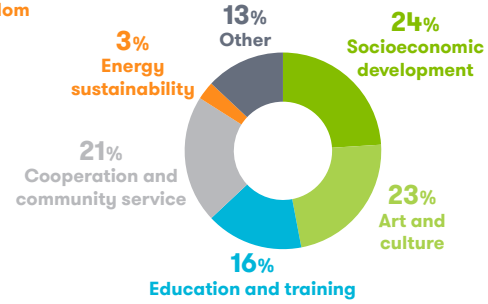
- Iberdrola has strengthened the operation of its foundation activities in Spain, the United Kingdom, the United States, Mexico, and Brazil through the actions of the Foundations Committee, as the body coordinating all of their activities and of the corresponding Boards of Trustees in each country.
- Contributions and amounts dedicated to activities have increased in all countries, including the United States, where the Avangrid Foundation has integrated a large portion of the social welfare actions carried out by UIL and its foundations.
- As regards the activities themselves, the four areas of the Master Plan (Training and Research, Art and Culture, Sustainability and Biodiversity, and Cooperation and Solidarity) have been promoted in all of the countries.
- In the training area, Iberdrola's *Scholarships and Research Assistance Programme* gave a total of 130 scholarships for students in the five aforementioned countries in 2016.
- The area of art and culture includes illumination projects like that for the *Municipality of San Sebastián*, support for exhibitions like the new *Energise Area of the National Museum of Scotland*, and projects supporting music like the *Eastman School of Music* in Rochester.
- In the area of sustainability and biodiversity, there have been multiple collaboration projects with educational and environmental centres in these five countries.
- In the area of cooperation and solidarity, there has been a strengthening of the *Social Assistance* programme in Spain and the many collaborations in the United States and the United Kingdom.

Programme results 2016

Contribution by region (%)



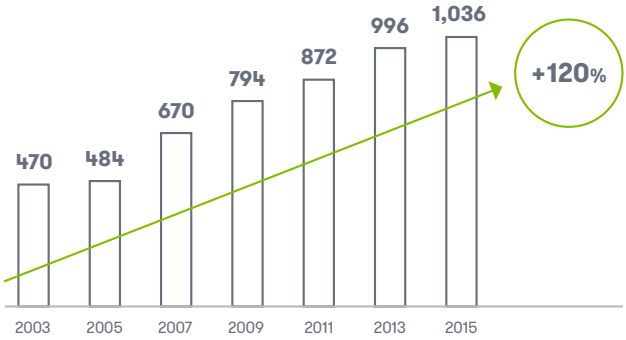
Contribution by programme (%)



Soundness and strength of the brand

- Management of the brand in such a way that it transmits the principles set out in the *Mission, Vision, and Values of the Iberdrola Group* and reflects the Company's strategy of commitment to the environment.
- Consolidation of an international brand, strengthening communication and alignment under a single brand positioning strategy in the countries in which the Company operates.

Brand value* (€M)



Source: *Ranking of Best Spanish Brands by Interbrand.*

Evolution of the digital ecosystem

- Offer of useful and dynamic information, with messages adapted to each stakeholder.
- Facilitate direct interaction with our stakeholders, overcoming barriers and making use of existing synergies.

Iberdrola on social media and the Internet:

Brand and reputation intelligence

- At Iberdrola, the establishment and attainment of goals allows for the conquering of challenges and sustainable growth. Thanks to the alignment between these goals and the expectations of the Stakeholders, both internal and external recognition is achieved and relations of trust are strengthened, thus increasing reputation.
- In 2016, the creation of a Brand and Reputation Intelligence Unit has allowed for progress down the path of acquiring an awareness and analysis of the brand and management of the corporate reputation as elements to take into account in short-, medium-, and long-term strategic decision-making.
- Good corporate governance is the great driver for identifying and evaluating reputation risks through policies, while the value of the brand and the value of the Company are the major beneficiaries of the implementation of an intelligence system that protects the Company from negative impacts on its reputation and risks. This is reflected in the following chart on the value creation process using brand and reputation analysis and intelligence tools:

Figure 1.
Brand and reputation intelligence value creation process

- Within this context, one of the greatest challenges on which progress has been made this year was the identification of reputational risk factors as well as the implementation of initiatives that raise the Company's awareness to confront and overcome them. Being aware of the opinion of the Stakeholders, their expectations, and what they think of the business is a vital issue for overcoming this challenge and maximising the success of the Company within a competitive marketplace and in the financial markets. Along these lines, a worldwide employee opinion survey was carried out in 2016. This has provided an awareness of the opinion of the employees regarding Iberdrola's reputation and the local brands through which it acts in the following countries: Spain, United Kingdom, United States, Mexico, and Brazil.
- Finally, good reputation shows that good governance is aligned not only with shareholders and the financial community but also with customers, employees, and each and everyone of the Stakeholders, for which reason management plans are being implemented with each of them.

International Volunteer Day in Scotland / UK

© Chris James

Iberdrola Tower, Bilbao
/ Spain

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5.

A Framework of Trust

5.1 Corporate Governance Model

Foundations of Iberdrola's corporate governance model

A. Corporate Governance System

Iberdrola is a leading multinational Group in the energy industry that seeks to create value in a sustainable manner for society, citizens, customers, and shareholders; which innovates and uses environmentally-friendly energy sources and considers its employees to be a strategic asset; committed to social return through all its business activities, generating employment and wealth in its environment, all within a strategy of social responsibility and compliance with tax regulations.

Iberdrola has adopted a Corporate Governance System made up of the *Mission, Vision, and Values* of the Group, *By-Laws*, *Corporate Policies*, *Internal Corporate Governance Rules*, and other internal codes and procedures, all available at www.iberdrola.com.

The content thereof is inspired by and based on a commitment to best corporate governance practices, business ethics, and social responsibility in all of its areas of activity.

Position	Director	Status	Date of last appointment	Ending date
Chairman & CEO	José Ignacio Sánchez Galán (Salamanca, Spain, 1950)	Executive	27-03-2015	27-03-2019
Director	Íñigo Víctor de Oriol Ibarra (Madrid, Spain, 1962)	Other external	08-04-2016	08-04-2020
Director	Inés Macho Stadler[1] (Bilbao, Spain, 1959)	Independent	08-04-2016	08-04-2020
Director	Braulio Medel Cámara (Marchena, Seville, Spain, 1947)	Independent	08-04-2016	08-04-2020
Director	Samantha Barber (Dunfermline, Fife, Scotland, United Kingdom, 1969)	Independent	08-04-2016	08-04-2020
Director	María Helena Antolín Raybaud (Toulon, France, 1966)	Independent	27-03-2015	27-03-2019
Director	Santiago Martínez Lage (Betanzos, A Coruña, Spain, 1946)	Independent	27-03-2015	27-03-2019
Director	José Luis San Pedro Guerenabarrena (Bilbao, Spain, 1946)	Other external	27-03-2015	27-03-2019
Director	Ángel Acebes Paniagua (Ávila, Spain, 1958)	Independent	27-03-2015	27-03-2019
Director	Georgina Kessel Martínez (Mexico City, Mexico, 1950)	Independent	28-03-2014	28-03-2018
Director	Denise Mary Holt (Vienna, Austria, 1949)	Independent	27-03-2015	27-03-2019
Director	José W. Fernández (Cienfuegos, Cuba, 1955)	Independent	27-03-2015	27-03-2019
Director	Manuel Moreu Munaiz (Pontevedra, Spain, 1953)	Independent	27-03-2015	27-03-2019
Director	Xabier Sagredo Ormaza (Portugalete, Spain, 1972)	Other external	08-04-2016	08-04-2020

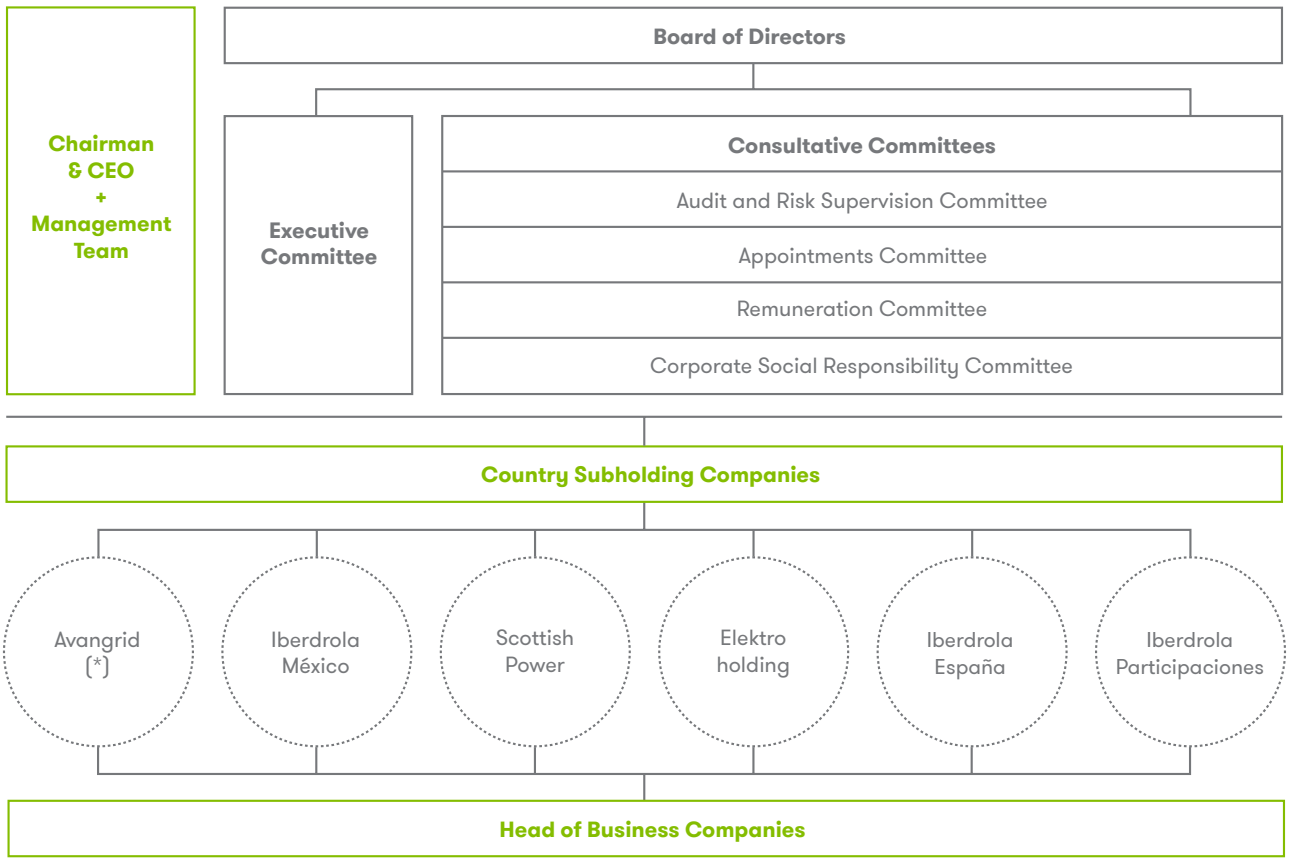
(1) Inés Macho Stadler is the lead independent director (*consejera coordinadora*).

B. Governance model

Appropriate differentiation between the duties of strategy and supervision and those of guidance and management:

- The Board of Directors of Iberdrola, S.A., made up of a large majority of independent directors, focuses its activity on the determination, supervision, and monitoring of the strategies and general guidelines that must be followed by the Group.
- The chairman of the Board of Directors & chief executive officer and the rest of the management team are responsible for the organisation and strategic coordination of the Group, through the dissemination, implementation, and monitoring of the overall strategy and basic guidelines.
- In all of the countries in which the Group operates, organisation and strategic coordination is implemented through country subholding companies, which group together equity stakes in the energy head of business companies carrying out their activities in the respective country and centralise the provision of services common to such companies. In addition, the Group has a country subholding company that groups together the non-energy businesses. Country subholding companies have Boards of Directors, including independent directors and their own Audit and Compliance Committees, Internal Audit divisions or units, or Compliance divisions.
- The head of business companies are in charge of the day-to-day administration and effective management of each business. They also have Boards of Directors, which include independent directors and specific management teams. This structure, which operates together with the Group's Business Model, allows for an overall integration of the businesses (Networks, Wholesale and Retail, and Renewables) and focuses on maximising the operational efficiency thereof through the implementation of best market practices.

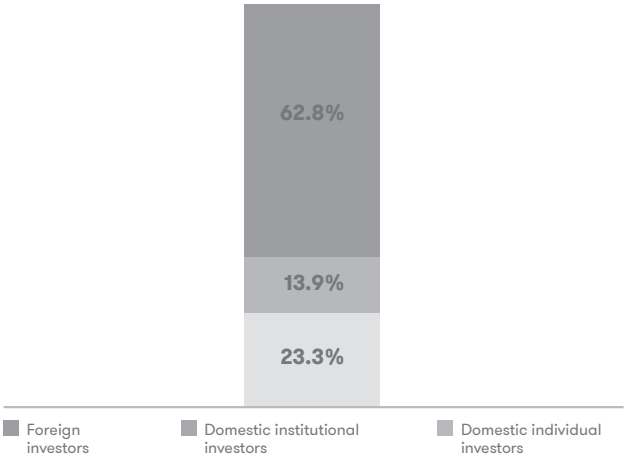
Corporate and governance structure of Iberdrola, S.A



(*) Company listed on the New York Stock. Exchange.

C. Equity structure

Iberdrola has more than 600,000 shareholders throughout the world, and none of them has a controlling interest.



Foreign institutional shareholders account for 62.8% of the capital.

External corporate governance awards / page 39

With Shareholder Week, which culminates with the holding of the General Shareholders' Meeting, Iberdrola brings the Company closer to and promotes interaction with its shareholders to give form to its corporate governance and social responsibility strategy, sharing events and initiatives regarding social-welfare, cultural, technological innovation, and digital transformation actions.

Iberdrola's response to the corporate governance challenge

A. Continuous Improvement of its corporate governance rules and practices

On corporate governance matters, the Company looks to the Good Governance Code of Listed Companies published by the CNMV and generally accepted recommendations in the international markets.

71.4% of the directors are independent.

Remuneration policy	Executive directors' variable remuneration tied to objectives.
	Transparency.
	Provision for revision and reimbursement of deferred variable remuneration.
Operation of the Board	71.4% of directors are independent.
	System of checks and balances, including a lead independent director (*consejera coordinadora*).
	All consultative committees have 100% or a majority of independent directors.
	Gender diversity: 5 women on the Board. All consultative committees are chaired by women.
	Cultural diversity: directors from 6 countries of origin.
	Rationale for proposed appointments.
	External evaluation of governance bodies.
Social responsibility and corporate reputation	Specific Corporate Social Responsibility Committee.
	Social Responsibility Policies.
	Company social action strategy through foundations related to the Iberdrola Group in Spain, United Kingdom, Brazil, United States, and Mexico.

Ethics and Social Responsibility / page 90

B. Commitment to shareholders and investors

- The strength of the Group's industrial and financial model will us to continue on a path of increased profits and shareholder remuneration thanks to balanced growth focused on the regulated networks businesses, renewables, and long-term contracted assets.
- Engagement: shareholders are the key players within the Corporate Governance System, which includes good governance practices beyond those required by applicable law. The *Shareholder Engagement Policy* is implemented through various channels of participation intended to build a continuous dialogue beyond the General Shareholders' Meeting.
- Boost shareholders' participation at the General Shareholders' Meeting through the payment of an attendance bonus. Since its implementation in 2007, the quorum in attendance at the General Shareholders' Meeting has exceeded 75%, and has exceeded 77% during the last three years.

The quorum in attendance at the 2016 General Shareholders' Meeting was 77.91%.

C. Alignment between corporate governance and strategy

- Director remuneration aligned with strategic objectives and shareholder return. The remuneration model for directors is based primarily on three components:

Remuneration model for the Board

Type of remuneration	External (non- executive) directors	Executive directors
Fixed	According to their duties	On market terms.
Short-term variable	Not applicable	Tied to annual targets.
Long-term variable	Not applicable	Tied to multi-annual targets and paid in shares (3-year accrual period and payment deferred over 3 years following accrual).

There were only 2.16% votes against the *Annual Director Remuneration Report 2015*.

Parameters to which the annual variable remuneration of executive directors is tied in 2017

Financial	Results. Shareholder return.
Social responsibility	Presence on international indices. Level of consensus received for the proposals of the Board at the General Shareholders' Meeting. Growing female presence in management positions. Labour climate. Professional training.

Parameters to which the multi-annual variable remuneration of executive directors is tied (2017-2019)

Net profit.
Total shareholder return.
Financial strength.
Reduction in CO_2 emissions.

Principal activities of the Board of Directors

Key issues in 2016

Iberdrola's Board of Directors has focused its activities on approving the strategic goals of the Group, on defining its organisational model, and on supervising the implementation and further development thereof.

Strategy		
Growth	The Board of Directors approves the strategic goals and determines the focus of the Group's most significant investments, ensuring that they are made in the businesses identified as priority, regulated, and renewable businesses, as well as in countries with a high credit rating.	Approval and update of the **Outlook 2016-2020** and of the **strategic pillars.**
		Approval of the **strategy and budgets** for financial year 2017.
Financial strength	The Board of Directors determines the financial strategy during a growth phase of the Company.	Approval of a set of **diversified financing sources.**
Sustainable remuneration	The Board of Directors ensures that shareholder remuneration is aligned with growth in the Group's results.	Validation of the **objective of growth in shareholder remuneration** in line with the increase in results.
		Approval of an **approximately 11% increase in shareholder remuneration with a charge to 2016.**
Noteworthy milestones: Outlook 2016-2020. Increase of close to 11% in shareholder remuneration with a charge to 2016.		
Supervision		
Supervision	The Board of Directors, with the support of the Executive Committee, supervises on an ongoing basis the implementation of the Group's strategy and the development of the Group's organisational model.	Detailed study of **priority markets.**
		Analysis of the **performance** and **expectations for the future** of the Businesses.
		Monitoring the **integration of Avangrid.**
		Regular supervision of **key financial indicators.**
		Monitoring of the impact that **the merger between Siemens and Gamesa** will have on Iberdrola.
Noteworthy milestone: Monitoring the integration of Avangrid and the merger between Siemens and Gamesa		

Iberdrola's Board of Directors has also devoted a significant portion of its time to dealing with other strategic issues relating to the management of the Group:

Risk supervision and control	
The Board of Directors is deeply involved in the supervision of the Group's risks: it monitors the level of risk by means of periodic tracking of the most significant threats.	**Identification and analysis of the main risks** facing the Group.
	Ongoing monitoring of risks with a possible impact on financial year 2016.
	Annual revision of the **Risk Policies.**
	Update of the guidelines on **risk limits.**
	Approval of the ***Report on Risk Control and Management Systems.***
Noteworthy milestone: Risk Analysis 2016-2020	

Director and senior officer remuneration	
The Board of Directors has supervised the remuneration model in order to verify that it is consistent with the Company's performance and with shareholder return, thus ensuring the maximisation of long-term value.	**Comparative analysis** of director remuneration.
	Freezing of **non-executive director remuneration** since 2008.
	Establishment of the limit on **variable remuneration** as well as the targets to which it is linked.
	Approval of the fixed and variable remuneration of **senior officers** for financial year 2016.
Noteworthy milestone: Comparative analysis of director remuneration and supervision of the consistency of the Group's remuneration model.	

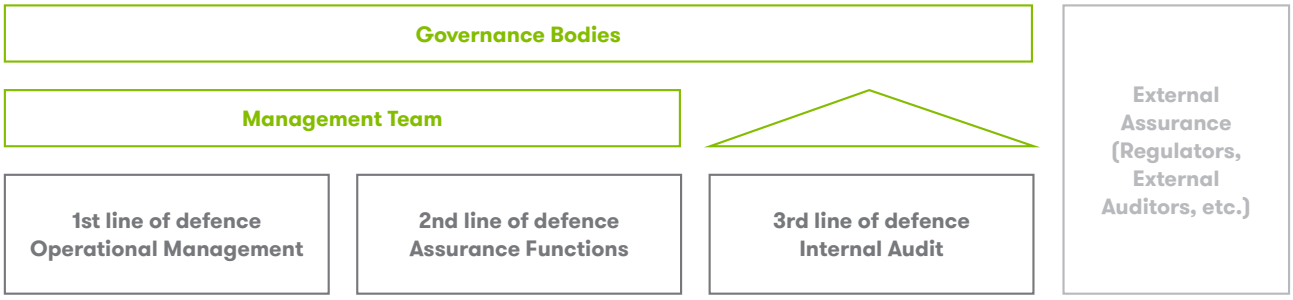
Corporate governance	
Ongoing efforts to identify and implement best corporate governance practices are key pillars for the creation of sustainable value.	Formalisation of the ***Mission, Vision, and Values*** **of the Iberdrola Group** as a integral norm of the Corporate Governance System.
	Making various improvements designed to **encourage shareholder participation in the General Shareholders' Meeting.**
	Successive amendments to the **Corporate Governance System** and approval of an ***Anti- Corruption and Anti-Fraud Policy.***
	Coordination and supervision of the **process of evaluation of the Board of Directors.**
	Review of **contacts** made by the chairman and the management team with **key market players.**
Noteworthy milestone: Ongoing improvement of the Corporate Governance System and inclusion of the *Mission, Vision, and Values* of the Iberdrola Group within the Company's set of rules	

Social responsibility and sustainability	
The Board is committed to maintaining leadership in the fight against climate change, the development of clean energy, and respect for the environment, as well as in the maximisation of the social dividend.	Amendment of various **social responsibility and sustainability policies** and formalisation of the commitment adopted by Iberdrola in the **fight against climate change.**
	Introduction of new measures to promote **gender equality** and the **reconciliation between professional and personal life.**
	Approval of incentives to strengthen the **Group's commitment to innovation** and to a **healthier and more egalitarian and just society.**
	Monitoring the **Group's activities in the area of sustainability** and the alignment thereof with the **main reference bodies.**
Noteworthy milestone: Formalisation of commitments relating to the fight against climate change.	

5.2 Three Lines of Defence

Three lines of defence model

The Internal Control System of Iberdrola and the companies of its Group is configured by reference to international best practices. It is based on a guarantee combined around three lines of defence, providing a comprehensive view of how the different parts of the organisation interact in an effective and coordinated manner, increasing the efficiency of the processes for management and internal control of the entity's significant risks.



Based on the document *"Guidance on the 8th EU Company Law Directive, article 41"* ECIIA/FERMA, September 2010.

1st line of defence
Operational Management

As the first line of defence, the management team and the professionals of Iberdrola and its Group are the direct managers of the risks of the entity. Thus, the Management of the Company is responsible for maintaining effective control and implementing procedures to control risks on a continuous basis.

Internal Control Objectives (COSO. May 2013)

Operations objectives- Pertain to the effectiveness and efficiency of the entity's operations, including operational and financial performance goals, and safeguarding assets against loss.

Reporting objectives- Pertain to internal and external financial and non-financial reporting and may encompass reliability, timeliness, transparency, or other terms as set forth by regulators, recognised standard setters, or the entity's policies.

Compliance objectives- Pertain to adherence to laws and regulations to which the entity is subject.

Significant Risks Facing Iberdrola's Primary Businesses / pages 48, 52, 56

2nd line of defence
Assurance Functions

As the second line of defence, certain functions provide the foundation for the entity's internal control system, proposing guidelines to the Board of Directors and monitoring how the first line of defence implements them.

The primary assurance functions within Iberdrola, within their respective areas of responsibility, are: (i) the Group's Risk Division, within the framework of its functions within the Comprehensive Risk Control and Management System; (ii) the Compliance Unit, which is responsible for the Compliance System; and (iii) the Internal Control Division, which is part of the Administration and Control Division, within its duties relating to the internal control and risk management systems in relation to the preparation of financial information (ICFRS).

Iberdrola adopts the three lines of defence model to ensure effective and integrated management of its Internal Control System.

Comprehensive Risk Control and Management System / page 86

Compliance Unit / page 90

3rd line of defence
Internal Audit

The Internal Audit function, as the third line of defence, proactively ensures the proper functioning of the internal control, risk management, and governance systems, systematically auditing the first and second lines in the performance of their respective duties of management and control.

To ensure its independence, the director of the Internal Audit Area reports hierarchically to the chairman of the Board of Directors and functionally to the Audit and Risk Supervision Committee. The Internal Audit divisions of the various country subholding companies have this same positioning, and are coordinated under the framework of the *Basic Internal Audit Regulations* of Iberdrola, S.A. and its Group.

The 2016 annual activities plans of the Internal Audit Area Division of Iberdrola, S.A. and of the Internal Audit divisions of the Group, with a risk-based focus looking to support the achievement of the Company's goals, responded to the requirements established by the Audit and Risk Supervision Committee of Iberdrola, S.A. and the respective Audit and Compliance Committees of the country subholding companies, and included work for the senior management and the rest of the organisation, including:

- Annual audits of compliance with the *Code of Ethics* at Iberdrola, S.A. and at each of the country subholding companies.
- Audits of the process for determining and monitoring the limits and indicators of the Risk Policies of the Group's businesses.
- Half-yearly reviews of the operation of the most critical controls of the Internal Control Over Financial Reporting (ICFR) System, as well as reviews of the various cycles of preparation of the financial information of Iberdrola, S.A. and the various companies of the Group, within the framework of the general goal of reviewing the entire ICFR over a period of 3 years.

Continuing with the commitment made in 2005, Internal Audit submits to an exhaustive review every five years of compliance with professional internal audit rules (called a Quality Assurance Review) by the Global Institute of Internal Auditors. During the last review in 2015, the certification of Iberdrola, S.A. and of ScottishPower was renewed and the scope of the certification was expanded to include Iberdrola España and Avangrid.

Furthermore, since Internal Audit obtained ISO 9001 certification in 1999, it has continued to renew it through the current version ISO 9001-2008, which is expected to be updated to version ISO 9001-2015 in 2017. This ensures that all of the Group's internal auditors perform duties under the same framework and that such framework is aligned with the international professional rules of the function.

Basic Internal Audit Regulations of Iberdrola, S.A. and its Group
Approved by the Board of Directors of Iberdrola, S.A. upon a proposal of its Audit and Risk Supervision Committee (updated on 15-Dec-2015).
Defines the nature, as an independent internal unit, and establishes the regulation, competencies, powers, and duties of Internal Audit, among other things.
Establishes the framework of relations with: i) the Board of Directors, its Chairman and Committees; ii) the Internal Audit divisions of the other companies of the Group; and iii) the rest of the organisation.
Disseminates the knowledge of the Internal Audit function among the professionals of the Group.
Serves as a reference for the management model and the quality system of the Internal Audit Area of the Company and the Internal Audit divisions of the other companies of the Group.

External assurance

Regulatory bodies and other entities external to the organisation play a significant role in the general structure of governance, internal control, and risks of Iberdrola, especially in the regulated businesses. The regulators establish requirements intended to strengthen the controls of an organisation and perform a function of independent and separate monitoring, and the auditors provide assurance regarding the true and fair view of the entity's financial information. In this regard, the powers of the Audit and Risk Supervision Committee of Iberdrola, S.A. and the Audit and Compliance Committees of the country subholding companies include ensuring the preservation of the independence of the auditors in the performance of their duties.

Regulatory Environment / page 44

Audit Report on the Consolidated Financial Statements

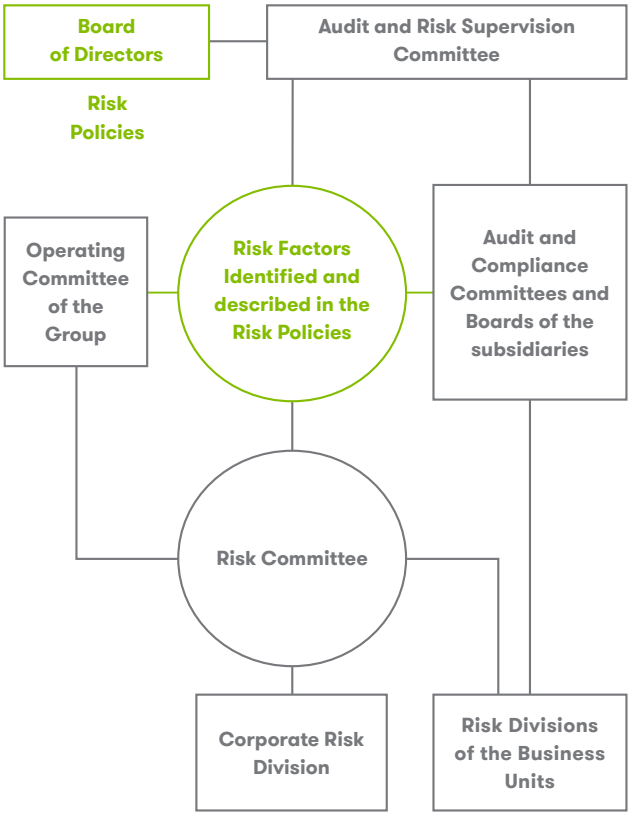
5.3 Risks

The essential elements of proper risk management are foresight, independence, and commitment to the business objectives of the Group.

Commitment of the Board of Directors and of senior management

Iberdrola's Board of Directors and senior management is strongly committed to and engaged in the management of the Group's risks:

- **Ex-ante:** acceptable levels of risk tolerance are reviewed and approved on an annual basis through risk policies and limits that establish the qualitative and quantitative risk appetite at the Group level and at each of the main businesses.
- **Ex-post:** periodic monitoring of significant risks and threats and the various exposures of the Group, as well as of compliance with the approved risk policies, limits, and indicators.



Comprehensive Risk Control and Management System

The *General Risk Control and Management Policy* of the Group approved by the Board of Directors establishes the mechanisms and basic principles for appropriate management of the risk/opportunity ratio, at a risk level that makes it possible to:

- Attain strategic goals with controlled volatility.
- Provide the maximum level of assurance.
- Protect the results and reputation of the Group.
- Defend the interests of the Stakeholders and guarantee the business stability and financial strength of the Group.

At the operational level, the Comprehensive Risk Control and Management System is structured around a Risk Committee and an independent specialised Risk Division that analyses and quantifies the risks within the main businesses of the Group.

Duties of the Risk Division

Centralised Approach – Active Management

Credit risk. Approval of counterparties and limits and/or establishment of admission criteria in order to minimise credit losses within the Group.
Market risk. Approval of detailed limits in order to delimit the effects of volatility in the markets in which the Group operates.

ERM* Approach – Integrated Vision

Ensure that the Group's significant risks are adequately identified, measured, managed, and controlled and that they are periodically reported to the various committees.
Instruments and reports:
– Risk policies and risk limits and indicators.
– Quarterly report on key risks.

Operational risk is managed through insurance and participation in the Group's information technology governance and cybersecurity committees.

(*) ERM: Enterprise Risk Management.

Risk policies and limits of the Iberdrola Group

The Group's Risk Policies are approved by the Board of Directors on an annual basis.

The country subholding companies of the various countries develop and approve their own policies through their Boards of Directors.

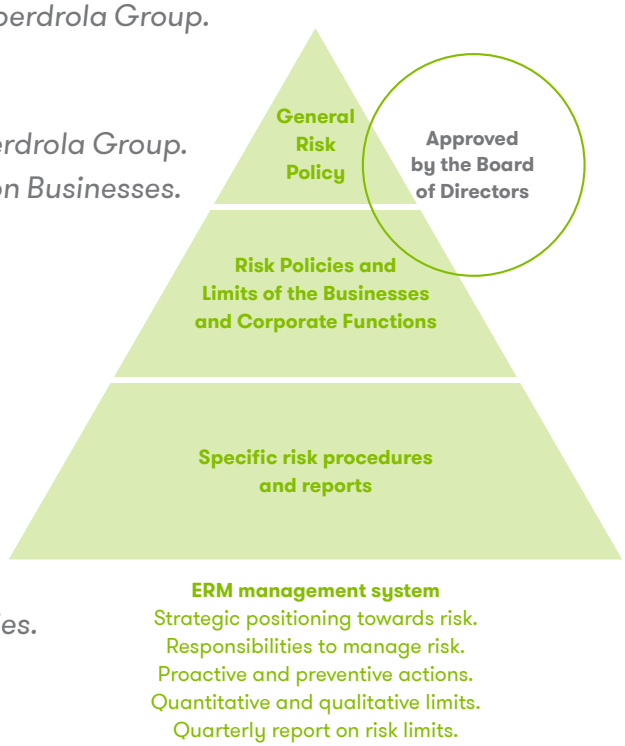
General Risk Control and Management Policy.

Specific risk policies for the various businesses of the Group:

- *Risk Policy for the Liberalised Businesses of the Iberdrola Group.*
- *Risk Policy for the Renewable Energy Businesses of the Iberdrola Group.*
- *Risk Policy for the Networks Businesses of the Iberdrola Group.*
- *Risk Policies for the Engineering and Construction Businesses.*
- *Risk Policies for the Real Estate Businesses.*

Corporate risk policies:

- *Corporate Credit Risk Policy.*
- *Corporate Market Risk Policy.*
- *Operational Risk in Market Transactions Policy.*
- *Insurance Policy.*
- *Investment Policy.*
- *Financing and Financial Risk Policy.*
- *Treasury Share Policy.*
- *Risk Policy for Equity Interests in Listed Companies.*
- *Reputational Risk Framework Policy.*
- *Procurement Policy.*
- *Information Technologies Policy.*
- *Cybersecurity Risk Policy.*



Principal risk factors of the Iberdrola Group

The Group is exposed to various risks inherent in the different countries, industries, and markets in which it operates, and which may prevent it from achieving its objectives and implementing its strategies. These risks, which are set out in the risk policies, are:

Credit risks: possibility of contractual breach by a counterparty, causing economic or financial losses.

Market risks: exposure to volatility in variables like prices of electricity and other energy commodities, exchange rate, interest rate, etc.

Business risks: deriving from the uncertainty of the behaviour of variables intrinsic to the business, characteristics of demand, climatology, etc.

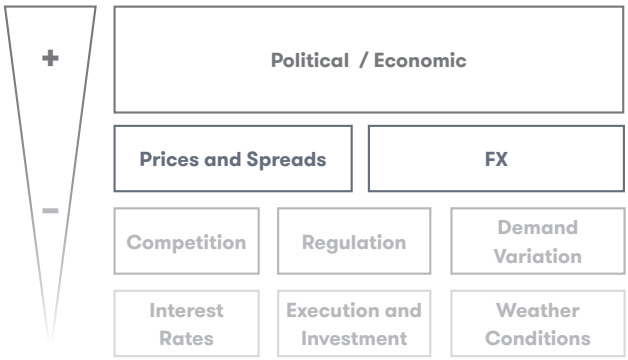
Operational, Technological, Environmental, Social, and Legal Risks: economic losses resulting from inadequate internal procedures, technical failures, human errors, etc.

Political and regulatory risks: coming from regulatory changes made by the regulators that can affect remuneration of the regulated businesses, environmental or tax provisions, etc.

Reputational risks: potential negative impacts on the Company arising from performance below the expectations of its Stakeholders.

Corporate governance risks: those that endanger the corporate interest and strategy of the Company.

Integrated Risk Analysis - Plan 2016-2020



Main sources of risk

The political/economic uncertainty of the countries in which the Iberdrola Group maintains a presence, which is difficult to quantify, represents the main source of risk due to its impact on key variables such as exchange rate, interest rate, regulatory changes, etc.

The prices of commodities and their impact on electricity prices represent the second source of risk for the Group.

Impact on Ebitda by business

Due to its intrinsic nature, despite representing only 20% of Ebitda, the Wholesale and Retail Business holds the greatest proportion of at-risk Ebitda for the period 2017 – 2020, amounting to between 4.5 and 5.5%. The various risk profiles of the businesses are as follows:

Wholesale and Retail Business: The main variable that affects the Group's results is the price of electricity, which is closely correlated to the price of the fuel used to produce it. These risks are mitigated by offsetting at-risk positions between wholesale and retail activities, by diversifying purchase/sale agreements and the specific clauses thereof, and by trading in derivatives.

Renewables Business: Risks deriving from the Renewables Business, mainly the uncertainty of wind resources and the established remuneration systems, are mitigated via:

- The wide geographical spread of the large number of available windfarms.
- The various regulatory frameworks aimed at fostering the development of renewable energy, based on formulas that can include premiums, green certificates, tax deductions, or regulatory tariffs that allow investors to obtain an appropriate and reasonable return.

Regulated Businesses: The regulation applicable to the Networks Businesses of each of the countries in which the Group operates establishes periodically updated frameworks that ensure a reasonable and predictable return. These frameworks provide incentives and penalties for efficiency, quality of service, and potentially for management of bad debts, with a minor and insignificant overall impact.

In Mexico, the Iberdrola Group sells most of its electricity production through long-term, fixed-price contracts to the Federal Electricity Commission (*Comisión Federal de Electricidad*) (CFE), and the rest of its production to private customers at prices indexed to the CFE rate.

Risk factors and mitigation measures

Greater detail is offered below regarding the main risk factors for the **income statement of a specific financial year** and the main measures of mitigation to address them.

The activities carried out by the Group are subject to various market, business, credit, operational and regulatory risks, arising out of the uncertainty of the main variables that affect them, including: changes in the price of commodities; changes in hydroelectric and wind production (both internal and external); change in demand for electricity and gas; and availability of the plants.

Changes in the price of electricity	The main variable affecting the results of the Group's Wholesale and Retail Businesses and Renewables Businesses as regards market prices is the price of electricity, which bears a close correlation to the price of fuel and applicable emission rights, required to produce such electricity.			
Changes in the prices of energy commodities	Offsetting at-risk positions between wholesale and retail activities allows for a large reduction in the Group's market risk; the remaining risk is mitigated via diversification of purchase/sale agreements and the specific clauses thereof, and by trading in derivatives.			
Profit margin	The Group's Renewables Businesses preferentially sell their energy at: i) regulated tariff; or ii) fixed price via long-term power purchase agreements (PPAs). The remaining market exposure of the Spain and United Kingdom Renewables Businesses is transferred to the Wholesale and Retail Business of such countries.			
	Possible impact of a 5% change in the price of electricity and/or of energy commodities and CO_2	Wholesale and Retail Business – Spain – United Kingdom – Mexico	● Includes the exposure of the Spain Renewables Business (windfarms prior to 2014) ● Includes the exposure of United Kingdom Renewables Business (component of energy farms subject to ROCs). ● Long-term agreements with the CFE(1) have no market risk	
		United States Renewables Business	● Includes 33% risk for windfarms without long-term sales agreements	
Change in hydroelectric resources Spain	In the long term, wet years compensate for dry years. In the short-to-medium term, the storage capacity of hyperannual reservoirs and the Group's portfolio of power plants mitigate the level of volatility of the annual results.		*Possible impact of lower hydroelectric production(*)* *(*) Corresponding to dry year, followed by two dry or semi-dry years.*	● Spain Wholesale and Retail Business
Change in wind resources of the Group	The geographical spread of the Iberdrola Group's windfarms mitigates the annual volatility of wind production at the Group level and its possible impact on results for a specific year.		*Possible impact of lower wind production*	● Group Renewables Business
Change in demand	Higher or lower growth in annual demand has a moderate short-term impact on the Group's results, given the characteristics of the Group's generation facilities and the structure of the long-term power purchase agreements (PPAs).		*Possible impact of 1% reduction in demand*	● Spain Wholesale and Retail Business ● United Kingdom Wholesale and Retail Business
Change in interest rate	In order to mitigate this risk, the Iberdrola Group maintains a fixed-rate and variable-rate debt structure, based on the structure of its revenues and the sensitivity thereof to changes in interest rates.		*Possible impact on financial cost of +25 basis point increase*	● Group financial cost
Change in exchange rate	The Group mitigates this risk by taking on debt and carrying out all its financial flows in the functional currency corresponding to each company, whenever possible and economically efficient, managing its open positions with financial derivatives. The risk associated with the translation of expected results from subsidiaries in a currency other than the euro is closed out annually.		*Possible impact on financial cost of 5% increase in currency*	● Group financial cost
Credit risk	This risk is appropriately managed and limited based on the type of transaction and the credit standing of the counterparties. As regards credit risk corresponding to accounts receivable for retail activity, late payments/defaults have been kept to moderate levels, close to 1% of the total invoicing for this activity.			
Operational risk	These risks are mitigated by making the necessary investments, applying operation and maintenance procedures and programmes (supported by quality systems), planning appropriate training and skills development for staff, and finally by obtaining appropriate casualty and civil liability insurance.			
Regulatory and political risk	The Group is subject to laws and regulations on tariffs and other regulatory aspects of its activities in the countries in which it does business. The introduction of new laws/regulations or amendments to existing ones could adversely affect operations, annual results and the financial value of the businesses of the Group.			

(1) CFE: Federal Electricity Commission (Comisión Federal de Electricidad)

● <15 M€ ● 15-50 M€ ● >50M€

5.4 Ethics and Social Responsibility

Compliance Unit

Iberdrola has a Compliance Unit, as a collective, internal, and permanent body linked to the Corporate Social Responsibility Committee of the Board of Directors.

There are also Audit and Compliance Committees at the level of each country subholding company and/or head of business company. Their duties including promoting a culture of ethical behaviour and zero tolerance for the commission of unlawful acts or fraud.

Iberdrola's Compliance System is made up of the substantive rules, formal procedures, and major activities within the Group to encourage the organisation to act in accordance with applicable ethical principles and legal provisions, through a set of procedures and actions designed to prevent, detect, and react to irregular actions, fraud, or actions contrary to the Iberdrola Group's Code of Ethics or applicable laws and regulations.

Main activities in the area of ethics and compliance

Various programmes and control mechanisms for different regulatory environments are implemented at the Group within the framework of the Compliance System.

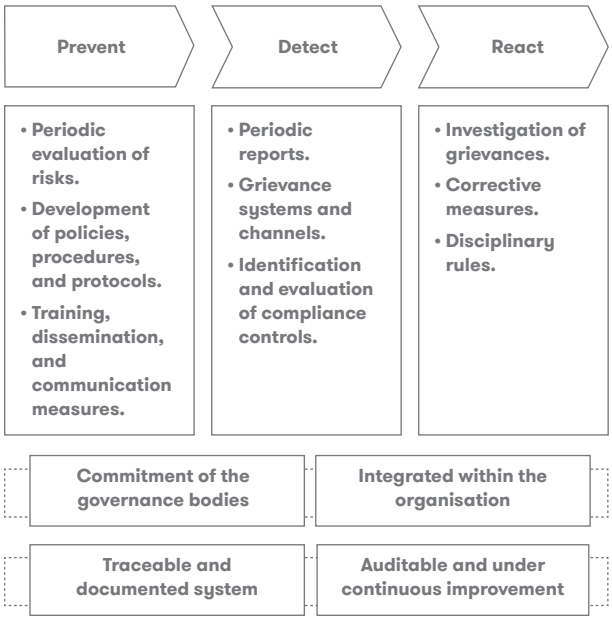
These include the crime prevention programmes, which are implemented within the framework of the process of reviewing and adapting the duties imposed by the Spanish Criminal Code, without prejudice to the legal provisions applicable in any other jurisdiction in which the Company does business, as well as the programme for compliance with the *Code of Ethics*, which includes specific training and communication plans for all professionals of the Group, among other things.

Iberdrola also has a Compliance Unit Office (the "Office"), managed by the Compliance Director and made up of members representing the various areas that form the Compliance System. All functions that are entrusted with powers relating to compliance are coordinated through the Office, which ensures the effective functioning of the Compliance System as a whole.

Powers of the Unit

The Compliance Unit has powers related to the *Code of Ethics*, the *Anti-Corruption and Anti-Fraud Policy*, the *Crime Prevention Policy*, the *Internal Regulations for Conduct in the Securities Markets*, legal provisions regarding the separation of activities, and all other powers that may be entrusted thereto by the Corporate Social Responsibility Committee or the Board of Directors of the Company or that are established in Iberdrola's Corporate Governance System.

The Iberdrola Group's compliance system



Principal awards

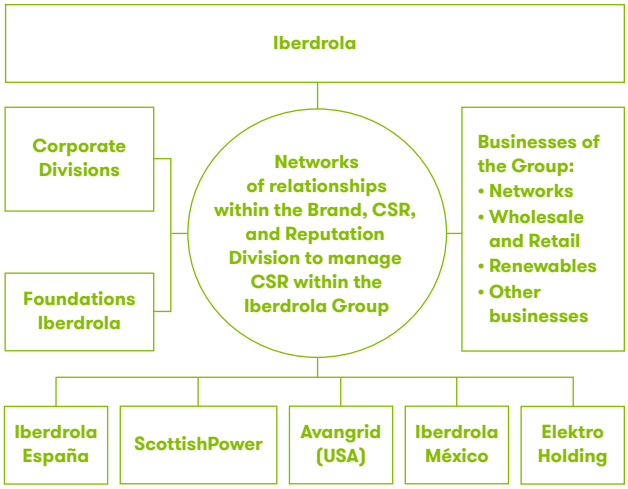
Iberdrola has been chosen for the fourth consecutive year as one of the most ethical companies in the world, according to the *World's Most Ethical Companies* ranking prepared by the *Ethisphere Institute*. This

Iberdrola considers its corporate values to include ethical principles, good corporate governance and transparency, and social commitment.

ranking recognises organisations that are committed to ethical leadership and behaviour at the corporate level.

NYSE Governance Services, together with the Ethisphere Institute, also awarded the "Compliance leader verification" certification to Iberdrola in 2015.

Organisation of social responsibility within the Group



The Iberdrola Group has an organisational structure designed to promote and manage responsible actions with its Stakeholders.

The Corporate Social Responsibility and Reputation Committee and the CSR and Reputation Committees of the country subholding companies coordinate the balanced development of social responsibility within the Iberdrola Group. The CSR Committee of the Board of Directors performs the duties of supervision within its purview.

CSR plans of the Group

2015 saw the approval of the *CSR 2015-2017 Plan* for the Iberdrola Group, covering five areas of activity (dialogue with local communities, measurement tools, etc.), with a focus based on the various Stakeholders.

The CSR Plan is made up of various programmes, projects, and monitoring indicators, both cross-sectional for all involved organisations of Iberdrola as well as specific for each business or corporate area of the Company.

Monitoring of the Plan is analysed on a half-yearly basis by the Corporate CSR and Reputation Committee and by the CSR Committee of the Board of Directors.

External awards

2016 world leader in utilities sector, with 91 points. Selected in all prior years.	Member of Dow Jones Sustainability Indices In Collaboration with RobecoSAM
Selected in 2017. Only Spanish electric company among the 100 most sustainable companies in the world.	GLOBAL100
First utility with nuclear assets to meet standards, selected for 6 years in a row.	FTSE4Good
A-List, the highest category.	CDP A LIST 2016 CLIMATE
Iberdrola a sponsor.	GLOBAL ROUNDTABLE ON CLIMATE CHANGE
Iberdrola selected AAA.	MSCI
Iberdrola selected.	NYSE EURONEXT
Qualified as "Gold Class" in the electricity sector.	ROBECOSAM Sustainability Award Gold Class 2017
First Spanish utility and fifth worldwide.	2016 GREEN Newsweek RANKINGS
Leader among Spanish utilities: electricity, gas, and water.	merco
Iberdrola selected	FORTUNE GLOBAL 500
Iberdrola among top 25 scoring companies.	InfluenceMap

Iberdrola shareholders during a virtual reality demonstration at Iberdrola Tower

© Antonio Triviño

6.

About this Report

This report, which Iberdrola directs to both its shareholders and investors and all of its Stakeholders, has been prepared under the innovative "integrated report" concept, and constitutes one more example of the Group's desire to be innovative in the area of transparency.

6.1 About this Report

Integrated report

- This report has been prepared in accordance with the reporting framework published by the International Integrated Reporting Council (IIRC) and in accordance with the recommendations thereof, taking into consideration the individual and consolidated financial statements of the Company formulated by the Board of Directors, audited and pending approval by the shareholders at the General Shareholders' Meeting of Iberdrola.
- A multi-disciplinary team made up of corporate businesses and areas of the Group was created in order to provide a complete view of the Company, its business model, the challenges and risks it faces, and its social, environmental, financial, and governance performance. The participating organisations guarantee the completeness of the information included.
- This content of this document has been reviewed by the Company's Operating Committee. It has also been reported on favourably by the Corporate Social Responsibility Committee, which has submitted the report to the Board of Directors for its final consideration. Based on all of the foregoing, the Board of Directors has approved this *Integrated Report February 2017* at its meeting of 21 February 2017.

Information boundaries

- The information submitted covers Iberdrola and its subsidiaries and affiliates. The information boundaries are defined in the Group's consolidated annual financial statements and *Sustainability Report*.
- The Group's performance in recent years is connected to external corporate transactions and internal management decisions, which the reader should take into account in order to properly interpret this report. These transactions and activities are described in the Group's public information, the following being particularly noteworthy:
  - The application of IFRS 11 to the 2013 to 2016 figures, which mainly affects Brazil.
  - The integration of UIL Holdings Corporation into Iberdrola USA (December 2015), which is now called Avangrid, a company listed on the New York Stock Exchange and the country subholding company of the Group in the United States.

Material aspects identified

- Iberdrola has channels of communication and dialogue with its Stakeholders, developed in accordance with the principles of the AA1000 Assurance Standard, as described in detail in the *Stakeholder Relations Policy and in the Sustainability Report*.
- The Company also performs materiality analyses that help identify matters of significance to its Stakeholders, bringing to light particularly sensitive financial, environmental, or social issues related to the business in the various communities and geographic areas in which the Group operates.
- The contents of this report have been selected by taking into account the existing channels for dialogue as well as the materiality analyses and the framework defined by the IIRC for this kind of information.

◉ **Social and Relational Capital / page 72**

This report has been prepared in accordance with the reporting framework published by the International Integrated Reporting Council (IIRC).

Internal and external verification

- This report has been subject to a process of internal verification, by means of a limited review performed by the Management of the Internal Audit Division of Iberdrola.
- Although it has not been subject to a process of independent external verification, a significant portion of the information contained herein relating to financial year 2016 and to previous years comes from annual financial reports and sustainability reports, all of which have been the subject of an external audit or verification for which the respective certificates are available. The rem aining information comes mainly from other reports or public presentations made by the Company.

Legal disclaimer with respect to forward-looking statements, errors, and omissions

- This document contains information and forward-looking statements regarding Iberdrola. Such statements include projections and estimates and their underlying assumptions, statements regarding plans, objectives, and expectations with respect to future transactions, investments, synergies, products, and services, and statements regarding future performance. Forward-looking statements are not historical facts and are generally identified by the words "expects", "anticipates", "believes", "intends", "estimates", and similar expressions.
- In this regard, although Iberdrola believes that the expectations reflected in such statements are reasonable, investors and holders of Iberdrola shares are cautioned that forward-looking information and statements are subject to risks and uncertainties, many of which are difficult to predict and generally beyond the control of Iberdrola, which risks could cause actual results and developments to differ materially from those expressed in, or implied or projected by, the forward-looking information and statements. These risks and uncertainties include those identified in the documents sent by Iberdrola to the National Securities Market Commission *(Comisión Nacional del Mercado de Valores)* and which are accessible to the public.
- Forward-looking statements are not guarantees of future performance and have not been reviewed by the auditors of Iberdrola. You are cautioned not to place undue reliance on the forward-looking statements, which speak only as of the date they were made. All forward-looking statements reflected in this report are subject to the warnings provided and are based on information available as of the date of approval hereof. Except as required by applicable law, Iberdrola does not undertake any obligation to publicly update its forward -looking statements or to revise any forward-looking information, even if new data are published or new events occur.

Integrated Report, February 2017
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Spain
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IBERDROLA

OCS-A 0501 MASS USA

VINEYARD WIND

Vineyard Wind

Attachment 5.6-5

Iberdrola SA Accounts (2015)

Integrated Report / February 2016

IBERDROLA

The energy that drives us

- **Comfort for homes**
- **Sustainability for the future**
- **Competitiveness for companies**
- **Innovation for Infrastructure**

Our goal is to offer a reliable, high-quality, and environmentally-friendly energy supply, in order to:

- Improve the well-being of people.
- Drive the economic and social development of the communities in which we are present.
- Create sustainable value for our shareholders, employees, customers, and suppliers.

Mission

We create **value** in a **sustainable** way and we are committed to **social return**

Vision

We want to be one global energy **lider** and create a **better future** for **people** with the support of our **human team**

Values

The twelve **values inspire** and **guide** the **group's strategy** and all of its **actions**

IBERDROLA

Race in the Whitelee
wind farm
/ United Kingdom

IBERDROLA

Iberdrola's Public Information

Iberdrola makes all of its public information available to our shareholders, employees, customers, suppliers, and society in general to provide trustworthy and relevant information regarding the Company's performance and its strategic lines for the coming years.

Annual information

Integrated Report.
Prepared based on the recommendations of the International Integrated Reporting Council (IIRC).

Financial Report.
Prepared according to international financial reporting standards and externally audited.

Corporate Governance Report.
Prepared according to the form provided by the National Securities Market Commission of Spain.

Sustainability Report.
Prepared according to the Global Reporting Initiative (GRI) guidelines and externally assured.

Activities Report of the Consultative Committees of the Board of Directors.
Prepared according to Iberdrola internal standards.

Director Remuneration Report.
Prepared according to the form provided by the Spanish National Securities Market Commission.

Report on Compliance with Legal Provisions on the Separation of Regulated Activities.
Prepared according to Iberdrola internal standards.

Report on Related-Party Transactions with Directors and Significant Shareholders.
Prepared according to Iberdrola internal standards.

Annual Report on the Application of the Shareholder Engagement Policy and the Policy regarding Communication and Contacts with Shareholders, Institutional Investors, and Proxy Advisors.
Prepared according to Iberdrola internal standards.

Report on the Independence of the Auditor in relation to the Audit Report for Financial Year 2015.
Prepared according to Iberdrola internal standards.

Additional information

Quarterly Results Report.
IBE Watch Fact Sheet.
Quarterly Shareholder Bulletin.
Innovation Report.
Biodiversity Report.
Greenhouse Gas Report.

Information on the corporate website www.iberdrola.com

About Us
Reputation and Sustainability
Press Room
Shareholders and Investors
Suppliers
Customers
Networks

Access the annual reports for financial year 2015 and supplementary documentation regarding the Iberdrola group by scanning the corresponding QR code using your smart phone or tablet.

⦿ This icon refers to related information.
It also indicates the existence of other specific reports where more information of interest can be accessed.

Integrated Report / February 2016

IBERDROLA

Table of Contents

1. Iberdrola Today

Letter from the Chairman & CEO 4

1.1 Iberdrola Today 8

1.2 Company Performance 9

1.3 Key Figures 10

1.4 Presence by Areas of Activity 12

2. Business Model and Strategy

2.1 The Future of Energy 26

2.2 Business Model 28

2.3 Iberdrola, a Different Company 29

2.4 Asset Management 30

2.5 Value Chain 32

2.6 Strategic Foundations 34

2.7 Capital and Business Relationship 37

2.8 Comparative Results and Awards 38

3. Iberdrola's Primary Businesses

3.1 Regulatory Environment 42

3.2 Networks 44

3.3 Wholesale and Retail 49

3.4 Renewables 52

3.5 Supply Costs 56

Notes:
— The company Iberdrola, S.A., parent company of the Iberdrola group, is referred to as "Iberdrola" or the "Company" in this report.
— The figures included in this translation follow the customary English convention, with figures in thousands separated by a comma (,) and decimals indicated by a full stop (.).
— €M: millions of euros; $M: millions of dollars.

4.

Our Assets

4.1
Financial Capital 60

4.2
Manufactured Capital 62

4.3
Intellectual Capital 64

4.4
Human Capital 66

4.5
Natural Capital 68

4.6
Social and Relationship Capital 70

5.

A Framework of Trust

5.1
Corporate Governance Model 76

5.2
Three Lines of Defence 80

5.3
Risks 82

5.4
Ethics and Social Responsibility 84

6.

About this Report

6.1
About this Report 88

Letter from the Chairman & CEO

Ignacio S. Galán. Chairman & CEO of Iberdrola
© Adrián Ruiz

"In anticipation of the energy transition, Iberdrola has committed to sustainable solutions that require greater electrification of the global economy".

Dear friends:

For the third consecutive year, I am pleased to present to you Iberdrola's Integrated Report, which provides a balanced reflection of the group's performance, reflects the most significant aspects affecting the performance of the company, and presents its strategic lines for the coming years.

In the near future, Iberdrola will be dealing with an energy scenario characterised by strong growth in global energy demand (30% increase by 2040, according to forecasts by the International Energy Agency), which must be supplied with clean and efficient technologies to meet global commitments on reducing emissions.

Although it represents only 25% of global greenhouse gas emissions, the electricity sector will play a decisive role in efficiently facing these challenges because of its enormous technological potential to contribute to decarbonising the economy, thanks to renewable energy. The forecasted 70% growth in electricity demand by 2040 is also explained by factors like the significant increase in the global population, heading towards 10 billion inhabitants by the middle of the century, mainly concentrated around urban areas, or the fact that more than 1 billion people still lack access to electricity supply.

In anticipation of the energy transition, Iberdrola has committed to sustainable solutions that require greater electrification of the global economy: more clean energy, more storage capacity, more backup power, more and smarter grids, and more digitisation.

Iberdrola will continue in this environment to develop its sustainable business model, which is focused on growth in regulated businesses and clean energy; geographic diversification in countries with high credit ratings; an increase in operational efficiency; the financial strength to exploit growth opportunities in the markets in which it does business; sustainable remuneration for shareholders; and a firm social commitment that seeks the creation of value for all of our Stakeholders.

A new growth phase

Outlook 2016-2020, which was recently presented by Iberdrola, establishes a net investment programme of 24,000 million euros, of which 17,000 million is for investments in growth. Of that total amount, the company already has investments of approximately 22,000 million euros in projects under construction or committed to in the United Kingdom, the United States, Mexico, Spain, and Brazil.

88% of the investments planned during the next five years will be focused on regulated businesses or long-term contracts, mainly in the areas of networks and renewables, which provide the safety, stability, and visibility that characterise our business model and which should generate 81% of the group's Ebitda by 2020.

By line of business, Iberdrola will allocate 46% of total investments to the areas of transmission networks and electric power distribution, 33% to renewable energy, and 9% to regulated wholesale generation. 12% of the total will be allocated to the traditional wholesale and retail business.

At the same time, we will continue improving operational efficiency thanks to progress in automation and digitisation in all businesses and processes, maintaining a solid financial position that will allow us to exploit opportunities for growth in our markets.

Based on the foregoing, we expect to obtain average annual growth of 6% in both gross operating profit and net profit of the group during 2016-2020.

This forecasted growth will allow us to increase shareholder remuneration in an upwardly sustainable manner, in line with results, with a payout of around 65-75%. Iberdrola will also maintain the flexible dividend formula used in recent years, keeping the current number of shares stable through buy-backs and retirements of shares as part of this formula.

This strategy will be supported by the Company's traditional values and in strict compliance with the principles of transparency and business ethics set out in our Corporate Governance System, which incorporates the main international recommendations in this field.

Firm commitment to sustainability

These strategic projections reaffirm our ongoing commitment to economic and social development in the areas in which we are present, in addition to the well-being of their citizens. We will continue to act as an engine of growth, wealth, and employment with our business activities, our investments, and our procurement from thousands of suppliers.

Iberdrola will continue to encourage the use of clean energy and looking after the environment. Although our emissions per kWh generated are already some 30% below the average for the European electricity sector, we have set the goal of an additional 50% reduction by 2030 and to be carbon neutral by 2050. And we are headed on the right path, given that by the end of last year, emissions intensity had already dropped 25% compared to 2007, with 63% of our current installed capacity being completely emissions-free.

"We will continue to act as an engine of growth, wealth, and employment with our business activities, our investments, and our procurement from thousands of suppliers".

The achievement of these goals is closely linked to our wager on technological innovation, which will continue to be a priority in order to maintain our lead in the development of new products, services, and business models that are transforming the industry. In 2015, we allocated 200 million euros to R&D, mainly to initiatives relating to clean energy, offshore wind, smart grids, digitisation, and new technologies, which will allow Iberdrola to continue meeting the energy needs of its customers, offering them new products and services to improve their well-being and quality of life.

This wager on innovation, which encompasses the entire Company, pushes us to continue strengthening the ongoing high-quality training of our workforce and to contribute to training new generations through the international scholarship programme, to which we have allocated approximately 11 million euros and by which more than 500 young people have engaged in masters' and postgraduate studies at the best universities of the countries where we do business.

In the coming years, we will continue with the "Electricity for all" programme to keep bringing electric power to people without it in emerging and developing countries. Under this programme, we have already contributed to almost a million and a half people being able to access electricity in various countries of Latin America and Africa.

Finally, in the area of social-welfare action, we will strengthen our activities supporting vulnerable groups, mainly through the Social Assistance Programme and the Corporate Volunteering Programme. And we will continue to encourage actions in the area of art and culture as a part of our corporate social responsibility, supporting the creation, preservation, and dissemination of our historical artistic heritage.

Drone inspection of wind farm / Spain

1.

Iberdrola Today

1.1 Iberdrola Today

Our Activities

- Production of electricity from renewable and conventional sources.
- Purchase/sale of electricity and gas on wholesale markets.
- Transmission and distribution of electricity.
- Supply of electricity, gas, and related energy services.
- Other activities, mainly linked to the energy sector.

Iberdrola is one of the leading electric companies in the world.

What We Are

The process of internationalisation carried out in recent years has led Iberdrola to be one of the leading electric companies, and among the largest utilities in the world by stock market capitalisation.

The corporate and governance structure is described in chapter 5.1 of this report and consists of:

- Iberdrola, as a holding company.
- Country subholding companies in the 5 main geographic areas of activity.
- Head of business companies reporting to the country subholding companies.

Presence focused on the Atlantic area

Iberdrola carries out its activities mainly in the five countries of the Atlantic area: Spain, the United Kingdom, the United States, Mexico, and Brazil.

Iberdrola group 2015 data

46,471
MW
Installed capacity

214,226
GWh
Electric power distributed [1]

360,000
People[3]
Indirect and induced employment

14,787
MW
Renewable installed capacity

33.8
Million
users

11,630
€M Tax contribution (€M 5,520 direct + €M 6,110[3] indirect and induced)

136,794
GWh
Net production

30,938
People[2]
Direct employment

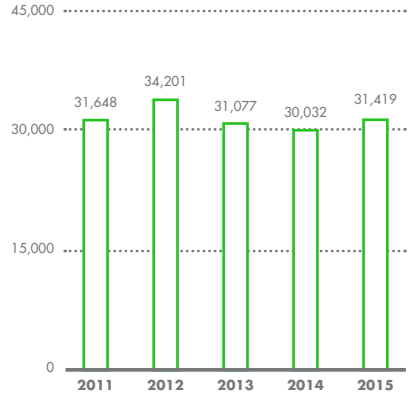
7,300
M€
Procurement awarded

3,223
M€
Investments

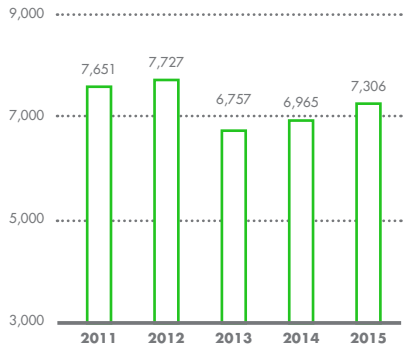
(1) Takes into account 100% of Neoenergia.
(2) At 31 December 2015.
(3) Annual impact estimated by Analistas Financieros Internacionales (AFI), based on Iberdrola's business during the 2010-2015 period.

1.2 Company Performance

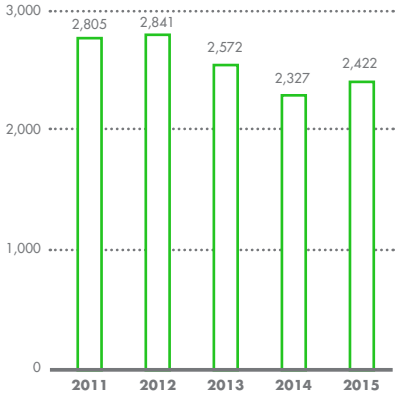
Revenues (€M)



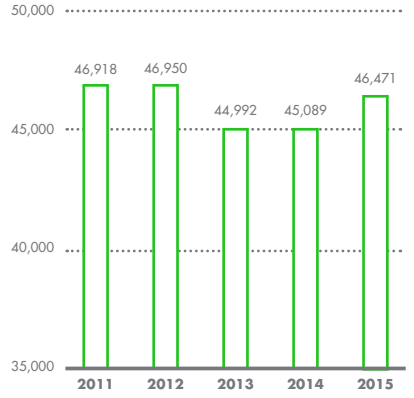
Ebitda (€M)



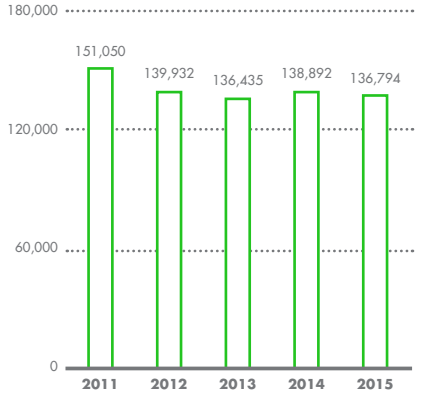
Net Profit (€M)



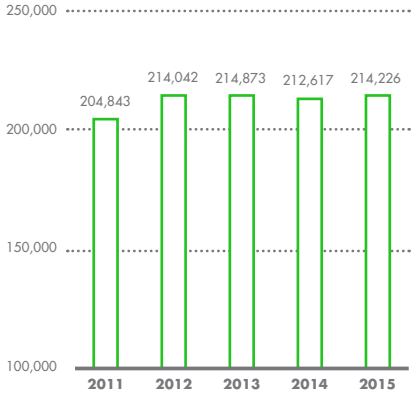
Installed capacity (MW)



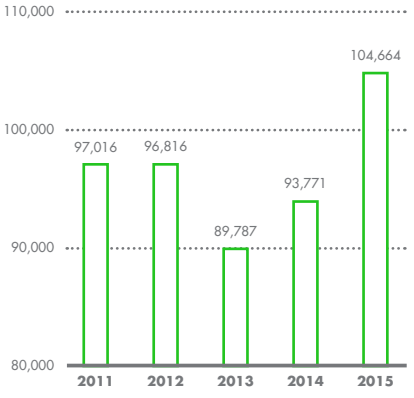
Net output (GWh)



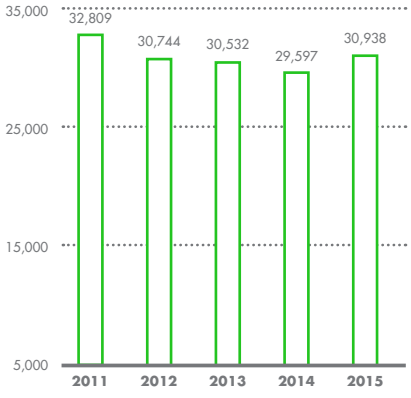
Energy distributed (GWh)[1]



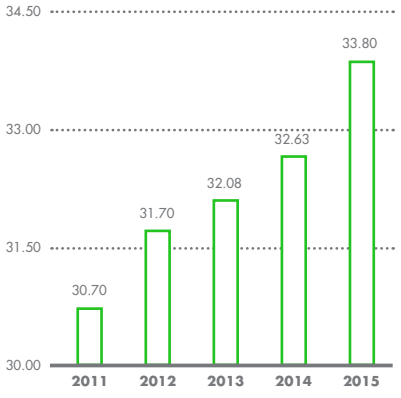
Assets (€M)



Employees



Users (millions)



* Note: Due to legal requirements, Iberdrola has applied International Financial Reporting Standard IFRS-11 to the financial information for the financial years 2013 to 2015, which aspect should be taken into account in evaluating the historical performance of the Company.
[1] Takes into account 100% of Neoenergia.

1.3 Key Figures

Financial performance (€M)	2011	2012	2013	2014	2015	Δ annual average 2011-15	Δ 2014-2015
Revenues	**31,648.0**	**34,201.2**	**31,077.1**	**30,032.3**	**31,418.7**	**–0.2%**	**4.6%**
Consolidated Gross Margin	12,025.8	12,578.1	11,781.9	12,179.5	12,842.7	1.7%	5.4%
Consolidated Ebitda	**7,650.5**	**7,726.6**	**6,756.9**	**6,964.5**	**7,305.9**	**–1.1%**	**4.9%**
Ebitda - Networks (regulated)	**3,825.4**	**3,773.7**	**3,346.5**	**3,534.7**	**3,601.6**	**–1.5%**	**1.9%**
Spain	1,555.2	1,348.3	1,450.3	1,438.5	1,449.7	–1.7%	0.8%
United Kingdom	832.3	937.3	939.0	1,024.8	1,138.0	8.1%	11%
United States	547.7	660.2	718.2	772.0	774.4	9.0%	0.3%
Brazil	890.2	827.9	239.0	299.4	239.5	–28.0%	–20.0%
Ebitda - Wholesale and Retail (liberalised)	**2,270.7**	**2,355.2**	**1,986.6**	**2,292.2**	**2,320.0**	**0.5%**	**1.2%**
Spain	1,570.7	1,605.4	1,341.2	1,517.6	1,502.2	–1.1%	–1.0%
United Kingdom	322.5	360.6	320.4	456.6	420.7	6.9%	–7.9%
United States	15.6	9.1	–22.6	–32.0	–58.4	–	–82.5%
Mexico	361.9	380.1	347.6	350.0	455.5	5.9%	30.1%
Ebitda - Renewables	**1,423.9**	**1,620.3**	**1,501.1**	**1,326.0**	**1,572.3**	**2.5%**	**18.6%**
Spain	668.1	804.3	668.4	420.6	473.2	–8.3%	12.5%
United Kingdom	173.9	168.1	231.8	265.2	437.6	25.9%	65.0%
United States	417.5	412.2	448.0	495.3	499.5	4.6%	0.8%
Mexico	13.7	37.2	34.1	38.2	43.0	33.1%	12.6%
Brazil	12.9	11.3	9.1	33.0	26.9	20.2%	–18.5%
Other	137.8	187.2	109.7	73.7	92.1	–9.6%	25.0%
Ebitda - other businesses	**168.6**	**44.3**	**0.5**	**–17.0**	**–10.6**	**–**	**37.6%**
Ebitda - Corporation and adjustments	**–38.1**	**–66.9**	**–77.8**	**–171.4**	**–177.4**	**–46.9%**	**–3.5%**
Amortisation charge, provisions, and other	**–3,145.4**	**–3,349.7**	**–4,537.5**	**–3,023.6**	**–3,476.6**	**–2.5%**	**–15.0%**
Operating profit (EBIT)	4,505.1	4,376.9	2,219.5	3,940.9	3,829.3	–4.0%	–2.8%
Financial result	**–1,061.9**	**–1,100.3**	**–1,277.9**	**–1,122.4**	**–1,023.1**	**0.9%**	**8.8%**
Results from companies accounted for using the equity method	–34.5	–187.5	205.0	135.4	55.3	–	–59.2%
Gains on non-current assets	**45.8**	**–13.9**	**–10.4**	**247.9**	**125.1**	**28.6%**	**–49.5%**
Profit before Tax (PBT)	3,454.4	3,075.1	1,136.1	3,201.8	2,986.6	–3.6%	–6.7%
Corporate tax	**–549.2**	**–206.5**	**1,466.7**	**–837.1**	**–527.1**	**1.0%**	**37.0%**
Non-controlling interests	–100.7	–27.9	–31.0	–38.2	–38.0	21.6%	0.5%
Net attributable profit	**2,804.5**	**2,840.7**	**2,571.8**	**2,326.5**	**2,421.6**	**–3.6%**	**4.1%**
Total assets	97,016.5	96,816.4	89,786.8	93,771.4	104,664.1	1.9%	11.6%
Equity	**33,207.8**	**34,084.8**	**35,288.6**	**35,790.5**	**40,956.1**	**5.4%**	**14.4%**
Net investments	4,002.0	3,259.0	3,053.0	2,848.0	3,223.0	–5.3%	13.2%
Funds from operations (FFO)	**6,047.0**	**6,196.0**	**5,619.0**	**5,459.0**	**5,906.7**	**–0.6%**	**8.2%**
Net financial debt	31,705.7	30,324.4	26,836.3	25,618.4	28,067.1	–3.0%	9.6%

Financial ratios	2011	2012	2013	2014	2015	Δ annual average 2011-15	Δ 2014-2015
Ebitda - outside eurozone (%)	**48.3**	**51.0**	**49.5**	**54.0**	**56.0**	**3.8%**	**3.7%**
Ebitda margin (Ebitda/revenue) (%)	24.2	22.6	21.7	23.2	23.3	–1.0%	0.2%
Net profit margin (Net profit/ Revenues) (%)	**8.9**	**8.3**	**8.3**	**7.7**	**7.7**	**–3.5%**	**0.1%**
NOE/Gross margin (%)	29.2	30.1	29.4	29.8	29.8	0.5%	0.0%
Net financial debt/ebitda (multiple)	**4.14**	**3.92**	**3.97**	**3.68**	**3.80**	**–1.9%**	**4.3%**
Financial leverage (%)	48.8	47.1	43.2	41.7	40.7	–4.5%	–2.5%
Funds from operations (FFO)/ Net financial debt (NFD)	**19.1**	**20.4**	**20.8**	**21.3**	**21.0**	**2.5%**	**–1.2%**
Retained cash flow (RCF/NFD) (%)	17.2	17.2	17.5	17.4	18.7	2.1%	7.5%
Return on equity (ROE) (%)	**8.6**	**8.3**	**7.5**	**6.7**	**6.3**	**–7.5%**	**–6.0%**

Stock market performance	2011	2012	2013	2014	2015	Δ annual average 2011-15	Δ 2014-2015
Stock market capitalisation (€M)	**28,465**	**25,753**	**28,922**	**35,756**	**41,507**	**9.9%**	**16.1%**
Number of shares at year-end (millions)	5,882	6,139	6,240	6,388	6,337	1.9%	–0.8%
Share price (€)	**4.84**	**4.20**	**4.63**	**5.60**	**6.55**	**7.9%**	**17.0%**
Earnings per share (EPS)	0.47	0.45	0.41	0.36	0.38	–5.2%	5.6%
Dividend per share (DPS)	**0.34**	**0.34**	**0.31**	**0.275**	**0.276**	**–5.1%**	**0.4%**
Dividend yield (%)	6.96	8.13	6.65	4.91	4.21	–11.8%	–14.3%
Total dividend (including payment in kind) (€M)	**1,982**	**2,093**	**1,922**	**1,716**	**1,732**	**–3.3%**	**0.9%**
Payout ratio (%)	71.1	65.4	65.5	73.8	71.5	0.1%	–3.1%
Price/net earnings per share (PER)	**10.10**	**9.31**	**11.25**	**15.37**	**17.17**	**14.2%**	**11.7%**

- *Sustainability Report*
- *Quarterly Results Report*
- *Consolidated Annual Financial Statements*

* Note: Due to legal requirements, Iberdrola has applied International Financial Reporting Standard IFRS-11 to the financial information for the financial years 2013 to 2015, which aspect should be taken into account in evaluating the historical performance of the Company.

Operating performance	2011	2012	2013	2014	2015	Δ annual average 2011-15	Δ 2014-2015
Installed capacity (MW)	46,918	46,950	44,992	45,089	46,471	–0.2%	3.1%
Net output (GWh)	151,050	139,932	136,435	138,892	136,794	–2.4%	–1.5%
Electric power distributed (GWh) (1)	204,843	214,042	214,873	212,617	214,226	1.1%	0.8%

Environmental performance	2011	2012	2013	2014	2015	Δ medio anual 2011-15	Δ 2014-2015
Emission-free installed capacity (%)	58.2	59.4	61.2	61.9	63.0	2.0%	1.8%
Renewable energy installed capacity (%)	29.7	30.5	31.6	32.5	31.8	1.7%	–2.1%
Emission-free production (%)	48.8	51.9	54.6	56.8	52.5	1.8%	–7.6%
Renewable energy production (%)	19.8	23.6	24.9	24.4	24.0	4.9%	–1.7%
Specific CO_2 emissions (t/GWh)	248	264	226	212	225	–2.4%	6.1%
Fuel consumption (M Tep)	20,172	19,236	18,968	18,849	19,001	–1.5%	0.8%
Environmental investments (€M)	1,297.6	1,062.4	1,015.7	1,100.9	1,014.2	–6.0%	–7.9%
Environmental expenses (€M)	261.3	723.3	686.4	635.7	669.2	26.5%	5.3%
Energy produced under certified environmental management systems (%)	87.6	85.2	84.4	85.0	84.0	–1.0%	–1.2%
Water use/overall production (m^3/GWh)	620	699	976	509	533	–3.7%	4.7%
Direct CO_2 emissions. Scope 1 (kt)	36,193	35,461	31,846	30,217	31,752	–3.2%	5.1%
Indirect CO_2 emissions. Scope 2 (kt)	1,156	2,122	997	1,544	963	–4.5%	–37.6%
CO_2 avoided due to efficiency initiatives (kt)	37,462	24,014	18,480	21,459	19,269	–15.3%	–10.2%
SO_2 emissions (t/GWh)	0.295	0.366	0.217	0.154	0.125	–19.3%	–18.8%
NOx emissions (t/GWh)	0.276	0.334	0.262	0.236	0.230	–4.5%	–2.5%

⦿ *Sustainability Report*
⦿ *Quarterly Results Report*
⦿ *Consolidated Annual Financial Statements*

(1) Takes into account 100% of Neoenergia.
(2) Supplies in the amount of 7,300 million euros were awarded during 2015.

Social performance	2011	2012	2013	2014	2015	Δ annual average 2011-15	Δ 2014-2015
Users (millions)	30.7	31.7	32.1	32.6	33.8	2.4%	3.6%
Electrical power	27.5	28.1	28.5	29.0	29.7	2.0%	2.5%
Spain	10.8	10.9	10.9	10.9	10.9	0.3%	0.1%
United Kingdom	3.2	3.5	3.5	3.5	3.5	2.3%	0.3%
United States	1.9	1.8	1.8	1.8	2.2	3.7%	22.2%
Latin America	11.7	11.9	12.4	12.8	13.1	2.9%	2.3%
Gas	3.3	3.6	3.6	3.6	4.1	5.4%	12.4%
Spain	0.8	0.8	0.8	0.8	0.9	2.7%	11.3%
United Kingdom	2.0	2.2	2.2	2.2	2.2	2.4%	0.0%
United States	0.6	0.6	0.6	0.6	1.0	13.3%	65.0%
Number of employees	32,809	30,744	30,532	29,597	30,938	–1.5%	4.5%
Permanent contracts (%)	98.0	98.0	98.5	98.5	98.4	0.1%	–0.0%
Employees with collective bargaining agreement (%)	81.2	79.8	79.4	79.0	76.6	–1.5%	–3.0%
Employee turnover (%)	6.2	10.6	6.6	8.6	7.0	3.1%	–18.5%
Diversity (men/women)	77/23	76/24	76/24	77/23	76/24	–	–
Ratio between basic entry level wage and local minimum wage (%)	162	151	154	161	153	–1.5%	–5.5%
Injury rate (IR)	0.46	0.34	0.46	0.39	0.28	–11.7%	–28.2%
Hours of training (millions of hours)	1.25	1.12	1.2	1.0	0.9	–7.0%	–9.0%
Hours of training per employee (h)	47.1	44.2	44.7	38.7	38.6	–4.9%	–0.2%
Funds for social development (€M)	116.2	51.7	91.7	65.0	46.0	–20.7%	–29.2%
Contributions to society (€M)	34.7	37.7	31.6	34.0	38.0	2.3%	11.8%
Rural electrification programmes (€M)	81.5	14	60	31	8	–44.0%	–74.2%
Investments in R&D (€M)	136	145	159	170	200	10.1%	17.6%
General procurement (€M invoiced) (2)	5,322	4,830	4,359	4,599	5,093	–1.1%	10.7%
Procurement from qualified suppliers (%)	78	84	87	92	94	4.8%	1.3%
Number of suppliers with social responsibility standards	1,078	1,233	1,202	1,326	1,536	9.3%	15.8%
Procurement in sensitive countries per ILO (%)	9.9	8.9	12.0	10.7	10.8	2.3%	1.2%
Procurement from local suppliers (%)	91	90	86	87	85	–1.7%	–2.3%

1.4 Presence by Areas of Activity

United Kingdom
Spain

Iberdrola in Spain

Leading energy company.
Δ 2015 / 2014. GDP +3.2%. Electricity demand +1.8%.

Primary facilities and brands

IBERDROLA ESPAÑA
Spain Subholding Company

IBERDROLA ESPAÑA Renovables
Renewables business

IBERDROLA ESPAÑA Redes
IBERDROLA DISTRIBUCIÓN ELÉCTRICA
Networks business

IBERDROLA ESPAÑA Generación
IBERDROLA
Wholesale and retail business

IBERDROLA Inmobiliaria
Real estate

IBERDROLA Ingeniería y Construcción
Engineering

Fundación IBERDROLA ESPAÑA
Foundation

2015 data

26,187
MW
Installed capacity[1]

92,676
GWh
Electric power distributed

10,569
Employees

6,106
MW
Renewable installed capacity

266,818
Km
Power lines

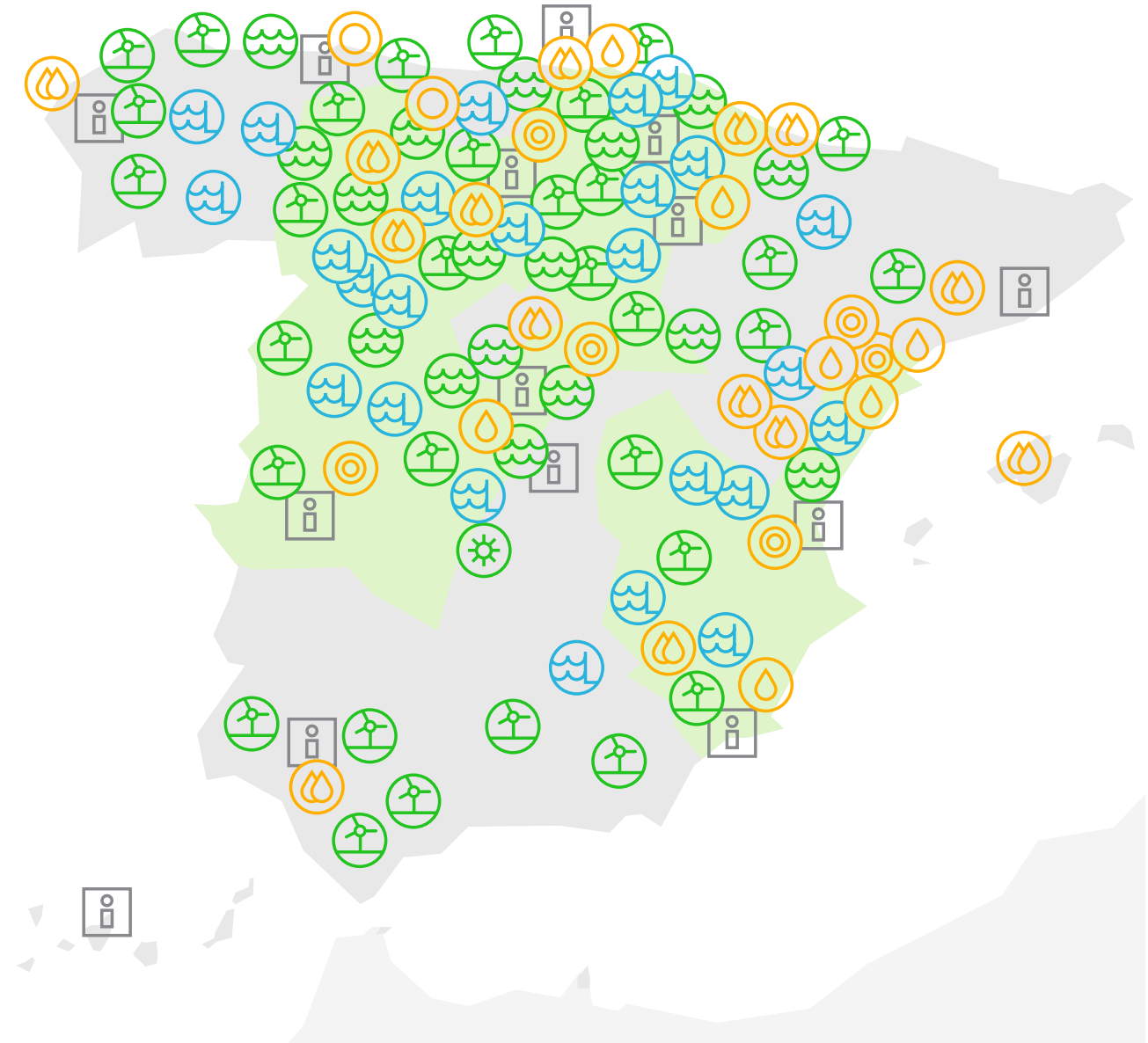
649
€M
Investments

55,512
GWh
Net production

11.8
Million
users

3,493
€M
Direct tax contribution

(1) Total MW managed. The International Financial Reporting Standard IFRS-11 is not being applied for operational purposes.



195
Wind farms
5,753 MW

89
Mini-hydro plants
303 MW

1
Solar thermal plant
50 MW

78
Hydroelectric plants
9,712 MW

8
Combined cycle gas plants
5,695 MW

21
Cogeneration plants
390 MW

6
Nuclear plants
3,410 MW

2
Thermal plants
874 MW

Main offices

Electricity distribution

Area of influence

Iberdrola in the United Kingdom

Leading wind producer. 3rd-leading network company.
Δ 2015 / 2014. GDP +2.2% / Electricity demand –1.2%.

Primary facilities and brands

SCOTTISHPOWER
United Kingdom Subholding Company

SCOTTISHPOWER RENEWABLES
Renewables business

SP ENERGY NETWORKS
Networks business

SCOTTISHPOWER Generation
Wholesale and retail business

IBERDROLA Engineering & Construction
Engineering

Foundation SCOTTISHPOWER
Foundation

2015 data

6,465
MW
Installed capacity[1]

36,213
GWh
Electric power distributed

6,696
Employees

1,630
MW
Renewable installed capacity

108,234
Km
Power lines

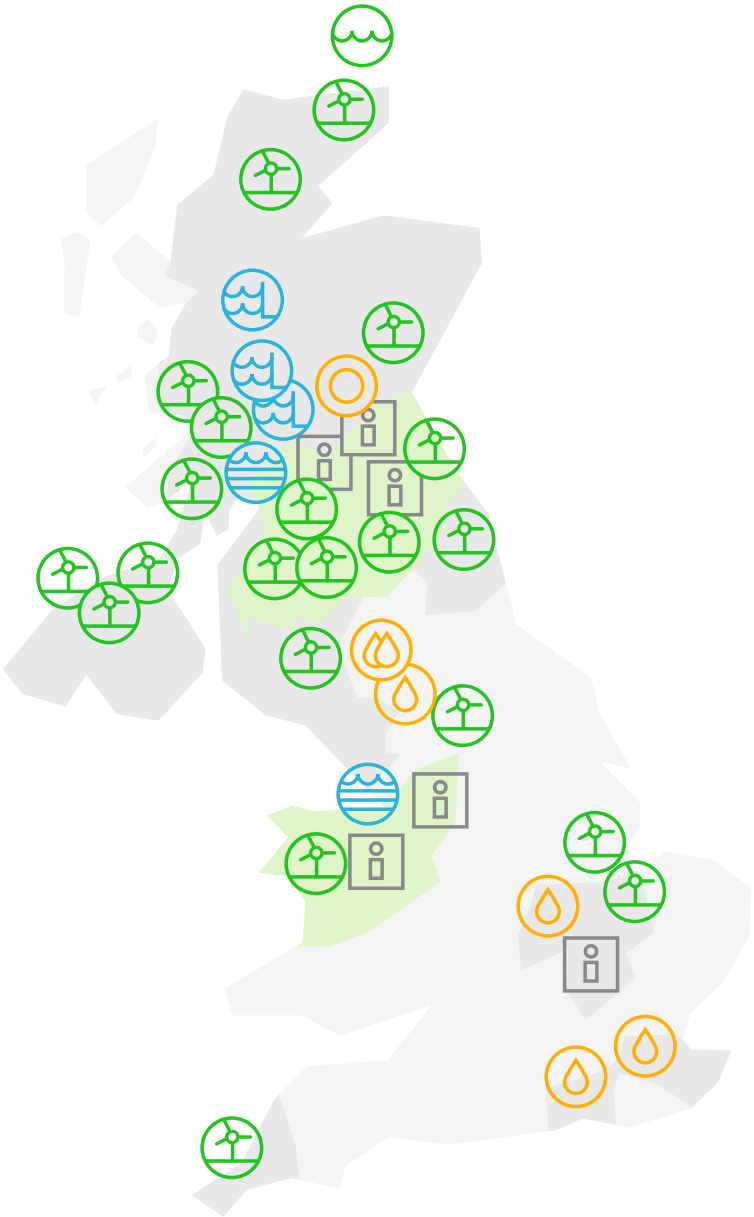
1,461
€M
Investments

18,635
GWh
Net production

5.7
Million
users

640
€M
Direct tax contribution

(1) Total MW managed. The International Financial Reporting Standard IFRS-11 is not being applied for operational purposes.



33
Wind farms
1,629 MW

1
Marine energy
1 MW

1
Underwater power line
425 Km

3
Hydroelectric plants
563 MW

1
Cogeneration plant
1 MW

4
Combined cycle gas plants
1,967 MW

1
Thermal plant
2,304 MW

Main offices

Electricity distribution

Area of influence

Iberdrola in the United States

Second-leading wind producer.
Electricity and gas distributor in New York, Maine, Connecticut and Massachusetts.
Δ 2015 / 2014. GDP +2.4% / Electricity demand –1.1%.

Primary facilities and brands

AVANGRID

United States Subholding Company

AVANGRID RENEWABLES ENSTOR

Renewables business

IBERDROLA Energy Projects

Engineering

AVANGRID Networks CENTRAL MAINE POWER MAINE NATURAL GAS NYSEG RG&E UI SCG CNG BERKSHIRE GAS

Regulated networks business and sale of electricity and gas

Foundation AVANGRID

Foundation

2015 data

6,458
MW
Installed capacity[1]

31,337
GWh
Electric power distributed

2.4
BCM
Gas storage capacity

5,695
MW
Renewable installed capacity

121,990
Km
Power lines

6,889
Employees

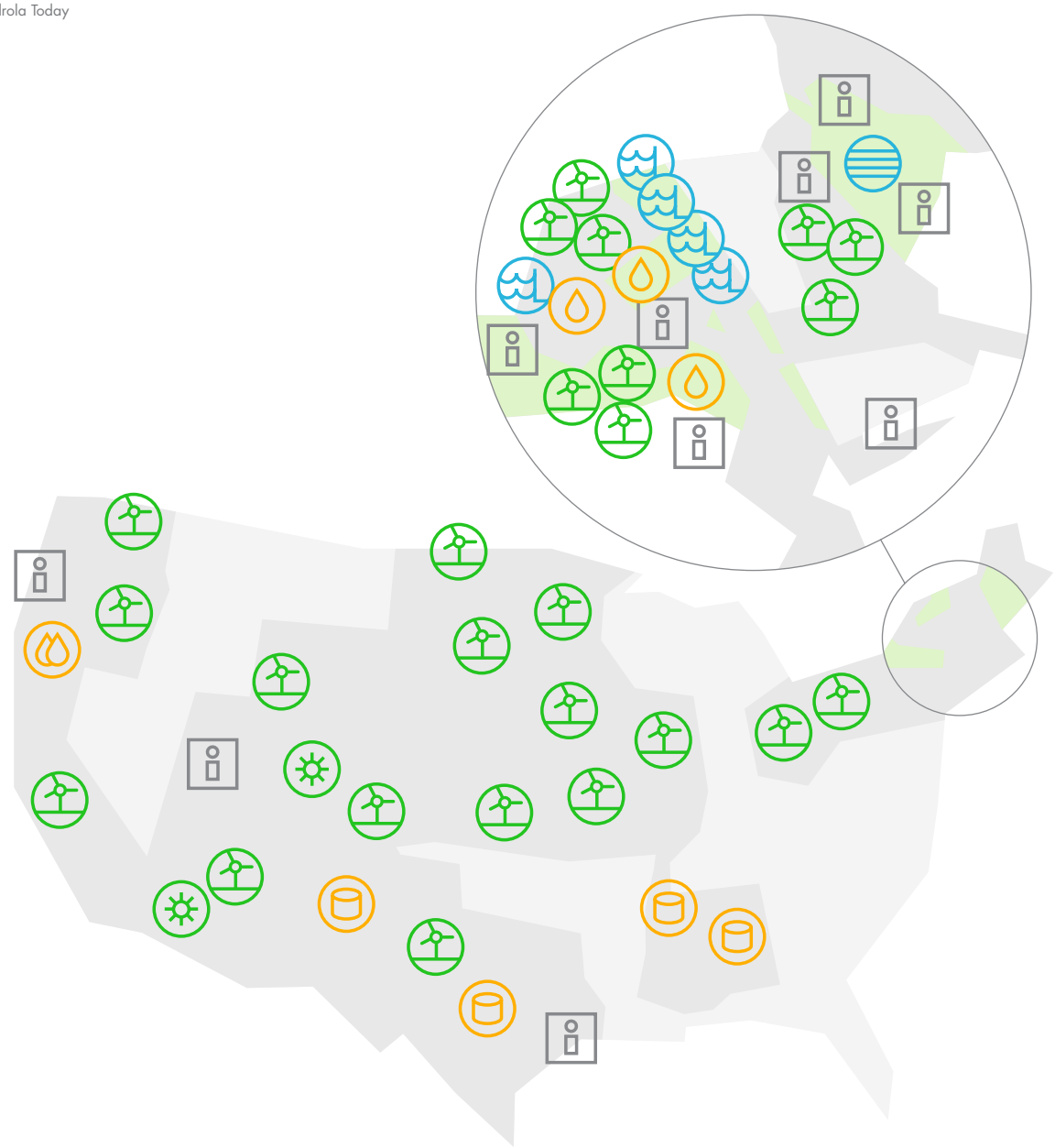
17,418
GWh
Net production

3.2
Million
users

503
€M
Investments

563
€M
Direct tax contribution

(1) Total MW managed. The International Financial Reporting Standard IFRS-11 is not being applied for operational purposes.



54
Wind farms
5,645 MW

2
Photovoltaic plants
50 MW

1
USA-Canada transmission line
708 Km

9
Hydroelectric plants
118 MW

1
Cogeneration plant
636 MW

2
Combined cycle gas plants
9 MW

4
Gas storage facilities

Main offices

Electricity distribution

Area of influence

Iberdrola in Mexico

Leading private electricity producer.
Δ 2015 / 2014. GDP +2.5% / Electricity demand +2.9%.

Primary facilities and brands

IBERDROLA MÉXICO

Mexico Subholding Company

IBERDROLA MÉXICO Renovables

Renewables business

IBERDROLA MÉXICO Generación

Generation business

IBERDROLA Ingeniería y Construcción

Engineering

2015 data

5,449
MW
Installed capacity[1]

38,866
GWh
Net production

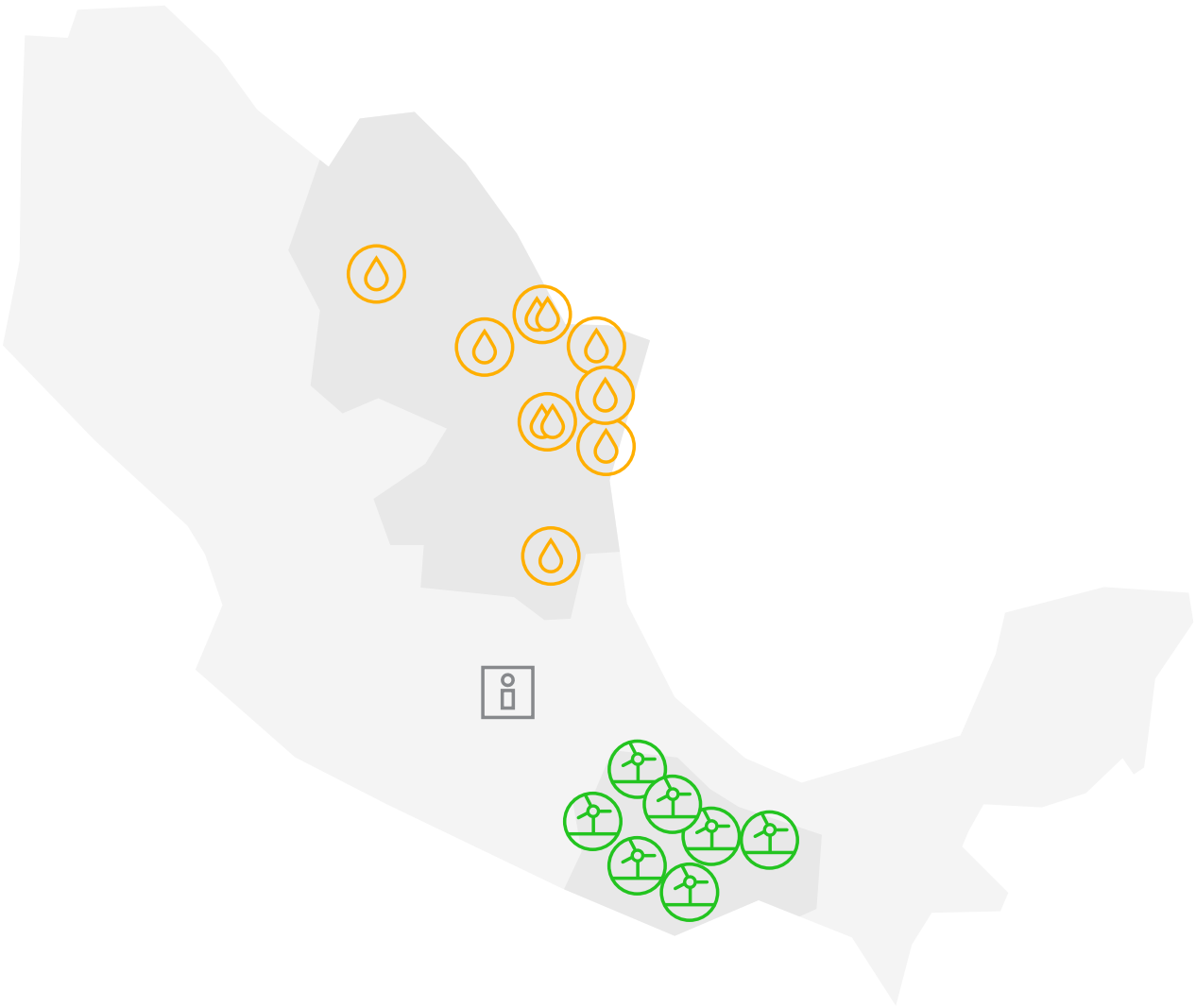
494
€M
Investments

367
MW
Renewable installed capacity

801
Employees

175
€M
Direct tax contribution

(1) Total MW managed. The International Financial Reporting Standard IFRS-11 is not being applied for operational purposes.



7
Wind farms
367 MW

2
Cogeneration plants
201 MW

5
Combined
cycle gas plants 4,881 MW

Main offices

Area of influence

Iberdrola in Brazil

Leading distributor in Brazil by number of customers.
Δ 2015 / 2014. GDP -3.8% / Electricity demand –2.1%.

Primary facilities and brands

IBERDROLA BRASIL
Brazil Subholding Company

IBERDROLA BRASIL Renovaveis
Renewables business

ELEKTRO
Networks business

ELEKTRO Comercializadora
Generation business

IBERDROLA Ingenieria y Construcción
Engineering

Instituto IBERDROLA BRASIL
Foundation

2015 data

1,169
MW
Installed capacity[1]

53,999
GWh
Electric power distributed[2]

3,747
Employees

246
MW
Renewable installed capacity

579,042
Km
Power lines

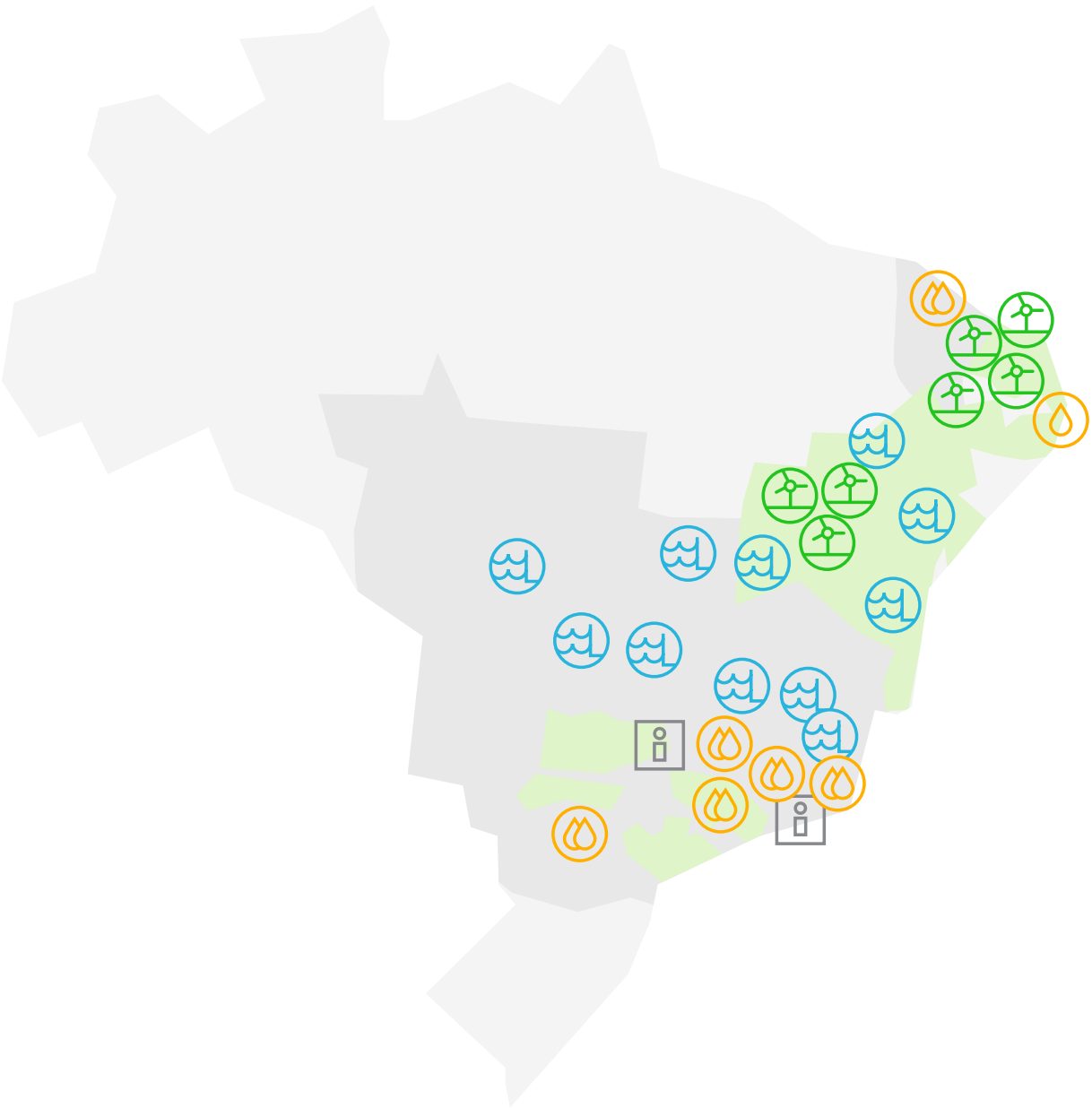
109
€M
Investments

4,802
GWh
Net production

13.1
Million
users

600
€M
Direct tax contribution

(1) Total MW managed. The International Financial Reporting Standard IFRS-11 is not being applied for operational purposes.
(2) Takes into account 100% of Neoenergia.



11
Wind farms
246 MW

12
Hydroelectric plants
682 MW

6
Cogeneration plants
31 MW

1
Combined cycle gas plant
211 MW

Main offices

Electricity distribution

Area of influence

West of Duddon Sands offshore windfarm / United Kingdom

2.

Business Model and Strategy

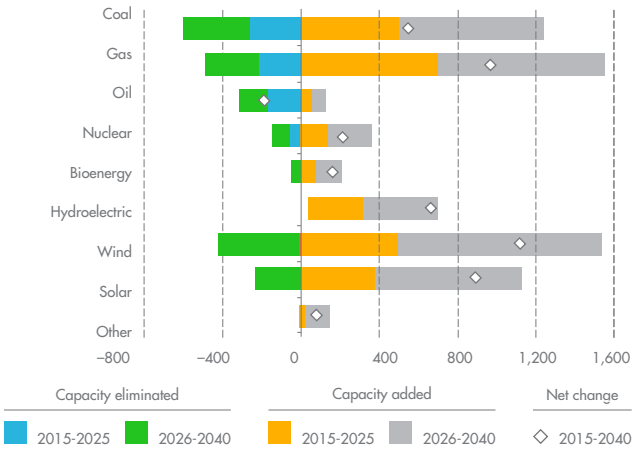
2.1 The Future of Energy

Opportunities for continued growth

The energy sector presents various opportunities for growth over the long term.

Change in global installed power generation capacity (GW)

Source: *World Energy Outlook 2015 – International Energy Agency*



"Hydroelectric generation, onshore and offshore wind power, and solar photovoltaic will spearhead this transformation, which should be accompanied by improvements in networks and back-up and storage technologies."

Ignacio Galán, at the WORLD ECONOMIC FORUM 2016

The future of electricity according to the WORLD ECONOMIC FORUM 2016

The electricity sector is experiencing a process of transition in which rapidly growing economies must supply electrical power in an accessible, affordable, reliable, and sustainable manner.

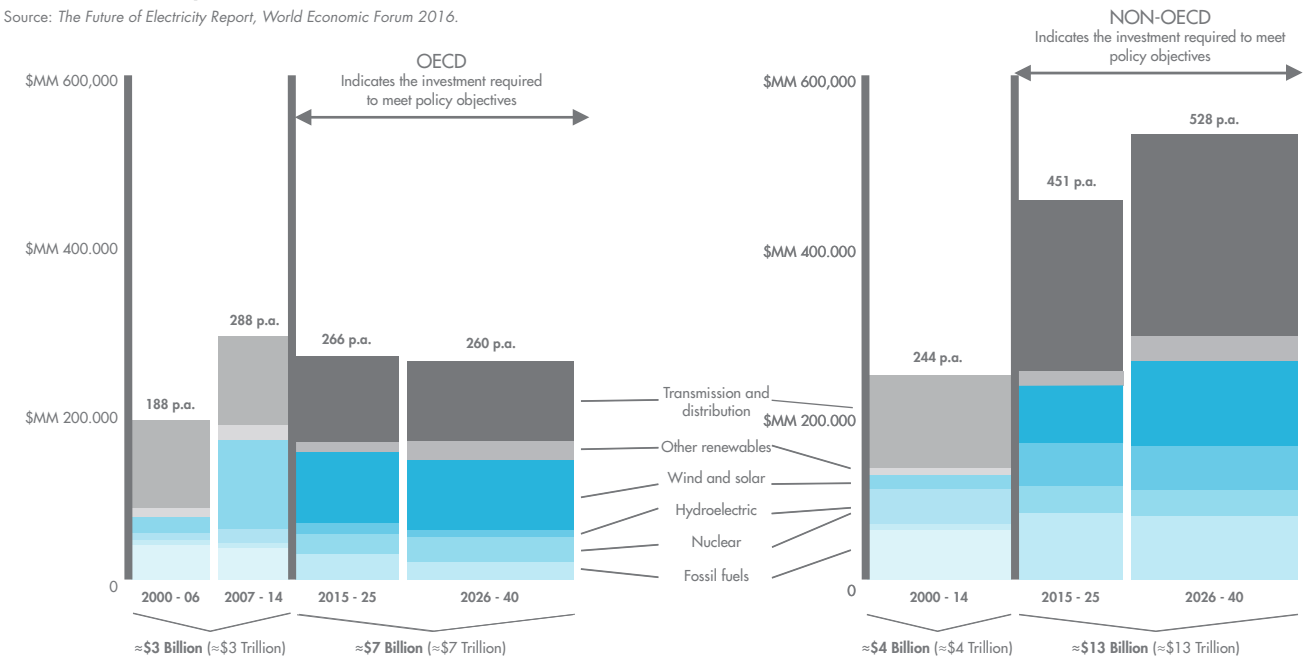
The coming decades will see a scenario marked by a 40% increase in energy demand through 2040 and by the commitments resulting from the Climate Change Conference held in Paris. The energy mix must thus be substantially changed, reducing the consumption of fossil fuels and increasing the contribution of electricity, mainly in sectors like transportation.

The technologies considered for further development in the coming years are those that are sufficiently mature to provide large-scale solutions at a reasonable cost, including hydroelectric, with a 60% increase in the next 25 years, and onshore and offshore wind.

An investment of approximately $7 trillion will be needed in OECD countries ($13 trillion in non-OECD countries) through 2040 to satisfy the growing demand for electricity and to meet the goals of global energy policies.

Investment in electricity infrastructure within and outside of the OECD

Source: *The Future of Electricity Report, World Economic Forum 2016.*



Evolution of demand[1,2]

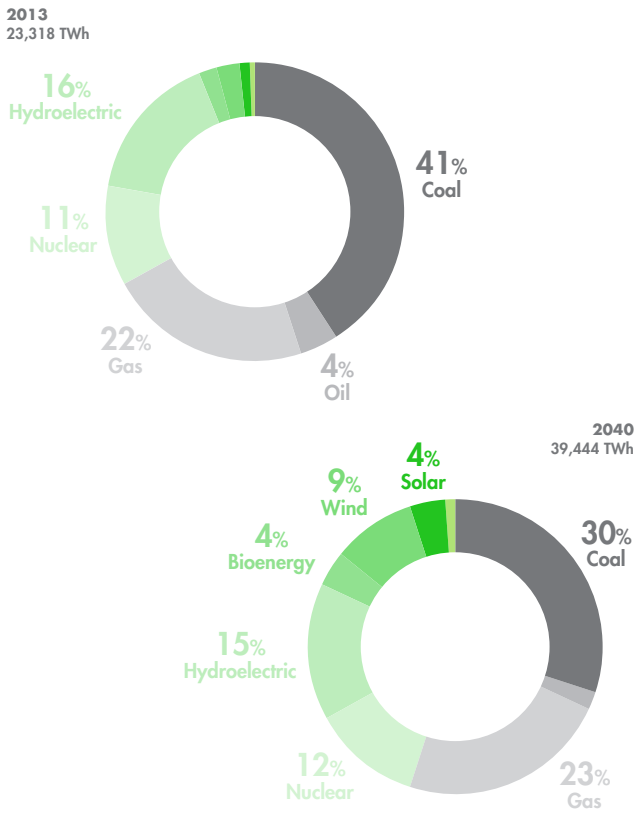
According to *World Energy Outlook 2015*, in a central scenario, world energy use will increase by more than one-third through 2040, led mainly by India, China, Africa, the Middle East, and South East Asia. Despite the use of more costly technology and a foreseeable future increase in the prices of fossil fuels, electricity will be more accessible in relation to GDP in most of these regions.

The EU Roadmap forecasts that electricity will at least double its share in final energy demand to 36-39% in 2050, for which reason it would reduce carbon emissions in heating systems and in the transport sector.

The electricity sector is leading the fight to eliminate CO_2 emissions, which causes a displacement towards power generation technologies with low CO_2 emissions.

Growth in global electricity production (TWh)[1]

Sources: 1.World Energy Outlook 2015 – International Energy Agency; 2. Energy Roadmap 2050 of the European Parliament.



Trends in production and use of electricity

Sectoral[1,2]

- Generation based on renewable energy will increase by some 8,300 TWh (more than one-half of the increase in total production) by 2040, reaching 50% in the EU, around 30% in China and Japan, and more than 25% in the United States and India; conversely, coal will represent less than 15% of electricity supply outside of Asia.
- Preferences for policies favourable to energy options low in CO_2 emissions will be strengthened by cost trends, as the extraction of oil and gas becomes increasingly more expensive, while the costs of renewables and more efficient end-use technology continue to fall.
- Unsustainable pressure on natural resources. A world economy four times larger than today is projected to use 80% more energy in 2050.

Technological[2,3]

- Technological advances and an improvement in efficiency are positive factors, but constant political efforts are essential to improve energy trends.
- Smart grids will introduce home automation to network management and electricity demand management, improving process efficiency.
- Technological developments, such as new renewable energies and advances in distributed generation, can change the current model of the electricity markets.
- Electricity storage, as a still-embryonic technological possibility, can open up new vistas for the operation and management of power systems.
- Technological progress as a path toward reducing emissions, both in obtaining fuels and in producing electricity and managing its use.

Consumption[1,2]

- 1.2 billion people, or 17% of the global population, currently lack access to electricity, and 2.7 billion people, or 38% of the global population, put their health at risk by resorting to the traditional use of solid biomass for cooking.
- Universal access to energy, as an element to improve well-being. *"World electricity demand will grow by 80% over the next 30 years driven by improved efficiency and the expansion of service to the 1.2 billion people who still do not have access to power"* (Ignacio Galán).
- The development of new uses and applications for electricity may result in new markets and opportunities: electric vehicles, robotics in the use of electricity, etc.

Sources: [1] *World Energy Outlook 2015 – IEA;* [2] *Energy Roadmap 2050 of the European Parliament;* [3] *World Energy Outlook 2014.*

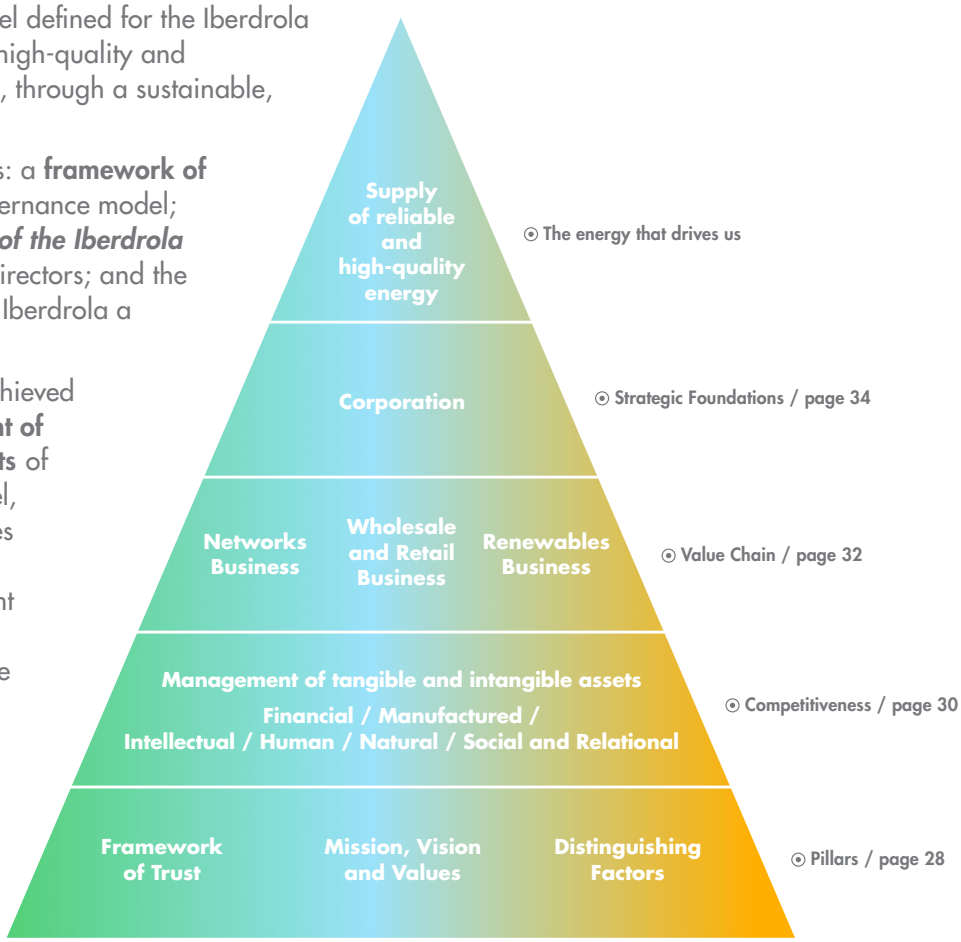
2.2 Business Model

The purpose of the business model defined for the Iberdrola group is the "supply of reliable, high-quality and environmentally-friendly energy", through a sustainable, long-term industrial enterprise.

The model is built on three pillars: a **framework of trust** based on an advanced governance model; the ***Mission, Vision, and Values of the Iberdrola group*** defined by the Board of Directors; and the **distinguishing factors** that make Iberdrola a different company.

The model's competitiveness is achieved through **responsible management of the tangible and intangible assets** of the Company. To apply this model, Iberdrola has defined the activities in which it seeks to be an active player, structuring its management into three global businesses: the Networks Business; the Wholesale and Retail Business; and the Renewables Business, with a Corporation as the group's central management unit.

The Corporation develops the group's strategy and oversees its execution.



Framework of trust

To ensure the sustainability of its business model, Iberdrola has implemented:

- A Corporate Governance System consistent with best international practices.
- Corporate ethics, internalised by the management units and the organisation as a whole.
- *Social Responsibility Policies*, with a view to meeting the expectations of Stakeholders.
- Advanced risk control, to maintain an optimal "risk/opportunity" balance, taking advantage of opportunities and mitigating risks.

Strategic Foundations / page 34

Mission, Vision, and Values of the Iberdrola group

"We want to be the leading multinational group in the energy sector at the forefront of a better future, sustainably creating value with a quality service for people...".

This vision is based on twelve corporate values:

- Value creation
- Ethical principles
- Good corporate governance and transparency
- Development of our workforce
- Social commitment
- Sense of belonging
- Safety and reliability
- Quality
- Innovation
- Respect for the environment
- Customer focus
- Institutional loyalty

2.3 Iberdrola, a Different Company

Iberdrola's Primary Businesses / page 41

Presence by Areas of Activity / page 12

Natural Capital / page 68

Focus on basic and regulated businesses

Approximately 75% of Ebitda comes from regulated businesses and long-term contracts.

International diversification

Approximately 55% of earnings are generated outside of Spain.

Commitment to clean and competitive energies

- Generation and production of largely emissions-free electricity.
- Large portfolio of offshore wind generation projects and wave and tidal power projects.
- Clear goals for reducing emissions.

Operational efficiency

In a comparative analysis of six European companies in the sector, according to a study by Ernst&Young, Iberdrola leads in three efficiency variables: net operating expenses over gross margin, workforce per unit of installed power, and workforce per number of users.

Financial strength and solidity of the group

- Strengthening of the balance sheet due to growth in Ebitda and operating cash flow, which allows for continued strength in solvency ratio levels.
- Liquidity position that covers financial needs for more than 18 months under a stress scenario.

Global, committed, and qualified workforce

- Stable and high-quality jobs, with high level of training.
- Health and safety as values: "accident reduction" goal.
- The companies of the group have been recognised: In Spain for their reputation (Merco) and in Brazil as the best company to work for in Latin America (Great Place to Work).

Iberdrola's Primary Businesses / page 41

Financial Capital / page 60

Human Capital / page 66

2.4 Management of Tangible and Intangible Assets

⦿ Financial Capital / page 60
⦿ Manufactured Capital / page 62
⦿ Intellectual Capital / page 64

	Financial Capital	Manufactured Capital	Intellectual Capital
What is it?	Financial resources the company already has or obtains through financing.	Tangible assets or goods used by the Company to carry out its business activities.	Intangible, knowledge-based assets.
Management Approach	Create value for shareholders through sustainable growth.	Offer a competitive supply of energy in a safe and reliable environment.	Consider innovation as a strategic element of the Company.
Significant Aspects	• Balanced growth. • Sound financial structure. • Operational efficiency. • Sustainable results and dividends.	• Power generation assets. • Power transmission and distribution assets. • Other assets.	• Promotion of R&D. • Efficiency and new products and services. • Disruptive technology and business models.

The Iberdrola group holds valuable assets for the development of its business model. The strategy defined by the Company transforms these assets to create value for all its Stakeholders.

Human Capital / page 66

Natural Capital / page 68

Social and Relationship Capital / page 70

Human Capital	Natural Capital	Social and Relationship Capital
Employee knowledge, skills, experience and motivation.	Natural resources affected by the Company's activities.	Ability to share, relate, and collaborate with its Stakeholders, promoting community development and well-being.
Guarantee the availability of a committed and qualified workforce.	Ensure the sustainable use of natural resources and contribute to combating climate change.	Promote relations of trust with Stakeholders, improving the quality of life of people in areas where the group has a presence.
• Global human resources management. • Goal of "accident reduction". • Talent management. • Diversity, equal opportunity, and reconciliation.	• Environmental management. • Preservation of biodiversity. • Prevention of pollution. • Operating excellence and energy efficiency. • Waste management.	• Stakeholder relations. • Community support and electricity access programmes. • Iberdrola group foundations. • Corporate reputation. • Brand management. • Informational transparency.

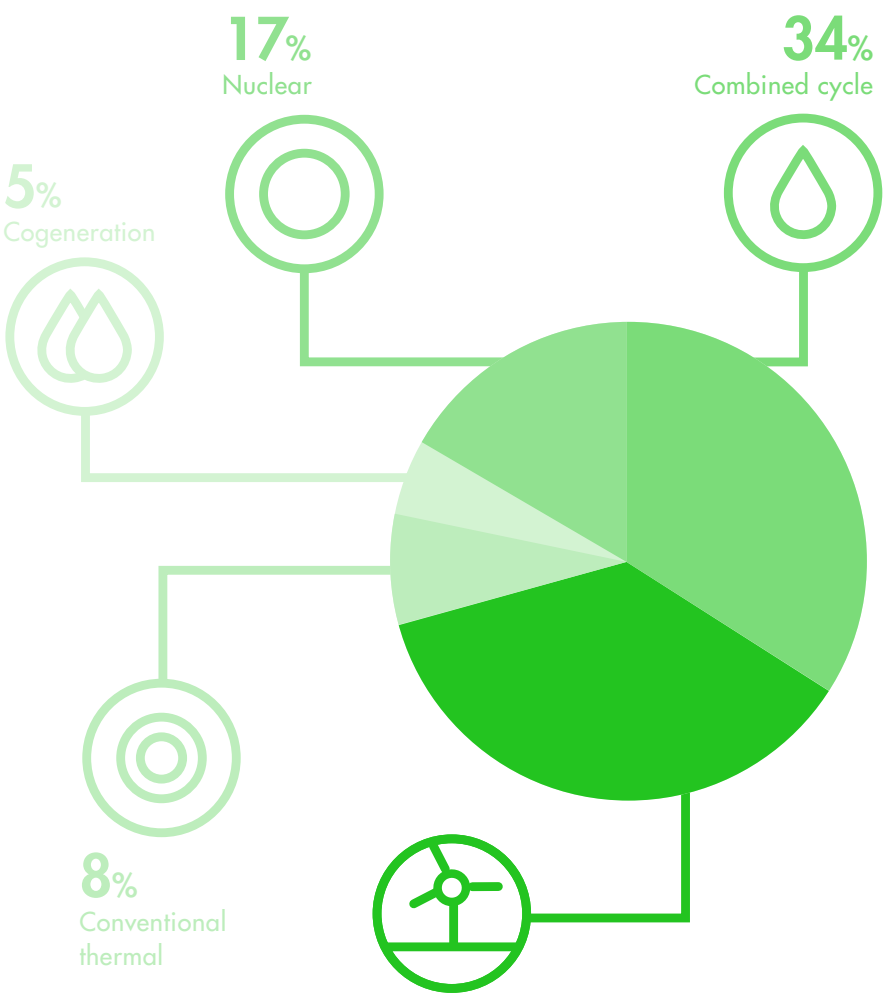
2.5 Value Chain

Power generation

Electricity production through the construction, operation, and maintenance of generating plants, and purchase/sale of energy on wholesale markets.

Generating plants*

* % of 2015 net output



Power transmission and distribution

Construction, operation, and maintenance of electrical lines, substations, transformer centres, and other infrastructure, to transfer electrical power from production centres to the end user.

Electric grids*

* At 31 December 2015

Overhead lines

4,000
High and medium voltage transformer substations

29,857 km
of transmission lines

856,461 km
of distribution lines

Retail sale of energy

Supply to end users of energy and additional products and services.

Users*

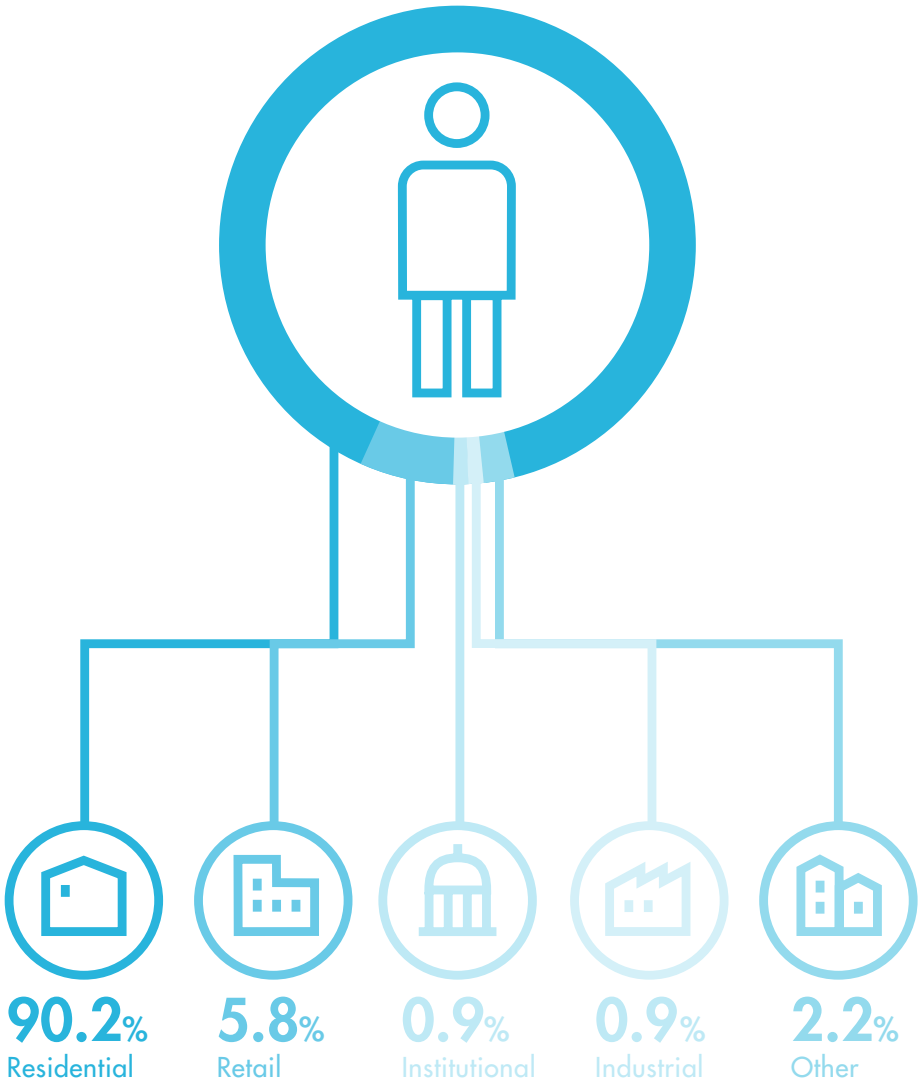
* % by sector at 31 December 2015

Underground lines

1.4 million
Medium to low voltage distribution transformers

938 km
of transmission lines

188,828 km
of distribution lines



2.6 Strategic Foundations for 2016-2020

Market conditions

The global energy markets currently reflect geopolitical factors affecting the countries producing oil and gas. Our scenario for the 2016-2020 period forecasts that current prices remain the same over the short term, sustained by a stable climate in the economies of Europe and North America, followed by a soft recovery at the end of the period. The diversification of businesses and countries will allow the Company to develop a strategy of growth and value creation that conforms to this environment.

Challenges and opportunities

Challenges

- Decarbonisation in the energy sector. Demand for cleaner and more sustainable energy.
- Management of a scenario of constant prices for energy in the short term.
- Attainment of higher efficiency levels in all businesses.
- Regulatory management in all businesses, with special emphasis on transmission and distribution businesses, and in the development of the single market in Europe.
- Implementation of an investment plan focused on growth in the businesses of regulated networks, renewables, and long-term contracted generation.

Opportunities

- Balanced business model focused on regulated activities and clean energy.
- Significant experience in the development and construction of network and emission-free generation projects.
- International diversification with a presence in countries with a stable and predictable regulatory framework that require investment in the electricity and gas sectors.
- High quality of assets.
- Proven management capacity, culture of efficiency, and results.
- Culture of innovation to implement digitisation in relation to customers and the development of new products and services.

Growth vectors 2016-2020

Investments

- United Kingdom: Iberdrola continues with its growth phase in the power transmission and distribution businesses and with the start-up of onshore and offshore renewable energy projects. Offshore wind will become significant beginning in 2018.
- United States: the Company, through AVANGRID, is facing growth in the area of distribution networks and also in transmission. It will also continue with new onshore wind developments.
- Mexico: it will consolidate its position as the largest private power generator in Mexico, taking advantage of the opportunities arising from the liberalisation of the sector.
- Brazil: experiencing a period of growth in hydroelectric capacity.
- Spain: maintenance and improvement of facilities.

Operational efficiency

- In all areas of activity.

.... expanding the geographic diversification of the Company and increasing its presence in regulated businesses with low risk and the generation of recurring cash flows.

The Future of Energy / page 26

Strategic pillars

Iberdrola's strategy for 2016-2020 will remain focused on balanced growth, ensuring its financial strength and the sustainability of its dividend policy, the growth of which will be linked to the growth in results.

New investments will be concentrated in countries with high credit ratings and in businesses that are preferably regulated or in long-term contracts, thus improving the profile of the Company.

1. Balanced growth

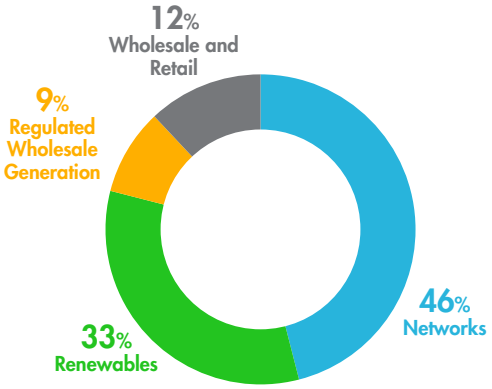
- Investments focused on businesses and countries with stable and predictable regulatory frameworks.
- Net investment of more than €M 24,000. Investments of more than approximately €M 22,000 are already awarded or under construction.
- Of the total investments during the period, €M 17,000 are focused on growth and the rest on maintenance and replacement.
- Electric power transmission and distribution networks will account for 46% of net investments. Of the overall amount, 33% will be dedicated to renewable energy and 9% to regulated wholesale generation. 12% of the total will be invested in the liberalised wholesale and retail business.
- The regulated businesses (networks, renewables, and long-term contract) will account for 88% of all planned investments.
- Geographically, Iberdrola will concentrate the bulk of its growth in the international area. By currency, 43% will be invested in dollars, 35% in pounds Sterling, 20%* in the Euro zone, and 2% in Brazilian reais.

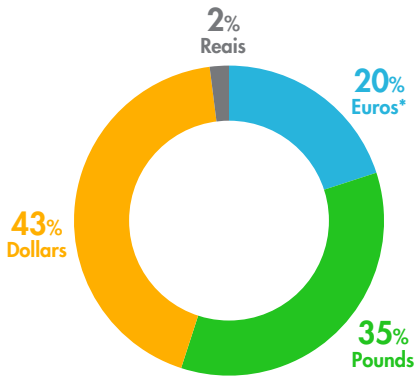
From 2016 to 2020, investments will be focused on countries with stable regulatory environments and the businesses of regulated networks, renewables, and generation under long-term contracts.

Financial Capital / page 60

Investment by business and currency 2016-2020

* Includes the offshore wind farm in Germany: Wikinger





2. Financial strength

- 2015 results were higher than initially forecast due to the good performance of the businesses, especially the regulated and long-term contract businesses, and the positive effect of the appreciation of the dollar and the pound Sterling. Ebitda reached €M 7,306 (+4.9%), with net profit of €M 2,422 (4.1%).
- In the coming years, the efficient operation of operating assets, together with the above-described investment plan, will lead to sustainable growth in the Company's results, with an estimated average annual increase of approximately 6% through 2020.
- As a result of the increase in investments, net debt will grow some €M 1,000 annually during the first years of the period, to reach approximately €M 31,000 in 2018/2019 thanks to the increase in operating cash flow.

The profile of the Company's businesses, together with a balanced investment plan, will allow for sustained growth in results of approximately 6%...

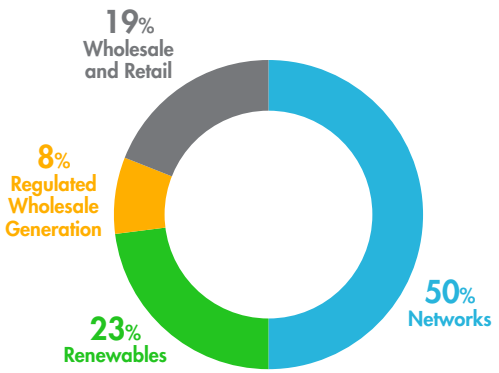
- Average annual operating cash flow (FFO) in the amount of €M 6,900 will amply exceed investments, which will reach an annual average of €M 4,800. By business, cash flow generation from the Liberalised and Networks businesses will be significantly greater than investments, while Renewables will generate cash somewhat higher than investments.
- Maintenance of the current financial model to provide subsidiaries with an optimal capital structure giving appropriate financial signals and which is consistent with an investment grade rating, while respecting current guidelines for structural subordination.
- Optimisation of liquidity position (around €M 8,000 - 9,000) to current market conditions in order to improve financial costs, maintaining 18 months of coverage even during stress scenarios.
- Strengthening of financial ratios, with the following medium-term goals:
  - Net debt/Ebitda ≤ 3.6
  - FFO/Net debt ≥ 22%

...resulting in the Company proposing a sustainable shareholder remuneration policy linked to the growth in results.

3. Sustainable dividend

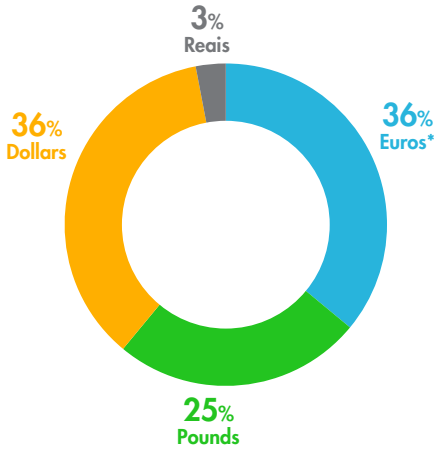
- Thanks to the strength of the results obtained in 2015, the Company has announced a proposed increase in the annual divided to 0.28 euro per share with a charge to financial year 2015.
- In the coming years, shareholder remuneration will grow in line with the increase in results, converging with a payout ranging between 65% and 75%.

Ebitda by business (forecast to 2020)



Ebitda by currency (forecast to 2020)

* Includes the offshore wind farm in Germany: Wikinger

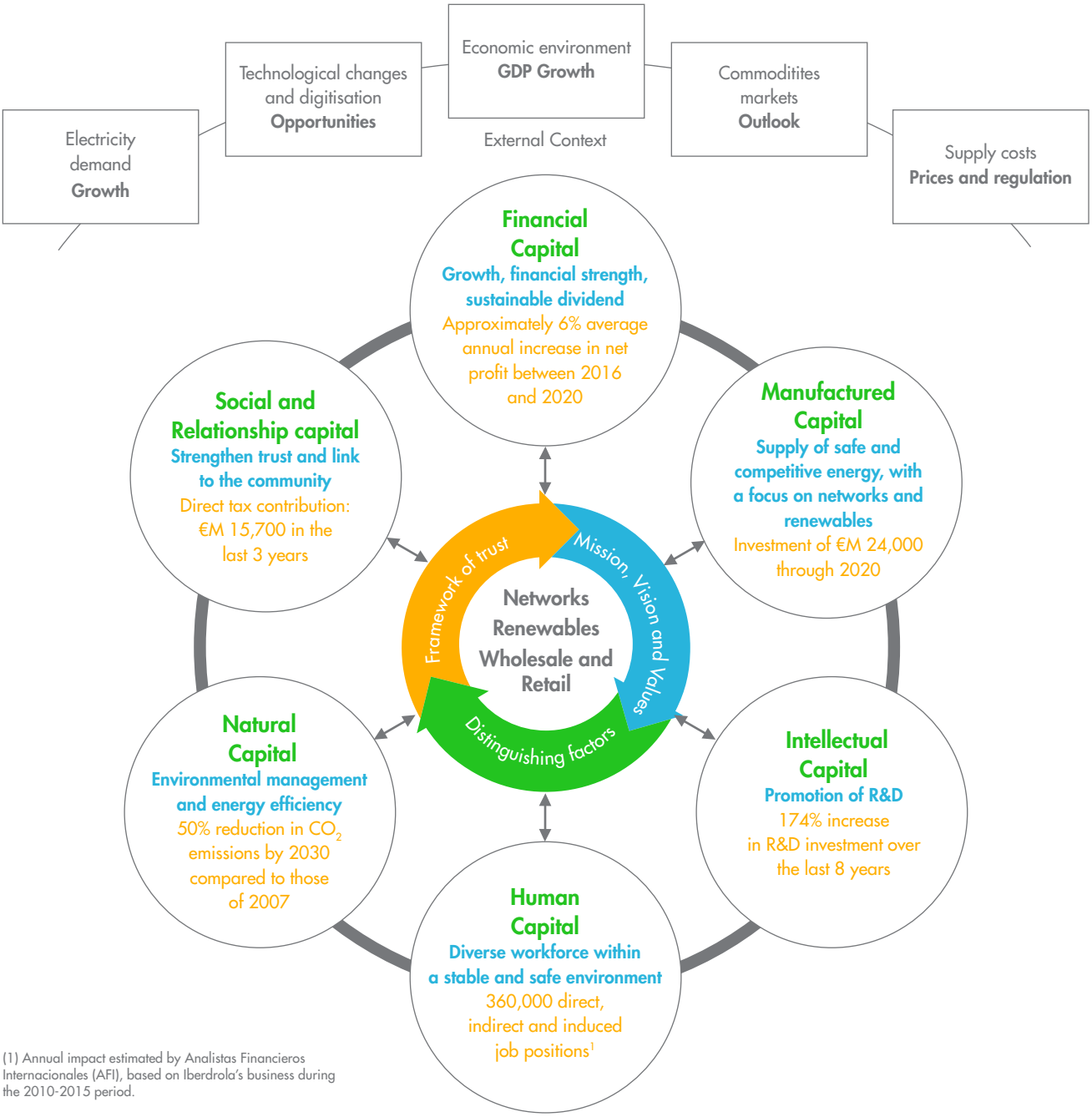


2.7 Capital and Business Relationship

The value created by the business strategy and model of Iberdrola over time translates into an increase in its capital, which in turn feeds back into a cycle of value creation, efficiently inter-relating the operations of the businesses and the capital of the Company.

The chart below shows for each chapter its strategic focus and quantifies an aspiration or achievement of the Company in this area.

This process creates shared value for both Iberdrola and for its Stakeholders, and constitutes a main vector for achieving the Company's goal to offer a reliable, high-quality, and environmentally-friendly energy supply.



(1) Annual impact estimated by Analistas Financieros Internacionales (AFI), based on Iberdrola's business during the 2010-2015 period.

2.8 Comparative Results and Awards

Comparative analysis*

Comparative economic/financial variables 2015

Growth in Ebitda

ACGR (%)	Average comparables	Iberdrola
31-Dec.-05 / 31-Dec.-15	2.1%**	8.0%

Growth in capitalisation

Total growth (%)	Average comparables	Iberdrola
31-Dec.-05 / 31-Dec.-15	–30.5%	99.4%

Iberdrola held 5th place at the European level in terms of stock market capitalisation for the last 10 years. It is now in first place.

Share price

Total growth (%)	Average comparables	Eurostoxx Utilities	Iberdrola
31-Dec.-05 / 31-Dec.-15	–55.1%	–30.2%	13.5%

* Comparable companies analysed: Engie, EDF, E.On, Enel, RWE.
ACGR: Annual Compound Growth Rate, i.e. weighted average annual growth.
**Bloomberg data. For EDF, E.ON, and RWE, the 2015 Ebitda figures are the estimates published by Bloomberg, due to the absence of final closing figures on the date of preparation of this document. In addition, for Engie, the 2005 figure is for GDF (prior to the merger of GDF and Suez SA).

Comparative performance of total shareholder return

Profitability (%)	Average comparables	Eurostoxx Utilities	Iberdrola
31-Dec.-05 / 31-Dec.-15	–9.1%	19.0%	64.2%

Iberdrola's performance

Over the last 10 years, Iberdrola has tripled its assets, has practically tripled its revenues, has doubled its Ebitda and net profit, and has increased shareholder remuneration by more than 20%, while maintaining its financial strength.

Iberdrola	31-Dec.-05	31-Dec.-15	Multiple
Assets (€M)	30,479	104,664	3.4x
Revenues (€M)	11,738	31,419	2.7x
Ebitda (€M)	3,378	7,306	2.2x
Net Profit (€M)	1,382	2,422	1.8x
Dividends (€/share)	0.22	0.27	1.2x
Net Debt/Ebitda	3.8	3.84	1.0x

Ignacio Galán at the offices of Torre Iberdrola / Bilbao

External awards

For the Company:

- Best European Utility (Institutional Investor Research): 2015, 2014, 2013, and 2011.
- Best Corporate Governance in Spain (World Finance): 2015, 2014, and 2012.
- Best Corporate Governance among European Utilities (Ethical Boardroom): 2015 and 2014.
- World's Most Ethical Company Index (Ethisphere Institute): 2016, 2015, and 2014.
- Leading Ibex 35 company in the tax transparency ranking 2014, from *Fundación Compromiso y Transparencia.*
- Euroshareholders Award for the best initiative in favour of minority shareholders (AEMEC): 2015
- Best European utility in investor relations (IR Magazine): 2015.
- Olimpia Award to recognise support and promotion of sport among people with disabilities, given by the Sports Council *(Consejo Superior de Deportes):* 2015.

For the chairman & CEO:

- Best European Utility CEO (Institutional Investor Research): 2015, 2014, 2013, and 2011.
- Responsible Capitalism Award (First): 2014.
- Commander of the Most Excellent Order of the British Empire: 2014.
- Honorary Doctorate from the Universities of Strathclyde (2013), Salamanca (2011) and Edinburgh (2011).

For other members of the Company:

- Best European Utility CFO (Institutional Investor Research): 2015, 2014, and 2012.
- Best European Utility Investor Relations (Institutional Investor Research): 2015, 2014, 2013, 2012, and 2011.

Other Awards / page 67, 85

West of Duddon Sands offshore wind turbine / United Kingdom

3.

Iberdrola's Primary Businesses

Regulation is a key factor in the sustainability of Iberdrola's activities.

Energy policies must set clear and predictable goals in order to attract the investment needed to guarantee a safe, competitive, and sustainable supply, developing its potential as a source of growth and employment.

3.1 Regulatory Environment

European Union

- 2015 saw the formalisation of the Paris Climate Change Conference (COP21) agreements, which entail a multilateral commitment to implement measures to reduce emissions in order to limit the increase in temperature to a maximum of 2°C through 2100. These measures will involve a major investment effort, which should be supported by signals incentivising low-carbon technologies, and the costs should be paid in accordance with the "polluting party pays" principle.
- There will be intensive regulatory activity by the European Commission in 2016.
- More far-reaching measures include expected market design reform proposals, as well as a directive on the safety of supply. There will also be proposals to modify the frameworks for renewables and energy efficiency, in line with the 2030 goals.
- Furthermore, there will be continued steps to reform the emissions market and it will be completed with a reform of the treatment of "diffuse" sectors.

Spain

- Most of the regulatory steps on electricity and gas reform were already taken during 2013 and 2014, eliminating the deficit in 2014.
- An energy efficiency fund is maintained by which all energies (electricity, gas, and petrol) contribute in proportion to their demand to the costs of implementing the European goal of energy efficiency for 2020.
- Continuation of a regulated tariff applying to approximately 90% of consumers.

United Kingdom

- The investigation by the Competition and Markets Authority (CMA) into the operation of the industry continues. Its final conclusions and proposed remedies are expected to be published in June 2016.
- The provisional conclusions of the CMA indicate that there is little concern about the wholesale market or vertical integration, although competition is considered to be weak in the Standard Variable Tariff sector and in the SME market. There will probably be reforms to deal with these problems.
- The new British government has taken measures to reduce the expected cost of the "green energy" support frameworks, but only for future facilities. Various support systems have been reduced or shut down, while it can be expected that others will be maintained.

United States and Canada

- The State of New York, along with other states, will continue to consider changes in the regulatory model for utilities, taking into account technological advances both in generation and distribution of electricity.
- In this context, in June the NY Public Service Commission, within the framework of the *Reforming the Energy Vision* (REV) process, published its white paper proposing reforms in the regulatory distribution model.
- During 2016, litigation progressed in determining whether the Environmental Protection Agency (EPA) can implement two independent regulations proposing a reduction in CO_2 emissions for the electricity generation sector with a 2030 horizon. This process will have a considerable impact on decision-making by electric companies.

Mexico

- The new energy reform, the legislative development of which will continue during 2016, ends the state monopoly in the hydrocarbon and electricity sectors. In the electricity sector, it will encourage investment in new generation projects that will operate in a competitive environment after the creation of various markets. The share of clean energy is forecast to increase by up to 35% by 2024 with the creation of a clean energy certification system, based on which certain supply obligations will be determined. Furthermore, contracts with individuals will also begin in the area of networks, which are still under state ownership and considered to be a public service.

Brazil

- The debate on the distribution of hydrological risk opened the door to the possibility of the renegotiation thereof (Law 13,2013/2015) based on a voluntary decision of the generator and in exchange for the payment of a premium into the "tariff flag" account.
- Despite the difficulties at the beginning of 2015, hydrological conditions improved and the possibility of rationing was excluded, which has allowed for a decoupling of the more expensive thermal plants and a reduction of the additional amount charged in the "red flag". The price of energy in the spot market has significantly decreased during the course of the year, in line with the improvement in hydrological conditions.
- The concession of 29 hydroelectric plants that did not adhere to Provisional Measure MP 579/2012 was terminated in 2015. At the end of the year they were auctioned, including the obligation to pay a fee for the award, which allowed the government to collect R$M 17,000. The power from these plants has been distributed among the players in the form of contributions.
- The requirements to renew the distribution concessions were defined during the year, focusing on quality and governance. 17 distributors have renewed their concession contracts within this new framework.

3.2 Networks

Regulatory environment of the business

Spain

- The transitional remuneration methodology approved in 2013 applied in 2015.
- Base unit costs and the methodology for calculating the pending remuneration parameters were approved in December 2015. The first regulatory period begins in 2016 and ends in 2019.

United Kingdom

- In 2016 Ofgem set the standards for the review of outputs expected for the mid-period RIIO-T1. This revision does not affect defined financial terms.
- The DPCR5 regulatory distribution period ended in March 2015 and RIIO-ED1 began for 2015-2023.

New tariff conditions for NYSEG and RG&E, the gas and electricity distributors in the State of New York (USA), will come into effect in 2016.

United States

- The current tariff conditions of NYSEG and RG&E (New York) were extended during 2015, while negotiations continued on the new terms to come into effect in 2016.
- In Maine, the first tariff agreement is being negotiated for MNG. Furthermore, the terms of the tariff agreement for CMP have been extended for an additional year.

Brazil

- The indicators to be used in the 4th cycle of the tariff revision for distributors were determined in 2015.
- The 4th tariff cycle for Elektro came into effect in August for the 2015-2019 period. The average tariff increase from this review was 4.2% for these four years.
- The tariff agreements for the distributors of Neoenergia will be in force through April 2017 for Celpe and April 2018 for Coelba and Cosern.
- The annual tariff update for 2015 was 11.43% for Coelba, 9.57% for Cosern, and 11.25% for Celpe.
- Coelba and Celpe have signed an agreement to improve the quality of supply with the regulator Aneel.

Denny substation, Scotland / United Kingdom

Objectives, risks, and principal activities

Objectives

- Satisfy supply under strict safety conditions, in compliance with environmental requirements.
- Increase quality in energy supply by investing in the expansion and renewal of networks, improvement of our processes, and use of the latest advances in technology.
- Maximise efficiency in system operations.
- Zero accidents.

Significant risks

- Regulatory uncertainty.
- Safety of individuals due to risk of accidents.
- Incidents with environmental impact.
- Major network incidents.
- Increased fraud.
- Technological and cybersecurity risks affecting the security of the facilities.

Principal activities 2015

- Spain: continuation of the STAR project for the roll-out of smart grids, after already installing over 6.5 million meters. 11 new electric substations were also placed into service.
- United Kingdom: the DPCR5 period ended in March 2015, meeting the objective established for this period.
- United States: completion of construction phase for the MPRP transmission project in Maine (700 km of network, 5 new substations, and 6 expanded substations).

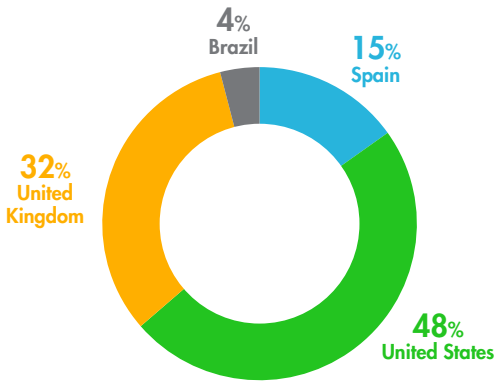
  2015 saw the commencement of the first project of IUSA Networks within NY Transco, a $1,700 M initiative sought by New York electric transmission companies to develop transportation infrastructure in New York. Iberdrola's has a 20% interest in NY Transco.
- Brazil: improvement plan launched at Neonergia to improve supply efficiency and quality. At Elektro, development of facilities to meet demand and connect new customers.

Outlook 2016-2020

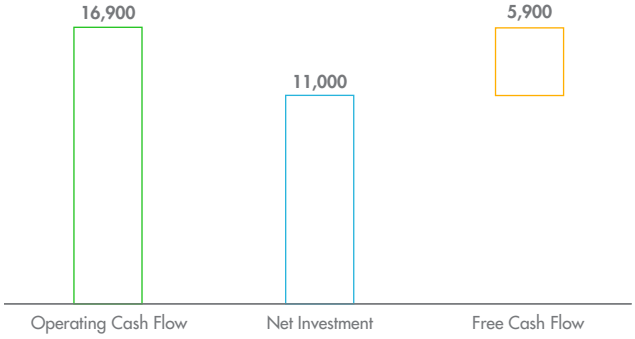
- Increased regulatory visibility in all countries, with investments of €M 11,000, allowing for a 22% increase in RAV*.
- Focus on digitalisation and grid automation (smart grids), service quality, and operational improvements.
- 2% increase in efficiency over the period (NOE/GM and NOE/RAV)*.
- Opportunities for selective growth in transmission.

*RAV: Regulatory Asset Value; NOE: Net Operating Expenditure; GM: Gross Margin.

Net Investment of €M 11,000 between 2016 and 2020, mainly in the United States and the United Kingdom



2016-2020 cash flow generation to finance investments (€ millions)



Key figures of the Networks business

		Spain		United Kingdom		United States[1]		Brazil				Total	
								Elektro		Neoenergia[2]			
Item	Unit	2014	2015	2014	2015	2014	2015	2014	2015	2014	2015	2014	2015
Gross margin	€M	1,936	1,952	1,331	1,472	1,498	1,698	459	392	–	–	**5,225**	**5,514**
Ebitda	€M	1,438	1,450	1,025	1,138	772	774	299	240	–	–	**3,534**	**3,602**
Electric power distributed	GWh	90,741	92,676	36,564	36,213	31,302	31,337	16,933	16,190	37,077	37,809	**212,617**	**214,226**
Users (Electricity)	Millions	10.8	10.9	3.5	3.5	1.8	2.2	2.4	2.5	10.3	10.6	**28.8**	**29.7**
Gas supply	GWh	–	–	–	–	38,261	36,325	–	–	–	–	**38,261**	**36,325**
Users (Gas)	Millions	–	–	–	–	0.6	0.8	–	–	–	–	**0.6**	**0.8**
Investments	€M	304	346	729	847	432	429	78	71	–	–	**1,541**	**1,693**
Workforce	N° people	3,906	3,801	2,894	2,851	4,133	5,113	3,801	3,486	4,050	4,338	**18,784**	**19,589**

International Financial Reporting Standard (IFRS) 11 has been applied to the financial information for both 2014 and 2015.
(1) UIL included in users and workforce in 2015.
(2) Operational information is deemed to be 100% from Neoenergia.

⊙ *Quarterly Results Report*

Safety, quality of supply, and operational efficiency are the three strategic pillars of the Networks business upon which the entire business rests.

Safety

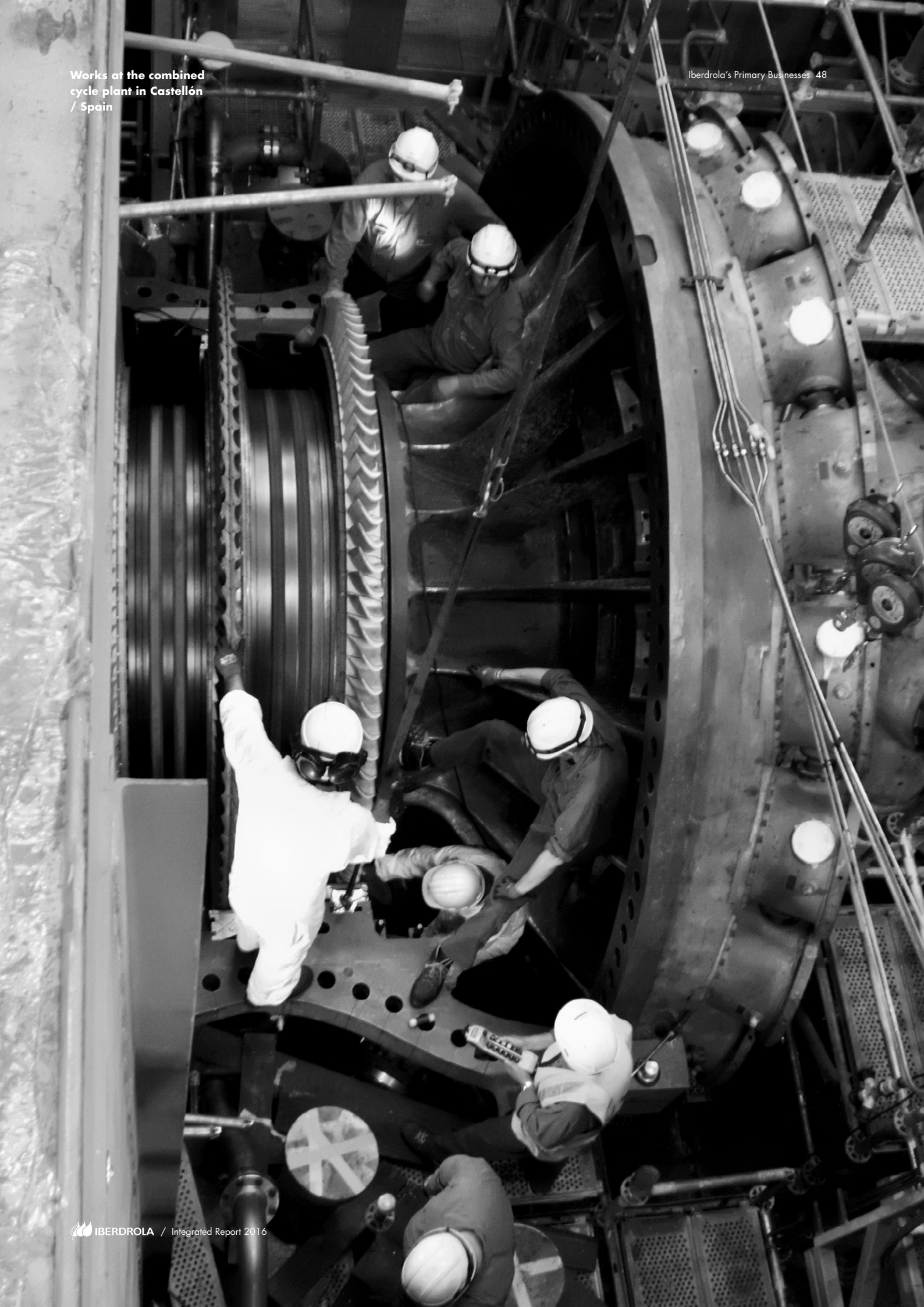
- Ongoing efforts to improve safety in networks activities, which is reflected in the decrease in the Incident Rate.
- Implementation of best practices at all networks companies to reduce the risks associated with operation.
- Strengthened measures to protect against cybersecurity risks associated with new grid management technologies.
- Development of safety improvement initiatives for all Networks personnel and subcontractors.

Quality of supply

- Ongoing effort to improve supply quality indicators.
- The service quality indicators between January and December 2015 were affected by poor meteorological conditions in Spain and the United States.
- Development of transmission and distribution projects to ensure the reliability of supply and optimise the cost of energy.
- Network automation project in Spain to improve operations.

Efficiency

- Increase in operating expenses contained despite strong increase in activity.
- Implementation of best practices throughout the networks companies, mainly in the areas of asset management, processes and technology, control systems, digitisation and automation, and customer service.
- Emphasis on the fight against electricity fraud in Spain, with recovery of almost 420 GWh.



Works at the combined cycle plant in Castellón / Spain

3.3 Wholesale and Retail

Regulatory environment of the business

Europe

- An agreement was reached in 2015 on the introduction of a Market Stability Reserve within the European Emissions Market. With a start date of 2019, it will reduce the surplus of emission rights in the market.
- The REMIT[1] reporting obligations will enter into force in 2016 to ensure the integrity and transparency of the gas and electricity market.

[1] REMIT: Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency.

Spain

- The Royal Decree governing administrative, technical, and financial conditions for internal consumption was approved in October 2015. It establishes the framework for this activity with legal guarantees for consumers and producers, and the charges for energy produced and internally consumed, with exemptions for consumers of <10kW.
- Law 8/2015 amending the Hydrocarbon Sector Act (*Ley del Sector de Hidrocarburos*) has created an organised Iberian gas market (Mibgas), which commenced operations on 16 December.
- The new interconnection between Spain and France entered into commercial operation in October 2015. In addition, the presidents of France, Spain, and Portugal and the president of the European Commission have signed a declaration committing to promote the interconnections between the three countries. In electricity, the goal is to reach 10% by 2020 using an undersea cable through the Bay of Biscay and two connections in the Pyrenees.
- The current capacity availability service of the generation facilities has been extended in 2016 until approval of the Royal Decree that will modify capacity payments.

United Kingdom

- The auction in the 2019/2020 capacity market took place in December 2015, with the participation of both existing plants and new projects. The resulting price was £18/kW and no combined cycle project won the auction.
- The Carbon Tax, which applies to carbon emissions, has been £18.08/t since April 2015. It will remain constant until 2020.
- Implementation of Project TransmiT, which establishes a new distribution of transmission charges among generators. The changes will take effect in April 2016.

Mexico

- The Wholesale Electricity Market Rules (*Bases del Mercado Eléctrico*) were approved in September 2015. The Electricity Market contemplates capacity auctions and Clean Emissions Certificates (*Certificados de Emisiones Limpias*) (CELs).
- The Short-term Market commenced operations in January 2016.
- The market respects the contracts previously established by Independent Power Producers and for Self-supply Plants.
- As from August 2015, consumers with consumption greater than 2MW can acquire their energy on the market.

Objectives, risks, and principal activities

Objectives

- Operating excellence, safety, and respect for the environment.
- Risk identification and minimisation.
- Safety and continuous improvement in operating efficiency.
- Competitive supply and excellence in service to customers.
- Analysis of growth opportunities.

Significant risks

- Regulatory uncertainty in the countries in which it operates.
- Operating risks: downtime of facilities and incidents with environmental impact.
- Market risk: uncertainty regarding fuel prices and revenues from the sale of electricity and gas.
- Credit, exchange-rate, and interest-rate risks.
- Technological and cybersecurity risks affecting the security of the facilities or the information of our customers.

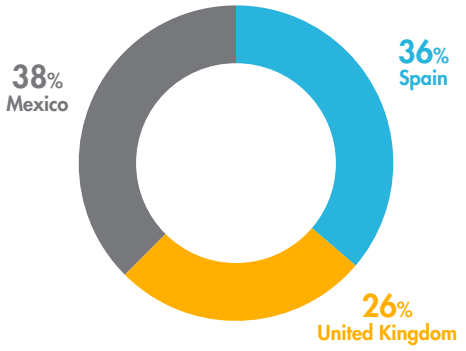
Principal activities 2015

- Spain: start-up of the San Pedro II (25 MW) and Muela II (852 MW) hydroelectric plants. Continued development of products and services adapted to the needs of customers (Customised Plans, Smart Solar, Iberdrola Smart Home ...).
- United Kingdom: the evacuation capacity of the Longannet TP has been abandoned and its closure has been requested for April 2016. Decrease in variable rates for domestic gas customers (–4.8%), effective as from February 2015, which will be followed by an additional decrease (–5.4%) beginning on 15 March 2016.
- Mexico: the construction programme for the Baja California III CCGT (300 MW), 5th unit of Monterrey CCGT (300 MW), and Ramos Arizpe cogeneration (50 MW) plants continues on schedule, with start-up in 2016. The San Juan del Río (50 MW) and Dynasol (57 MW) cogeneration projects also commence. CFE tender awarded for the Escobedo CCGT (857 MW), with entry into operation in 2018.
- Brazil: at year-end 2015, construction ended on the Teles Pires hydroelectric plant, with a total of 1,820 MW, of which 362 MW correspond to Iberdrola, which holds its stake through Neoenergia.

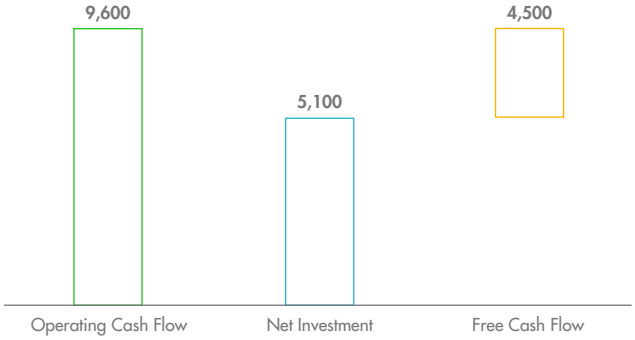
Outlook 2016-2020

- Investments of €M 5,100, mainly to increase installed capacity and to deploy smart meters in the United Kingdom.
- Start-up of 3,450 MW in Mexico, of which 1,600 MW are already under construction.
- In Retail, wager on digitisation, personalisation of products for the customer, and service excellence.
- Continuing improvement of operational processes and practices to increase efficiency.

Investment of €M 5,100 during the period, of which €M 3,700 are for growth



2016-2020 cash flow generation to finance investments (€ millions)



Key figures of the Wholesale and Retail business

		Spain		United Kingdom		United States and Canada		Mexico		Total	
Item	Unit	2014	2015	2014	2015	2014	2015	2014	2015	2014	2015
Gross margin	€M	3,068	2,971	1,205	1,306	3	–20	457	584	**4,734**	**4,842**
Ebitda	€M	1,517	1,502	457	421	–32	–58	350	455	**2,292**	**2,320**
Installed capacity	MW	19,174	20,081	4,835	4,835	NA	NA	5,028	5,082	**29,037**	**29,998**
Net output (excluding renewables)	GWh	47,844	43,616	15,810	14,925	NA	NA	35,175	38,128	**98,829**	**96,669**
Electricity contracts	Millions	10.4	10.4	3.3	3.3	NA	NA	NA	NA	**13.7**	**13.7**
Gas contracts	Millions	0.8	0.9	2.2	2.2	NA	NA	NA	NA	**3.0**	**3.1**
Products and services contracts	Millions	4.4	4.9	0.1	0.1	NA	NA	NA	NA	**4.5**	**5.0**
Total retail contracts	Millions	15.7	16.2	5.5	5.5	NA	NA	NA	NA	**21.2**	**21.7**
Investments	€M	146	188	98	94	4	4	170	370	**419**	**655**
Workforce	N° people	3,478	3,395	2,505	2,491	114	108	434	489	**6,531**	**6,483**

International Financial Reporting Standard (IFRS) 11 has been applied to the financial information for both 2014 and 2015.

⊙ *Quarterly Results Report*

The Wholesale and Retail business is focused on the safety of operations, the loyalty of customers, and growth in Mexico, which will allow for the stability of results and ensure the generation of funds for the group.

Efficiency

- Optimisation of coal production, with investments in low-cost NO_x in Spain.
- Facilitating operations in complementary markets.
- Operating improvements to increase the availability and energetic yield of the Mexico facilities.
- Abandonment of evacuation capacity of the Longannet TP as from April 2016.

Prices

- Minimisation of risks through appropriate hedging of all generation, including renewable generation.

Growth in generation

- Mexico: Placement into service of more than 750 MW in 2016-2017:
  - Baja California III CCGT (300 MW).
  - 5th Unit of Monterrey CCGT (300 MW).
  - Kimberly Clark Ramos cogeneration (50 MW).
  - Kimberly Clark San Juan del Río cogeneration (50 MW).
  - Dynasol cogeneration (57 MW).
- United Kingdom: Widespread deployment of smart meters beginning in 2016, to reach 100% of customers by 2020.

Supply

- Customer loyalty-building in mature markets through the development of new products and personalised services adapted to the needs of customers.
- Retail development in Mexico pursuant to changes in legal provisions on energy reform.

3.4 Renewables

Regulatory environment of the business

Spain

- The terms and conditions for new renewable capacity auctions were defined in 2015, which means recommencement of investment in the wind sector after various years without investments. This auction was held on 14 January, with the award of 500 MW in wind and 200 MW in biomass.

United Kingdom

- Upon completion in 2016 of the various current reforms to contain expenses, it is expected that there will be more visibility regarding the changes in the Levy Control Framework and the existing margin for growth in offshore wind.
- 2016 will also be key for the definition of support for the future development of onshore wind, after moving forward the end of the Renewable Obligation to April 2016, with a one-year grace period.

The business will engage in sustainable growth, based on onshore and offshore wind investments in the countries most important to the group.

United States

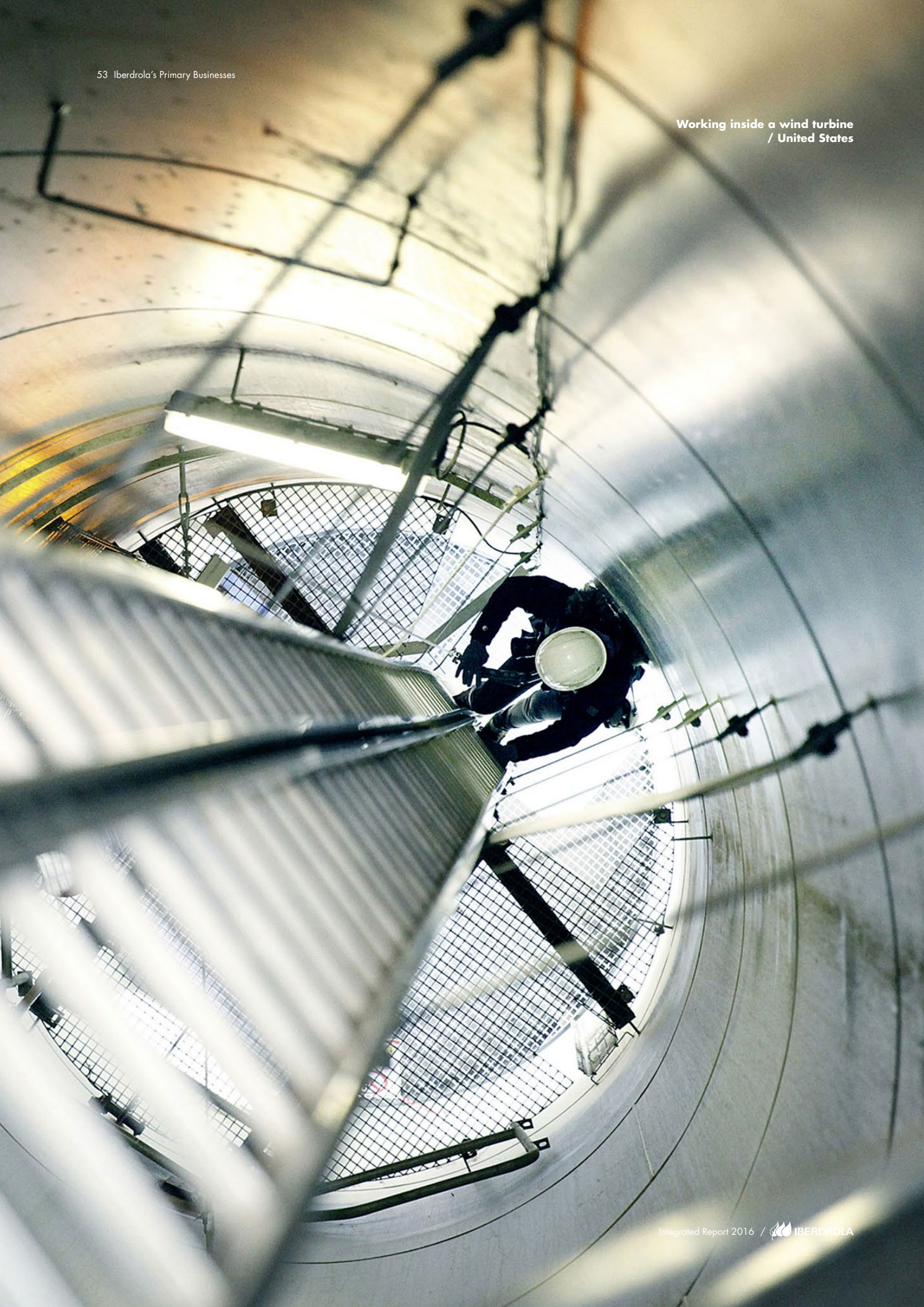
- The tax incentives for wind and solar power have been extended once again. This time the extension is for various years (through 2020 in the case of wind and 2022 for solar), with a gradual reduction that in the case of non-residential solar stays at 10% until the deadline. This extension gives the project portfolio greater visibility.
- It is expected that government schemes to encourage renewables will retain a relatively stable framework.

Mexico

- A Clean Energy goal of 35% by 2024 has been set in the Energy Transition Act (*Ley de la Transición Energética*).
- In the renewables area, there will be auctions of clean energy certificates. The first will take place in March 2016 with delivery in 2018. The second auction, which may include capacity and clean energy certificates for 2019, will also be held in 2016.

Brazil

- The auction model for the development of wind and solar energy is expected to be stable. 1.2 GW of wind and 1.8 GW of photovoltaic were awarded under this mechanism during 2015.
- The proper development of the transmission grid will be increasingly important for growth of the renewables sector, as well as the mechanisms for integrating areas such as the North East.



Working inside a wind turbine / United States

Objectives, risks, and principal activities

Objectives

- Safety in operations.
- Efficiency in operations to maximise the profitability of the assets.
- Efficiency in construction costs, with a particular emphasis on offshore projects.
- Profitable growth in onshore and offshore wind investments in the countries that are strategic for the group.

Significant risks

- Price uncertainty due to competitive auctions in the markets in which it operates.
- Prices of energy and green certifications.
- Operational and technological risk.
- Risk of access to evacuation networks and limits on production due to technical restrictions on networks.
- Cybersecurity risks with an impact on operations centres of the facilities.

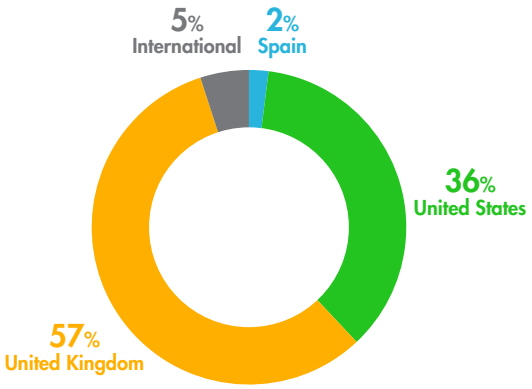
Principal activities 2015

- 2015 saw the start-up of a 202 MW wind farm in the United States and two wind farms in Mexico with a total of 136 MW.
- There has also been commencement/approval of the construction of 5 wind farms with a total of 746 MW in the United States, 8 wind farms with a total capacity of 450 MW in the United Kingdom, and six winning projects for 174 MW from the 2014 tenders in Brazil.
- In offshore wind, there is continued progress on the construction of the 350 MW Wikinger offshore projects in the Baltic Sea (Germany). In addition, the East Anglia I offshore project in the United Kingdom has been awarded a "contract for difference" in the first auction of this kind in the United Kingdom, with a maximum capacity of 714 MW.

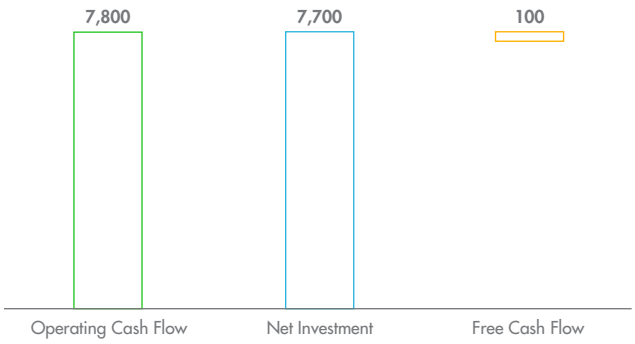
Outlook 2016-2020

- Increase in competition for the entry of new capacity, mainly via auction.
- Investments of €M 7,700, mainly to increase installed capacity in the United States, the United Kingdom, and Brazil.
- Start-up of 3,450 MW, of which 2,440 MW are already under construction.
- Start-up of two offshore wind farms: Wikinger (350 MW) and East Anglia I (714 MW).
- Continuing operational improvement, with cost savings, optimisation of useful life of the assets, and improvement in the capacity curve.

Investment plan of €M 7,700 over the period, of which €M 7,000 are for growth



2016-2020 cash flow generation to finance investments (€ millions)



Key figures of the Renewables business

		Spain		United Kingdom		United States		Mexico		Brazil		Rest of World		Total	
Item	Unit	2014	2015	2014	2015	2014	2015	2014	2015	2014	2015	2014	2015	2014	2015
Gross margin	€M	728	751	368	572	736	822	51	57	42	36	108	123	**2,033**	**2,361**
Ebitda	€M	421	473	265	438	495	499	38	43	33	27	74	92	**1,326**	**1,572**
Installed capacity	MW	5,865	5,861	1,612	1,615	5,534	5,534	231	367	187	187	621	621	**14,051**	**14,186**
Output	GWh	12,685	11,463	3,083	3,694	14,462	13,868	671	738	344	441	1,247	1,371	**32,492**	**31,576**
Load factor	%	24.7	22.3	23.4	26.2	31.0	28.8	33.2	31.5	37.2	39.1	22.9	25.2	**27.2**	**25.7**
Investments	€M	–13.4	9.9	475.2	488.8	236.5	69.6	62.7	124.7	20.8	38.4	–23.4	3.4	**758.2**	**734.8**

Notes:

– The figures for the United Kingdom include those of the offshore division.

– The investment figures for Spain and Rest of World in 2014 are negative due to writeoffs and reclassifications of past investments.

⊙ *Quarterly Results Report*

The business will focus on the safety of operations and on sustainable growth, based on onshore and offshore wind investments in the countries most important to the group. Efficiency is a key factor for business sustainability in the medium and long terms. Iberdrola will take technological advances into account and will act on the supply chain to allow for improvement in the coming years.

Load factor

Maximising the load factor of facilities, while minimising down time through operating and maintenance measures, as well as other external factors.

Operation and maintenance costs

Continuous improvement in efficiency through global standardisation and systematisation processes.

Project portfolio

Development of the portfolio of onshore wind projects in the United Kingdom, the United States, Mexico, and Brazil, and the East Anglia 3 (United Kingdom) and St Brieuc (France) offshore wind projects.

3.5 Supply Costs, the Main Factor in the Political and Social Agenda

The cost of electricity supply is taking on a greater role in the political and social agenda. The principal challenge is to reconcile safe and environmentally-friendly supply with the use of renewable energy at prices that are competitive and can be afforded by society as a whole.

In the European Union

- An analysis of electricity prices in recent years reveals that taxes and components associated with energy and environmental policies have grown the most, reaching half of the bill in countries like Spain, due to the significant renewables effort made by the electric sector. A competitive electricity supply necessarily entails the elimination of cost components outside of the service itself in the electricity bill, and paying for these costs through general taxes or taxes on all polluting energies.
- The strategy of the Energy Union that commenced in 2015 responds to the need to comply with the 2030 environmental agenda (according to the European Council in October 2014: 40% reduction in greenhouse gas emissions, 27% increase in renewables, and 27% improvement in energy efficiency), monitoring the safety of supply as well as the competitiveness of the European industry and the need for prices that are accessible for European citizens.

In Spain

- Rates paid by electricity consumers include costs deriving from the pursuit of strategic energy goals: environmental (aid for renewable energy and the costs of reducing CO_2 emissions), industrial (interruptibility of large consumers and aid for co-generation), social (subsidies for electricity in non-mainland territories), economic (recovery of tariff deficits from previous years), and public finance.
- Less than half the costs of electricity supply are directly related to providing the service; the rest are subsidies and taxes. With some supply costs below the European average, the end prices of electrical energy for Spanish consumers are higher than the Community average.

In the United Kingdom

- Public debate on energy prices has focused on the investigation launched by the Competition and Markets Authority (CMA).
- The increase in costs unrelated to energy, such as those associated with networks and government support systems, have restricted an expansion of the reductions in energy prices.

In the United States

- Tariff revisions currently under discussion or preparation reflect pressure by regulators to limit returns on capital, while at the same time maintaining the investments required to improve the network infrastructure.
- The closure of coal plants and the new regulation developed by the Environmental Protection Agency (EPA) may increase pressure on gas and electricity prices, although shale gas production may limit this impact.
- Restrictions on transporting natural gas by pipeline in the Northeast could lead to volatility in electricity market prices during periods of extreme weather.
- The development of smart grids, the rapid replenishment of supplies in the face of extreme weather conditions, new EPA regulations, and the integration of new energy sources into the system require major investments, which sometimes conflicts with the desire to limit compensation to the companies.

In Mexico

- Energy reforms were launched in 2014, with one of the key goals being to reduce system costs in order to lower electricity prices for end users. The reform is ongoing at the corresponding regulatory bodies: the implementing act is already approved and the various market instruments are being put into operation.
- The fall in commodities prices during 2015 has allowed for a reduction of the CFE's tariff.

In Brazil

- To cover the high costs from the long period of drought, "tariff realism" has been applied by which extraordinary tariff revisions and a readjustment of the "tariff flags" has rebalanced the economic/financial equilibrium of the distributors.
- 2015 was marked by negotiations of hydrological risk, which culminated with the approval of law 13,203/2015. This allows hydroelectric generators to voluntarily assign hydrological risk in exchange for a premium, obtaining funds from a power production cost overrun offset mechanism, called "tariff flags".

Iberdrola will support frameworks that expand market deregulation and transparency and that provide incentives for required investments and efficient operations, through tariff structures that give efficient signals to consumers and do not penalise them with costs unrelated to the supply of electricity.

West of Duddon Sands offshore wind turbines / United Kingdom

4.

Our Assets

Iberdrola's assets are the basis for the creation of value by the Company, which carries out its activities through the sound management thereof.

In this report, Iberdrola's assets are identified in accordance with the IIRC classification system:

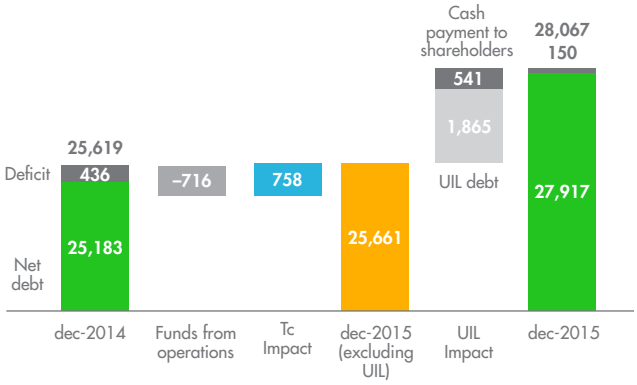
- **Financial Capital**
- **Manufactured Capital**
- **Intellectual Capital**
- **Human Capital**
- **Natural Capital**
- **Social and Relationship Capital**

4.1 Financial Capital

	Management Approach	Results 2105	Outlook
Balanced growth	The Company has an investment policy consistent with its strategic vision and financial policy. The main goals are: • Ensure a return on capital through projects and investments preferably in regulated businesses, renewable assets, or long-term contracts. • Increase geographic diversification, further balancing the contribution of the countries in which it does business. • Tailor investment levels to the actual needs of each market.	• Total investment of €M 3,223, with almost 91% channelled into regulated businesses. • The United Kingdom was the country absorbing the highest volume of investments, with 46% of the total, followed by Spain with 20%, the United States with 16%, and Mexico with 15% of the amount invested.	• Strict investment criteria based on earnings security, project profitability, and strategic fit. • Selection of businesses and countries with predictable and stable regulation. • Net investment of more than €M 24,000 over the 2016-2020 period, of which 88% will be dedicated to regulated businesses, renewables, or long-term contracts. • The United Kingdom will continue to be the area with the highest volume of investments, with 39% of the total, followed by the United States with 34%, Spain with 16%, and Latin America with 11%.
Solid financial structure	• Iberdrola considers financial strength to be one of the strategic cornerstones that allows it to successfully face potential turbulence in the markets and to be in a position to exploit growth opportunities in the countries in which it does business. • The financial policy seeks stabilisation and subsequent improvement in solvency ratios, balancing an increase in debt with the generation of additional cash flow from new investments. • The debt structure is in line with the profile of the business, which is mostly regulated, and the composition thereof reflects the results obtained in the relevant currencies.	• Gross margin of €M 12,843, growing by 5.4%. • Net profit of €M 2,422, a 4.1% increase over the prior year. Recurring net profit was €M 2,261 (+7.0%), as a result of the favourable performance of the businesses. • Cash flow of €M 5,907 (+8.2%). • Pro forma net debt is practically the same, as the generation of cash flow offsets the impact of the appreciation in foreign currency. The merger of UIL adds €M 2,406, putting the year-end figure at €M 28,067. • Liquidity of more than €M 8,000, which covers more than 36 months of financing needs.	• Average annual Ebitda and net profit growth of approximately 6% during the 2016-2020 period. • Average annual net investments of approximately €M 4,800, compared to average annual cash flow generation (FFO) of €M 6,900. • As a result of the investment process, increase in net debt to approximately €M 31,000 between 2018 and 2019, and subsequent decrease to €M 30,000 by 2020. • Progressive improvement of the net debt/Ebitda and operating cash flow/net debt financial ratios. • Optimisation of the liquidity position to cover financing needs for 24 months.
Operational efficiency	• The current macroeconomic and regulatory environment requires an additional effort to keep operating costs under control.	• Net operating expense increases 5.4% due to the effect of the appreciation of the pound and the dollar. Excluding this impact, it would have decreased by 1.6%.	• Progressive absorption of the increase in expenses, which will grow less than gross margin during the 2016-2020 period, maintaining an industry-leading position of leadership in cost efficiency.
Sustainable results and dividends	• Iberdrola offers its shareholders an industrial enterprise for the long-term creation of value. The confidence of its shareholders enables Iberdrola to secure the resources needed to move its enterprise forward.	• Shareholder remuneration of 0.28 euro per share, equal to a dividend yield of 4.21% • Flexible dividend offering tax benefits.	• Increase of dividend to 0.28 euro per share, with a charge to 2015 profits. • Maintenance of the flexible dividend programme. • Target of maintaining the number of shares at 6,240 million, neutralising the capital increases associated with implementation of the flexible dividend programme. • Potential growth in shareholder remuneration, in line with the increase in results, based on a payout ratio of between 65% and 75%.

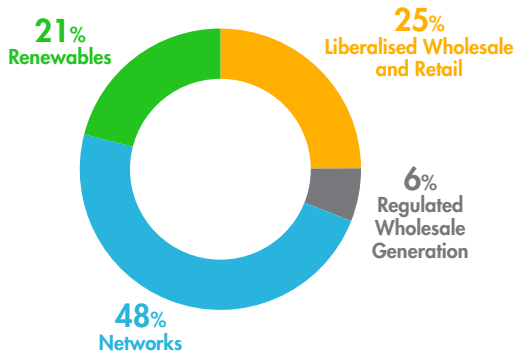
Create value for the shareholder with sustainable growth

Net Debt (€M)

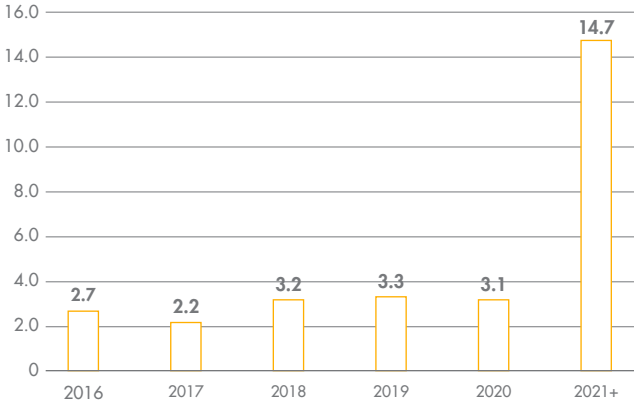


Pro forma Net Debt is practically the same, as the generation of cash flow offsets the impact of the appreciation in foreign currency. The merger of UIL adds €M 2,406 (value at 31 December 2015), putting the year-end figure at €M 28,067.

Ebitda by business 2015



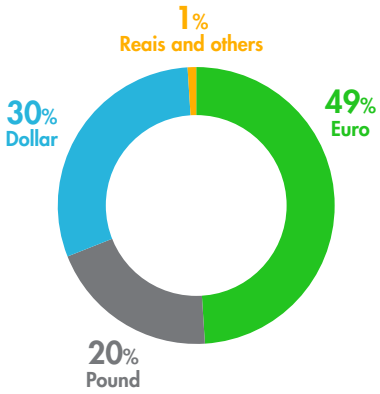
Maturity of financial debt* (€M)



Includes €M 1.5 in notes. Includes €M 1,865 of UIL debt (value at 31 December 2015).

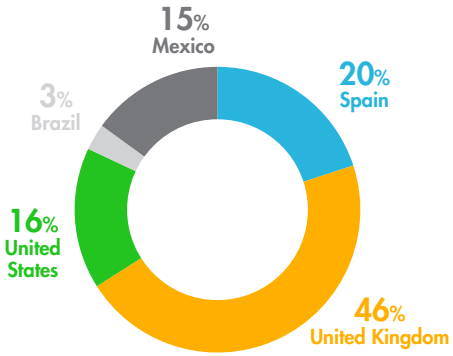
Comfortable maturity profile.

Debt structure by currency in 2015



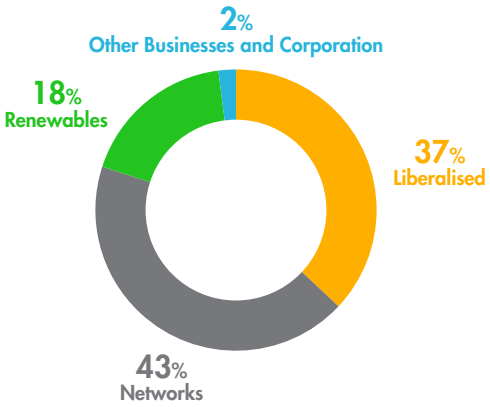
Debt structured by origin of cash flow earned in each currency. Includes derivatives to hedge net investment.

Investment by geographic area 2015



Diversification of investments, with a heavy concentration outside of the euro zone.

Gross margin by business 2015

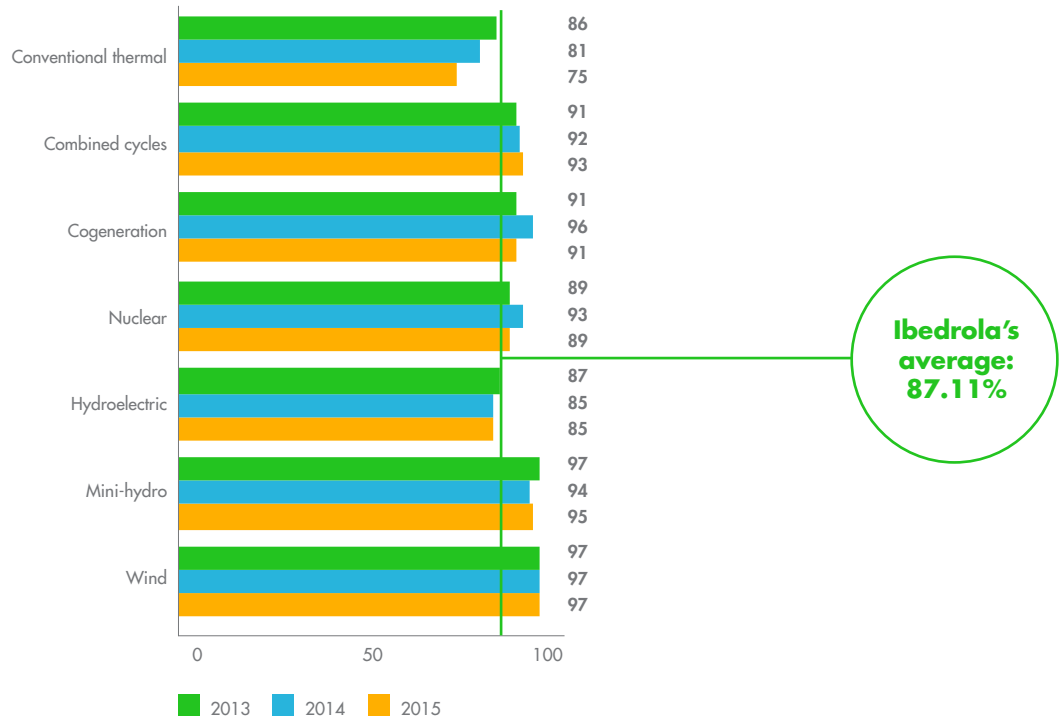


4.2 Manufactured Capital

	Size	Principal Activities 2015	Outlook
Electric power generation assets	• Iberdrola's generation assets comprise nearly 300 wind farms, almost 90 hydroelectric power plants (in addition to the mini-hydro plants), 34 thermal power stations using various technologies, 5 of which are nuclear, and other facilities built and operated according to the best available practices.	• ISO 9000 certification has been attained for the operation of wind farms in Spain and the United Kingdom.	• Almost 1,400 MW of onshore wind (450 MW United Kingdom, 746 MW United States, and 174 MW Brazil) and 1,060 MW offshore wind (350 MW Wikinger and 714 MW East Anglia I) under construction. • In Mexico, construction will continue on 1,450 MW in combined cycle and 160 MW in cogeneration. • In Portugual, there is continued construction of the Tamega hydro complex, with 1,160 MW. • In Brazil, work continues on the construction of the Baixo Iguazu (350 MW total) and Belo Monte (11,233 MW total) hydroelectric plants, through Neoenergia.
Power transmission and distribution assets	• Iberdrola's electricity transmission and distribution networks comprise over 30,000 km of transmission lines, over 1 million km of distribution lines, roughly 4,000 substations and over 1.4 million transformers, built and operated to supply a high-quality, reliable service.	• The Maine Power Reliability Project in Maine has been completed. This began in 2010 and entailed an investment of more than $M 1,400. • The DPCR5 regulatory period has ended in the United Kingdom. During its 5-year term (2010-2015), it has made a fundamental leap forward in renewal of the distribution networks in Scotland and Wales.	• Significant proposed transmission projects in the State of Maine to allow for the construction of two wind farms that will help to meet the demands for renewable generation in New England by 2020. • Investments in the United Kingdom transmission network, to improve the reliability and quality of supply. Especially noteworthy is a subsea cable linking the networks of Scotland and England (Western Link). • Development of the P2020 strategic project in Spain, aimed at achieving increased efficiency, operational safety, and quality of supply.
Other Assets	• Iberdrola manages more than 680,000 m² of offices throughout the world, with a total of 769 properties, of which 358 are located in Spain, 44 in the United Kingdom, 117 in the United States, 231 in Brazil, and 19 in the rest of the world. These properties are designed, built, and operated in accordance with sustainability and efficiency standards.	• All of the real property in Spain is covered by a certified environmental management system in accordance with the ISO 14001 standard, with the scope being expanded this year to the offices in Portugal (Porto and Lisbon) and to the United Kingdom (Ochil House). • The headquarters in Madrid and Bilbao also have a certified energy management system in accordance with the international ISO 50001 standard.	• Expansion of the scope of the energy management system at the main properties in Spain, in order to understand energy use and consumption. This information is obtained by implementing control systems and defining base lines. • 2016 is expected to see the completion of phase I of the San Augustín Campus construction project and the new ScottishPower headquarters in Glasgow; both projects under a LEED certification for sustainable building.

Offer a secure supply of energy that is competitive in price and quality

Average availability factor of Iberdrola's generation facilities (%)

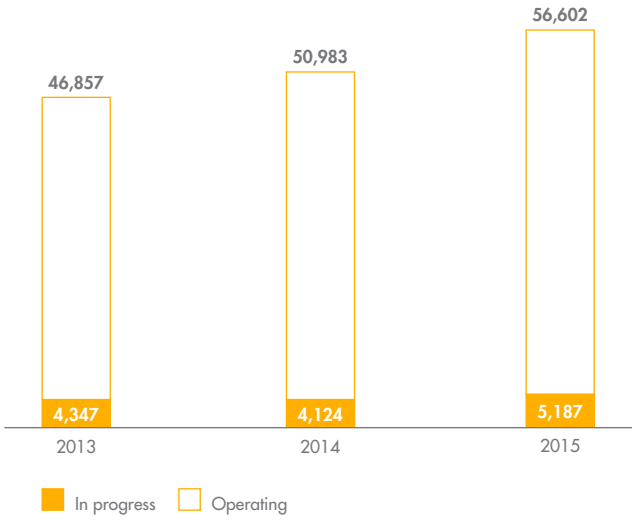


Quality of electricity supply

Average power outage duration		2014	2015
Spain	TIEPI (m)	55.7	61.9
United Kingdom	CML (m)	44.0	34.8
United States	CAIDI (h)	1.89	1.89
Brazil	DEC (h)	19.93	18.81
Power outage frequency		**2014**	**2015**
Spain	NIEPI (number)	1.07	1.20
United Kingdom	CI (ratio)	48.0	40.1
United States	SAIFI (index)	1.23	1.21
Brazil	FEC (frequency)	7.62	7.22

TIEPI: Installed Capacity Equivalent Interrupt Time.
CML: Customer Minutes Lost Per Connected Customer.
CAIDI: Customer Average Interruption Duration Index.
DEC: Equivalent Duration of Interruption by Consumer Unit.
NIEPI: Installed Capacity Equivalent Interrupt Number.
CI: Customer Interruptions Per 100 Connected Customers.
SAIFI: System Average Interruptions Frequency Index.
FEC: Equivalent Frequency of Interruption by Consumer Unit.

Property, plant, and equipment (€M)



4.3 Intellectual Capital

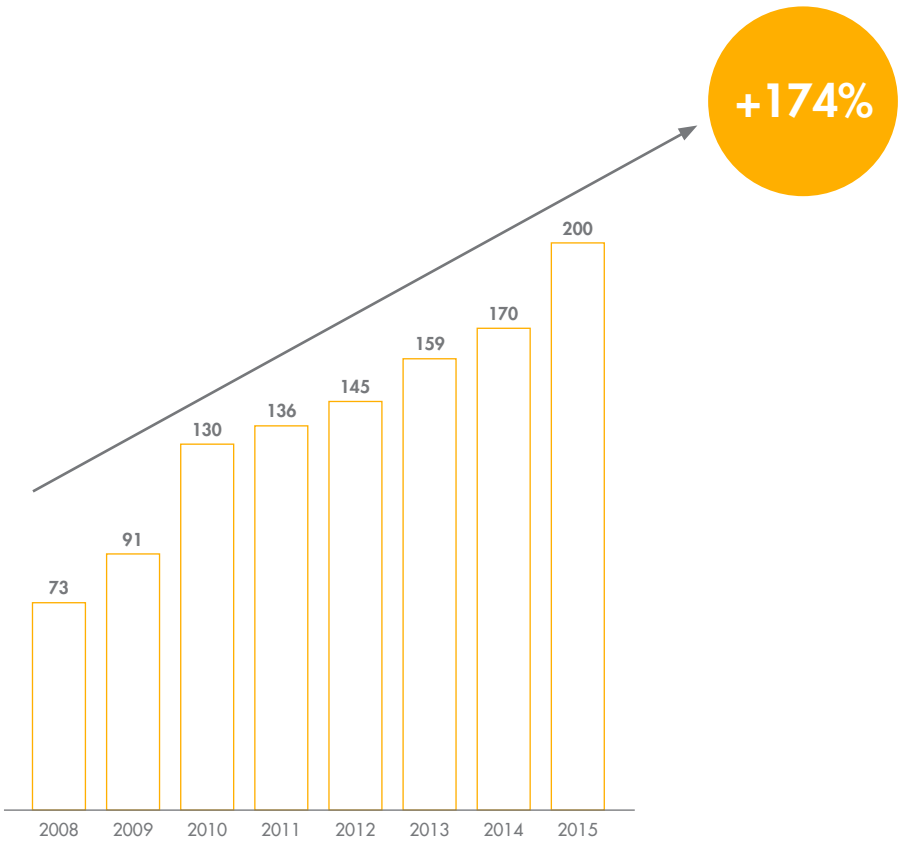
	Management Approach	Principal Activities 2015	Outlook
Promotion of R&D	• Innovation is Iberdrola's primary tool for ensuring the Company's sustainability, efficiency, and competitiveness. R&D efforts are aimed at optimising operational conditions, improve security, and reduce environmental impact. ⦿ Innovation Report	• Significant increase in R&D investment: €M 200 in 2015, a 18% increase over 2014. • More than 200 R&D projects, with initiatives relating to smart grids, clean generation, offshore wind power, and new business technologies and models. • Iberdrola has been given the National Innovation and Design Award 2015 in the category of "Internationalisation".	• Development of the R&D Plan 2015-2017. • Strengthening of an open and decentralised international management model that prioritises collaboration with technology providers and the promotion of employee innovation. • Continue to promote R&D projects.
Efficiency and new products and services	• Continuous optimisation of our operations, management of the lifecycle of facilities and equipment, reduction in operating and maintenance costs, and decreasing environmental impact. • Development of new and competitive products and services that adapt to an increasingly global market, the main goal of which are to meet the needs of customers.	• New category of products that allow customers to choose the plan that best suits their lifestyle, without needing to change their consumption habits. • New products and services in the areas of energy efficiency, electric vehicles, smart grids, and distributed generation. This includes Smart Solar Iberdrola, through which customers can generate and consume their own electrical power, optimising consumption and improving the energy efficiency of their facility.	• Positioning as innovation leaders on prestigious external indices and ratings. • Foster the creation of new business opportunities for Iberdrola.
Disruptive technology and business models	Through Iberdrola Ventures-Perseo, the Company's corporate venture capital programme, investments are made in disruptive technologies and new businesses to ensure the sustainability of the energy model. Lines of activity: • Customer-Focused Solutions: energy efficiency, demand management, green mobility, etc. • Distributed Energy Resources: innovative generation and storage solutions. • Renewable Energy: technologies related to renewable generation (solar, wind, offshore). • New technologies applied to the operation and maintenance of energy infrastructures: robots, sensors, software, etc.	With an investment of more than €M 50 since 2008. The main activities in 2015 included: • Investment alongside CDTI in the Basque company Atten2, a spin-off of IK4-TEKNIKER with headquarters at the Guipúzcoa Technology Park in Eibar. The company is specialised in the design, manufacture, and sale of sensors to monitor fluid flows, primarily lubricating oil, in industrial applications. Its first products, OilHealth and OilWear, are sensors used for monitoring oil in wind turbines. • In the social investment sphere, investment in SunFunder, which has built a funding platform to allow financial investors and companies to participate in a diversified portfolio of off-grid solar projects in emerging market countries in Africa, Latin America, and Asia. To date, SunFinder has financed more than 5 million dollars in projects, to the benefit of more than 360,000 users.	• Ensure Iberdrola's access to the energy technologies of the future. • Foster entrepreneurship and the development of an innovative entrepreneurial fabric within the energy sector: investment in initiatives with a high social and job creation component. • Establish alliances with key technology providers for Iberdrola (Open Innovation Ventures). • Through the Innvierte programme alongside CDTI, use public and private venture capital to develop and strengthen innovative technological startups with high growth potential in Spain.

Highlight the value of the Company's intangible assets

Main R&D research projects

Renewable energy	• Various projects to improve the efficiency of assets and models for the design of wind farms. Diagnosis Matrix Project to diagnose anomalies and prevent failures of wind turbines. • Continuation of OWA activities in the United Kingdom to reduce costs and the implementation risk of offshore wind technology. Floating Lidar project, to replace fixed meteorological towers with floating stations using an alternative measuring system known as "Lidar". • Integration of renewable energies. SmartWind project, which implements models and simulations for the use of wind farm-related storage to provide standby services.
Smart Grids	• Completion of the Price project, the goal of which was to meet the needs identified for the development of a smart grid within an efficient, safe, and sustainable framework. • UpGrid project for the integration of active demand and low-voltage distributed generation. • The Arc, Flexnet, and Visor projects are being carried in the United Kingdom to strengthen smart grids.
Clean generation	• The CO_2Formare project to capture CO_2 emitted by generation plants and use it to replace sodium hypochlorite to resolve the problem of "macrofouling" in a sustainable manner while reducing the environmental impact on both atmospheric emissions and that aquatic environment. • Significant progress was made on the Filtraciones Project, with the development of a new methodology for efficiently inspecting water channels.

Investments in R&D (€M)



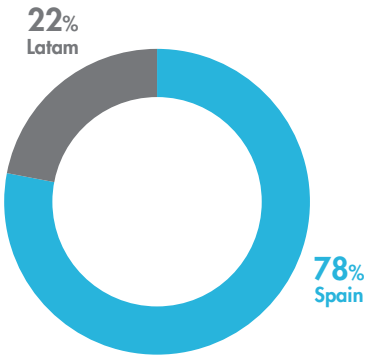
4.4 Human Capital

	Management Approach	Principal Activities 2015	Outlook
Global human resources management	• Achieve the goals of competitiveness and business efficiency in a climate of social peace, fostering stable, high-quality employment. • Harmonise human resources processes and make inroads with implementing the Iberdrola culture in all countries, respecting specific local conditions.	• Implementation of the project for global consolidation of the Human Resources Model (OneHR project) at Elektro. • Management of an appropriate labour relations framework that can be adapted to suit business and social requirements.	• Strengthen the commitment to social responsibility, fostering ethical and responsible behaviour. • Consolidate the Human Resources function at AVANGRID, extending and unifying best practices.
Goal of "accident reduction"	• Prioritise the safety of individuals at the group's facilities and within its sphere of influence, fostering a progressive reduction in incident rates and improving health and safety conditions. • Replicate throughout the group the best practices identified in the area of occupational health and safety, fostering a culture of excellence in management and coordinating global preventive activities.	• Attainment and/or maintenance of the OHSAS 18001 certification, and approval of a system of global prevention standards in accordance with the group's policy. Assessment of level of conformance to global standards. • Monitoring of proactive and reactive indicators among the group's companies for the global scorecard. • Continue harmonisation and monitoring of goals. • Identification and application of best safety practices/Exchange of lessons learned/Creation of groups to promote safe behaviour.	• Continue with assessment of level of conformance to global standards and the implementation of improvement groups to promote safe behaviour. • Continue developing certifications of the group in accordance with OHSAS 18001. • Analysis of incident rate and establishment of goals for a global model for the management of occupational health and safety at subcontractors. • Global campaigns to raise awareness on certain types of common accidents. • Define the global SSL strategy for the coming years.
Talent management	• Drive staff qualifications, preparing employees to work in a multicultural environment and making continual efforts to improve their employability. • Develop alternatives to compensate for factors stemming from the ageing of the workforce. • Define a framework to develop a global quality management system.	• Promotion of job and international mobility within multicultural teams. • Review of the programmes and initiatives at the Management School, launch of the mobile version of e-leaders. • Expansion of the professional training and development model to other countries (Mexico and Brazil). • Unification of the process for identifying the group with potential for management development. • Campaign to encourage Gender Equality in hiring processes.	• Strengthen the talent and leadership development management model at the international level. • International certification of training quality. • Define and implement the Global Development Roadmap for the Iberdrola group. • Global executive talent management.
Diversity, equal opportunity, and reconciliation	• Guarantee a social model committed to professional excellence and the quality of life of our employees. • Development of labour relations based on equal opportunity, non-discrimination, and respect for diversity. • Create a high-quality working environment by committing to reconciliation. • In the countries in which the Company operates, foster a position of leadership in these areas similar to that enjoyed in Spain.	• International cultural exchange programmes. • Corporate Volunteerism focused on the integration of vulnerable groups, including: "International Volunteering Day", the "Sao Paulo 2.0" international volunteering programme, the "*Luces y Acción*" ("Lights, Action") programme, and the "*IBERDROLA con los refugiados*" ("IBERDROLA for refugees") project. • Joining in the "Engineering Foundation Programme" in the United Kingdom and renewal of "Troops to Energy" in the United States and "Energy for the future" in Brazil.	• Increase in team pride, workforce satisfaction, job commitment, and productivity. • Foster improvements in the quality of people's lives through social-welfare activities in all of the countries in which the Iberdrola group has a presence, creating a global volunteer community. • Promote the internationalisation of social programmes and strengthen ties among the employees of the group at the global level.

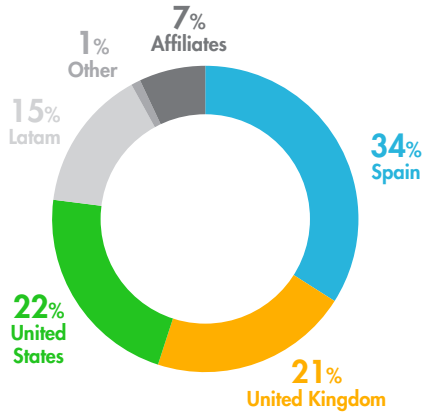
Ensure the availability of a committed, qualified workforce in a safe and stable environment

Growth and geographic diversification of the workforce

2006: 16,155 employees.



2015: 30,938 employees



⦿ Key Figures / page 10

Commitment to people

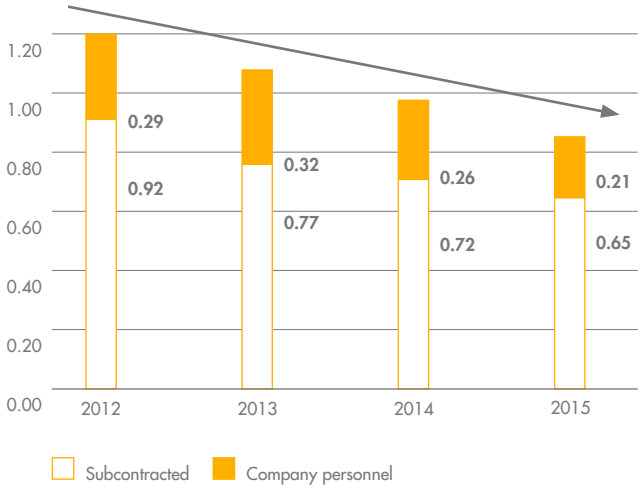
- Iberdrola Sao Paulo Volunteerism 2.0-2015
- "My guest" cultural exchange programme 2015.

First MBA Iberdrola graduates 2015-2016 in "Global Energy Industry"

Social recognition

- Iberdrola: top preferred company to work for in Spain in the energy sector and 7th place generally among companies in Spain.
- Elektro: again chosen as best company to work for in Brazil.

Incident rate (2012-2015): gradual reduction



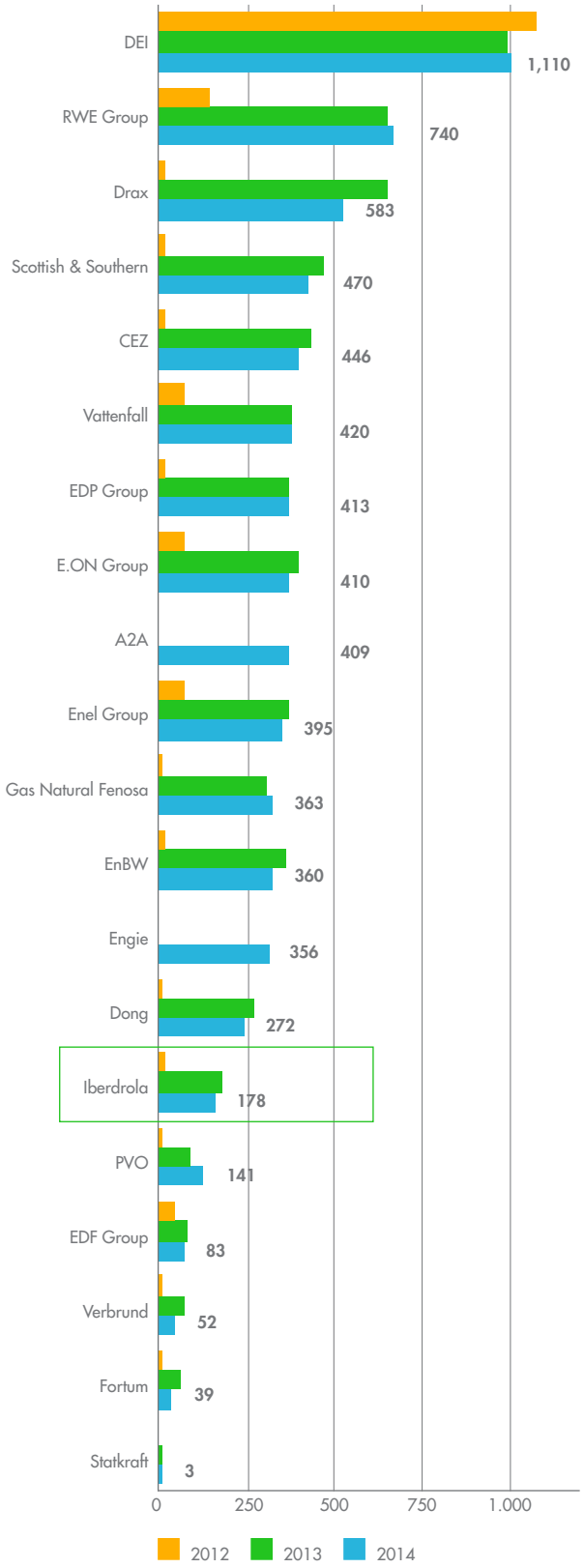
37.5% in subcontracted personnel and 36.4% in Company personnel.

4.5 Natural Capital

	Management Approach	Principal Activities 2015	Outlook
Environmental management and biodiversity	• Actively promote environmental contemplating the life cycle and biodiversity due to the repercussions thereof on the availability of natural resources and its ties to social development. • Inform and raise awareness, both internally and externally, of the compatibility of the Company's activities with the protection, conservation, and sustainable use of the natural environment.	• New environmental projects from the product life cycle perspective. • Development of the Iberdrola group's Environmental Footprint. • The Comprehensive Environmental Management System has been expanded in Portugal. • ISO 14001 certification of the Integrated Management System in the United Kingdom. • Development and certification of Environmental Product Declaration (EPD) for the kWh produced by the Degollada and los Lirios wind farms. • Participation in the Biodiversity Pact *(Pacto por la Biodiversidad)* working group. • Assessment of ecosystemic services generated by infrastructure.	• Broader implementation of the ISO 14001 standard. • Verification by AENOR of the organisation's Environmental Footprint. • Development of EDP for an offshore wind farm. • Certification of a Sustainable Shareholders' Meeting. • Restoration, recovery, improvement, and maintenance of surroundings and habitats. • Identification and classification of the biodiversity in the vicinity of Iberdrola's facilities and dissemination of the knowledge acquired.
Prevention of pollution	• Prevent pollution and the emission of greenhouse gases through practices that reduce or eliminate the production of pollutants at source. • Reduce emissions per GWh produced via the installation of desulphurisation units, the introduction of improvements to the combustion process, and the decommisisoning of less environmentally efficient units.	• 25% reduction in intensity of CO_2 emissions per kWh produced since 2007. • Thermal emission factor has decreased from 476 gr/thermal kWh generated in 2014 to 461 gr/kWh generated in 2015. • Increase in emission-free installed capacity to 63%. • Registration of verified carbon footprint by the Spanish Ministry of Agriculture, Food, and Environment. • New commitment to reduce emissions and actively participate in the Paris Climate Change Conference. • Preparation of new sustainable mobility plan.	• Achieve a 50% reduction in emissions intensity by the year 2030 in comparison to 2007. • Carbon neutral by 2050. • Develop innovation projects geared towards reducing pollution. • Actively participate in achieving the Sustainable Development Goals approved in September 2015 (goals 6, 7, and 13).
Operating excellence and energy efficiency	• The performance of activities that foster environmental conservation will enable Iberdrola to improve its competitiveness, with greater efficiency in the production and use of energy. • Efficient management of scarce resources such as water is a priority for the Company.	• Activities aimed at continual improvement to increase energy efficiency and promote the use of environmentally friendly resources.	• Development and promotion of ecodesign initiatives. • Life-cycle and green purchasing analysis.
Waste management	• Non-hazardous waste is managed via environmental management systems, which set targets for waste reduction and the use of recycled material. • The production and disposal of hazardous waste is carried out in accordance with the strict laws applicable in each country.	• Reuse of waste from thermal coal plants. • Carry out waste minimisation plans, recycling plans, and awareness campaigns aimed at employees.	• Make progress in the optimisation of waste management: circular economy. • Draw up economic/financial analyses of the best waste management strategies.

The environmental dimension is a key factor in the concept of sustainability

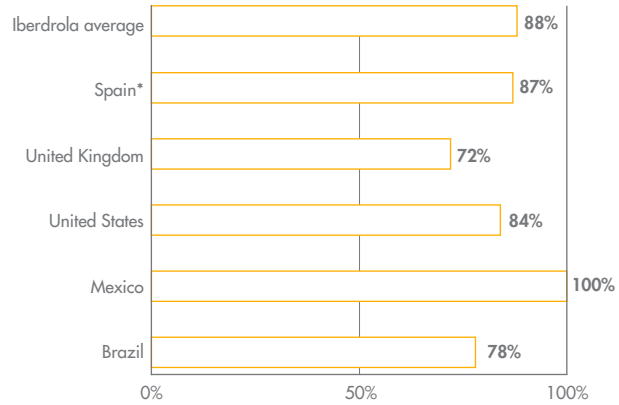
CO_2 emissions at companies in the sector
(Carbon factor in kg of CO_2/MWh)



European carbon factor 2014: 313 kg CO_2 /MWh

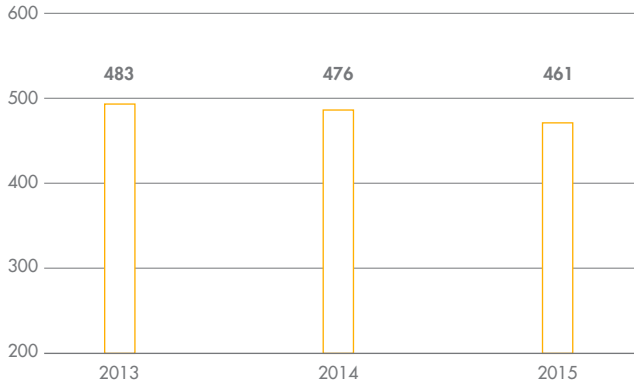
Source: *"Facteur carbone européen Comparaison des émissions de CO_2 des principaux électriciens européens" PwC France. Nov 2015*

Production of Iberdrola plants using local energy sources in the countries in which it operates

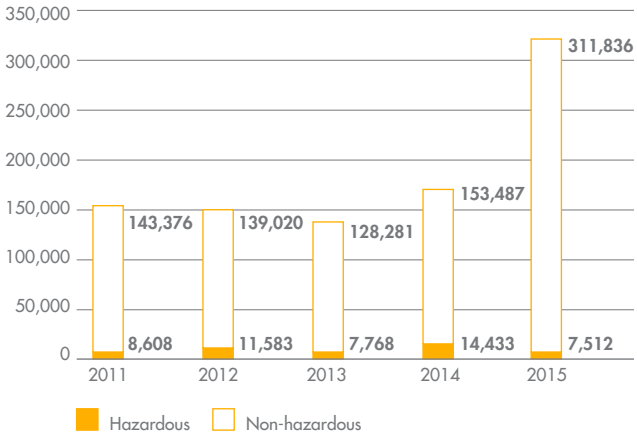


* Nuclear fuel acquired from the Spanish company Enusa is considered a local source.

Intensity of emissions at the thermal plants of the group (CO_2/MWh)



Volume of recovered, reused, or recycled waste (t)



Key Figures / page 10

4.6 Social and Relationship Capital

Stakeholder relations

Iberdrola wants to strengthen trust and the connection to institutions and companies in its environment, maintaining responsible relations with groups that affect or are affected by the activities carried out by the Company (Stakeholders).

Management Approach

Iberdrola's strategic approach sets great store by its relations with Stakeholders, giving importance to the dual facets of this relationship:

- In terms of social responsibility, meeting their expectations and needs.
- In terms of reputation, managing Stakeholders' perception of the Company.

A materiality analysis allows for prioritisation of the issues most important to the Company's Stakeholders.

Principal Activities 2015 and Outlook

- Updating the channels of communication with Stakeholders to identify the most important issues and provide a well balanced, reasonable response thereto.
- Monitoring of the AA1000 Assurance Standard, in accordance with the principles of inclusiveness, materiality, and responsiveness established in such standard, both in the businesses as well as in the corporate areas of the group. The AA1000 standard will continue to be advanced and applied throughout the Company in the coming years.
- The Board of Directors approved a Stakeholder Relations Policy, which has undergone an exhaustive review by a working group in which external experts have participated.

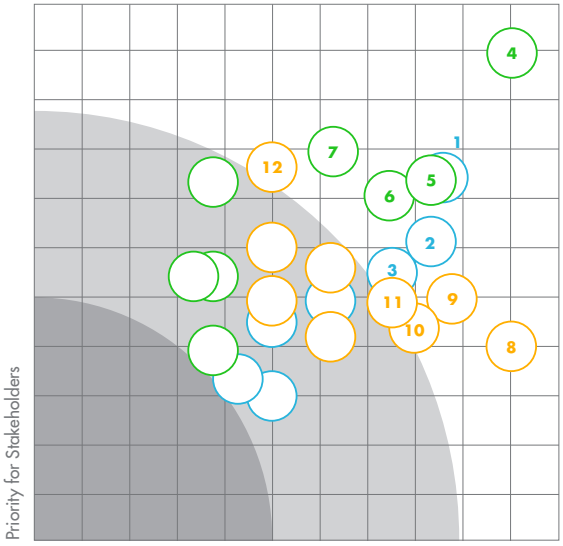
Materiality

Materiality analysis

A study of materiality allows for prioritisation of the issues most important to the Iberdrola's Stakeholders. The chart below summarises the main issues.

In the *Sustainability Report 2015* Iberdrola explains the management approaches taken by the Company in regard to these significant issues and any results achieved during the financial year.

2015 Iberdrola Group Materiality Analysis



- Economic dimension
- Environmental dimension
- Social dimension

Material matters

1. Business innovation and opportunities
2. Economic performance and fiscal transparency
3. Customer satisfaction
4. Development of renewable energy
5. Electricity generation
6. Climate change strategy
7. Electricity and gas supply
8. Human rights
9. Attraction and retention of talent
10. Socioeconomic impact on the local community
11. Health and safety of employees and contractors
12. Access to energy for vulnerable customers

Other identified matters

Anti-corrupción
Unfair competition and monopolistic practices
Public policy
Supply chain management
Environmental performance: operating efficiency
Environmental impact management
Biodiversity impact management
Water use management
Labour practices
Development of human capital
Social-welfare actions
Physical security of facilities (community)

Community support and electricity access programmes

Primary programmes

Activities 2015

- Contribution of €M 38 to the community, measured according to the London Benchmarking Group (LBG) international standard, in the countries in which Iberdrola operates.
- International corporate volunteering programme, offering more than 8,000 volunteering opportunities to employees in Spain, the United Kingdom, the United States, Mexico, and Brazil.
- Entrepreneurial support: over €M 36 of procurement from companies in operation for less than 5 years, and €M 70 in venture capital for new initiatives with high technological value.
- Programmes and pricing to aid vulnerable groups in Spain, the United Kingdom, the United States, and Brazil.
- Rural electrification programmes in Brazil, to which over €M 8 has been allocated on a consolidated basis.
- Programmes implemented by the foundations created by Iberdrola in the principal countries in which it operates.
- Development of the *Programa Electricidad para todos (Electricity for All Programme).*

Electricity for All

- The Sustainable Development Goals (SDGs) 2015-2030, approved at the UN Sustainable Development Summit in New York (September 2015), entail the recognition of energy as an engine of sustainable growth.
- The *Electricity for All Programme* is Iberdrola's response to this demand to extend universal access to modern forms of energy, with environmentally sustainable, financially affordable, and socially inclusive models. This initiative is focused on sustainable electrification activities in emerging and developing countries.
- Iberdrola has set itself the goal of reaching 4 million beneficiaries of this programme by 2020. At year-end 2015, the programme already exceeded 1.4 million users.

Economic value distributed (€M)

Item	2014	2015
Procurement from suppliers	4,599	5,093
Payments to providers of capital	2,753	1,646
Payments to government administrations	2,445	2,746
Employee remuneration	2,086	2,187

⊙ *Sustainability Report*

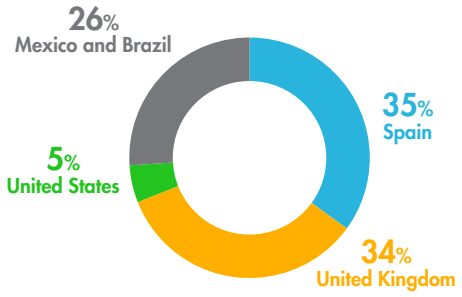
Iberdrola group foundations

Activities 2015

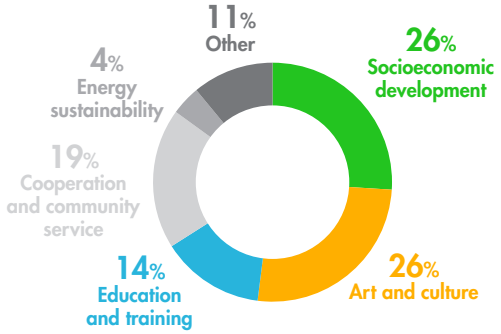
- Iberdrola has implemented a new foundation structure that entails having a foundation in the countries in which it does business. Each foundation is linked to Iberdrola's country subholding company in Spain, the United Kingdom, the United States, Mexico, and Brazil.
- It has also created a Foundations Committee, an internal body that must ensure the proper coordination of all of the foundation-related activities of the Iberdrola group.
- As regards the activities themselves, it has adapted and promoted the four areas of the Master Plan:
  - Training and research
  - Art and culture
  - Sustainability and biodiversity
  - Cooperation and community service (solidarity)
- In the training area, Iberdrola's *Scholarships and Research Assistance Programme* gave a total of 115 scholarships for students in the five aforementioned countries in 2015.
- In the area of art and culture, projects in Spain included the illumination of special buildings and museums, including the *Lighting the Prado* project and the *Atlantic Romanesque* restoration project.
- In the area of sustainability and biodiversity, there have been multiple collaboration projects with educational and environmental centres in these five countries.
- The area of cooperation and community service (solidarity) includes the *Iberdrola España Social Assistance* programme, which supports more than 30 social-welfare projects annually.

Programme results 2015

Contribution by region (%)



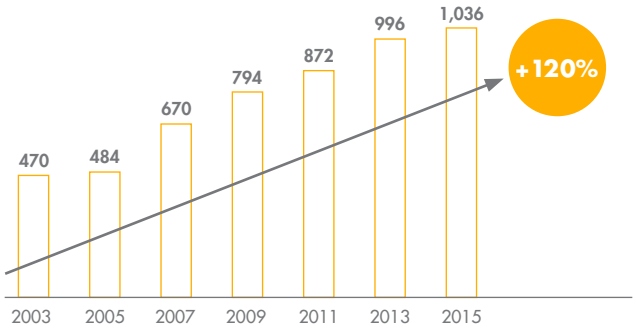
Contribution by programme (%)



Soundness and strength of the brand

- Management of the brand in such a way that it transmits the principles set out in the *Mission, Vision, and Values of the Iberdrola group* and reflects the Company's strategy of commitment to the environment.
- Consolidation of an international brand, strengthening communication and alignment under a single brand positioning strategy in the countries in which the Company operates.

Brand value* (€M)

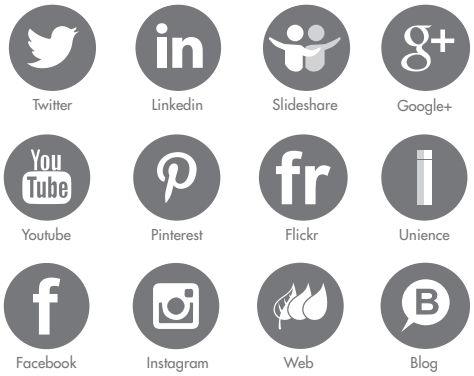


* Source: *Ranking of Best Spanish Brands by Interbrand.*

Evolution of the digital ecosystem

- Offer of useful and dynamic information, with messages adapted to each stakeholder.
- Facilitate direct interaction with our stakeholders, overcoming barriers and making use of existing synergies.

Iberdrola on social media and the Internet



Corporate reputation

- Iberdrola's Reputational Management Model progressed in the improvement of tools to understand the opinion of Stakeholders during 2015.
- To strengthen this understanding, an analysis and intelligence department has been established to properly respond to the specific needs of the Stakeholders.
- In 2015, the drive to evaluate the group's reputation allowed for an evaluation of the Company's reputation within 12 groups or subgroups, using the international Reptrak standard.
  1. Society
  2. Shareholder
  3. Employees
  4. Employees' family environment
  5. Former employees
  6. Competitors
  7. Environment
  8. Customers
  9. Loyal customers
  10. Potential customers
  11. Former customers
  12. Non-customers
- This evaluation has contributed to the Company's materiality analysis and to understanding the level of alignment between Iberdrola's actions and the perceptions of its Stakeholders.
- It has also contributed to the implementation and improvement of the recommendations of the Reputation Plan 2015-2017 during this financial year.
- The improvement in coordination with the departments responsible for Stakeholder relations has allowed for progress in managing reputation risk, in the application of the *Company's Reputational Risk Framework Policy,* and in the international standardisation of the types of activities with reputational impact.
- Advances in the progressive integration of online and offline listening tools favour the detection of reputational opportunities to differentiate Iberdrola from the rest of the industry, as well as to better understand the reputational and media context.
- Based on the *Stakeholder Relations Policy,* a department was created in 2015 to further the development of this policy and thus to assist in improving reputation.

Prado Museum Restoration Workshop / Spain
© 2015 National Heritage

Iberdrola tower, Bilbao / Spain

5.

A Framework of Trust

5.1 Corporate Governance Model

Foundations of Iberdrola's corporate governance model

A. Corporate Governance System

Iberdrola is a multinational leader in the energy industry that seeks to create value in a sustainable manner for society, citizens, customers, and shareholders; which innovates and uses environmentally-friendly energy sources and considers its employees to be a strategic asset; committed to social return through all its business activities, generating employment and wealth in its environment, all within a strategy of social responsibility and compliance with tax regulations.

Iberdrola has adopted a Corporate Governance System made up of the *Mission, Vision, and Values of the Iberdrola group, By-Laws, Corporate Policies, Internal Corporate Governance Rules*, and other internal codes and procedures, all available at www.iberdrola.com.

The content thereof is inspired by and based on a commitment to best corporate governance practices, business ethics, and social responsibility in all of its areas of activity.

Position	Director	Status	Date of last appointment	Ending Date
Chairman & CEO	Mr José Ignacio Sánchez Galán (Salamanca, Spain, 1950)	Executive	27-03-2015	27-03-2019
Director	Mr Xabier de Irala Estévez (New York, United States, 1946)	Proprietary	22-06-2012	22-06-2016
Director	Mr Íñigo Víctor de Oriol Ibarra (Madrid, Spain, 1962)	Other external	22-06-2012	22-06-2016
Director	Ms Inés Macho Stadler (Bilbao, Spain, 1959)	Independent	22-06-2012	22-06-2016
Director	Mr Braulio Medel Cámara (Marchena, Seville, Spain, 1947)	Independent	22-06-2012	22-06-2016
Director	Ms Samantha Barber (Dunfermline, Fife, Scotland, United Kingdom, 1969)	Independent	22-06-2012	22-06-2016
Director	Ms María Helena Antolín Raybaud (Toulon, France, 1966)	Independent	27-03-2015	27-03-2019
Director	Mr Santiago Martínez Lage (Betanzos, A Coruña, Spain, 1946)	Independent	27-03-2015	27-03-2019
Director	Mr José Luis San Pedro Guerenabarrena (Bilbao, Spain, 1946)	Other external	27-03-2015	27-03-2019
Director	Mr Ángel Jesús Acebes Paniagua (Ávila, Spain, 1958)	Independent	27-03-2015	27-03-2019
Director	Ms Georgina Kessel Martínez (Mexico City, Mexico, 1950)	Independent	28-03-2014	28-03-2018
Director	Ms Denise Mary Holt (Vienna, Austria, 1949)	Independent	27-03-2015	27-03-2019
Director	Mr José W. Fernández (Cienfuegos, Cuba, 1955)	Independent	27-03-2015	27-03-2019
Director	Mr Manuel Moreu Munaiz (Pontevedra, Spain, 1953)	Other external	27-03-2015	27-03-2019

B. Governance model

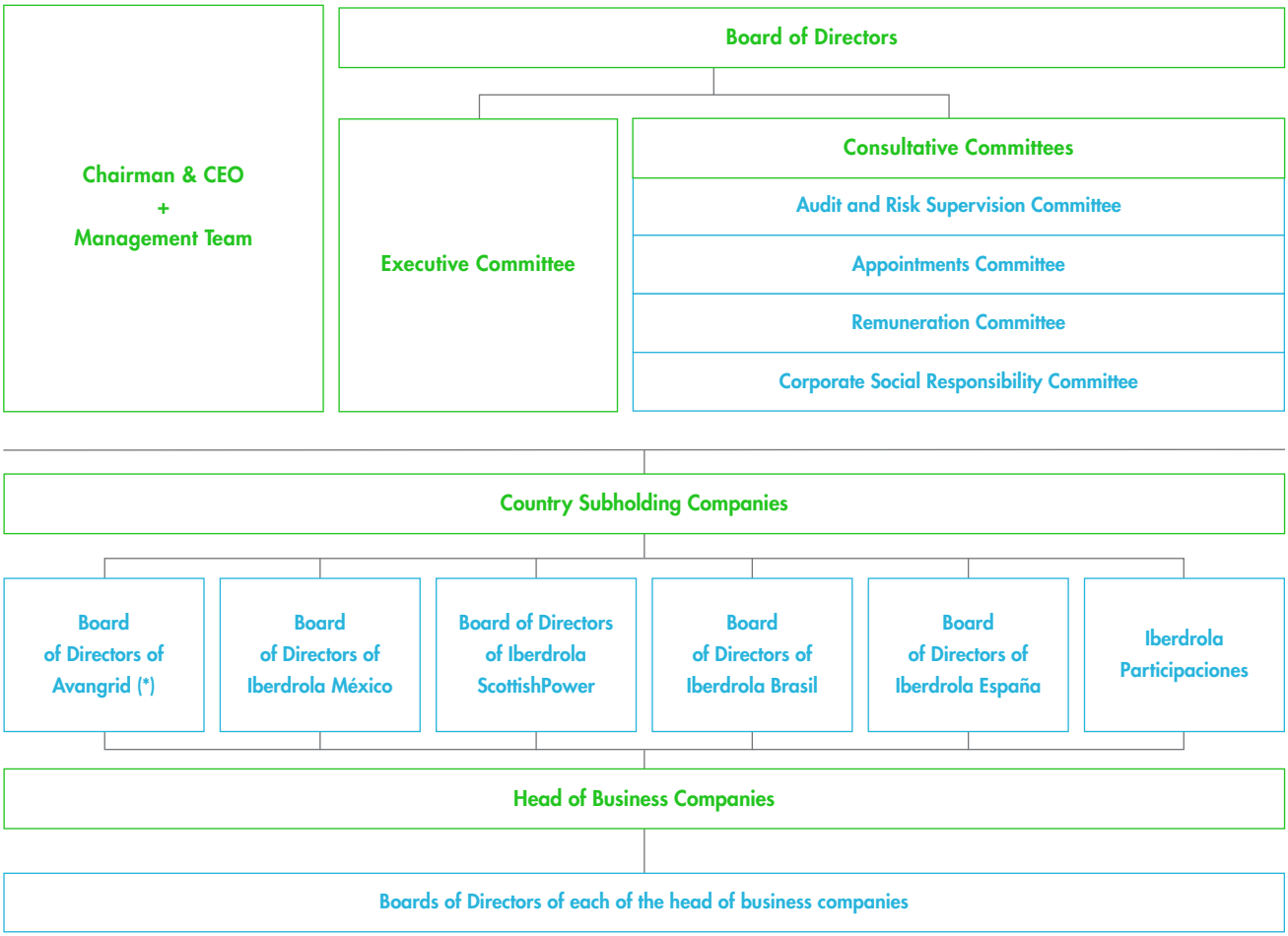
Appropriate differentiation between the duties of strategy and supervision and those of guidance and management:

- The Board of Directors of Iberdrola, made up of a large majority of independent directors, focuses its activity on the determination, supervision, and monitoring of the strategies and general guidelines that must be followed by the group.
- The chairman of the Board of Directors & chief executive officer and the rest of the management team are responsible for the organisation and strategic coordination of the group, through the dissemination, implementation, and monitoring of the overall strategy and basic guidelines.
- In all of the countries in which the group operates, organisation and strategic coordination is implemented through country subholding companies, which group together equity stakes in the energy head of business companies carrying out their activities in the respective country and centralise the provision of services common to such companies. In addition, the group has a country subholding company that groups together the non-energy businesses.

  Country subholding companies have boards of directors, including independent directors and their own Audit and Compliance Committees, Internal Audit divisions or units, or Compliance divisions.
- The head of business companies are in charge of the day-to-day administration and effective management of each business. They also have boards of directors, which include independent directors and specific management teams.

  This structure, which operates together with the group's Business Model, allows for an overall integration of the businesses (Networks, Wholesale and Retail, and Renewables) and focuses on maximising the operational efficiency thereof through the implementation of best market practices.

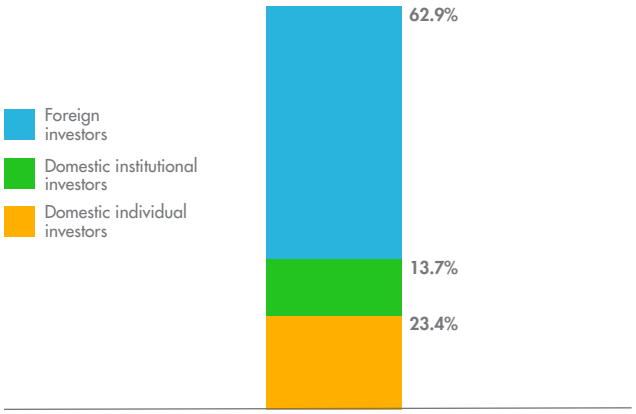
Corporate and governance structure of Iberdrola, S.A



(*) Company listed on the New York Stock Exchange.

C. Equity structure

Iberdrola has more than 600,000 shareholders throughout the world, and none of them alone has the power of control.



Foreign institutional shareholders account for 62.9% of the capital.

External corporate governance awards / page 39

With Shareholder Week, which culminates with the holding of the General Shareholders' Meeting, Iberdrola brings the company closer to and promotes interaction with its shareholders to give form to its corporate governance and social responsibility strategy, sharing events and initiatives regarding social-welfare, cultural, technological innovation, and digital transformation actions.

Iberdrola's response to the corporate governance challenge

A. Continuous Improvement of its corporate governance rules and practices

On corporate governance matters, the Company looks to the *Good Governance Code of Listed Companies* published by the CNMV and generally accepted recommendations in the international markets.

69% of the non-executive directors are independent.

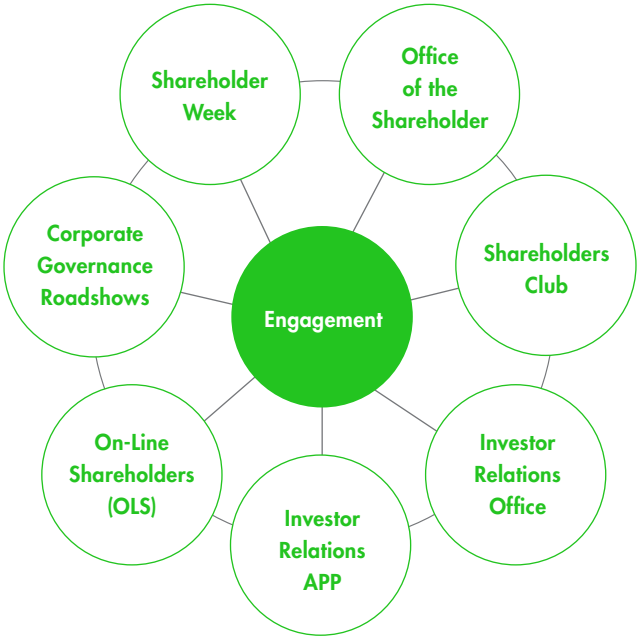
Remuneration policy	Executive directors' variable remuneration tied to objectives.
	Transparency.
	Provision for revising deferred variable remuneration.
Operation of the Board	69% of non-executive directors are independent, all having less than 12 years in office.
	System of checks and balances, including a lead independent director (consejera coordinadora).
	All consultative committees have 100% or a majority of independent directors.
	Gender diversity: 5 women on the Board. All consultative committees are chaired by women.
	Cultural diversity: directors from 7 countries of origin.
	Rationale for proposed appointments.
	External evaluation of governance bodies.
Social responsibility and corporate reputation	Specific Corporate Social Responsibility Committee.
	Social Responsibility Policies.
	Company social action strategy through foundations related to the Iberdrola group in Spain, United Kingdom, Brazil, United States, and Mexico.

Ethics and Social Responsibility / page 84

B. Commitment to shareholders and investors

- The strength of the group's industrial and financial model will allow us to continue on a path of increased profits and shareholder remuneration thanks to balanced growth focused on the regulated networks businesses, renewables, and long-term contracted assets.
- Engagement: shareholders are the key players within the Corporate Governance System, which includes good governance practices beyond those required by applicable law. The *Shareholder Engagement Policy* is implemented through various channels of participation intended to build a continuous dialogue beyond the General Shareholders' Meeting.
- Boost shareholders' participation at the General Shareholders' Meeting through the payment of an attendance bonus. Since its implementation in 2007, the quorum in attendance at the General Shareholders' Meeting has exceeded 75%, and has exceeded 78% during the last two years.

The quorum in attendance at the 2015 General Shareholders' Meeting was 78.65%.



C. Alignment between corporate governance and strategy

- Director remuneration aligned with strategic objectives. The remuneration model for directors is based on three primary components:

Remuneration model for the Board

Type of remuneration	External (non-executive) directors	Executive directors
Fixed	According to their duties.	On market terms.
Short-term variable	Not applicable	Tied to annual targets.
Long-term variable	Not applicable	Tied to multi-annual targets and paid in shares (3-year accrual period and payment deferred over 3 years following accrual).

There were only 1.15% votes against the *Annual Director Remuneration Report 2014*.

Parameters to which the annual variable remuneration of executive directors is tied in 2016

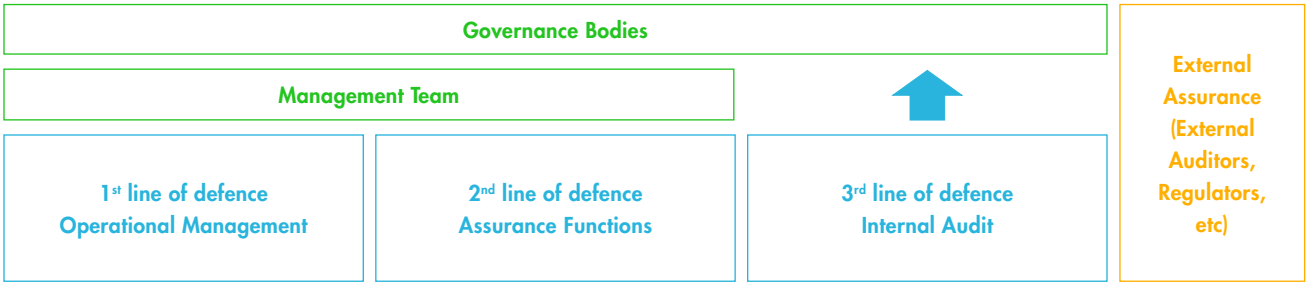
Financial	Results. Shareholder return.
Industrial	Quality and service level. Labour climate.
Social responsibility	Growth in emission-free installed capacity. Presence on international indices. Level of consensus received for the proposals of the Board at the General Shareholders' Meeting.

⊙ *Annual Director Remuneration Report 2015*

5.2 Three Lines of Defence

Three lines of defence model

The Internal Control System of Iberdrola and the companies of its group is configured by reference to international best practices. It is based on a guarantee combined around three lines of defence, providing a comprehensive view of how the different parts of the organisation interact in an effective and coordinated manner, increasing the efficiency of the processes for management and internal control of the entity's significant risks.



Based on the document "Guidance on the 8th EU Company Law Directive, article 41" ECIIA/FERMA, September 2010.

Operational Management

As the first line of defence, the management team and the professionals of Iberdrola and its group are the direct managers of the risks of the entity. Thus, the Management of the Company is responsible for maintaining effective control and implementing procedures to control risks on a continuous basis.

Risks facing Iberdrola's primary businesses / pages 46, 50, 54

Internal Control Objectives (COSO. May 2013)

- **Operations objectives-** Pertain to the effectiveness and efficiency of the entity's operations, including operational and financial performance goals, and safeguarding assets against loss.
- **Reporting objectives-** Pertain to internal and external financial and non-financial reporting and may encompass reliability, timeliness, transparency, or other terms as set forth by regulators, recognised standard setters, or the entity's policies.
- **Compliance objectives-** Pertain to adherence to laws and regulations to which the entity is subject.

Assurance functions

As the second line of defence, certain functions provide the foundation for the entity's internal control system, proposing guidelines to the Board and monitoring how the first line of defence implements them.

The primary assurance functions within Iberdrola, within their respective areas of responsibility, are: (i) the group's Risk Division, within the framework of its functions within the Comprehensive Risk Control and Management System; (ii) the Compliance Unit, which is responsible for the Compliance System; and (iii) the Internal Control Division, which is part of the Administration and Control Division, within its duties relating to the internal control and risk management systems in relation to the preparation of financial information (ICFRS).

Comprehensive Risk Control and Management System / page 82

Compliance Unit / page 84

Iberdrola adopts the three lines of defence model to ensure effective and integrated management of its Internal Control System.

Internal Audit

The Internal Audit function, as the third line of defence, oversees the internal control and risk management systems, auditing how the first and second lines carry out their respective duties of management and control.

To ensure its independence, the director of the Internal Audit Area reports hierarchically to the chairman of the Board of Directors and functionally to the Audit and Risk Supervision Committee. The Internal Audit divisions of the various country subholding companies have this same positioning, and are coordinated under the framework of the Basic Internal Audit Regulations of the Company and its group.

The 2015 annual activities plans of the Internal Audit Area Division of the Company and of the Internal Audit divisions of the group responded to the requirements established by the Audit and Risk Supervision Committee of the Company and the respective Audit and Compliance Committees of the country subholding companies in their respective regulations, and included work for the Senior Management and the rest of the organisation, including:

- Annual audits of compliance with the *Code of Ethics* at Iberdrola and at each of the country subholding companies.
- Audits of the process for determining and monitoring the limits and indicators of the *Risk Policies of the businesses of the group*.
- Half-yearly reviews of the operation of the most critical controls of the Internal Control Over Financial Reporting (ICFR) System, as well as reviews of the various cycles of preparation of the financial information of Iberdrola and the various companies of the group, within the framework of the general goal of reviewing the entire ICFR over a period of 3 years.

Continuing with the commitment made in 2005, Internal Audit continues to submit to an exhaustive review every five years by the Global Institute of Internal Auditors of compliance with professional internal audit rules (called a Quality Assurance Review). In 2015 the certification of Iberdrola and of ScottishPower was renewed and the scope of the certification was expanded to include Iberdrola España and AVANGRID.

Basic Internal Audit Regulations

- Approved by the Board of Directors of the Company upon a proposal of its Audit and Risk Supervision Committee (updated on 15-Dec-2015).
- Defines the nature, as an independent internal unit, and establishes the regulation, competencies, powers, and duties of Internal Audit, among other things.
- Establishes the framework of relations with: i) the Board of Directors, its chairman, and the Audit and Risk Supervision Committee; ii) the Internal Audit divisions of the other companies of the group; and iii) the rest of the organisation.
- Disseminates the knowledge of the Internal Audit function among the professionals of the group.
- Serves as a reference for the management model and the quality system of the Internal Audit Area of the Company and the Internal Audit divisions of the other companies of the group.

External assurance

The auditors, regulatory bodies, and other entities external to the organisation play a significant role in the general structure of governance, internal control, and risks of Iberdrola, especially in the regulated businesses. The regulators establish requirements with the intention to strengthen the controls of an organisation and perform a function of independent and separate monitoring. On the other hand, the auditors provide assurance regarding the true and fair view of the entity's financial information.

Regulatory Environment / page 42

Audit Report on the Consolidated Financial Statements

5.3 Risks

Main risks facing the Iberdrola group

The Iberdrola group is exposed to various risks inherent in the different countries, industries, and markets in which it operates and in the activities it carries out, which may prevent it from achieving its objectives and from successfully implementing its strategies. The following significant risks can be pointed out:

- Regulatory uncertainty in the countries in which it operates.
- Volatility in the prices of electricity and fuel, including the potential effects of the collapse in oil prices.
- Volatility in exchange rates and interest rates.
- Changes in the production of and demand for electricity and gas due to the effect of climatological variables (temperature, hydraulic activity, wind activity), and growth in internal consumption over the long term.
- Operational risks due to downtime of facilities and significant incidents affecting the grids, including those arising from improper access to information or to the information technology and communications systems of the group (cyberattacks).

A detailed description of the risks that materialised in 2015 can be found in section "E.5" of the *Annual Corporate Governance Report 2015*, available at www.iberdrola.com.

Commitment of the Board of Directors and of senior management

Iberdrola's Board of Directors and senior management is strongly committed to and engaged in the management of the group's risks:

- Acceptable levels of risk tolerance are reviewed and approved ex ante on an annual basis through risk policies and limits the qualitative and quantitative risk appetite at the group level and at each of the main businesses.
- There is then a periodic monitoring ex post of significant risks and threats and of compliance with the approved risk policies and limits.

⊙ *Consolidated Annual Financial Statements*

Duties of the Risk Division

ERM Approach – Integrated Vision

Ensure that the group's significant risks are adequately identified, measured, managed, and controlled and that they are periodically reported.
Basic instruments:
- Risk policies and limits.
- Reports on key risks.

Centralised Approach – Active Management

Credit risk
- Approval of counterparties and limits and/or establishment of admission criteria in order to minimise credit losses within the group.

Market risk
- Approval of detailed limits in order to delimit the effects of volatility in the markets in which the group operates.

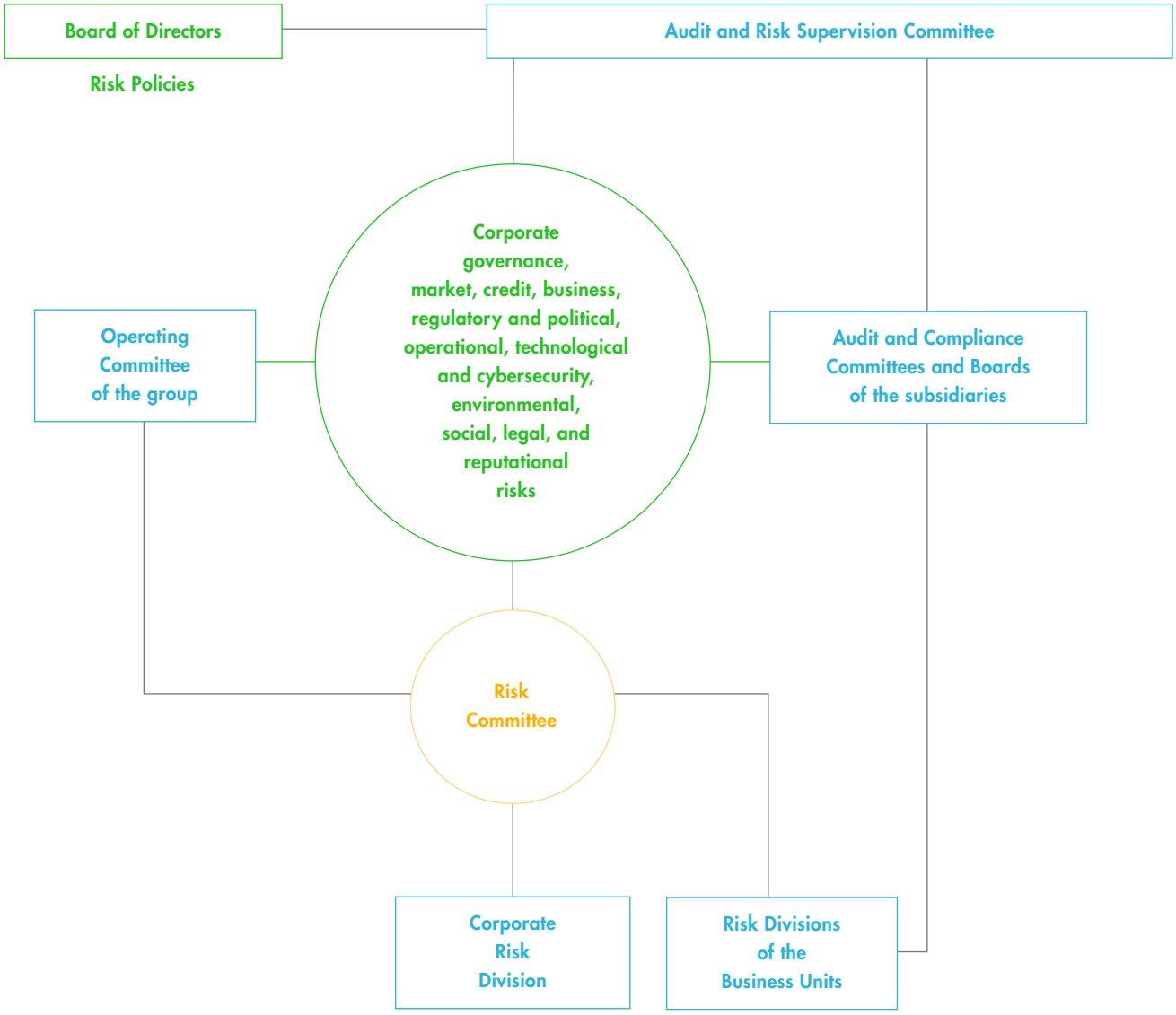
Operational risk management through insurance and participation on the group's information technology governance and cybersecurity committees.

The essential elements of proper risk management are foresight, independence, and commitment to the business objectives.

Comprehensive Risk Control and Management System

At the operational level, the commitment of the Board of Directors is implemented by means of a Comprehensive Risk Control and Management System, supported by a Risk Committee and an independent specialised risk organisation deployed within the main businesses of the group.

⦿ Risks facing Iberdrola's primary businesses
/ pages 46, 50, 54



5.4 Ethics and Social Responsibility

Compliance Unit

Iberdrola has a Compliance Unit, which is a collective, internal, and permanent body linked to the Corporate Social Responsibility Committee of the Board of Directors.

Within each country subholding and/or head of business company, there are also compliance divisions linked to the Audit and Compliance Committees or the Board of Directors of each company. Their duties including promoting a culture of ethical behaviour and zero tolerance for the commission of unlawful acts or fraud.

Iberdrola's Compliance System is made up of the substantive rules, formal procedures, and major activities within the group to encourage the organisation to act in accordance with applicable ethical principles and legal provisions, through a set of procedures and actions designed to prevent, detect, and react to irregular actions, fraud, or actions contrary to the Iberdrola group's *Code of Ethics* or applicable laws and regulations.

Main activities in the area of ethics and compliance

Various programmes and control frameworks for different regulatory environments are implemented at the group within the framework of the Compliance System.

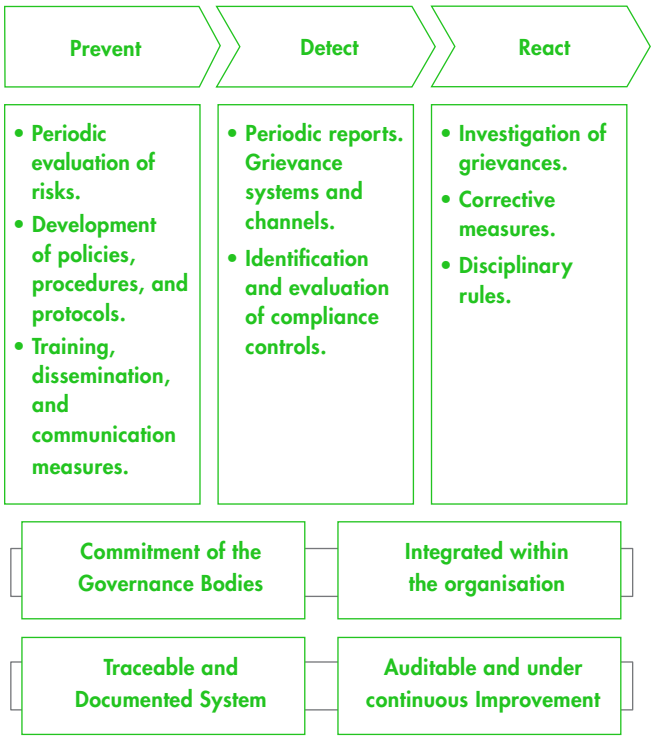
These include crime prevention programmes, which are implemented taking into consideration the duties imposed by the Spanish Criminal Code, without prejudice to the legal provisions applicable in any other jurisdiction in which the Company does business, as well as the programme for compliance with the *Code of Ethics*, which includes specific training and communication plans for all professionals of the group, among other things.

Iberdrola also has a Compliance Unit Office (the "Office"), managed by the director of the Compliance Unit and made up of members representing various regulatory areas and assurance functions of the group. The Office is configured as a consultative and support committee relating to the various activities of the group within the framework of developing an effective Compliance System.

Powers of the Compliance Unit

The Compliance Unit has powers related to the *Code of Ethics*, the *Crime Prevention and Anti-Fraud Policy*, the *Internal Regulations for Conduct in the Securities Markets*, legal provisions regarding the separation of activities, and all other powers that may be entrusted thereto by the Corporate Social Responsibility Committee or the Board of Directors of the Company or that are established in Iberdrola's Corporate Governance System.

The Iberdrola group's ethics and compliance system



Compliance leader verification

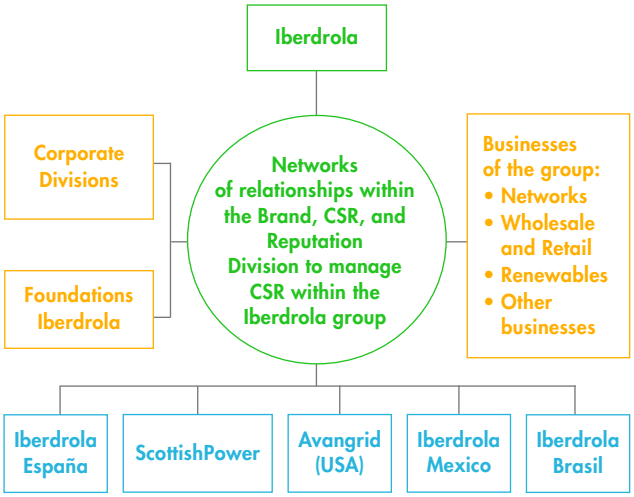
In 2015, NYSE Governance Services, together with the Ethisphere Institute, performed an independent evaluation of the Compliance System, after which Iberdrola received "Compliance leader verification" certification.

This acknowledgement is given to those companies with the best compliance programmes in their industry, and which have decided to proactively invest resources to promote a culture of compliance.

Iberdrola considers its corporate values to include ethical principles, good corporate governance and transparency, and social commitment.

Organisation of social responsibility within the Iberdrola group

The group has an organisational structure designed to promote and manage responsible actions with its Stakeholders.



The Corporate Social Responsibility and Reputation Committee and the Corporate Social Responsibility and Reputation Committees of the country subholding companies coordinate the balanced development social responsibility within the Iberdrola group. The Corporate Social Responsibility Committee of the Board of Directors performs the duties of supervision within its purview.

Corporate social responsibility plans of the group

2015 saw the approval of the *Corporate Social Responsibility Plan 2015-2017* for the Iberdrola group, covering five areas of activity (dialogue with local communities, measurement tools, etc.), with a focus based on the various Stakeholders.

This Plan is made up of various programmes, projects, and monitoring indicators, both cross-sectional for all involved organisations of Iberdrola as well as specific for each business or corporate area of the Company.

Monitoring of the Plan is analysed on a half-yearly basis by the Corporate Social Responsibility and Reputation Committee and by the Corporate Social Responsibility Committee of the Board of Directors.

External awards

Total score: 87 points. Only European electric company to have been included in all 16 editions of the index.	Member of Dow Jones Sustainability Indices In Collaboration with RobecoSAM
Only Spanish electric company among the world's 100 most sustainable companies.	GLOBAL100
Five consecutive years on the index. First utility with nuclear assets selected for the index.	Iberdrola confirmed as FTSE4Good constituent — FTSE Russell
Climate Disclosure Leadership Index (CDLI). Rating: 100 points.	CDP A LIST CLIMATE
Climate Performance Leadership Index A.	CDP CLIMATE DISCLOSURE LEADER 2015
Iberdrola a sponsor.	GLOBAL ROUNDTABLE ON CLIMATE CHANGE
Iberdrola selected.	MSCI
Iberdrola selected.	NYSE EURONEXT
Sustainability Yearbook 2015: "*Silver Class*" in the electricity sector.	ROBECOSAM Sustainability Award Silver Class 2015
Most sustainable Spanish utility and fourth most sustainable utility in the world.	NEWSWEEK'S GREEN RANKINGS 2015
Leader among Spanish utilities: electricity, gas, and water.	merco
Leading company on the Ibex 35 in *Transparency ranking 2014.*	FUNDACIÓN COMPROMISO Y TRANSPARENCIA

Commercial office customer / Spain

6.

About this Report

This report, which Iberdrola directs to both its shareholders and investors and all of its Stakeholders, has been prepared under the emerging "integrated report" concept, and constitutes one more example of the group's desire to be innovative in the area of transparency.

6.1 About this Report

Integrated report

- This report has been prepared in accordance with the reporting framework published by the International Integrated Reporting Council (IIRC) and in accordance with the recommendations thereof, taking into consideration the individual and consolidated financial statements of the Company formulated by the Board of Directors, audited and pending approval by the shareholders at the General Shareholders' Meeting of Iberdrola.
- A multi-disciplinary team made up of corporate businesses and areas of the group was created in order to provide a complete view of the Company, its business model, the challenges and risks it faces, and its social, environmental, financial, and governance performance. The participating organisations guarantee the completeness of the information included.
- The Corporate Social Responsibility Committee of the Board of Directors has reported favourably on this report and has submitted it to the Board of Directors for the approval thereof.

This report has also been reviewed by the Company's Operating Committee.

Iberdrola's Board of Directors, after analysing this report and considering these assessments, approved the *Integrated Report February 2016* at its meeting of 23 February 2016.

Information boundaries

- The information submitted covers Iberdrola and its subsidiaries and affiliates. The information boundaries are defined in the group's consolidated annual financial statements and *Sustainability Report*.
- The group's performance over the last years is connected to external corporate transactions and internal management decisions, which the reader should take into account in order to properly interpret this report. These transactions and activities are described in the group's public information, the following being particularly noteworthy:
  - The acquisition and merger of companies in Brazil (2011) and the nationalisation in Bolivia (2011).
  - The focus on a group management model based on global businesses as from 1 January 2011.
  - The application of IFRS 11 to the 2013 to 2015 figures, which mainly affects Brazil.
  - The merger of Iberdrola USA and UIL Holdings in the United States (December 2015), with the new company taking the name AVANGRID.

Material aspects identified

- Iberdrola has channels of communication and dialogue with its Stakeholders, developed in accordance with the principles of the AA1000 Assurance Standard, as described in detail in the *Sustainability Report*.
- In addition, it performs materiality analyses that help identify matters of significance to the Company's Stakeholders, bringing to light particularly sensitive financial, environmental, or social issues related to the business in the various communities and geographic areas in which the group operates.
- The contents of this report have been selected by taking into account the existing channels for dialogue as well as the materiality analyses and the framework defined by the IIRC for this kind of information.

Social and Relationship Capital / page 70

This report has been prepared in accordance with the reporting framework published by the International Integrated Reporting Council (IIRC).

Internal and external verification

- This report has been subject to a process of internal verification, by means of a limited review performed by the Management of the Internal Audit Division of Iberdrola.
- Although it has not been subject to a process of independent external verification, a significant portion of the information contained herein relating to financial year 2015 and to previous years comes from annual financial reports and sustainability reports, all of which have been the subject of an external audit or verification for which the respective certificates are available. The remaining information comes mainly from other reports or public presentations made by the Company.

Legal disclaimer with respect to forward-looking statements, errors, and omissions

- This document contains forward-looking information and statements about Iberdrola. Such statements include projections and estimates and their underlying assumptions, statements regarding plans, objectives, and expectations with respect to future transactions, investments, synergies, products, and services, and statements regarding future performance. Forward-looking statements are not historical facts and are generally identified by the words "expects", "anticipates", "believes", "intends", "estimates", and similar expressions.
- In this regard, although Iberdrola believes that the expectations reflected in such statements are reasonable, investors and holders of Iberdrola shares are cautioned that forward-looking information and statements are subject to risks and uncertainties, many of which are difficult to predict and generally beyond the control of Iberdrola, which risks could cause actual results and developments to differ materially from those expressed in, or implied or projected by, the forward-looking information and statements. These risks and uncertainties include those identified in the documents sent by Iberdrola. to the National Securities Market Commission (*Comisión Nacional del Mercado de Valores*) and which are accessible to the public.
- Forward-looking statements are not guarantees of future performance and have not been reviewed by the auditors of Iberdrola. You are cautioned not to place undue reliance on the forward-looking statements, which speak only as of the date they were made. All forward-looking statements reflected in this report are subject to the warnings provided and are based on information available as of the date of approval hereof. Except as required by applicable law, Iberdrola does not undertake any obligation to publicly update its forward-looking statements or to revise any forward-looking information, even if new data are published or new events occur.

Integrated Report, February 2016
Publisher: IBERDROLA, SA.
Spain

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IBERDROLA

IBERDROLA

OCS-A 0501 MASS USA

VINEYARD WIND

Vineyard Wind

Attachment 5.6-6

Iberdrola SA Accounts (2014)

Integrated Report / February 2015

IBERDROLA

Integrated Report / February 2015

IBERDROLA

Iberdrola's Public Information

To provide our shareholders, employees, customers, suppliers, and society in general with trustworthy and relevant information regarding the Company's performance and its strategic lines for the coming years.

Annual Information

- **Integrated Report**
  Prepared based on the recommendations of the International Integrated Reporting Council (IIRC).
- **Financial Report**
  Prepared according to international financial reporting standards and externally audited.
- **Corporate Governance Report**
  Prepared according to the form provided by the National Securities Market Commission of Spain.
- **Sustainability Report**
  Prepared according to the Global Reporting Initiative (GRI) guidelines and externally assured.
- **Report of the Consultative Committees of the Board of Directors**
  Prepared according to Iberdrola internal standards.
- **Director Remuneration Report**
  Prepared according to Iberdrola internal standards.
- **Report on Compliance with the Code for the Separation of Activities**
  Prepared according to Iberdrola internal standards.

Additional Information

- Quarterly Results Report
- IBE *Watch Fact Sheet*
- Quarterly Shareholder Bulletin
- Innovation Report
- Biodiversity Report
- Greenhouse Gas Report

Information on the Corporate Website
www.iberdrola.com

- About Us
- Reputation and Sustainability
- Press Room
- Shareholders and Investors
- Customers
- Suppliers
- Networks

This icon refers to the pages of this report where related information can be found. It also gives information on other specific reports where more information of interest can be accessed.

Access the 2014 annual reports and get further information on the Iberdrola group by scanning the corresponding QR code using your smartphone or tablet.

Your energy, our energy.

Comfort for homes

Our goal is to offer a reliable, high-quality, and environmentally-friendly energy supply.

Sustainability for the future

Drive the economic and social development of the communities in which we are present.

Innovation for infrastructure

Improve the well-being of people.

Competitiveness for companies

Create sustainable value for our shareholders, employees, customers, and suppliers.

IBERDROLA

Table of contents

1 Iberdrola today

Letter from the chairman 4

1.1 Iberdrola Today 6

1.2 Company Performance 9

1.3 Key Figures 10

1.4 Presence by Area of Activity 14

2 Business model and strategy

2.1 The Future of Energy 22

2.2 Business Model 24

2.3 Iberdrola, a Different Company 25

2.4 Asset Management 26

2.5 Value Chain 28

2.6 Strategic Foundations 31

2.7 Comparative Results and Awards 34

3 Iberdrola's primary businesses

3.1 Regulatory Environment 38

3.2 Networks 41

3.3 Wholesale and Retail 45

3.4 Renewables 49

3.5 Supply Costs 52

Notes: The figures included in this translation follow the customary English convention, with figures in thousands separated by a comma (,) and decimals indicated by a full stop (.). €M = millions of euros.
$M = millions of dollars.

4 Our assets

4.1 Financial Capital 56

4.2 Manufactured Capital 58

4.3 Intellectual Capital 60

4.4 Human Capital 62

4.5 Natural Capital 64

4.6 Social and Relationship Capital 66

5 A framework of trust

5.1 Corporate Governance Model 72

5.2 Risks 76

5.3 Ethics and Social Responsibility 78

5.4 Triple Line of Defence 80

6 About this report

6.1 About this Report 84

Ignacio S. Galán
Chairman of Iberdrola

"We will continue maximising our economic and social contribution and impact in the communities in which we operate".

Dear friends:
I am pleased to present to you, for the second consecutive year, Iberdrola's *Integrated Report*, which sets forth the most significant future risks and opportunities for the company, as well as the strategy we have designed to face them, whilst maximising our positive impacts on stakeholders and in all of the societies in which we operate.
For that reason, Iberdrola will continue to engage in business in accordance with a sustainable business model, based on the long term, geographic diversification, a focus on regulated activities, the quality of our assets, efficiency, and financial strength. We will do so whilst making a special effort in the ongoing promotion of ethics, transparency, good governance, innovation, and inclusion. Our goal is to continuing sharing our capabilities with all of society, and to generate trust through continuous dialogue and engagement with our stakeholders.
With this model, we hope to continue being one of the leading utilities worldwide, which currently produces and supplies electricity –cleanly, reliably, and responsibly– to approximately one hundred million people, primarily in the United Kingdom, the United States of America, Mexico, Brazil, and Spain, whilst fostering their economic and social development at the same time.

For that purpose, we expect to continue progress in achieving the goals that we set out in the *Outlook 2014-2016*. One example of our path to compliance is the results obtained in 2014, during which gross operating income (EBITDA) increased by 3.1% compared to the previous year –to the sum of 6,965 million euros– while net profit came to 2,327 million euros, in both cases surpassing the estimates we had made and which we made public on Investor Day in February 2014.
We also expect to continue building our financial strength, as we did last year, when we reduced debt by more than 1,492 million euros, to 25,344 million euros*, which allowed us to reduce the net debt/EBITDA ratio to 3.6x, from 4x in 2013. This meant a big step towards our goal of bringing net debt to 25,000 million euros by year-end 2016 and of achieving a net debt/ EBITDA ratio below 3.5x.
All of this will allow us to continue maintaining our commitment to shareholder compensation, which in 2014 was 0.27 euro per share, reaching a total shareholder return** of 30.1% for the year.

Economic and social contribution and impact

At the same time, we are continuing to maximise our economic and social impact in the communities in which we operate by means of investments worth 11,200 million euros through 2016 (some 3,000 million euros in 2014), mainly for electricity transmission and distribution networks, and clean energy; and procurement in an amount of more than 5,000 million euros annually.
Furthermore, we will continue contributing to public coffers with a volume of direct taxes that last year amounted to 5,500 million euros (10,500 million*** if we add indirect and induced contributions). We

will also continue our wager on the maintenance and creation of stable high-quality employment, especially among younger persons. Today, Iberdrola gives direct, indirect, or induced employment to 350,000*** people all over the world.
The management of human capital will continue to be a priority for the company, in areas such as: training (with more than a million annual hours for employees (3% of working hours) and an international youth scholarship programme); professional promotion; and equality (progressive equivalence between men and women in the workforce).
We will also continue encouraging the reconciliation of family and professional life; international mobility; and job safety (with a goal of 0 accidents). Our objective is to continue increasing team pride and employee satisfaction, which during the last labour climate survey received a rating of approximately 8 out of 10.
Furthermore, R&D+i at Iberdrola (to which we allocated 170 million euros in 2014 alone) will continue to be focused on efficiency, sustainability, and the development of new products and services. We expect to continue to be at the head of the most innovative utilities in Europe, as the European Commission has recently certified.
In addition –as I already mentioned– we are going to further intensify our policy of dialogue and engagement with our stakeholders: employees, customers, suppliers, and especially our shareholders: more than 600,000 –many of them pensioners. Along these lines, our investors will continue to be at the centre of our Corporate Governance System, which we will continue to conform to the best domestic and international practices to strengthen our leadership in this area. At the same time, ethics and compliance will continue to be absolutely priority aspects at Iberdrola, both for our internal management and throughout the supply chain.

Care for the environment

As regards our contribution to caring for the environment, even though our emissions per kWh are already 30% less than the average for the European electricity sector, we have set goals for a 30% reduction in the intensity of our emissions by 2020 as compared to 2007, and to be carbon neutral by 2050. Together with this, we will continue minimising the environmental impact of our facilities and launching initiatives to support the biodiversity of our surroundings, such as with bird protection.
Finally, we will continue with our commitment to support art and culture, through illumination, restoration, exhibitions, etc. And we will especially drive our social action programmes directed towards improving the quality of life for persons in situations of vulnerability or social exclusion, as we have been doing in recent years. One example of this is the *Electricity for All Programme* (*Programa electricidad para todos*), which was launched in 2014 to strengthen activities promoting access to electricity in emerging and developing countries.
Our challenge in future years will be to continue staying at the forefront of the leading sustainability indices, such as *Dow Jones Sustainability*, *FTSE4Good*, *Oekom* and *Carbon Disclosure*, among others.
This way, we can continue to create value for all of our stakeholders – our shareholders, employees, customers, suppliers... – and contribute to progress in all of the territories in which we operate. Because Iberdrola serves society and, more importantly, the well-being of people.

“We will even further intensify our policy of dialogue and engagement with our stakeholders”.

* As adjusted by the dividend paid in December.

** Total shareholder return (TSR): includes the dividends received by the shareholders and the increase in price of the shares.

*** Annual impact estimated by Analistas Financieros Internacionales (AFI), based on Iberdrola’s business during the 2009-2013 period.

Iberdrola today

Lempster Wind Farm in New Hampshire
/ United States of America

1

1.1 Iberdrola today

Our activities

- Production of electricity from renewable and conventional sources.
- Purchase/sale of electricity and gas on wholesale markets.
- Transmission and distribution of electricity.
- Supply of electricity, gas, and related energy services.
- Other activities, mainly linked to the energy sector.

Iberdrola is one of the leading electric companies in the world.

What we are

The process of internationalisation carried out in recent years has made the Iberdrola of today one of the leading electric companies, and among the largest utilities in the world by stock market capitalisation.

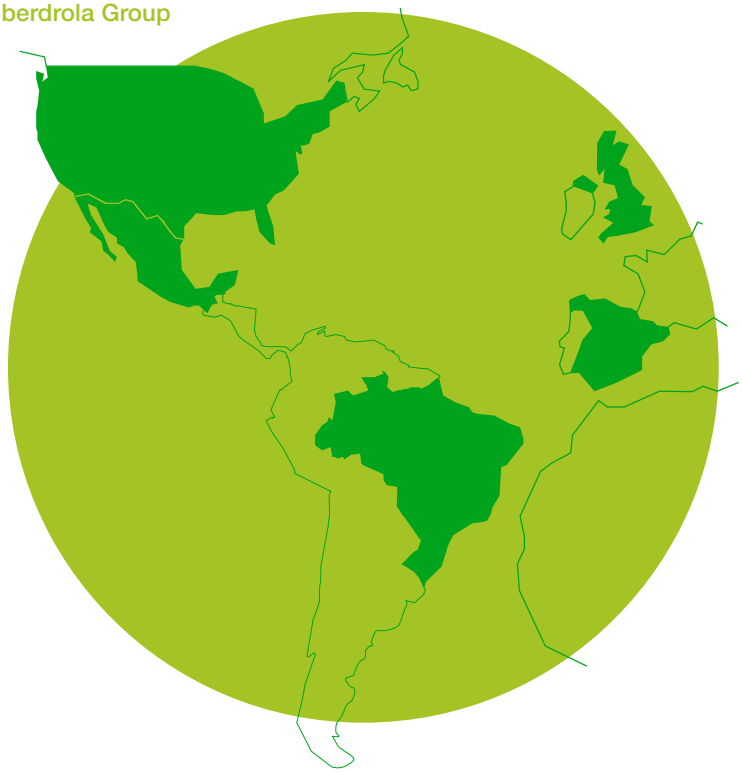
The corporate and governance structure is described in chapter 5.1 of this report and consists of:

- Iberdrola, as a holding company.
- Country subholding companies in the 5 main geographical areas of activity.
- Heads of business companies reporting to the country subholding companies.

Presence focused on the Atlantic area

Iberdrola carries out its activities mainly in the five countries of the Atlantic area: Spain, the United Kingdom, the United States of America, Mexico, and Brazil.

Iberdrola Group



(1) At 31 December 2014.
(2) Annual impact estimated by Analistas Financieros Internacionales (AFI), based on Iberdrola's business during the 2009-2013 period.

2014 Data
Iberdrola Group

45,089
MW **Installed capacity**

14,652
MW **Renewable installed capacity**

138,892
GWh **Net output**

214,613
GWh **Electric power distributed**

32.6
Millions of users

29,597
People (1) **Direct employment**

350,000
People (2) **Indirect and induced employment**

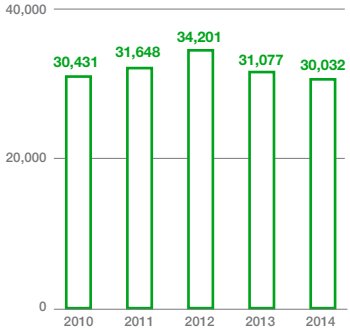
10,500
€M **Tax contribution**
(€M 5,500 direct + €M 5,000 (2) indirect and induced)

5,408
€M Awarded **Procurement**

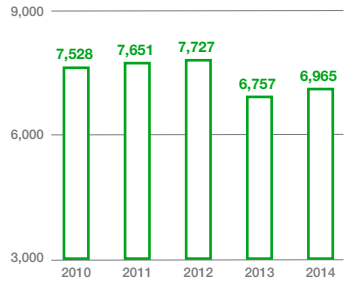
2,848
€M **Investments**

1.2 Company performance

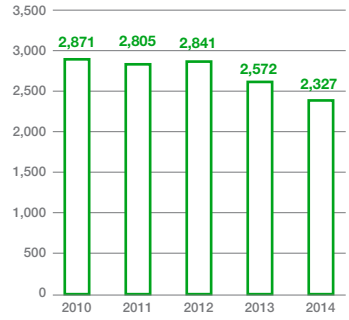
Revenues (€M)



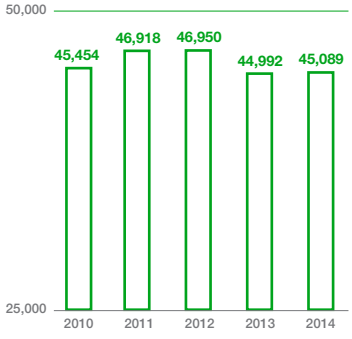
Ebitda (€M)



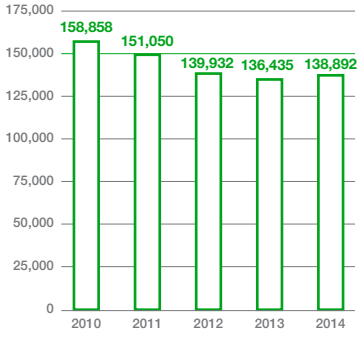
Net profit (€M)



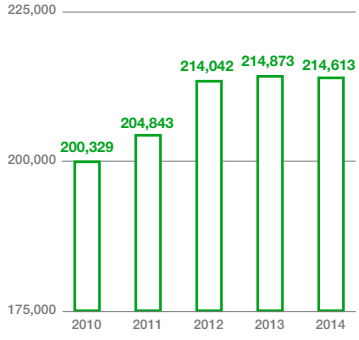
Installed capacity (MW)



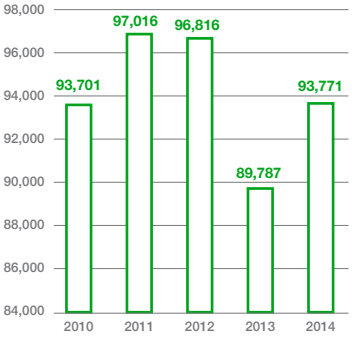
Net output (GWh)



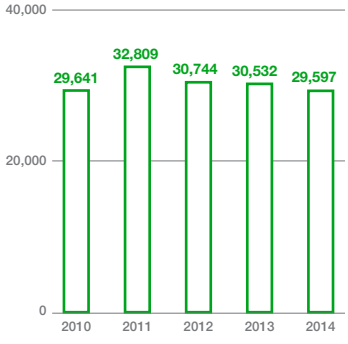
Energy distributed (GWh)



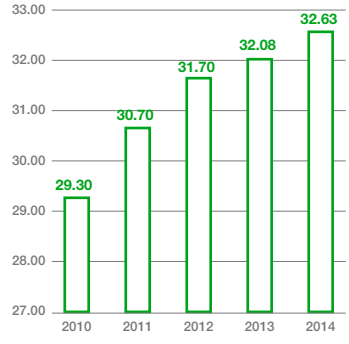
Assets (€M)



Employees



Users (millions)



*** Note: Due to legal requirements, Iberdrola has applied international financial reporting standard IFRS-11 to the financial information for the financial years 2013 and 2014, which aspect should be taken into account in evaluating the historical performance of the Company.**

1.3 Key figures

Financial performance (€M)	2010	2011	2012	2013	2014	Δ Annual average 2010-14	Δ 2010-14
Revenues	**30,431.0**	**31,648.0**	**34,201.2**	**31,077.1**	**30,032.3**	**-0.3%**	**-3.4%**
Consolidated gross margin	11,645.2	12,025.8	12,578.1	11,781.9	12,179.5	1.1%	3.4%
Consolidated ebitda	**7,528.0**	**7,650.5**	**7,726.6**	**6,756.9**	**6,964.5**	**-1.9%**	**3.1%**
Ebitda - Networks (regulated)	**3,450.9**	**3,825.4**	**3,773.7**	**3,346.5**	**3,534.7**	**0.6%**	**5.6%**
Spain	1,389.7	1,555.2	1,348.3	1,450.3	1,438.5	0.9%	-0.8%
United Kingdom	793.6	832.3	937.3	939.0	1,024.8	7.3%	9.1%
United States	710.8	547.7	660.2	718.2	772.0	2.2%	7.5%
Brazil	556.8	890.2	827.9	239.0	299.4	-11.6%	25.3%
Ebitda - Wholesale and Retail (liberalised)	**2,445.3**	**2,270.7**	**2,355.2**	**1,986.6**	**2,292.2**	**-1.6%**	**15.4%**
Spain	1,483.1	1,570.7	1,605.4	1,341.2	1,517.6	0.6%	13.2%
United Kingdom	539.6	322.5	360.6	320.4	456.6	-3.8%	42.5%
United States	15.8	15.6	9.1	-22.6	-32.0	-75.6%	41.6%
Mexico	406.8	361.9	380.1	347.6	350.0	-3.5%	0.7%
Ebitda - Renewables	**1,455.7**	**1,423.9**	**1,620.3**	**1,501.1**	**1,326.0**	**-2.2%**	**-11.7%**
Spain	758.2	668.1	804.3	668.4	420.6	-11.1%	-37.1%
United Kingdom	111.3	173.9	168.1	231.8	265.2	34.6%	14.4%
United States	449.8	417.5	412.2	448.0	495.3	2.5%	10.6%
Mexico	12.0	13.7	37.2	34.1	38.2	54.6%	12.0%
Brazil	7.8	12.9	11.3	9.1	33.0	80.8%	262.6%
Other	116.6	137.8	187.2	109.7	73.7	-9.2%	-32.8%
Ebitda - Other businesses	**201.2**	**168.6**	**44.3**	**0.5**	**-17.0**	**-27.1%**	**-3,500%**
Ebitda - Corporation and adjustments	**-25.1%**	**-38.1**	**-66.9**	**-77.8**	**-171.4**	**145.7%**	**120.3%**
Amortisation charge, provisions, and other	**-2,698.2**	**-3,145.4**	**-3,349.7**	**-4,537.5**	**-3,023.6**	**3.0%**	**-33.4%**
Operating profit (EBIT)	4,829.7	4,505.1	4,376.9	2,219.5	3,940.9	-4.6%	77.6%
Financial result	**-1,287.9**	**-1,061.9**	**-1,100.3**	**-1,277.9**	**-1,122.4**	**-3.2%**	**-12.2%**
Results from companies accounted for using the equity method	27.4	-34.5	-187.5	205.0	135.4	98.5%	-34.0%
Gains on non-current assets	**271.8**	**45.8**	**-13.9**	**-10.4**	**247.9**	**-2.2%**	**-248.3%**
Profit before tax (EBT)	3,841.0	3,454.4	3,075.1	1,136.1	3,201.8	-4.2%	181.8%
Corporate tax	**-899.3%**	**-549.2**	**-206.5**	**1,466.7**	**-837.1**	**-1.7%**	**-157.1%**
Non-controlling interests	-70.8	-100.7	-27.9	-31.0	-38.2	-11.5%	23.2%
Net attributable profit	**2,870.9**	**2,804.5**	**2,840.7**	**2,571.8**	**2,326.5**	**-4.7%**	**-9.5%**
Total assets	93,701.0	97,016.5	96,816.4	89,786.8	93,771.4	0.0%	4.4%
Equity	**31,663.1**	**33,207.8**	**34,084.8**	**35,288.6**	**35,790.5**	**3.3%**	**1.4%**
Net investments	5,099.0	4,002.0	3,259.0	3,053.0	2,848.0	-11.0%	-6.8 %
Operating cash flow (FFO)	**5,468**	**6,047**	**6,196**	**5,619**	**5,459**	**0.0%**	**-2.8%**
Net financial debt	30,014.8	31,705.7	30,324.4	26,836.3	25,618.4	-3.7%	-4.5%

Financial ratios	2010	2011	2012	2013	2014	Δ Annual average 2010-14	Δ 2013-14
Ebitda - Outside eurozone (%)	**47.1**	**48.3**	**51.0**	**49.5**	**54.0**	**3.7%**	**9.1%**
Ebitda margin (Ebitda/sales) (%)	24.7	24.2	22.6	21.7	23.2	-1.5%	6.9%
Net profit margin (Net Profit/Sales) (%)	**9.4**	**8.9**	**8.3**	**8.3**	**7.7**	**-4.5%**	**-7.2%**
NOE/Gross margin (%)	29.1	29.2	30.1	29.4	29.8	0.6%	1.4%
Net financial debt/ ebitda (multiple)	**3.99**	**4.14**	**3.92**	**3.97**	**3.68**	**-1.9%**	**-7.3%**
Financial leverage (%)	48.7	48.8	47.1	43.2	41.7	-3.6%	-3.7%
Funds from operations (FFO)/Net financial debt (NFD)	**18.6**	**19.1**	**20.4**	**20.8**	**21.3**	**3.7%**	**2.4%**
Retained cash flow (RCF)/NFD (%)	20.1	17.2	17.2	17.5	17.4	-3.4%	-0.6%
Return on equity (ROE) (%)	**9.5**	**8.6**	**8.3**	**7.5**	**6.6**	**-7.6%**	**-12.0%**

Stock market performance	2010	2011	2012	2013	2014	Δ Annual average 2010-14	Δ 2013-14
Stock market capitalisation (€M)	31,631	28,465	25,753	28,922	35,756	3.3%	23.6%
Number of shares at year-end (millions)	5,484	5,882	6,139	6,240	6,388	4.1%	2.4 %
Share price (€)	5.77	4.84	4.20	4.63	5.60	-0.7%	20.9%
Earnings per share (EPS)	0.52	0.47	0.45	0.41	0.36	-7.7%	-12.2%
Dividend per share (DPS)	0.34	0.34	0.34	0.31	0.27	-4.8%	-11.3%
Dividend yield (%)	5.93	6.96	8.13	6.65	4.91	-4.3%	-26.2%
Total dividend (including payment in kind) (€M)	1,859	1,982	2,093	1,922	1,685	-24.8%	-99.1%
Payout ratio (%)	65.2	71.1	65.4	65.5	75.0	3.8%	14.5%
Price/net earning per share (PER)	11.02	10.10	9.31	11.25	15.37	9.9%	36.6%

- **Sustainability report**
- **Quarterly results report**
- **Consolidated financial statements**

* Note: Due to legal requirements, Iberdrola has applied international financial reporting standard IFRS-11 to the financial information for the financial years 2013 and 2014, which aspect should be taken into account in evaluating the historical performance of the Company.

Operating performance	2010	2011	2012	2013	2014	Δ Annual average 2010-14	Δ 2013-14
Installed Capacity (MW)	**45,454**	**46,918**	**46,950**	**44,992**	**45,089**	**-0.2%**	**0.2%**
Net output (GWh)	158,858	151,050	139,932	136,435	138,892	-3.1 %	1.8%
Electrical power distributed (GWh)	**200,239**	**204,843**	**214,042**	**214,873**	**214,613**	**1.8%**	**-0.1%**

Environmental performance	2010	2011	2012	2013	2014	Δ Annual average 2010-14	Δ 2013-14
Emission-free installed capacity (%)	**57.3**	**58.2**	**59.4**	**61.2**	**61.9**	**0.4%**	**1.6%**
Renewable energy installed cacpacity (%)	27.9	29.7%	30.5	31.6	32.5	1.6%	6.5%
Emission-free production (%)	**47.8**	**48.8**	**51.9**	**54.6**	**56.8**	**0.5%**	**2.1%**
Renewable energy production (%)	16.5	19.8	23.6	24.9	24.4	5.0%	20.0%
Specific CO_2 emissions (t/GWh)	**258**	**248**	**264**	**226**	**212**	**-1.0%**	**-3.9%**
Fuel consumption (M Tep)	21,994	20,172	19,236	18,968	18,849	-2.1%	-8.3%
Environmental investments (€M)	**142.4**	**1,297.6**	**1,062.4**	**1,015.7**	**1,100.9**	**202.8%**	**811.2%**
Environmental expenses (€M)	149.7	261.3	723.3	686.4	635.7	18.6 %	74.5 %
Energy produced under certified environmental management systems (%)	**88.7**	**87.6**	**85.2**	**84.4**	**85**	**-0.3%**	**-1.2%**
Water use/overall production (m^3/GWh)	645	620	699	976	509	-1.0%	-3.9%
Direct CO_2 emissions. Scope 1 (kt)	**39,939**	**36,193**	**35,461**	**31,846**	**30,217**	**-2.3%**	**-9.4%**
Indirect CO_2 emissions. Scope 2 (kt)	1,358	1,156	2,122	997	1,544	-3.7%	-14.9%
CO_2 avoided due to efficiency initiatives (kt)	**25,188**	**37,462**	**24,014**	**18,480**	**21,459**	**12.2%**	**48.7%**
SO_2 emissions (t/GWh)	0.397	0.295	0.366	0.219	0.154	-6.4%	-25.7%
NO_x emissions (t/GWh)	**0.302**	**0.276**	**0.334**	**0.262**	**0.236**	**-2.2%**	**-8.6%**

- **Iberdrola's primary businesses / page 36**
- **Our assets / page 54**
- **About this report / page 82**

Social performance	2010	2011	2012	2013	2014	Δ Annual average 2010-14	Δ 2010-14
Users (millions)	**29.3**	**30.7**	**31.7**	**32.1**	**32.6**	**2.8%**	**1.7%**
Electrical power	25.8	27.5	28.1	28.5	29.0	3.1%	1.8%
Spain	10.6	10.8	10.9	10.9	10.9	0.7%	0.4%
United Kingdom	3.3	3.2	3.5	3.5	3.5	1.5%	0.3%
United States	1.8	1.9	1.8	1.8	1.8	0.0%	0.0%
Latin America	10.1	11.7	11.9	12.4	12.8	6.7%	3.2%
Gas	3.5	3.3	3.6	3.6	3.6	0.9%	1.4%
Spain	0.6	0.8	0.8	0.8	0.8	8.3%	2.4%
United Kingdom	2.0	2.0	2.2	2.2	2.2	2.5%	0.0%
United States	0.9	0.6	0.6	0.6	0.6	-8.3%	0.0%
Number of employees	**29,641**	**32,809**	**30,744**	**30,532**	**29,597**	**0.0%**	**-3.1%**
Permanent contracts (%)	98.0	98.0	98.0	98.5	98.5	0.1%	0.0%
Employees with collective bargaining agreement (%)	**80.0**	**81.2**	**79.8**	**79.4**	**79.0**	**-0.3%**	**1.3%**
Employee turnover (%)	12.4	6.2	10.6	6.6	8.6	-7.7%	30.2%
Diversity (men/women)	**75/25**	**77/23**	**76/24**	**76/24**	**77/23**	**N/A**	**N/A**
Ratio between basic entry level wage and local minimum wage (%)	143	162	151	154	161	3.2%	6.0%
Incident rate (IR)	**0.65**	**0.46**	**0.34**	**0.46**	**0.39**	**-10.0%**	**-15.2%**
Hours of training (millions of hours)	1.02	1.25	1.12	1.2	1.0	0.2%	-14.2%
Hours of training per employee (h)	**35.9**	**47.1**	**44.2**	**44.7**	**38.7**	**1.9%**	**-13.4%**
Funds for social development (€M)	88.1	116.2	51.7	91.7	65.0	-6.6%	-29.1%
Contributions to society (€M)	**32.6**	**34.7**	**37.7**	**31.6**	**34.0**	**1.1%**	**7.5%**
Rural electrification programmes (€M)	55.4	81.5	14	60	31	-11.0%	-48.4%
Investments in R&D+i (€M)	**130**	**136**	**145**	**159**	**170**	**7.7%**	**6.8%**
General procurement (€M invoiced)	5,893	5,322	4,830	4,359	4,599	-2.1%	24.1%
Procurement from qualified suppliers (%)	**98**	**78**	**84**	**87**	**92**	**-1.5%**	**6.3%**
Number of suppliers with social responsibility standards	187	1,078	1,233	1,202	1,326	152.3%	10.3%
Procurement in sensitive countries per ILO (%)	**N/Av.**	**9.9**	**8.9**	**12.0**	**10.7**	**N/A**	**-10.8%**
Procurement from local suppliers (%)	92	91	90	86	87	-1.4%	1.2%

A2 SEA

Installation of one of the 108 wind turbines at the West of Duddon Sands Offshore Wind Farm / United Kingdom

1.4 Presence by areas of activity

Iberdrola in Spain
Leading energy company.

2013 / 2014

GDP 1.4%
Electricity demand -1.2%

Electricity distribution

Area of influence

Corporate offices

2014 Data

25,283
MW Installed capacity

6,109
MW Renewable installed capacity

61,052
GWh Net output

90,729
GWh Electric power distributed

266,024
Km Power lines

11.7
Millions of users

10,975
Employees

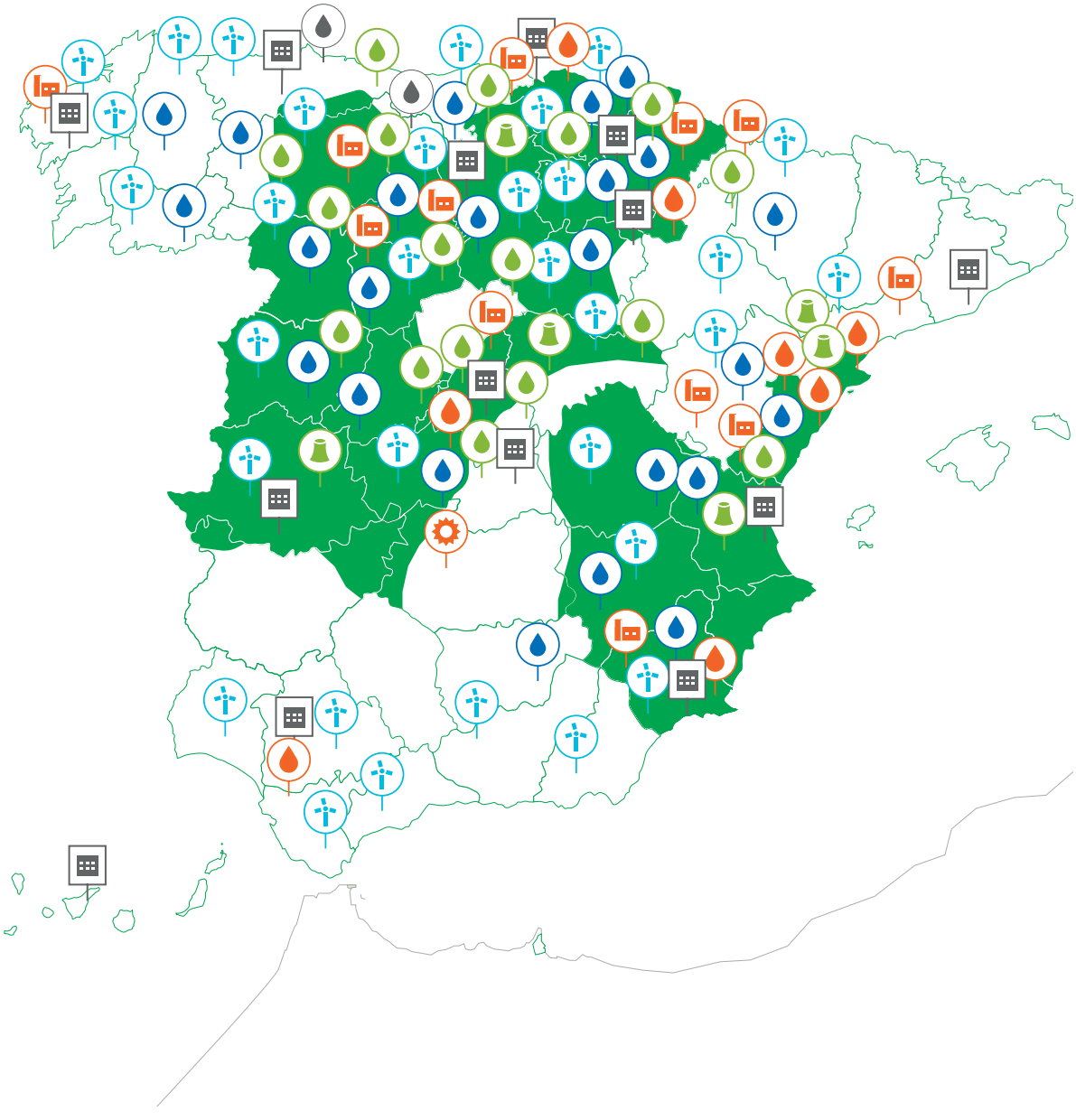
520
€M Investments

3,292
€M Direct tax contribution

Primary facilities

195 Wind farms 5,701 MW	119 Hydroelectric plants 8,807 MW	91 Mini-hydro plants 358 MW	6 Nuclear plants 3,410 MW	8 Combined cycle gas plants 5,695 MW	21 Cogeneration plants 388 MW	1 Solar 50 MW	2 Thermal plants 874 MW

Wholesale and Retail	Distribution	Engineering and Contruction	Property Development	Foundation
IBERDROLA	IBERDROLA DISTRIBUCIÓN ELÉCTRICA	IBERDROLA Ingeniería y Construcción	IBERDROLA Inmobiliaria	Fundación IBERDROLA



Iberdrola in the United Kingdom
Leading wind producer.
Third-leading network company.

2013 / 2014

GDP +2.6%
Electricity demand -6.1%

2014 Data

6,462
MW Installed capacity

1,627
MW Renewable installed capacity

18,920
GWh Net output

36,539
GWh Electric power distributed

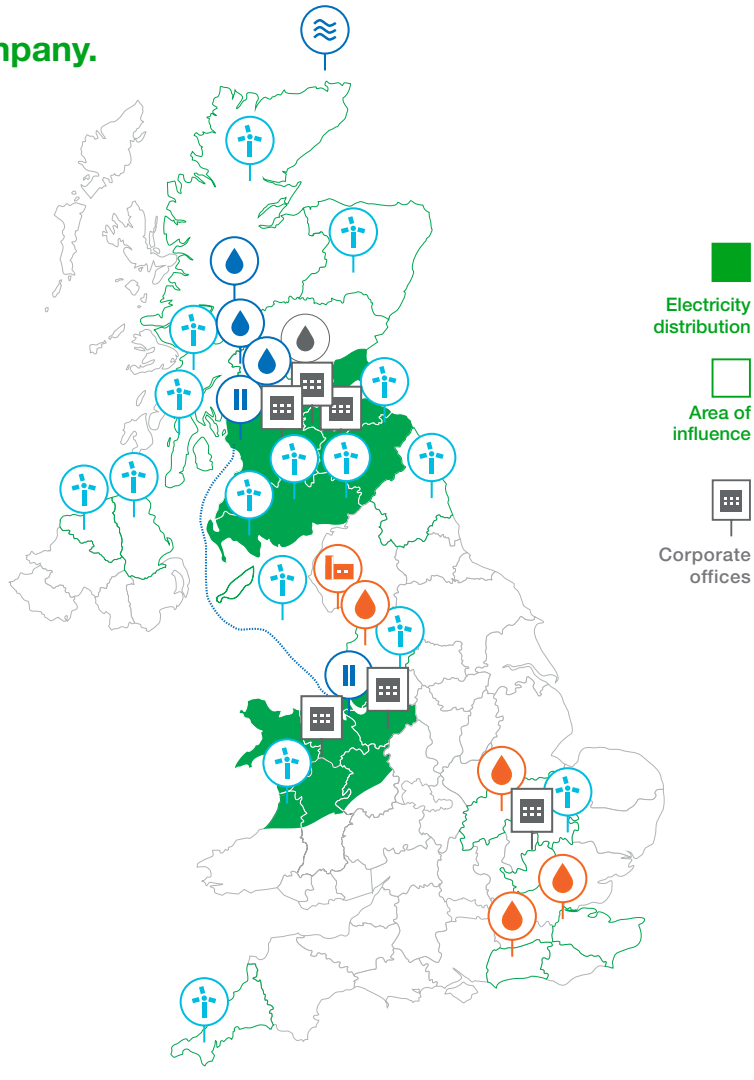
104,078
Km Power lines

5.7
Millions of users

6,856
Employees

1,301
€M Investments

454
€M Direct tax contribution



Primary facilities

32 Wind farms 1,626 MW

3 Hydroelectric plants 563 MW

1 Underwater power line (under construction) 418 KM

1 Marine energy 1 MW

1 Cogeneration plant 1 MW

4 Combined cycle gas plants 1,967 MW

1 Thermal plant 2,304 MW

Corporate: SCOTTISHPOWER

Distribution: SP ENERGY NETWORKS

Renewables: SCOTTISHPOWER RENEWABLES

Engineering and Construction: IBERDROLA Engineering & Construction

Foundation: Foundation SCOTTISHPOWER

Iberdrola in the United States
Second-leading wind producer.
Third-leading gas storage company.
Electricity and gas distributor in New York and Maine.

2013 / 2014

GDP +2.4%
Electricity demand -2.6%

2014 Data

6,479
MW Installed capacity

5,695
MW Renewable installed capacity

17,549
GWh Net output

33,335
GWh Electric power distributed

107,098
Km Power lines

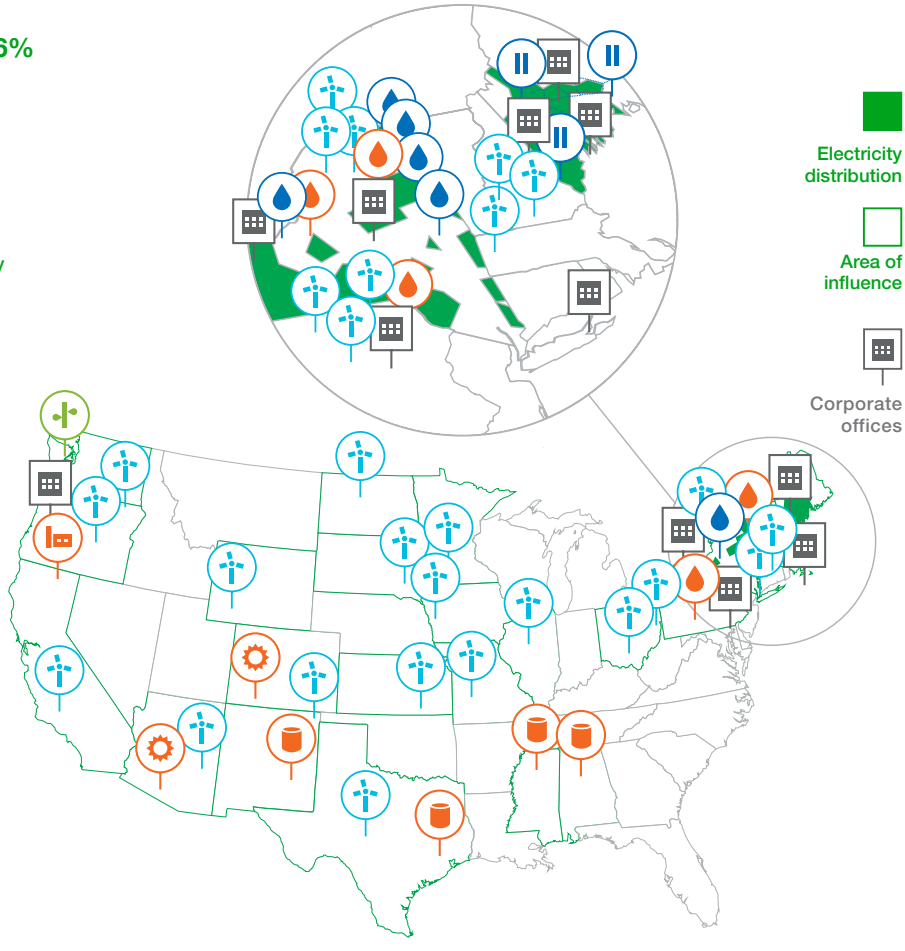
2.4
Millions of users

2.4
BCM Gas storage capacity

5,057
Employees

673
€M Investments

459
€M Direct tax contribution



Primary facilities

54 Wind farms 5,590 MW

9 Hydroelectric plants 118 MW

1 Transmission line (under construction) 708 KM

1 Biomass plant 55 MW

1 Cogeneration plant 636 MW

3 Combined cycle gas plants 30 MW

2 Photovoltaic plants 50 MW

4 Gas storage

Corporate
IBERDROLA USA

Renewables
IBERDROLA RENEWABLES

Distribution and Retail
CENTRAL MAINE POWER
RG&E
NYSEG

Engineering and construction
IBERDROLA Energy Projects

Gas storage
ENSTOR

Iberdrola in Mexico
Leading private electricity producer.

2013 / 2014

GDP +2.1%
Electricity demand +1.5%

2014 Data

5,259
MW Installed capacity

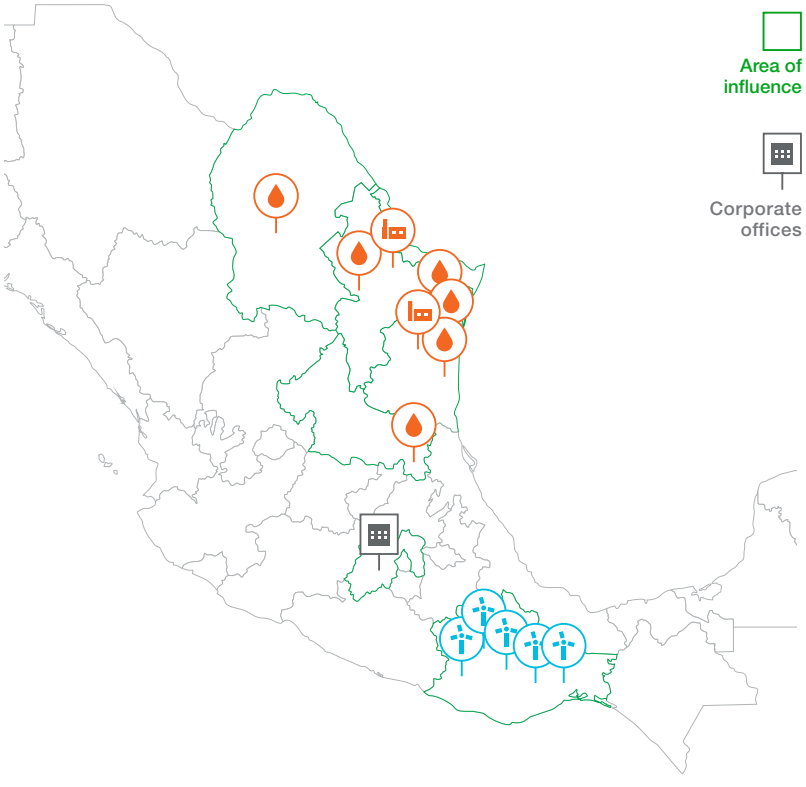
231
MW Renewable installed capacity

35,928
GWh Net output

736
Employees

233
€M Investments

184
€M Direct tax contribution



Primary facilities

5
Wind farms
231 MW

2
Cogeneration plants
201 MW

6
Combined cycle gas plants
4,827 MW

Wholesale

IBERDROLA

Engineering and Contruction

IBERDROLA
Ingeniería y Construcción

Iberdrola in Brazil
Leading distributor in Brazil by number of customers.

2013 / 2014

GDP +0.1%
Electricity demand +2.3%

2014 Data

862
MW **Installed capacity**

245.5
MW **Renewable installed capacity**

3,987
GWh **Net output**

54,010
GWh **Electric power distributed**

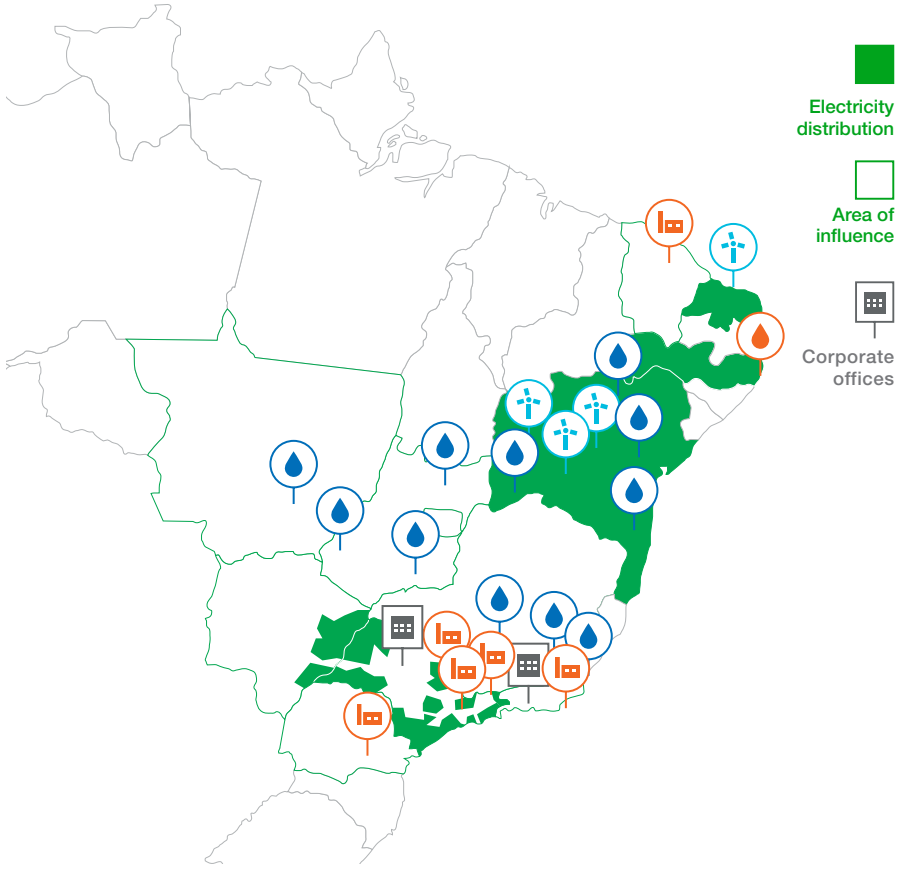
556,949
Km **Power lines**

12.8
Millions of users

5,818
Employees

96
€M **Investments**

1,009
€M **Direct tax contribution**



Primary facilities

11
Wind farms
246 MW

11
Hydroelectric plants
381 MW

6
Cogeneration plants
32 MW

1
Combined cycle gas plant
203 MW

Distribution	Supply	Engineering and Contruction	Renewables	Social Causes
ELEKTRO	ELEKTRO Comercializadora	IBERDROLA Ingeniería y Construcción	IBERDROLA	Instituto ELEKTRO

Business model and strategy

Working on the Alzira-Gandia Line / Spain

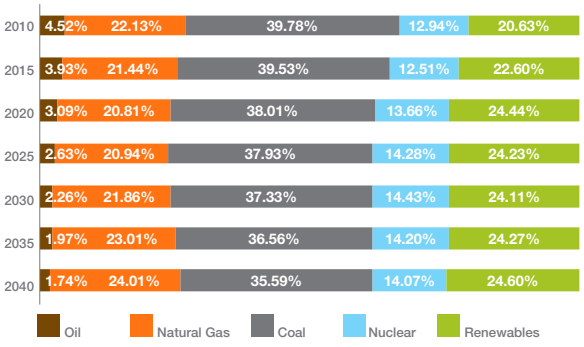
2

2.1 The future of energy

Opportunities for continued growth

The energy sector will present various opportunities for growth over the long term.

Sources of energy for global electricity generation, 2010-2040 (TWh)



Source: *International Energy Outlook 2014, Energy Information Administration, U.S.*

"One of the foremost challenges facing the energy sector in the coming years will be to secure the enormous resources required to finance vital investments".

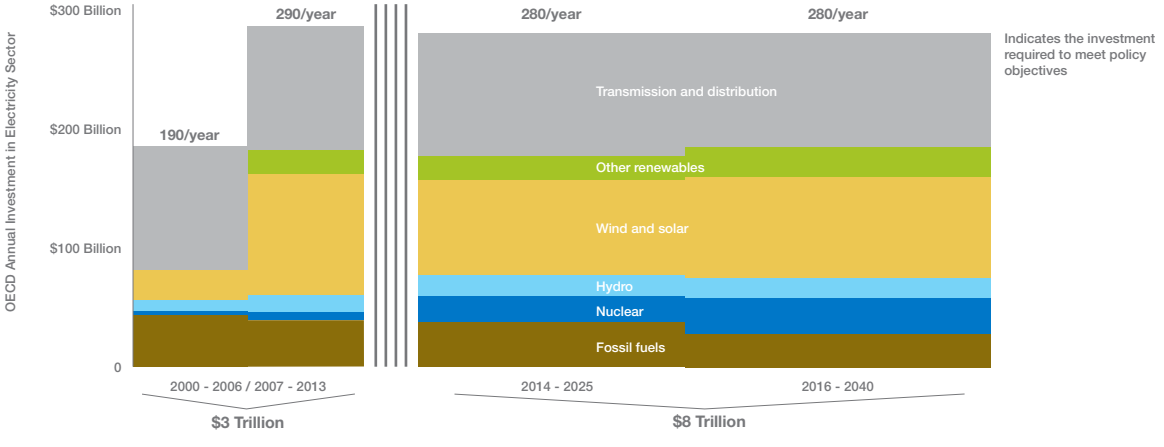
Ignacio Galán, at the *World Economic Forum 2015.*

"The Future of Electricity", according to the *WORLD ECONOMIC FORUM 2015*

The electricity sector is immersed in a process of transition characterised by:

- A significant reduction in the cost of renewable technologies, combined with new sources of natural gas. This offers the opportunity to "decarbonise" the sector, increase energy security, and reduce dependence on the import of fuel.
- Heavy investment by the OECD countries, reaching 3 trillion dollars since 2000, in new renewable and conventional energy plants, the transmission and distribution of energy, and the development of energy efficiency measures. Another 8 trillion dollars will be necessary during the 2014-2040 period.
- Improvement in the reduction of carbon intensity per unit generated and increase in energy security through the reduction in imports of fossil fuels.

Maintenance of high levels of investment through 2040



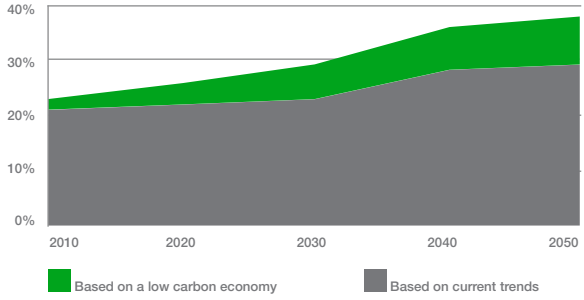
Source: *The Future of Electricity Report, World Economic Forum 2015.*

Evolution of demand

Within the current context, it is expected that energy consumption will evolve in the coming years following the GDP trend in each region. According to a PwC report, average annual GDP growth in the Atlantic area where Iberdrola operates will be positive through 2050.

The EU Roadmap forecasts that electricity will at least double its share in final energy demand to 36-39 percent in 2050, for which reason it would reduce carbon emissions in heating systems and in the transport sector (electricity could satisfy about 65% of demand from automobiles and light duty vehicles).

Electricity share
(in % of final energy demand)



Source: *Energy Roadmap 2050. Communication from the Commission to the European Parliament.*

Average annual GDP growth in the Atlantic area where Iberdrola operates will be positive through 2050.

Trends in production and use of electricity

Sectoral[1]

- The electricity sector is leading the transformation of global energy. According to *World Energy Investment Outlook 2014*, the electricity sector contributes more than any other to reducing the proportion of fossil fuels in the energy mix.
- The transition towards a low-emission economy due to the global drive towards a reduction in greenhouse gases (GHG). The OECD forecasts that global GHG emissions will increase by 50% due to a 70% increase in CO_2 emissions relating to power generation.
- Unsustainable pressure on natural resources. A world economy four times larger than today is projected to use 80% more energy in 2050. Without more effective policies to improve the panorama of unsustainable pressure on natural resources, the share of fossil-fuel based energy in the global energy consumption will still remain at about 85%.

Technological[2,3]

- Technological advances and an improvement in efficiency are grounds for optimism, but constant political efforts are essential to change energy trends for the better.
- Smart grids will introduce home automation to network management and electricity demand management, improving process efficiency.
- Technological developments, such as new renewable energies and advances in distributed generation, can change the current model of the electricity markets.
- Electricity storage, as a still-embryonic technological possibility, can open up new vistas for the operation and management of power systems.
- Technological progress as a path toward reducing emissions, both in obtaining fuels and in producing electricity and managing its use.

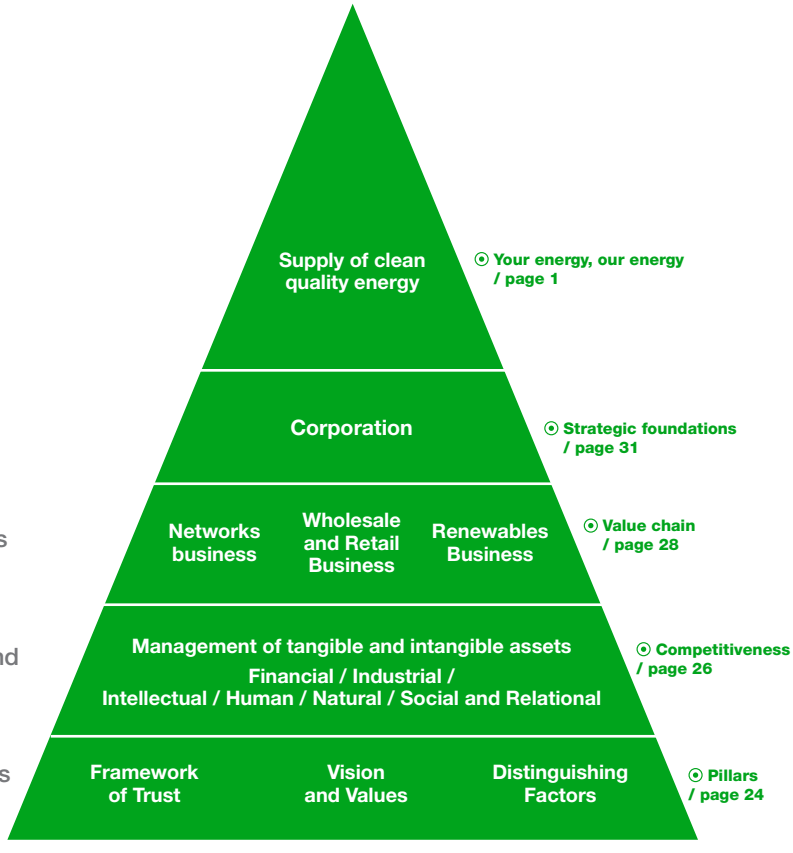
Consumption

- Universal access to energy, as an element to improve well-being. *"World electricity demand will grow by 80% over the next 30 years driven by improved efficiency and the expansion of service to the 1.3 billion people who still do not have access to power". Ignacio Galán.*
- The development of new uses and applications for electricity may result in new markets and opportunities: electric vehicles, robotics in the use of electricity, etc.

[1] Source: *"OECD Environmental Outlook to 2050"*;
[2] Source: *"Energy Roadmap 2050"*;
[3] Source: *World Energy Investment Outlook" (2014).*

2.2 Business model

The purpose of the business model defined for the Iberdrola Group is the "supply of reliable, high-quality and environmentally-friendly energy", through a sustainable, long-term industrial enterprise.
The model is built on three pillars: a **framework of trust** based on an advanced governance model; the Group's **vision and values** approved by its management units; and the **distinguishing factors** that make Iberdrola a different company.
The model's competitiveness is achieved through **responsible management of the tangible and intangible assets** of the Company.
To apply this model, Iberdrola has defined the activities in which it seeks to be an active player, the **value chain**, structuring its management into three global businesses: the Networks Business; the Wholesale and Retail Business; and the Renewables Business, with a Corporation as the Group's central management unit.
The Corporation develops the Group's strategy and oversees its execution.



Framework of trust

To ensure the sustainability of its business model, Iberdrola has implemented:

- A Corporate Governance System consistent with best global practices.
- Corporate ethics, internalised by the management units and the organisation as a whole.
- *Social Responsibility Policies, with a view to meeting the expectations of stakeholders.*
- Advanced risk control, to maintain an optimal "risk/opportunity" balance, taking advantage of opportunities and mitigating risks.

Strategic foundations / page 31

Vision and values

"We aspire to be the preferred global energy company because of our commitment to the creation of value, quality of life, the safety of people and of supply, the protection of the environment, and customer focus".

The Group's vision is based on six values:

- Corporate ethics and responsibility.
- Financial results.
- Respect for the environment.
- Sense of belonging and trust.
- Safety and reliability.
- Customer focus.

2.3 Iberdrola, a different company

Main businesses of Iberdrola / page 36

Presence by areas of activity / page 14

Natural capital / page 64

Focus on basic and regulated businesses

Approximately 75% of Ebitda comes from regulated businesses.

International diversification

Approximately 55% of earnings are generated outside of Spain.

Commitment to clean and competitive energies

- Generation and production of largely emission-free electricity.
- Large portfolio of offshore wind generation projects and wave and tidal power projects.
- Clear goals for reducing emissions.

Operational efficiency

In a comparative analysis of six European companies in the sector, according to a study by Ernst&Young, Iberdrola leads in three efficiency variables: net operating expenses over gross margin, workforce per unit of installed power, and workforce per number of users.

Financial strength and solidity of the group

- Strengthening of the balance sheet by reducing debt and improving solvency ratios.
- Liquidity position that covers financial needs for more than 30 months, even under stress scenarios.

Global, committed and qualified workforce

- Stable and high-quality jobs, with high level of training.
- Health and safety as values: “accident reduction” goal.
- Group companies in Spain and Brazil are considered best places to work in their sector, by Merco and *Guía Você*.

Iberdrola’s primary businesses / page 36

Financial capital / page 56

Human capital / page 62

2.4 Management of tangible and intangible assets

	Financial capital	Manufactured capital	Intellectual capital
	Financial capital / page 56	Manufactured capital / page 58	Intellectual capital / page 60
What is it?	Economic resources the company holds or obtains through financing.	Tangible assets or goods used by the Company to carry out its activities.	Intangible, knowledge-based assets.
Management approach	*To create value for shareholders through sustainable growth.*	*To offer a competitive supply of energy in a safe and reliable environment.*	*To consider innovation as a strategic element of the Company.*
Significant assets	• Sound financial structure. • Operational efficiency. • Monitoring of investments. • Sustainable results and dividends.	• Power generation assets. • Power transmission and distribution assets. • Other assets.	• Promotion of R&D+i. • Efficiency and new products and services. • Disruptive technologies and business models.

The Iberdrola Group holds valuable assets for the development of its business model. The strategy defined by the Company transforms these assets to create value for all its stakeholders.

Human capital / page 62

Human capital

Employee knowledge, skills, experience and motivation.

To guarantee the availability of a committed and qualified workforce.

- Global human resources management.
- Goal of “accident reduction”.
- Talent management.
- Diversity, equal opportunity, and reconciliation.

Natural capital / page 64

Natural capital

Natural resources affected by the Company’s activities.

To ensure sustainable use of natural resources and contribute to combating climate change.

- Environmental management.
- Preservation of biodiversity.
- Prevention of pollution.
- Operating excellence and energy efficiency.
- Waste management.

Social and relational capital / page 66

Social and relational capital

Ability to share, relate, and collaborate with its stakeholders, promoting community development and well-being.

To promote relations of trust with stakeholders, improving the quality of life of people in areas where the Group has a presence.

- Stakeholder relations.
- Community support and electricity access programmes.
- Foundations and non-profit associations linked to the Iberdrola Group.
- Corporate reputation.
- Reputation management.
- Informational transparency.

2.5 Value chain

Power generation

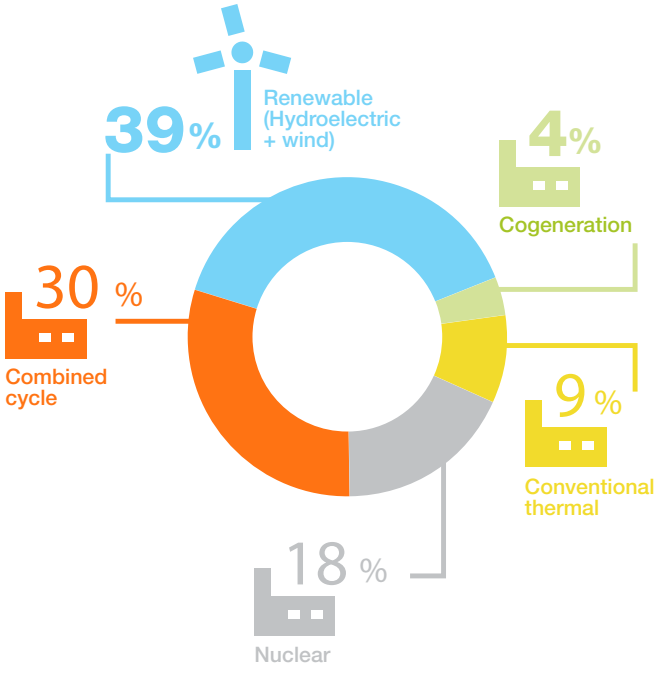
Electricity production through the construction, operation, and maintenance of generating plants, and purchase/sale of energy on wholesale markets.

Power transmission and distribution

Construction, operation, and maintenance of electrical lines, substations, transformer centres, and other infrastructure to transmit electric power from production centres to end users.

Generating plants*

* % of 2014 net output



Electricity networks*

* At 31 December 2014

Overhead lines

4,000
High and medium voltage transformer substations

29,446 Km
Transmission lines

846,281 Km
Distribution lines

Energy supply

Supply to end users of energy and additional products and services.

Users*

* % by sector at 31 December 2014

Underground lines

1.4 million
Medium to low voltage distribution transformers

960 Km
Transmission lines

187,868 Km
Distribution lines

Almendra Dam,
Salamanca / Spain

2.6 Strategic foundations for 2014-2016

Market conditions

The global energy scenario is trending toward moderate growth in the medium and long terms, driven by the economic recovery. The Company has designed a strategy to address this scenario, with specific measures adapted to the particular needs of its areas of activity.

Challenges and opportunities

Challenges

- Management of a scenario involving slow recovery in the demand for electrical power.
- Attainment of higher efficiency levels in all businesses.
- Regulatory management in all businesses, with special emphasis on transmission and distribution businesses.
- Containment of financial expenses in an environment of potential increases in medium-term interest rates.

Opportunities

- International diversification with a presence in countries with a stable and predictable regulatory framework.
- Balanced business model focused on regulated activities.
- High quality of assets.
- Culture of innovation, efficiency, and results.
- Proven management capacity.

...maintaining a commitment of sustainable remuneration to shareholders.

Growth vectors 2014-2016

Investments

- United Kingdom: Iberdrola is facing a period of expanding activity in energy transmission and distribution, as well as in onshore and offshore renewable energy projects.
- United States of America: The Company is facing growth in the networks area and in new onshore wind projects.
- Latin America: The Company will consolidate its position as the largest private generator of electricity in Mexico. In Brazil it anticipates a period of growth in hydroelectric capacity.
- Spain: Maintenance and improvement of facilities.

Operational efficiency

- In all areas of activity.

...with potential additional growth in EBITDA from improvements in market conditions and energy prices.

Beyond 2016 ...

- Projects undertaken in 2014-2016 will provide higher contribution to results.
- Additional investments in stable and attractive businesses and countries.
- Further efficiency measures: structural optimisation and additional headcount reduction.
- Portfolio management to explore new opportunities for growth.

....to increase shareholder remuneration in line with results.

The future of energy / page 22

Strategic pillars

Iberdrola's strategy for 2014-2016 will be based on consolidating its financial strength, investing in regulated businesses, and continuing to implement efficiency improvements; thereby maintaining the same strategic pillars that enabled the successful navigation of the global economic and financial crisis.

1. Balanced risk profile

- Investments focused on businesses and countries with stable and predictable regulatory frameworks.
- Gross investment of €M 11,200, representing net investment of €M 9,600, with €M 4,400 focused on growth and the rest on maintenance and replacement.
- Electric power transmission and distribution networks will account for 57% of total net investments. Of the overall amount, 22% will be dedicated to renewable energy and 19% to generation.
- The regulated businesses (networks, renewables, and regulated generation) will account for 88% of all planned investments.
- Geographically, Iberdrola will concentrate most of its efforts in the United Kingdom (41%); followed by Latin America (24%) (mainly Mexico), the United States of America (17%), and Spain (15%).

2. Operational efficiency

- Continue implementing measures to promote savings and contain operating costs, with a view to improving efficiency and partially absorbing the effects of inflation and activity growth, on both personnel expenses and outside services:

Personnel

- Organic reduction of 1,000 employees in existing businesses.
- Approximately 27,000 employees by year-end 2016.

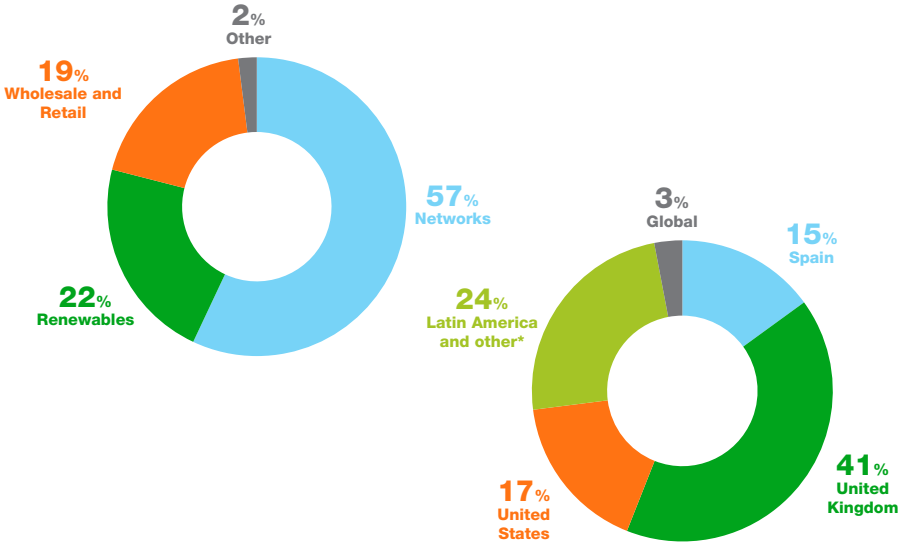
External services

- Optimisation of corporate structure.
- Procurement management.
- Process management.

From 2014 to 2016, investments will be focused on companies with stable regulatory environments.

Financial capital / page 56

Investment by businesses and by areas geographical 2014-2016



* Includes investments in Neoenergia.

3. Financial strength

- Net debt reduction of €M 1,800, down to €M 25,000 by year-end 2016.
  - Operating cash flow (FFO) exceeding investments across all businesses.
  - Divestment of €M 500, in addition to the €M 2,000 in the divestment plan announced in 2012.
  - Change in the financial model to provide subsidiaries with an optimal capital structure providing appropriate financial signals, in line with current guidelines for structural subordination.
  - Optimisation of liquidity position (<€M 9,000) to current market conditions in order to improve financial costs, maintaining 24 months of coverage even during stress scenarios.
- Strengthening of financial ratios, with the following goals through 2016:
  - Leverage ≈ 40%.
  - Net debt/EBITDA <3.5.
  - FFO/Net debt >22%.

Resulting in growth over the period and a sustainable shareholder remuneration policy.

- After the impact of fiscal and regulatory modifications in Spain, the Company estimated Ebitda of €M 6,600 and net profits of €M 2,300 for 2014, with subsequent average growth of 4% annually through 2016.
- Due to the good performance of the businesses, 2014 results were higher than initially forecast. Ebitda reached €M 6,965, with net profit of €M 2,327.
- In this scenario, the Group maintains the goal of providing its shareholders with an annual remuneration of at least €0.27 (gross) per share, which could increase based on profits, with a payout of between 65% and 75%.

€M	2014	Average annual growth* 2014-2016
Ebitda	6,965	4%
Net profit	2,327	**4%**

* Average annual growth potential of 4% calculated based on initial results forecasts for 2014: €M 6,600 Ebitda and €M 2,300 net profit.

2.7 Comparative results and rewards

Comparative analysis*

Comparative economic/financial variables 2014

Growth in EBITDA

CAGR (%)	Average comparables	Iberdrola
31-Dec.-04 / 31-Dec.-14	2.2%**	9.1%

Growth in Capitalisation

Total growth (%)	Average comparables	Iberdrola
31-Dec.-04 / 31-Dec.-14	-2.2%	112.1%

Iberdrola held 6th place at the European level in terms of stock market capitalisation for the last 10 years. It is now in third place.

Share price

Total growth (%)	Average comparables	Eurostoxx Utilities	Iberdrola
31-Dec.-04 / 31-Dec.-14	-32.0%	-7.1%	19.7%

*Comparable companies analysed: GDF Suez, EDF, E.On, Enel, RWE. Uses a start date of 7 July 2005 for GDF-Suez (the date on which GDF commenced listing), and 18 November 2005 for EDF (the date of its IPO).
ACGR: Annual Compound Growth Rate, i.e. weighted average annual growth.
**For GDF Suez, the 2004 figure is for Suez S.A. (prior to the merger of GDF and Suez SA).

Comparative performance of total shareholder return

Profitability (%)	Average comparables	Eurostoxx Utilities	Iberdrola
31-Dec.-04 / 31-Dec.-14	20.9%	55.8%	83.3%

Iberdrola's performance

Over the last 10 years, Iberdrola has quadrupled its assets, tripled its revenues, doubled its EBITDA and net profit, and increased shareholder remuneration by more than 40%, while maintaining its financial strength.

Iberdrola	31-Dec.-04	31-Dec.-14	Multiple
Assets (€M)	26,189	93,771	3.6x
Revenues (€M)	8,725	30,032	3.5x
EBITDA (€M)	2,913	6,965	2.4x
Net Profit (€M)	1,196	2,327	1.9x
Dividends (€/share)	0.19	0.27	1.4x
Net Debt/Ebitda	3.7	3.7	1.0x

Other awards / pages 63 and 79

Ignacio Galán
at 10 Downing Street / London

External awards

For the Company:

- Best European Utility (Institutional Investor Research): 2014, 2013, 2011.
- Best Corporate Governance in Spain (World Finance): 2014, 2012.
- Best corporate governance among European utilities (Ethical Boardroom): 2014.
- World's Most Ethical Company Index (Ethispher Institute): 2014.
- Excellence in corporate governance (Institute of Directors, Golden Peacock Award): 2013.
- Leading Ibex 35 company in the tax transparency ranking 2014, from Fundación Compromiso y Transparencia.

For the Chairman and CEO:

- Best European Utility CEO (Institutional Investor Research): 2014, 2013, 2011.
- Responsible Capitalism Award (First): 2014.
- Commander of the Most Excellent Order of the British Empire: 2014.
- Honorary Doctorate from the Universities of Salamanca (2011), Strathclyde (2013), and Edinburgh (2011).

For other members of the Company:

- Best European Utility CFO (Institutional Investor Research): 2014, 2012.
- Best European Utility Investor Relations (Institutional Investor Research): 2014, 2013, 2012, 2011, and 2010.

Iberdrola's primary businesses

Regulation is a key factor in the sustainability of Iberdrola's activities.

Energy policies must set clear and predictable goals in order to attract the investment needed to guarantee a safe, competitive, and sustainable supply, developing its potential as a source of growth and employment.

View of the West of Duddon Sands offshore complex with the substation in the foreground / United Kingdom

3

3.1 Regulatory environment

European Union

- Work continues on completing the internal market. Guidelines have been published to authorise state aid for renewables and back-up generation, preserving the internal market and price competitiveness to the extent possible.
- There are various ongoing initiatives to drive the development of energy infrastructure, including a strengthening of interconnections in Spain and the United Kingdom.
- A new energy and climate framework for 2030 has been approved that includes a goal to reduce CO_2 emissions by 40%, and others targeting a 27% increase in renewables and decrease in consumption. This new framework will give investors long-term signals for building infrastructure.
- Initiatives are being promoted to strengthen and stabilise the signal on emissions trading, in order to promote the change towards low-emission technologies.

Spain

- Most of the regulatory steps on electricity and gas reform were already taken during 2013 and 2014, for which reason a tariff deficit is not expected for 2014.
- An energy efficiency fund has been created by means of which all energies (electricity, gas, and gasolines) contribute in proportion to their demand to the costs of implementing the European goal of energy efficiency for 2020.
- A regulated tariff applying to approximately 90% of consumers is maintained.

United Kingdom

- In April 2014 the Competition and Markets Authority (CMA) opened an investigation into the entire gas and electricity supply sector. Its conclusions and proposed remedies will be published at the end of 2015.
- The Government's Energy Market Reform package, which mainly deals with the capacity market and the implementation of contracts for difference for low carbon energy, was mostly completed in 2014.
- There will be work on reforming the wholesale market, for integration into the single European market.

Brazil

The unfavourable water situation is driving the use of more expensive thermal generation and an increase in energy prices on the spot market. A number of measures have been implemented to try to mitigate the effects of this situation:

- Provision of funds to mitigate the impact on distributors of involuntary exposure to the spot market.
- Reduction in the maximum price of energy on the spot market, from R$822/MWh to R$388/MWh.
- Use of tariff bands since the beginning of 2015, which are intended to signal the cost of generation to consumers. The tariff rises when more expensive sources of generation are used.
- Approval at year-end 2014 of a modification in the concession agreements for distributors, allowing them to recognise regulatory assets and liabilities.

United States and Canada

- The State of New York, along with other states, will continue to consider changes in the regulatory model for utilities, taking into account technological advances both in generation and distribution of electricity.
- There is expected to be continuing debate on the establishment of an efficient and stable foundation for investment in renewable energy, influenced by the latest controversies over climate change and fracking.
- The Environmental Protection Agency (EPA) expects to publish two independent regulations in 2015 proposing a reduction in CO_2 for the electricity generation sector that could have a considerable impact on decision-making for electric companies.

Mexico

- The new energy reform, the legislative development of which will continue during 2015, ends the state monopoly in the hydrocarbon and electricity sectors. In the electric sector, it will encourage investment in new generation projects that will operate in a competitive environment after the creation of various markets. The share of clean energy is forecast to increase to 35% by 2024 with the creation of a Clean Energy Certification system, based on which certain supply obligations will be determined. Furthermore, contracts with private parties will begin in the area of networks, which are still under state ownership and considered to be a public service.

Line inspections,
Burgos / Spain

3.2 Networks

Regulatory environment of the business

Spain

- The transitional remuneration methodology approved in 2013 is being applied in 2014 and 2015.
- Awaiting a complete definition of the new regulatory scheme, which is pending publication of the base unit costs.

United Kingdom

- Transmission activity managed under the RIIO-T1 scheme in effect for the 2013-2021 period.
- The current DPCR5 regulatory period ends in April 2015. In November 2014 Ofgem published a final determination for the new RIIO-ED1 2015-2023 period.

New tariff periods entered into force for ScottishPower in the United Kingdom and for Elektro in Brazil during 2015.

United States

- In 2014 current tariff conditions were extended for distributors in New York.
- A new rate agreement entered into force on July 2014 for CMP (Maine), which will be in effect for one year.

Brazil

- The indicators to be used in the 4th cycle of the tariff revision for distributors will be determined in 2015.
- Elektro's tariff agreement ends in August 2015, when the 4th tariff cycle will begin. In 2014, the annual tariff adjustment was 37.78%.
- The tariff agreements for the distributors of Neoenergia are in force through April 2017 for Celpe and April 2018 for Coelba and Cosern. The annual tariff update for 2014 was 17.79% for Coelba, 15.35% for Cosern, and 12.75% for Celpe.
- The Brazilian government has eliminated the impact on results and limited the impact of involuntary exposure to the spot market on the cash flow of the distributors.

Objectives, risks and principal activities

Objectives

- Satisfy supply under strict safety conditions, in compliance with environmental requirements.
- Increase quality in energy supply by investing in the expansion and renewal of networks, improvement of our processes, and use of the latest advances in technology.
- Maximise efficiency in system operations.
- Zero accidents.

Significant risks

- Regulatory uncertainty.
- Safety of individuals from risk of accidents.
- Incidents with environmental impact.
- Major network incidents.
- Increased fraud.

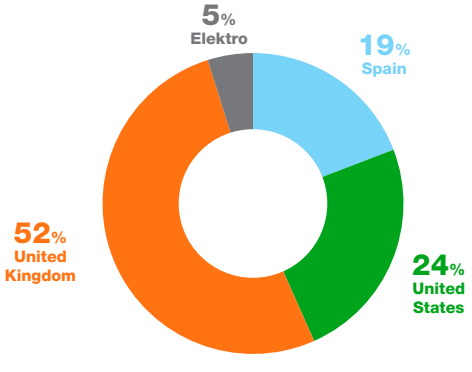
Principal activities 2014

- Spain: continuation of the STAR project for the roll-out of smart grids, after already installing over 4 million meters. 12 new electric substations were also placed into service.
- **United Kingdom:** the DPCR5 period ended in March 2015. At 31 December 2014, there was more than 90% compliance with the commitments made.
- **United States:** progress in accordance with forecast for the MPRP transmission project in Maine (700 km of network, 5 new substations, and 6 expanded substations). The level of project achievement exceeded 90%. The NY Transco initiative was launched in 2014 to develop $M 1,700 in transmission infrastructure in NY through 2018. Iberdrola contributes 20% to the programme (the other contributions will be made by transmission companies in the State of New York).
- **Brazil:** development of facilities to cover increases in demand, and connection of new customers.

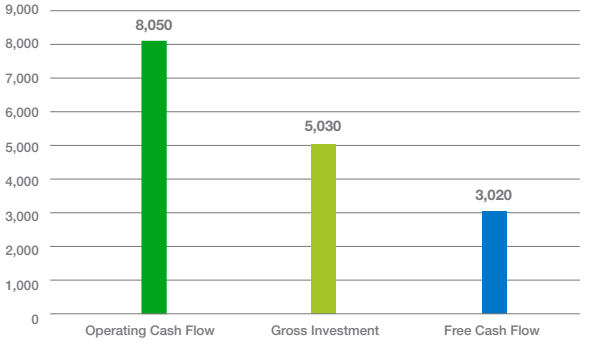
Outlook

- 57% of the Iberdrola Group's investments will be allocated to the Networks business.
- Work is being carried out to identify new development opportunities in transmission and the application of new technologies for the development of smart grids.

Net investment of €M 5,030 between 2014 and 2016, 56% for growth activities



Generation of cash flow 2014-2016 to finance investments (€M)



Key figures of the Networks Business

		Spain		United Kingdom		United States		Brazil				Total	
								Elektro		Neoenergia[1]			
Item	Unit	2013	2014	2013	2014	2013	2014	2013	2014	2013	2014	2013	2014
Gross margin	€M	1,905	1,952	1,193	1,331	1,469	1,498	396	459	-	-	4,962	5,241
Ebitda	€M	1,450	1,439	939	1,025	718	772	239	299	-	-	3,346	3,535
Electric power distributed	GWh	91,656	90,729	37,750	36,539	33,187	33,335	16,663	16,933	35,552	37,077	214,809	214,613
Users (Electricity)	Millions	10.8	10.8	3.5	3.5	1.8	1.8	2.4	2.4	10.0	10.3	28.6	28.8
Gas supply	GWh	-	-	-	-	37,069	40,870	-	-	-	-	37,069	40,870
Users (Gas)	Millions	-	-	-	-	0.6	0.6	-	-	-	-	0.6	0.6
Investments	€M	283	304	587	729	543	432	80	75	-	-	1,494	1,541
Workforce	No.	4,055	3,906	2,910	2,894	4,131	4,133	3,778	3,801	2,182	2,091	17,056	16,825

International financial reporting standard (IFRS) 11 has been applied to the financial information for both 2013 and 2014.

(1) Operational information is deemed to be 100% from Neoenergia.

Quarterly results report

Safety, quality of supply, and operational efficiency are the three strategic pillars of the Networks Business upon which the entire business rests.

Safety

- Ongoing efforts to improve safety in networks activities, which is reflected in the decrease in the Incident Rate.
- Implementation of best practices at all networks companies to reduce the risks associated with operation.
- Development of safety improvement initiatives for all Networks personnel and subcontractors.
- There has been a 23% reduction in network anomalies in Spain.

Quality of supply

- Ongoing effort to improve supply quality indicators.
- Between January and December 2014 the quality of service indicators generally improved over the prior period in all of the Company's areas of operation, exceeding the best historical records in Spain, and at Elektro in Brazil.
- Development of transmission and distribution projects in the United Kingdom and United States to ensure the reliability of supply and optimise the cost of energy.
- Network automation project in Spain to improve its operation.

Efficiency

- Increase in operating expenses contained despite strong increase in activity.
- Implementation of best practices throughout the networks companies, mainly in the areas of asset management, processes and technology, control and automation systems, and customer service.

Monterrey Combined Cycle Plant / Mexico

3.3 Wholesale and retail

Regulatory environment of the business

Spain

- The new billing method of the *Voluntary Price for the Small Consumer* based on daily prices, implemented since April 2014, and the new regulated billing form since October.
- The current capacity availability service has been extended in 2015 while the Royal Decree modifying capacity payments is developed during the course of the year.
- Applicable remuneration for cogeneration and waste facilities specified due to approval of RDL 9/2013.

United Kingdom

- The *Secure & Promote* obligations to facilitate access by small suppliers and to create a market for wholesale electricity products entered into force on 31 March 2014.
- The first auction in the 2018/2019 capacity market took place in December 2014, with the participation of both existing plants and new projects. The clearing price was 19.40 £/kW.
- The *Carbon Tax*, which applies to carbon emissions, will increase from 9.55 £/t to 18.08 £/t in April 2015, changing the equilibrium of the market. After that, it will remain constant until 2020.
- The changes in transmission network tolls for generators will become effective in April 2016.
- The ECO programme, which requires suppliers to comply with certain targets to reduce emissions and home energy costs, has been extended through 2017.

Europe

- The REMIT[1] registration and information obligations, to ensure the integrity and transparency of the wholesale energy market, will enter into effect in 2015.

Mexico

- The Electricity Industry Act (*Ley de la Industria Eléctrica*) (LIE) establishing a timetable for liberalisation was approved in August 2014. Load centres included in self-supply contracts or that have a capacity above 3 MW, which limit will be progressively reduced to 1 MW over the next three years, may thus be qualified users.
- During the first half of 2015, it is expected that there will be approval of the general terms for the electricity market, which must implement a capacity market and a power market, with the ability to enter into hedge agreements. The electricity market will allow the development of new generation by private investors.

[1] **REMIT: Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency.**

Objectives, risks and principal activities

Objectives

- Operating excellence, safety, and respect for the environment.
- Risk identification and minimisation.
- Continuous improvement in operating efficiency.
- Competitive supply and excellence in service to customers.
- Analysis of growth opportunities.

Significant risks

- Regulatory uncertainty in the countries in which it operates.
- Changes in production of and demand for electricity and gas.
- Fluctuations in hydroelectric, wind, and solar production.
- Environmental costs and costs of fossil fuels.
- Changes in the market prices for electricity and gas.
- Credit, exchange-rate, and interest-rate risks.
- Risk of accidents with an environmental impact.
- Operating risks due to downtime of facilities.

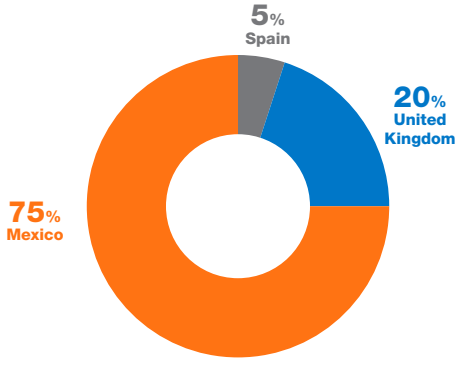
Principal activities 2014

- **Spain:** request authorisation for the closing of the Castellón 3 (800 MW) CCGT plant to optimise the generating facilities of the Group. Continue developing customer loyalty-building initiatives (*Fixed payment* campaign, *Customers* app, etc).
- **United Kingdom:** agreement with National Grid to provide the Supplemental Balancing Reserve (SBR) service for the 2014-2015 period, guaranteeing 675 MW of capacity to the system. Decrease in residential electricity and gas rates due to changes in the ECO programme.
- **Mexico:** Placement into service of the expansion of the Enertek (37 MW) cogeneration plant and commencement of construction on the Kimberly Clark (50 MW) cogeneration plant, the Baja California III (300 MW) CCGT plant, and the 5th unit of the Monterrey (300 MW) CCGT plant.

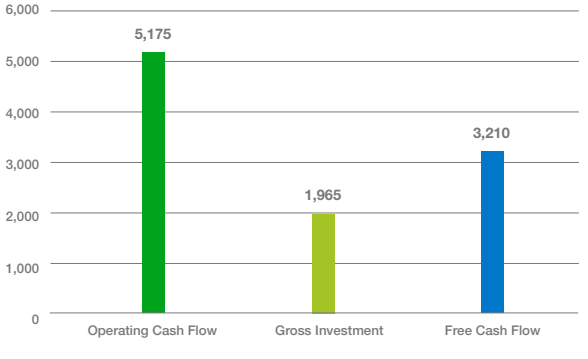
Outlook

- Focus stays on efficiency of operations, resources, and operation of generating plants in Spain and the United Kingdom.
- New flexible hydroelectric capacity in Spain: San Pedro II (25 MW) HP and final start-up of La Muela (852 MW).
- Mexico is focus for growth in generation and search for new generating opportunities.
- Supply, customer loyalty-building in mature markets (Spain and United Kingdom), and development in Mexico.

Net investment of €M 1,200 between 2014 and 2016 in growth activities and app. €M 250/year in maintenance



2014-2016 Cash flow generation to finance investments (€M)



Key figures of the Generation and Retail Business

		Spain		United Kingdom		United States and Canada		Mexico		Total	
Item	Unit	2013	2014	2013	2014	2013	2014	2013	2014	2013	2014
Gross margin	€M	2,926	3,068	1,045	1,205	14	3	453	457	4,439	4,734
Ebitda	€M	1,343	1,517	320	457	-23	-32	348	350	1,989	2,292
Installed capacity	MW	19,379	19,174	4,865	4,835	N/A	N/A	4,987	5,028	29,231	29,037
Net output (excluding renewables)	GWh	44,219	47,844	17,142	15,810	N/A	N/A	34,212	35,175	95,573	98,829
Electricity contracts	Millions	10.6	10.4	3.4	3.3	N/A	N/A	N/A	N/A	14.0	13.7
Gas contracts	Millions	0.8	0.8	2.2	2.2	N/A	N/A	N/A	N/A	3.0	3.0
Products and services contracts	Millions	3.7	4.4	0.1	0.1	N/A	N/A	N/A	N/A	3.8	4.5
Total retail contracts	Millions	15.1	15.7	5.8	5.5	N/A	N/A	N/A	N/A	20.9	21.2
Investments	€M	145	146	123	98	4	4	54	175	325	423
Workforce	No. people	3,552	3,478	2,981	2,505	122	117	433	442	7,088	6,542

International financial reporting standard (IFRS) 11 has been applied to the financial information for both 2013 and 2014.

Quarterly results report

The Wholesale and Retail Business is focused on operating efficiency, the loyalty of customers, and growth in Mexico, which will allow for the stability of results and ensure the generation of funds for the Group.

Efficiency

- Optimisation of coal production, with investments in low-cost NO_x in Spain and the United Kingdom.
- Facilitating operations in complementary markets in Spain and the United Kingdom.
- Operating improvements to increase the availability and energetic yield of the Mexico facilities.

Growth in generation

- Mexico: Placement of 650 MW into service in 2016:
  - Baja California III CCGT (300 MW).
  - 5th Unit of Monterrey CCGT (300 MW).
  - Kimberly Clark Ramos Cogeneration (50 MW).
- United Kingdom: Participation in 2019-2020 capacity auction with the Damhead Creek II CCGT (800 MW).

Supply

- Building loyalty of customers in Spain and launching new energy efficiency products and services (home electricity protection scheme, etc).
- Recover quality of service in Supply in United Kingdom after the stabilisation of the new systems.
- Retail development in Mexico pursuant to changes in legal provisions on energy reform.

Maintenance work on a wind turbine at Maranchón Wind Farm / Spain

3.4 Renewables

Regulatory environment of the business

Spain

- Stability in current regulation of renewable energy is expected after the regulatory adjustments made in 2014.

United Kingdom

- During 2014 facilities were pre-qualified in order to access the contracts for differences auctions process. The first auction will take place in February 2015.
- The *Renewable Obligation*, which continues to be interesting for our onshore facilities, can still be chosen through 2017.

The business will develop sustainable growth, based on onshore and offshore wind investments in the countries most important to the Group.

United States

- There is an extension of the incentives for wind energy plants that began construction before year-end 2014. No changes for solar energy that enters into service before 1 January 2017.
- It is expected that government schemes to encourage renewables will retain a relatively stable framework.
- The adoption of measures to improve the integration of renewables into electricity systems will continue to progress.

Mexico

- The new energy reform, although still in development, is expected to be an active means of developing renewable energy.
- The general foundations of the system are already in place based on tradable clean energy certificates, and in which it appears that auctions will play an important role.

Brazil

- The auction model for the development of wind and solar energy is expected to be stable. 2.2 GW of wind and 0.9 GW of photovoltaic were awarded under this mechanism during 2014.
- The local content requirements for material investment in facilities may be increased.

Objectives, risks and principal activities

Objectives

- Efficiency in operations to maximise the profitability of the assets.
- Profitable growth in onshore and offshore wind investments in the countries that are strategic for the Group.

Significant risks

- Regulatory uncertainty in the countries in which it operates.
- Prices of energy and green certifications.
- Operational and technological risk.
- Risk of access to evacuation networks and limits on production due to technical restrictions on networks.

Principal activities 2014

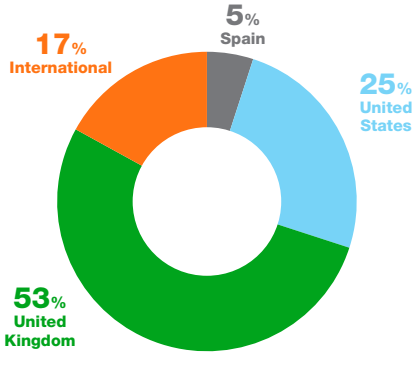
- 215 MW of onshore wind capacity were installed during the year: 202 MW in the United States and 13 MW in the United Kingdom.
- Two installations with a total of 136 MW in Mexico and a third with 38 MW in the United Kingdom are also under construction.
- In Brazil, 174 MW was awarded in two auction awards in June and November of this year.
- In the offshore wind area in the United Kingdom, there has been the startup of the West of Duddon Sands wind farm (388 MW*) and final approval has been received for the construction of the East Anglia One wind farm.
- The main contracts have been awarded for the 350 MW Wikinger project, located in Germany in the waters of the Baltic Sea.

** Iberdrola has 50% share (194 MW).*

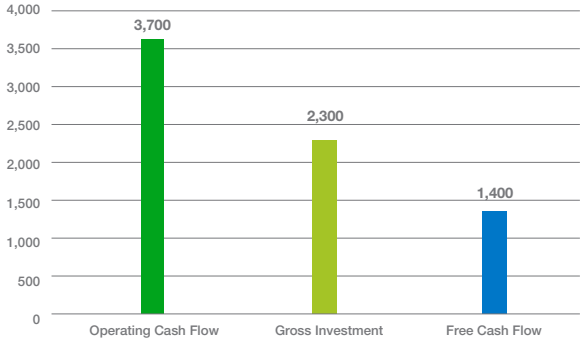
Outlook

- Deceleration of investments, with moderate current growth, and potential to make additional investments.
- New facilities are focused on the United States, the United Kingdom, Mexico, and Brazil.
- Promotion of offshore wind projects, through a strategy based on technological efficiency and investment profitability.

Investment plan of €M 2,300 between 2014 and 2016, 90% for growth activities



2014-2016 Cash flow generation to finance investments (€M)



Key figures of the Renewables Business

		Spain		United Kingdom		United States		Mexico		Brazil		Rest of World		Total	
Item	Unit	2013	2014	2013	2014	2013	2014	2013	2014	2013	2014	2013	2014	2013	2014
Gross margin	€M	978	728	303	368	704	736	41	51	17	42	159	108	2,201	2,033
Ebitda	€M	668	421	232	265	448	495	34	38	9	33	110	74	1,501	1,326
Installed capacity	MW	5,865	5,865	1,462	1,612	5,332	5,534	231	231	49	187	621	621	13,560	14,051
Output	GWh	13,275	12,685	2,767	3,083	14,336	14,462	560	671	143	344	1,573	1,247	32,653	32,492
Load factor	%	25.80%	24.7%	25.5%	23.4%	30.7%	31.0%	29.9%	33.2%	33.0%	37.2%	24.6%	22.9%	27.8%	27.2%
Investments	€M	-28.7	-13.5	526.9	475.1	40.5	236.5	65.7	62.7	0.0	20.8	3.6	-23.4	608.0	758.2

— The new consolidation standard deriving from international financial reporting standard IFRS-11 has been applied to the financial information for both 2013 and 2014. In the application thereof to operating information, 244.32 MW in Spain, 161 MW in the United States, 122 MW in Italy, 75 MW in Brazil, and 15 MW in the United Kingdom is no longer consolidated.

— The 2014 investment figures for Spain include a reversion of old provisions as well as the removal of the turbine warehouse used for projects in another country.

— The investment figures for the United States are net of ITC tax incentives.

— The figures for the United Kingdom include those of the offshore division.

— The investment figure for Rest of World include the removal of the turbine warehouse used for other countries.

Quarterly results report

The business will have sustainable growth, based on onshore and offshore wind investments in the countries most important to the Group. Efficiency is a key factor for business sustainability in the medium and long terms. Iberdrola will take technological advances into account and will act on the supply chain to allow for improvement in the coming years.

Load factor

Maximising the load factor of facilities, while minimising down time through operating and maintenance measures, as well as other external factors.

Prices

Minimisation of risks through appropriate hedging.

Operation and maintenance costs

Continuous improvement in efficiency through global standardisation and systematisation processes.

Project portfolio

Development of the portfolio of onshore wind projects in the United Kingdom, the United States, Mexico, and Brazil, and the Wikinger (Germany) and East Anglia 1 (United Kingdom) offshore wind projects.

3.5 Supply costs, the main factor in the political and social agenda

The cost of electricity supply is taking on a greater role in the political and social agenda. The principal challenge is to reconcile secure and environmentally friendly supply with the use of renewable energy at prices that are competitive and can be afforded by society as a whole.

In the European Union

- The impact of high energy costs on the competitiveness of European industry and the well-being of citizens is one of the issues of greatest concern in the EU. The accords on the 2030 framework for climate and energy propose measures for meeting environmental targets whilst allowing energy prices to remain competitive.
- Various initiatives are being adopted to improve this situation. In January 2014 the European Commission released an analysis of the components of final energy prices, making it possible to identify the measures required to reduce them.
- There are measures to support industrial sectors at risk of being pushed off-shore due to carbon emission costs, and to protect vulnerable customers.

In Spain

- Rates paid by electricity consumers incorporate costs derived from the pursuit of strategic energy goals: environmental (aid for renewable energy and the costs of reducing CO_2 emissions), industrial (interruptibility of large consumers and aid for co-generation), social (subsidies for domestic coal mining and for electricity in non-mainland territories), economic (recovery of tariff deficits from previous years), and public finance.
- Less than half the costs of electricity supply are directly related to providing the service; the rest are subsidies and taxes. With some supply costs below the European average, the end prices of electrical energy for Spanish consumers are higher than the Community average.

In the United Kingdom

- There is intense public debate on electricity and gas prices, with the involvement of political leaders and wide media coverage. This will be on the agenda in the run-up to the general elections in May 2015, with the government championing more competition and the opposition championing more regulation.
- The recent decline in international gas prices partly offset the rising costs of the energy policy, mainly the Energy Companies Obligation (ECO). In January, all of the companies announced reductions in their gas rates.
- The required future investment in networks and cleaner generation will also entail greater price pressure.

In the United States

- Tariff revisions currently under discussion or preparation reflect pressure by regulators to limit returns on capital, while at the same time maintaining the investments required to improve the network infrastructure.
- The closure of coal plants, following the appearance of unconventional gas and new regulations being drawn up by the Environmental Protection Agency (EPA), may increase pressure on gas and electricity prices.
- Restrictions on transporting natural gas by pipeline in the Northeast may lead to volatility in electricity market prices during periods of extreme weather.
- The development of smart grids, the rapid replenishment of supplies in the face of extreme weather conditions, and the integration of new energy sources into the system require major investment, which sometimes conflicts with the goal of limiting compensation to the companies.

In Brazil

- Involuntary exposure of distributors to the short-term market, together with the increase in the price of energy in this market, due mainly to the unfavourable water scenario the country is experiencing, has generated a cash flow imbalance for distributors during all of 2014. This was recognised and alleviated by the government, earmarking specific funds that will have to be covered by upcoming tariff adjustments.

In Mexico

- Energy reforms were launched last year, with one of the key goals being to reduce system costs in order to lower electricity prices for end users. The reform is ongoing at the corresponding regulatory bodies.

Iberdrola will support frameworks that expand market deregulation and transparency and that provide incentives for required investments and efficient operations, through tariff structures that give efficient signals to consumers and do not penalise them with costs unrelated to the supply of electricity.

Our assets

Iberdrola's assets are the basis for the creation of value by the Company, which carries out its activities through the sound management of these assets.

In this report, Iberdrola's assets are identified in accordance with the IIRC classification system:

- Financial capital
- Manufactured capital
- Intellectual capital
- Human capital
- Natural capital
- Social and relationship capital

Iberdrola International Volunteering Day
2014 / United Kingdom

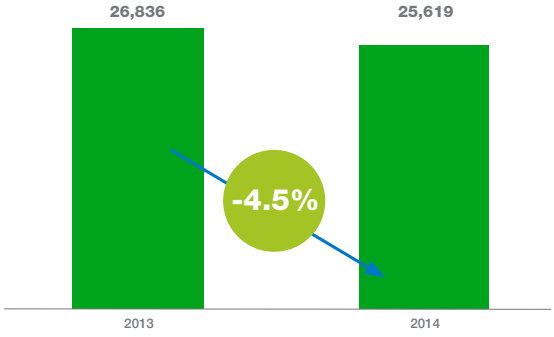
4

4.1 Financial capital

	Management approach	2014 Results	Outlook
Solid financial structure	• Iberdrola is committed to bolstering its financial strength in order to successfully contend with market turbulence and be well placed to capitalise on the expected medium-term upturn in the economic cycle. Its strategy is geared towards further reducing debt, attaining positive cash flow in all of the businesses, and improving its solvency ratios.	• Gross margin of €M 12,179, growing by 3.4%. • Net profit of €M 2,327, a year-on-year drop of 9.5% due to the impact of regulatory and tax measures in Spain. Recurring net profit was €M 2,113 (-2.8%). • Cash flow of €M 5,459. • Reduction of net debt by €M 1,217, to €M 25,619. • Liquidity of more than €M 9,000, which covers more than 30 months of financing needs.	• Average annual EBITDA and net profit growth of 4% over the 2014-2016 period. • Maintenance of net debt at approximately €M 25,000 in 2015 and 2016. • Improvement of the net debt/EBITDA and operating cash flow/net debt financial ratios. • Optimisation of the liquidity position to cover financing needs for 24 months.
Operational efficiency	• The current macroeconomic and regulatory environment requires an additional effort to keep operating costs under control.	• Net operating expense increased 4.8% due to the drop in activations and other non-recurring effects, such as efficiency measures affecting future periods. • Recurring operating expenses grew 1.1%, less than the gross margin. Therefore, the net operating expenses / gross margin ratio improved to 28.8%, compared to 29.4% in 2013.	• Containment of increase in operating expenses, keeping them below gross margin growth and thereby helping to boost efficiency.
Monitoring of investments	Targeted control of investments will enable: • Assurance of return on equity through projects geared towards rapid recovery or increased stability of results, focusing on regulated businesses. • Generation of positive free cash flow in all businesses and reduction of financial debt. • Tailoring of investment levels to the actual needs of each market.	• Total investment of €M 2,848, with almost 81% channelled into regulated businesses. • Divestment plan of €M 2,500 almost completely implemented.	• Strict investment criteria based on earnings security, project profitability, and short implementation periods. • Strategies of investment in businesses and countries with predictable and stable regulation, and divestiture of non-strategic assets and in non-strategic countries. • Net investment of €M 9,600 over the 2014-2016 period, concentrating on regulated businesses.
Sustainable results and dividends	• Iberdrola offers its shareholders an industrial enterprise for the long-term creation of value. The confidence of its shareholders enables Iberdrola to secure the resources needed to move its enterprise forward.	• Shareholder remuneration of 0.275 euro per share, equal to a dividend yield of 4.91% • Flexible dividend offering tax benefits.	• Continuation of the flexible dividend programme, with a target annual payout of 0.27 euro per share over the 2014-2016 period. • Target of maintaining the number of shares at 6,240 million, neutralising the capital increases associated with implementation of the flexible dividend programme. • Potential increase in the dividend per share, based on net profit.

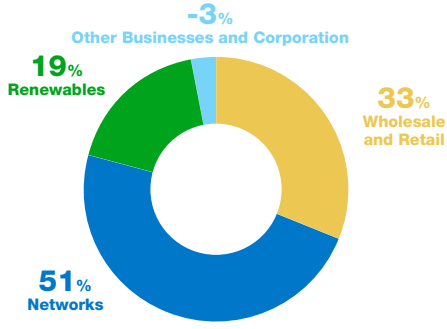
Create value for the shareholder with sustainable growth

Debt (€M)

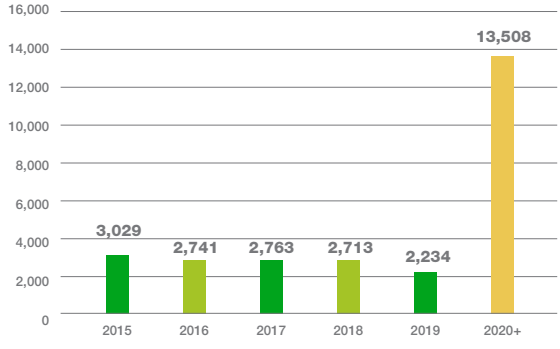


Strengthening of the balance sheet, as planned.

Ebitda by business 2014



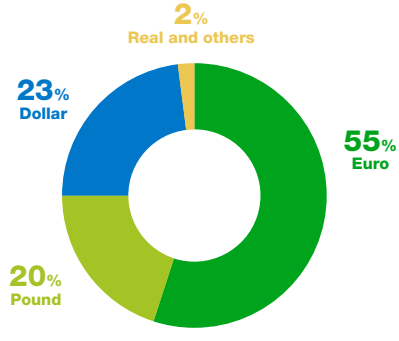
Maturity of financial debt* (€M)



* Does not include drawn credit facilities.
** Assumes renewal of outstanding balance of notes in the amount of 829 thousand euros.

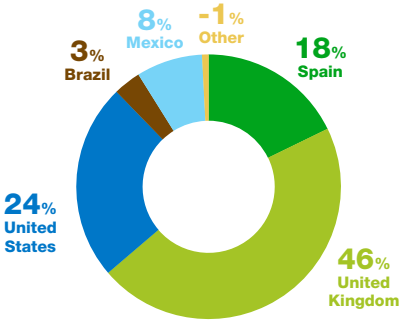
Comfortable maturity profile.

Debt structure by currency in 2014



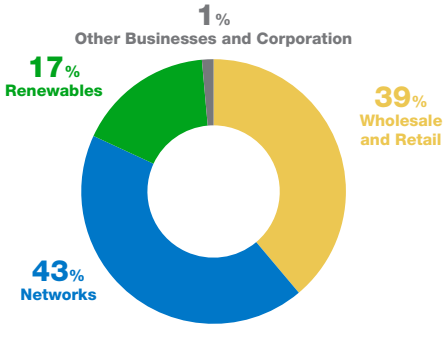
Debt structured by origin of cash flow earned in each currency

Investment by geographic areas 2014



Diversification of investments, with a heavy concentration outside of the euro zone.

Gross margin by business 2014

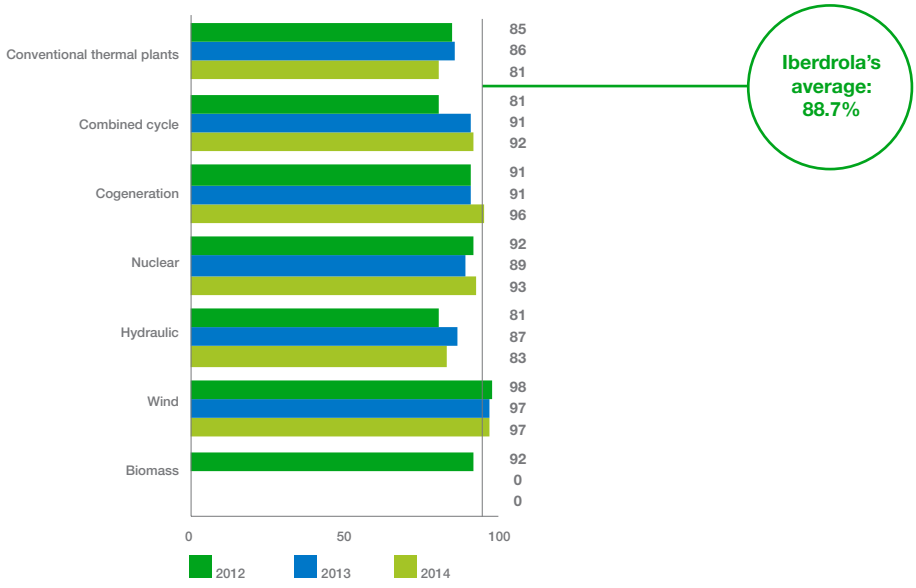


4.2 Manufactured capital

	Scope	Principal activities 2014	Outlook
Electrical power generation assets	• Iberdrola's generation assets comprise nearly 300 wind farms, almost 90 hydroelectric power plants (in addition to the mini-hydro plants), 34 thermal power stations using various technologies, 5 of which are nuclear, and other facilities built and operated according to the best available practices.	• ISO 9001 and ISO 14001 quality and environmental certification has been attained for the Company's generation operations in Spain, the United Kingdom, and Mexico. • ISO 9000 certification has also been attained for the operation of wind farms in Spain and the United Kingdom.	• Commencement in England of the largest renewables project in the Company's history, East Anglia, an offshore wind farm with a capacity of 7,200 MW in one of the most important enclaves in the world. • In Mexico, together with an analysis of coming developments, construction will continue on the combined cycle plants of Baja California III (300 MW) and Unit 5 of Monterrey (300 MW), as well as the new Kimberly Clark cogeneration station (50 MW). They are expected to enter into operation in 2016.
Power transmission and distribution assets	• Iberdrola's electricity transmission and distribution networks comprise over 30,000 km of transmission lines, over 1 million km of distribution lines, roughly 4,000 substations and over 1.4 million transformers, built and operated to supply a high-quality, reliable service.	• Iberdrola USA obtained ISO 9001:2008 certification in 2014 for the quality management system covering the design, construction and startup of large electricity and natural gas investment projects. • The quality of service indicators improved over the prior period in all of the Company's areas of operation, exceeding the best historical records in Spain, the United Kingdom, and Brazil.	• Construction of a new electricity transmission line corridor between the electricity systems in Canada and the United States, aimed at improving reliability in the New England area. • Investments in the United Kingdom transmission network, to improve the reliability and quality of supply. Especially noteworthy is the "Western Link", a subsea cable linking the networks of Scotland and England. • Development of the P2020 strategic project in Spain, aimed at achieving increased efficiency, operational safety, and quality of supply.
Other assets	• Iberdrola has corporate offices in all of the geographic regions in which it distributes electricity, as well as other buildings and ancillary infrastructure associated with its operations.	• Certifications have been obtained for the energy management system in accordance with the UNE-EN ISO 50001:2011 standard for the Torre Iberdrola (Bilbao) and Tomás Redondo (Madrid) properties in Spain. • All of the real property in Spain is covered by a certified environmental management system, with the scope being expanded to the sales offices in 2014.	• Expansion of the environmental management system at the ScottishPower properties. • Construction of the new corporate headquarters of ScottishPower in Glasgow, Scotland. This 14-storey building, which is currently under construction, is located in the centre of Glasgow and will have a maximum capacity of more than 1,700 workers. • Construction of the Iberdrola Campus in the Community of Madrid (Spain), which is expected to open in 2016.

Offer a secure supply of energy that is competitive in price and quality

Average availability factor of Iberdrola's generation facilities

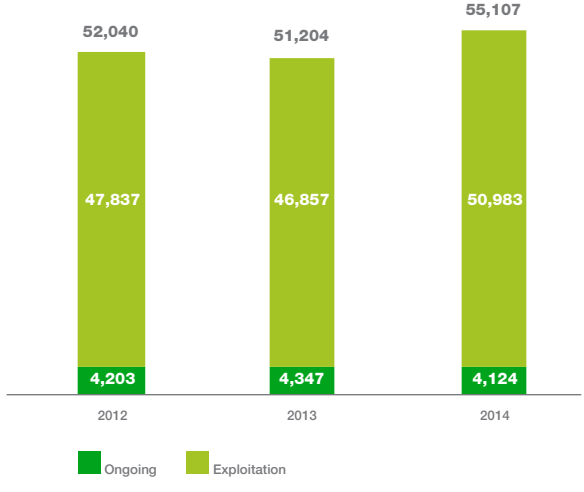


Quality of electricity supply

Average power outage duration		2013	2014
Spain	TIEPI (m)	62.4	55.7
United Kingdom	CML (m)	44.0	44
United States	CAIDI (h)	2.47	1.89
Brazil	DEC (h)	18.61	19.93
Power outage frequency		**2013**	**2014**
Spain	NIEPI (no.)	1.20	1.07
United Kingdom	CI (ratio)	44.0	48.00
United States	SAIFI (index)	1.24	1.23
Brazil	FEC (frequency)	7.64	7.62

TIEPI: Installed Capacity Equivalent Interrupt Time.
CML: Customer Minutes Lost Per Connected Customer.
CAIDI: Customer Average Interruption Duration Index.
DEC: Equivalent Duration of Interruption by Consumer Unit.
NIEPI: Installed Capacity Equivalent Interrupt Number.
CI: Customer Interruptions Per 100 Connected Customers.
SAIFI: System Average Interruptions Frequency Index.
FEC: Equivalent Frequency of Interruption by Consumer Unit.

Property, plant, and equipment (€M)



4.3 Intellectual capital

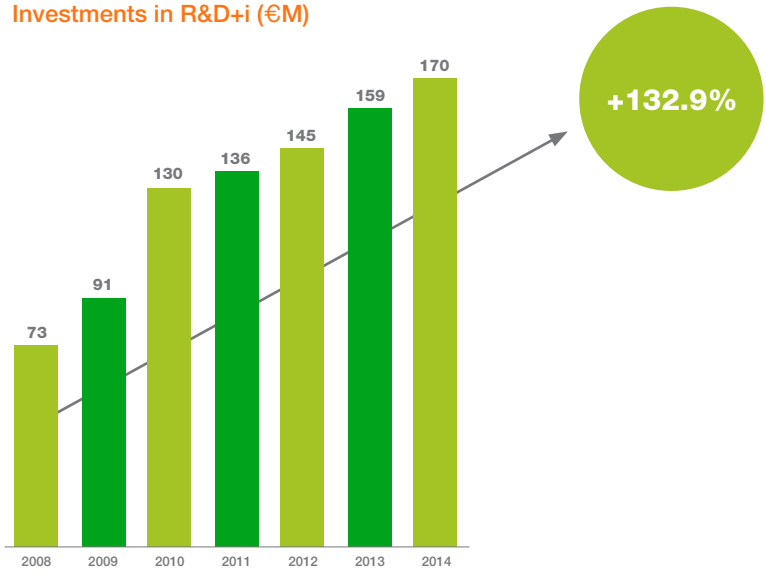
	Management approach	Principal activities 2014	Outlook
Promotion of R&D+i	• Promotion of research, development and innovation (R&D+i) activities, enabling Iberdrola to guarantee the sustainability and reliability of supply. ⦿ **Innovation report**	• Significant increase in R&D+i investment: €M 170 in 2014, a 7% increase over 2013. • Open, decentralised international R&D+i management model that prioritises collaboration with technology providers and the promotion of employee innovation. • Implementation of over 200 R&D+i projects within the various Businesses of the Group.	• Development of the R&D+i Plan 2014-2016. • Consolidation of an open, decentralised international management model. • Continue to promote R&D+i projects.
Efficiency and new products and services	• Continuous optimisation of our operations in the management of the lifecycle of facilities and equipment, reducing operating and maintenance costs, and decreasing environmental impact. • New products and services that meet customer needs in an increasingly global and competitive market.	• New products and services in the areas of energy efficiency, electric vehicles, smart grids, and distributed generation. • Creation of an R&D+i technology centre in Qatar relating to the development of smart grids.	• Positioning as innovation leaders on prestigious external indices and ratings. • Foster the creation of new business opportunities for Iberdrola.
Disruptive technology and business models	Through *Iberdrola Ventures-Perseo*, the Company's corporate venture capital programme, investments are made in disruptive technologies and new businesses to ensure the sustainability of the energy model. Lines of activity: • Distributed energy resources (DER): customer-side technologies including energy efficiency and active demand response, distributed generation and storage, green mobility, etc. • Renewable energy: solar (PV and thermal), wind (offshore), marine (wave and tidal), etc. • New technologies for the operation and maintenance of energy infrastructures. • Other technologies aimed at improving the sustainability of the energy sector.	With an investment of more than €M 48 since 2008. The main activities in 2014 included: • An investment in the Californian company *QBotix*, which develops tracking systems using robotics, designed to significantly reduce the cost of developing and operating photovoltaic solar plants. • The launch of the *Open Innovation Ventures programme*, to boost cooperation with key technology partners in order to accelerate the development of new products of interest to Iberdrola. The first activity under this programme was the creation of the *GDES Tech4Services venture*, owned by Iberdrola and Grupo Dominguis, to develop and market technologies and new products for use in the operation and maintenance of assets in the electric sector.	• Ensure Iberdrola's access to the energy technologies of the future. • Foster entrepreneurship and the development of an innovative entrepreneurial fabric within the energy sector: investment in initiatives with a high social and job creation component. • *Open Innovation Ventures*: establishment of alliances with key technology providers for Iberdrola. • Within the framework of the Spanish government's Innvierte programme, more than €M 25 will be invested in the coming years in new technology projects for the energy sector.

Emphasise the value of the Company's intangible assets

Main R&D+i research projects

Renewable energy	• OCOA Project for the development of new gravity foundations for installation at intermediate depths (30-50 metres). • Continuation of OWA activities in the United Kingdom to reduce costs and the implementation risk of offshore wind technology. • Completion of the INNPACTO OPENFOAM project to develop computational analysis models and their application to energy resource estimates. • Various projects to improve operation and maintenance in order to reduce operating costs.
Smart grids	• Deployment of smart grids and PRICE projects in Spain and ARC and *Flexible Net* in Scotland. European UPGRID project for the advanced operation and the exploitation of low- and medium-voltage networks in the area of smart grids, strengthening the ability for them to be integrated into the active demand and distributed generation network. • Other European projects like *Grid4EU* and *iGreenGrid* projects for the integration of renewable energy into electricity networks.
Clean generation	• The *Coeben II* and *DESOX* projects for the reduction of NO_x and SO_2 emissions, respectively. • *INSROCA*, *SIRO* and *ECRIGEN* projects to ensure the structural integrity of files and maximise the life cycle. • *CO2FORMARE* project to reduce environmental impact.

Investments in R&D+i (€M)



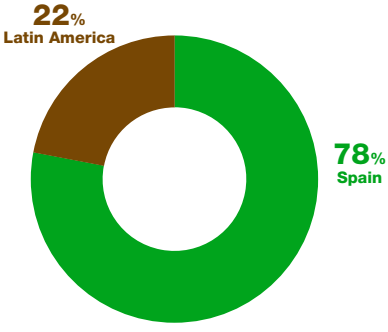
4.4 Human capital

	Management approach	Principal activities 2014	Outlook
Global human resources management	• Achieve the goals of competitiveness and business efficiency in a climate of social peace, fostering stable, high-quality employment. • Harmonise human resources processes and make inroads with implementing the Iberdrola culture in all countries, respecting specific local conditions.	• Implementation of the project for global consolidation of the Human Resources Model (OneHR project) in the United Kingdom, Mexico, Brazil, and ROW. • Management of an appropriate labour relations framework that can be adapted to suit business and social requirements.	• Strengthen the commitment to social responsibility, fostering ethical and responsible behaviour. • Consolidate the Human Resources function at Elektro, extending and unifying best practices.
Goal of "accident reduction"	• Prioritise the safety of individuals at the Group's facilities and within its sphere of influence, fostering a progressive reduction in incident rates and improving health and safety conditions. • Replicate the best practices identified with respect to occupational health and safety, fostering a culture of excellence in management and coordinating global preventive activities.	• Attainment and/or maintenance of the OHSAS 18001 certification, and development of a system of global prevention standards. • Establishment of proactive and reactive indicators among the Group's companies for the global scorecard. • Continue harmonising and monitoring of goals. • Identification and application of best safety practices/Exchange of lessons learned/Creation of groups to promote safe behaviour.	• Assessment of level of conformance to global standards. • Analysis of incident rate and establishment of a global model for the management of occupational health and safety at subcontractors. • Systems to identify and recognise the best ideas in order to optimise health and safety. • Global campaigns to raise awareness on certain types of common accidents.
Talent management	• Drive staff qualifications, preparing employees to work in a multicultural environment and making continual efforts to improve their employability. • Develop alternatives to compensate for factors stemming from the ageing of the workforce. • Define a framework to develop a global quality management system.	• Promotion of job and international mobility within multicultural teams. • New programmes and initiatives at the Management School to strengthen collaborative learning (e-leaders). • International non-management professional development process (Spain, United States, and United Kingdom). • Campaign to encourage Gender Equality in hiring processes.	• Strengthen the talent and leadership development management model at the international level. • International certification of training quality. • Define and implement the Global Development Roadmap for the Iberdrola Group. • Global executive talent management.
Diversity, equal opportunity, and reconciliation	• Tackle diversity in all Human Resources activities of the Group, ensuring equal opportunity and the labour integration of disadvantaged groups. • Develop these principles, providing measures to help reconcile personal, family, and working life. • In the countries in which Iberdrola operates, foster a position of leadership in these areas similar to that enjoyed in Spain.	• International cultural exchange programmes. • International Volunteering Day. "Sao Paulo 2.0" multicultural volunteer programme in Brazil and professional volunteering programme in Ethiopia. • Continue with "Family-Responsible Company" certifications. • Join with "*Women in Renewable Energy Scotland*" in the United Kingdom, "*Troops to Energy*" in the United States, and "*Energy for the future*" in Brazil.	• Foster improvements in the quality of people's lives through social-welfare activities in all of the countries in which the Iberdrola Group has a presence, creating a global volunteer community. • Strengthen team pride and job commitment. • Promote the internationalisation of social programmes and bring together employees from various countries.

Ensure the availability of a committed, qualified workforce in a safe and stable environment

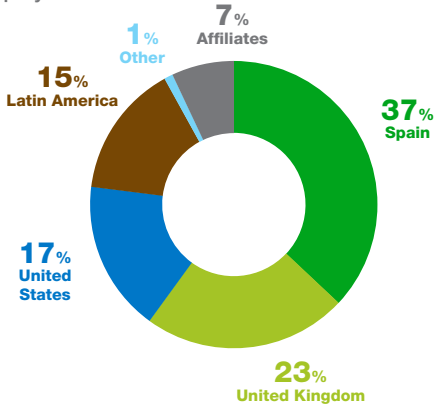
Growth and geographic diversification of the workforce

2006: 16,155 employees

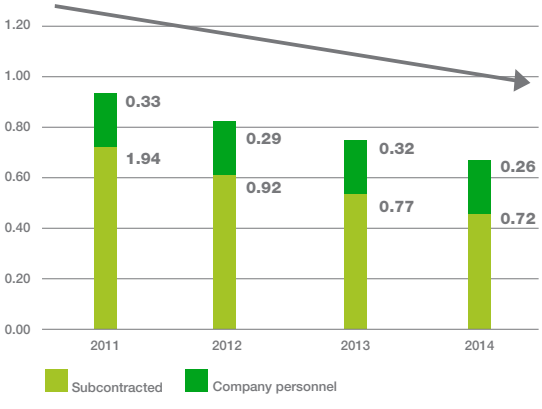


2014: 29,597 employees

Key figures / page 10



Incident rate (2011-2014): progressive reduction



-32% in subcontracted personnel and -21% in Company personnel.

Committment to people

Iberdrola Sao Paulo Volunteering 2.0-2014

"My guest" cultural exchange programme 2014

Social recognition

Iberdrola: among the best 3 companies to work for in Spain.

Elektro: again chosen as best company to work for in Brazil.

Iberdrola university restoration report

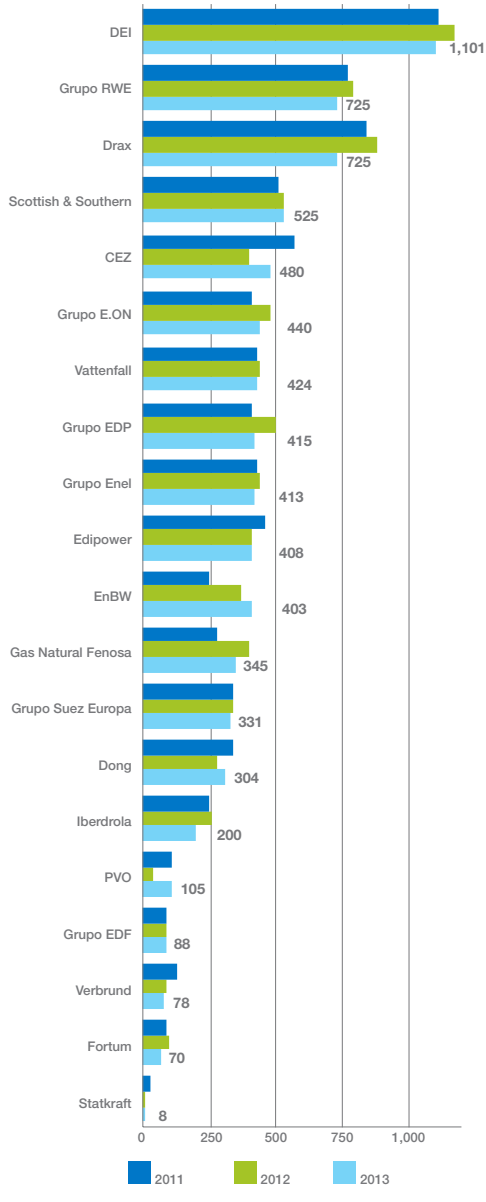
4.5 Natural capital

	Management approach	Principal activities 2014	Outlook
Environmental management and biodiversity	• Actively promote environmental and biodiversity management due to the repercussions thereof on the availability of natural resources and its ties to social development. • Inform and raise awareness, both internally and externally, of the compatibility of the Company's activities with the protection, conservation, and sustainable use of the natural environment.	• Implementation of corporate model for environmental risk management. • Development of a methodology for economic evaluation of ecosystem services and the impact on biodiversity. • Fostering and promotion of social values relating to the environment and natural resources. • Approval of EU LIFE2+ CO2FORMARE Project at the Castellón plant.	• Restoration, recovery, improvement, and maintenance of surroundings and habitats. • Identification and classification of the biodiversity in the vicinity of Iberdrola's facilities and dissemination of the knowledge acquired. • Broader implementation of the ISO 14001 standard.
Prevention of pollution	• Prevent pollution and the emission of greenhouse gases through practices that reduce or eliminate the production of pollutants at source. • Reduce emissions per GWh produced via the installation of desulphurisation units, the introduction of improvements to the combustion process, and the decommissioning of less environmentally efficient units.	• 6% reduction in intensity of CO_2 emissions per kWh produced. • Thermal emission factor has decreased from 483 gr/thermal kWh generated in 2013 to 476 gr/kWh generated in 2014. • Increase in emission-free installed capacity. • Development of methodology to calculate the environmental footprint of the Group's activities (*EPI Environmental Performance Index Project*). • Signing of the CDP *Roadmap to Paris*, with a commitment to reduce emissions and participation in the Climate Change Week in New York.	• Achieve a 30% reduction in emissions intensity by the year 2020 in comparison to 2007, a figure 20% better than the scenario suggested by the IEA. • Increase the scope of independent verification of emissions. • Develop innovation projects geared towards reducing pollution. • Active participation in preparations for the upcoming Climate Change Conference to be held in Paris (December 2015).
Operating excellence and energy efficiency	• Performing activities that foster environmental conservation will enable Iberdrola to improve its competitiveness, with greater efficiency in the production and use of energy. • Efficient management of scarce resources such as water is a priority for the Company.	• Activities aimed at continual improvement to increase energy efficiency and promote the use of environmentally friendly resources. • Public water management strategy via the CEO Water Mandate and CDP Water.	• Development and promotion of eco-design initiatives. • Life-cycle and green purchasing analysis.
Waste management	• Non-hazardous waste is managed via environmental management systems, which set targets for waste reduction and the use of recycled material. • The production and disposal of hazardous waste is carried out in accordance with the strict laws applicable in each country.	• Reuse of waste from thermal coal plants. • Carry out waste minimisation plans, recycling plans, and awareness campaigns aimed at employees. • Iberdrola and GE Hitachi join in a project to reuse nuclear fuel in the United Kingdom.	• Make progress in the optimisation of waste management. • Draw up economic and financial analyses of the best waste management strategies.

The environmental dimension is a key factor in the concept of sustainability

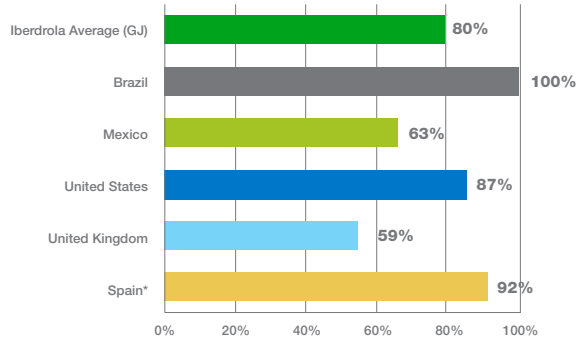
CO_2 emissions at companies in the industry

(Carbon factor in kg CO_2/MWh)



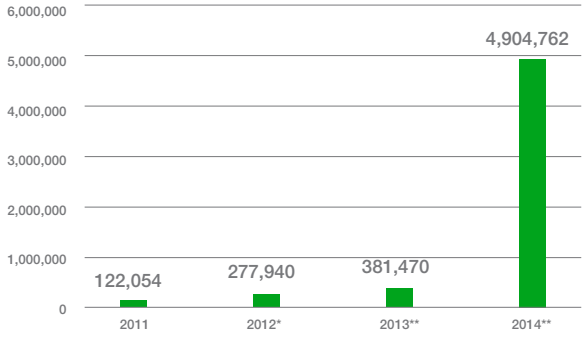
European carbon factor 2013: 328 kg CO_2/MWh
Source: "Changement climatique et Électricité, factor carbone européen Comparaison des émissions de CO2 des principaux électriciens européens" PwC France.

Production of Iberdrola plants using local energy sources in the countries in which it operates



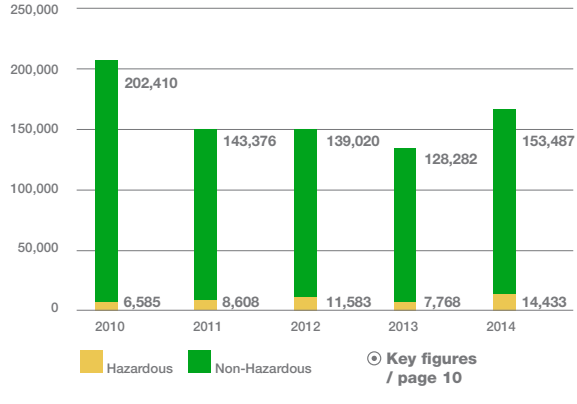
* Nuclear fuel acquired from the Spanish company ENUSA is considered a local source.

Energy savings of green products and services (GJ)



* Includes data from Spain and Brazil.
** Includes data from Spain, the United States of America, and Brazil.

Volume of recovered, reused, or recycled waste



Key figures / page 10

4.6 Social and relationship capital

Stakeholder relations

Iberdrola wants to strengthen trust and the connection to institutions and companies in its environment, maintaining responsible relations with groups that affect or are affected by the activities carried out by the Company (stakeholders).

	Management approach	Principal activities 2014 and outlook
Stakeholder relations	Iberdrola's strategic approach sets great store by its relations with stakeholders, giving importance to the dual facets of this relationship: • In terms of social responsibility, meeting stakeholder expectations and needs. • In terms of reputation, managing stakeholders' perception of the Company.	• Consolidation of channels of communication with stakeholders to identify the most important issues and provide a well balanced, reasonable response thereto. • Completion of implementation of the AA1000 Assurance Standard, in accordance with the principles of inclusiveness, materiality, and responsiveness established in such standard, through a multi-annual programme deployed in the businesses as well as in the corporate areas of the Group. The AA1000 standard will continue to be applied and refined through the Company in the coming years. • The Board of Directors approved a *Stakeholder Relations Policy* in February 2015.

A materiality analysis allows for prioritisation of the issues most important to the Company's stakeholders.

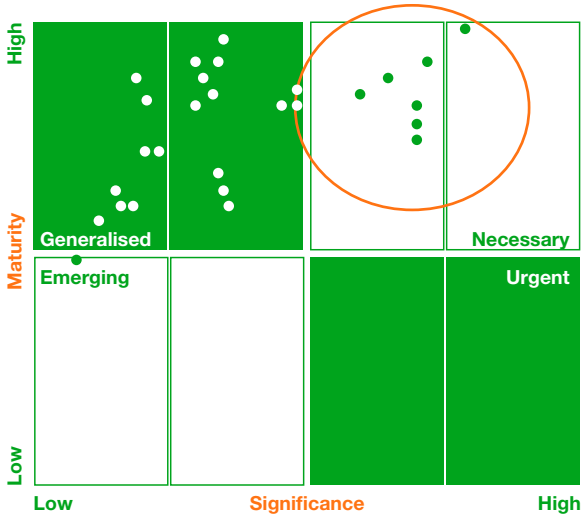
Materiality

Materiality analysis

Evaluation of materiality enables the issues that are most important to stakeholders to be prioritised according to their degree of significance and maturity. These issues are represented in the upper right quadrant of the chart, and comprise the following:

- Electricity generation.
- Renewable energy development.
- Price risk management.
- Climate change strategy.
- Business opportunities.
- Government relations/public policy/lobbying.
- Customer relations management.
- Impacts on and benefits for local communities.
- Transmission and distribution.

In the *Sustainability Report 2014* Iberdrola explains the management approaches taken by the Company in regard to these significant issues and any results achieved during the financial year.



Community support and electricity access programmes

Primary programmes

Activities 2014

- Contribution of €M 34 to the community, measured according to the London Benchmarking Group (LBG) international standard, in the countries in which Iberdrola operates.
- International corporate volunteering programme, offering more than 6,000 volunteering opportunities to employees in Spain, the United Kingdom, the United States, Mexico, and Brazil.
- Entrepreneurial support: over €M 41 of procurement from companies in operation for less than 4 years, and €M 70 in venture capital for new initiatives with high technological value.
- Programmes and pricing to aid vulnerable groups in Spain, the United Kingdom, the United States, and Brazil.
- Rural electrification programmes in Brazil, to which over €M 31 has been allocated on a consolidated basis.
- Programmes implemented by the Foundations created by Iberdrola in the principal countries in which it operates.
- Development of the Electricity for Everyone programme.

Electricity for everyone

In order to promote universal access to electricity, Iberdrola implements a programme with the following lines of action:

a) financing of projects through equity investment,

b) activities conducted by the Businesses in the countries in which the Company has a presence, and

c) development of projects with a high social component, with support for NGOs and through corporate volunteering.

As a major support tool, a Chair for the Universalisation of Basic Energy Services was created within the Centre for Innovation in Technologies for Human Development (*Centro de Innovación en Tecnologías para el Desarrollo Humano*) of Universidad Politécnica de Madrid (ITD-UPM).

Economic value distributed (€M)

Item	2013	2014
Procurement from suppliers	4,359	4,599
Payments to providers of capital	2,554	2,753
Payments to government	2,591	2,391
Employee remuneration	1,998	2,320

⦿ Sustainability report

Foundations linked to the Iberdrola group: Fundación Iberdrola

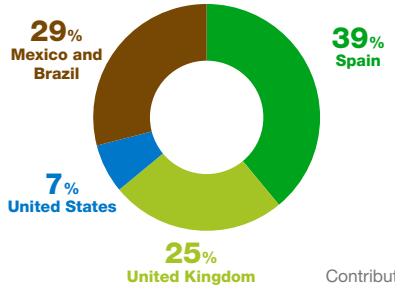
Activities 2014

- Fundación Iberdrola, which is linked to Iberdrola España, S.A.U., the subholding company grouping together the energy businesses in Spain, has completed its Master Plan 2010-2014 in its four areas of activity:
  – Training and research
  – Art and culture
  – Sustainability and biodiversity
  – Cooperation and community service
- The *Scholarship and Research Aid Programme in Energy and Environmental Research* granted 80 Master's scholarships at prestigious universities in Spain, the United Kingdom, and the United States in 2014. In addition, 4 scholarships were granted for training and research at the Restoration Workshop of the Prado Museum and the Fine Arts Museum in Bilbao.

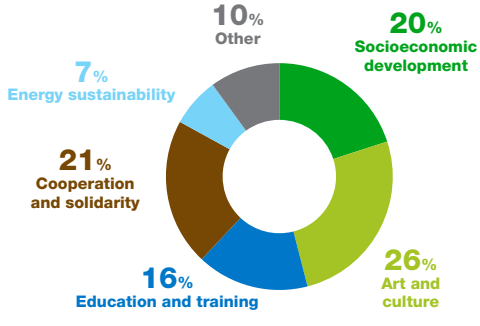
  The Prince of Asturias Chair in Information Science and Related Technologies at the University of New Mexico, focusing primarily on research in the area of smart grids, has become firmly established.
- In 2014, 45 social organisations benefited from the *Social Assistance* programme.
- Significant examples in other areas are the restoration of Romanesque churches in Spain and Portugal within the Atlantic Romanesque Programme, and the Bird Migration project in collaboration with *SEO-BirdLife*.

Programme results 2014

Contribution by region (%)



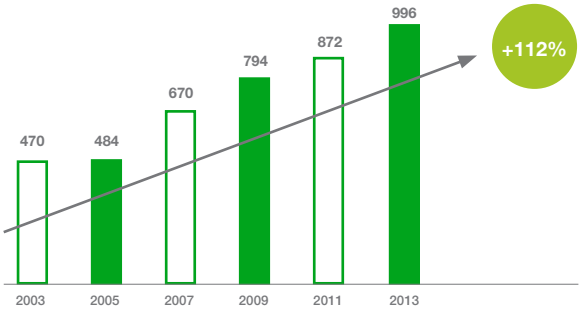
Contribution by programme (%)



Soundness and strength of the brand

- Manage the brand in such a way that it transmits the corporate Vision and Values and reflects the environmental commitment of the Company's strategy.
- Consolidation of an international brand, strengthening communication and alignment under a single brand positioning strategy in the countries in which the Company operates.

Brand value* (€M)



* Source: *Ranking of Best Spanish Brands by Interbrand*.

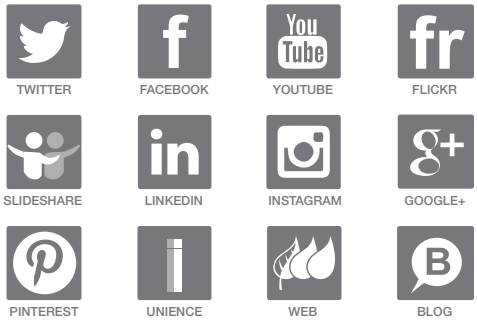
Corporate reputation

- Stakeholders are a significant element in the management of Iberdrola's reputation.
- The Group's reputational management model assesses the degree of alignment between the company's actions and the perceptions of its stakeholders.
- Management of the reputational strengths of Iberdrola compared to its competitors.
- Periodic evaluation of the Group's reputation, a process initiated in 2005, using the *RepTrak* international standard.
- Completion of the Reputation Programme 2013-2014, incorporating reputation as a cultural factor of Iberdrola.
- Identification of priority stakeholders, society, customers, and regulatory bodies for the new Reputation Plan 2015-2017.
- Specific actions to improve stakeholder confidence in the 7 dimensions of Iberdrola's reputation model, which is aligned with the Reptrak international standard.
- Progress made in reputational risk management, stemming from implementation of the Company's *Reputational Risk Framework Policy*. Coordination and integration of the Triple Line of Defence function.
- Updating and monitoring of the reputational impact activities map.
- Reputational analysis of perception in social media and detection of reputational opportunities to differentiate Iberdrola from the industry.
- Monitoring and management of external indices.

Evolution of the digital ecosystem

- Offer useful and dynamic information, with messages adapted to each stakeholder.
- Facilitate direct interaction with our stakeholders, overcoming barriers and making use of existing synergies.

Iberdrola on social media and the internet



Training at Maranchón Wind Farm,
Guadalajara
/ Spain

A framework of trust

Iberdrola Tower,
Bilbao / España

5

5.1 Corporate governance model

Foundations of Iberdrola's corporate governance model

A. Corporate governance system

Iberdrola has adopted a Corporate Governance System made up of the *By-Laws*, *Corporate Policies*, internal corporate governance rules, and other internal codes and procedures, all available at www.iberdrola.com.

The content thereof is inspired by and based on a commitment to the values assumed by the Company and to best corporate governance practices, business ethics, and social responsibility in all of its areas of activity.

The Company pursues the fulfilment of the corporate interest, which is understood as the common interest of all shareholders of an independent company oriented towards the sustainable exploitation of its corporate object and the creation of long-term value for the shareholders' benefit, taking into account other stakeholders related to its business activity and to its institutional reality. Furthermore, the Company aspires for its conduct and that of the persons connected therewith to adhere to ethical and social responsibility principles.

Position	Director	Status	Date of last appointment	Date term ends
Chairman & Chief Executive Officer	Mr José Ignacio Sánchez Galán (Salamanca, Spain, 1950)	Executive	26-03-2010	26-03-2015
Director	Mr Xabier de Irala Estévez (New York, United States, 1946)	Proprietary	22-06-2012	22-06-2016
Director	Mr Íñigo Víctor de Oriol Ibarra (Madrid, Spain, 1962)	Independent	22-06-2012	22-06-2016
Director	Ms Inés Macho Stadler (Bilbao, Spain, 1959)	Independent	22-06-2012	22-06-2016
Director	Mr Braulio Medel Cámara (Marchena, Seville, Spain, 1947)	Independent	22-06-2012	22-06-2016
Director	Ms Samantha Barber (Dunfermline, Fife, Scotland, United Kingdom, 1969)	Independent	22-06-2012	22-06-2016
Director	Ms María Helena Antolín Raybaud (Toulon, France, 1966)	Independent	26-03-2010	26-03-2015
Director	Mr Santiago Martínez Lage (Betanzos, A Coruña, Spain, 1946)	Independent	26-03-2010	26-03-2015
Director	Mr José Luis San Pedro Guerenabarrena (Bilbao, Spain, 1946)	Other external	22-06-2012	26-03-2015
Director	Mr Ángel Jesús Acebes Paniagua (Ávila, Spain, 1958)	Independent	22-06-2012	26-03-2015
Director	Ms Georgina Kessel Martínez (Mexico City, Mexico, 1950)	Independent	28-03-2014	28-03-2018
Director	Ms Denise Mary Holt (Vienna, Austria, 1949)	Independent	24-06-2014	27-03-2015
Director	Mr José W. Fernández (Cienfuegos, Cuba, 1955)	Independent	17-02-2015	27-03-2015
Director	Mr Manuel Moreu Munaiz (Pontevedra, Spain, 1953)	Other external	17-02-2015	27-03-2015

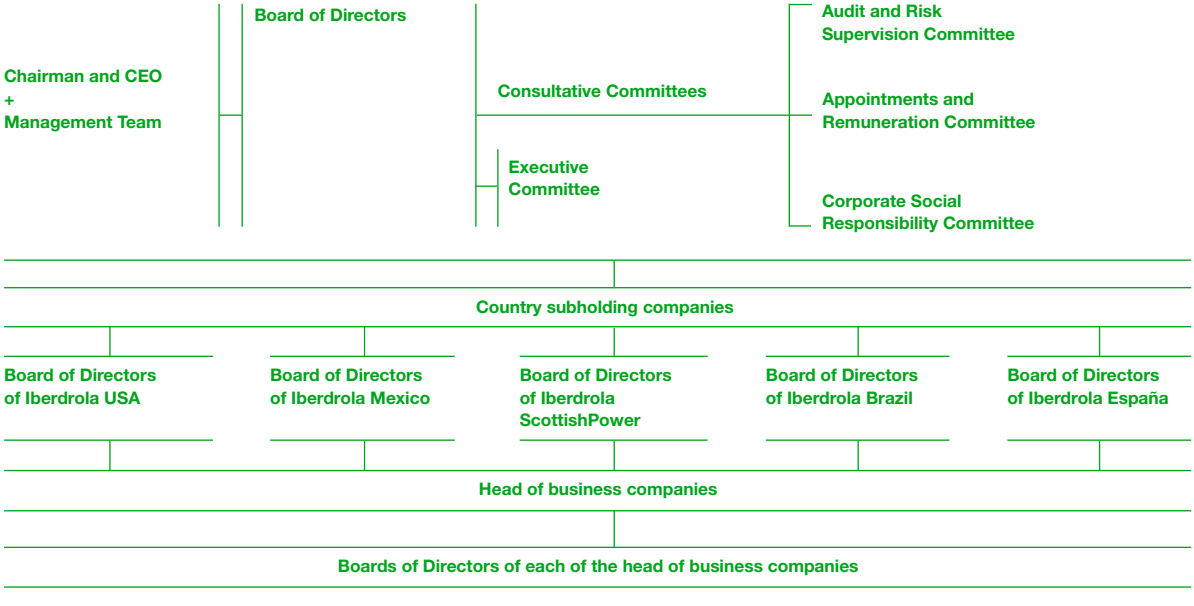
B. Governance model

Appropriate differentiation between the duties of supervision and management:

- The Board of Directors of Iberdrola, S.A., made up of a large majority of independent directors, focuses its activity on the determination, supervision, and monitoring of the strategies and general guidelines that must be followed by the Group.
- The chairman of the Board of Directors & chief executive officer and the rest of the management team are responsible for the organisation and strategic coordination of the Group, through the dissemination, implementation, and monitoring of the overall strategy and basic guidelines.
- In all of the countries in which the Company operates, organisation and strategic coordination is implemented through country subholding companies, which group together equity stakes in the head of business companies carrying out their activities in the respective country and centralise the provision of services common to such companies. The country subholding companies have boards of directors that include independent directors and their own audit and compliance committees, internal audit areas, and compliance units or divisions.
- The head of business companies are in charge of the day-to-day administration and effective management of each business. They also have boards of directors, which include independent directors and specific management teams.

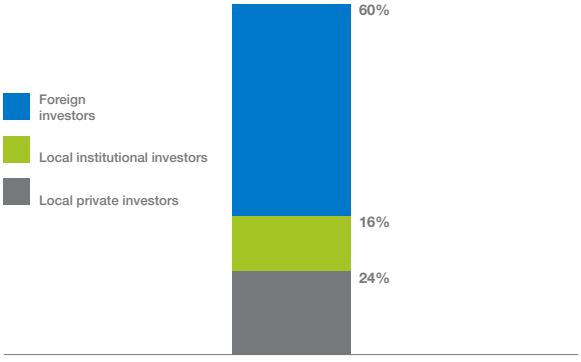
This structure, which operates together with the Group's Business Model, allows for an overall integration of the businesses (Networks, Liberalised, and Renewables) and focuses on maximising the operational efficiency thereof through the exchange of best practices among the companies involved.

Iberdrola's corporate and governance structure.



C. Equity structure

Iberdrola has more than 600,000 shareholders throughout the world, and none of them has the power of control.



Foreign institutional shareholders account for 60% of the capital.

External corporate governance awards / page 34

Iberdrola's response to the corporate governance challenge

A. Continuous improvement of its corporate governance rules and practices

The Company refers to generally accepted recommendations in the international markets on corporate governance matters.

77% of the non-executive directors are independent.

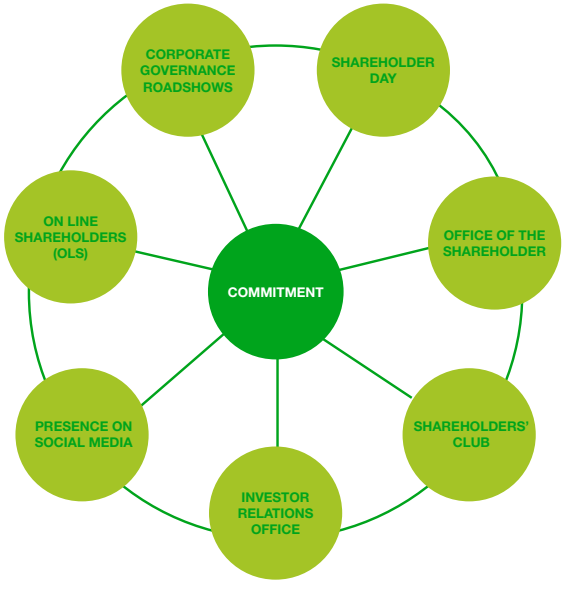
Remuneration policy	Executive directors' variable remuneration tied to objectives.
	Transparency.
	Provision for revising deferred variable remuneration.
Operation of the Board	77% of non-executive directors are independent, all having less than 12 years in office.
	System of checks and balances, including a lead independent director (*consejera coordinadora*).
	All members of the consultative committees are independent.
	Gender diversity: 5 women on the Board. All consultative committees are chaired by women.
	Cultural diversity: directors from 7 countries of origin.
	Rationale for proposed appointments.
	External evaluation of governance bodies.
Social responsibility and corporate reputation	Specific Corporate Social Responsibility Committee
	Social Responsibility Policies.
	Company social responsibility strategy through connected foundations in Spain, United Kingdom, Brazil, United States, and Mexico.

Ethics and social responsibility / page 78

B. Commitment to shareholders and investors

- The strength of the Group's industrial and financial model has made it possible to consolidate profits and maintain shareholder remuneration despite the decline in the economic environment and the impact of regulatory measures in various countries.
- Engagement: Shareholders are the key players within the Corporate Governance System, which include good governance practices beyond those required by applicable law. The *Shareholder Engagement Policy* is implemented through various channels of participation intended to build a continuous dialogue beyond the General Shareholders' Meeting.
- Participation encouraged: Iberdrola has encouraged shareholders' participation at the General Shareholders' Meeting through the payment of an attendance bonus. Since its implementation in 2007, attendance at the General Shareholders' Meeting has exceeded 75%, and has exceeded 81% during the last two years.

The quorum at the 2014 General Shareholders' Meeting was 82.24%.



C. Alignment between corporate governance and strategy

- Director remuneration aligned with strategic objectives. The remuneration model for directors is based on three primary components:

Remuneration model for the Board

Type of remuneration	External (non-executive)	Executive directors
Fixed	According to their duties.	On market terms.
Short-term variable	Not applicable	Tied to annual targets.
Long-term variable	Not applicable	Tied to multi-annual targets and paid in shares (3-year accrual period and payment deferred over 3 years following accrual).

Variable remuneration is tied to pre-established financial, industrial, and social responsibility parameters, including shareholder return. The Annual Director Remuneration Report 2013 only received 1.37% votes against.

Parameters to which the annual variable remuneration of executive directors is tied in 2015

Financial	Results. Shareholder return.
Industrial	Quality and service level. Labour climate.
Social responsibility	Presence on international indices. Publication of an integrated report. Level of consensus received for the proposals of the Board at the General Shareholders' Meeting.

⊙ **Annual director renumeration report 2014**

5.2 Risks

Main risks facing the Iberdrola Group

The Iberdrola Group is exposed to various risks inherent in the different countries, industries, and markets in which it operates and in the activities it carries out, which may prevent it from achieving its objectives and from successfully implementing its strategies. The following significant risks can be pointed out:

- Regulatory uncertainty in the countries in which it operates.
- Volatility in the prices of electricity and fuel, including the potential effects of the collapse in oil prices.
- Volatility in exchange rates and interest rates.
- Changes in the production of and demand for electricity and gas due to the effect of climatological variables (temperature, hydraulic activity, wind activity), and growth in internal consumption over the long term.
- Operational risks due to downtime of facilities and significant incidents affecting the grids, including those arising from improper access to information or to the information technology and communications systems of the Group (cyberattacks).

Commitment of the Board and of Senior Management

Iberdrola's Board of Directors and Senior Management is strongly committed to and engaged in the management of the Group's risks:

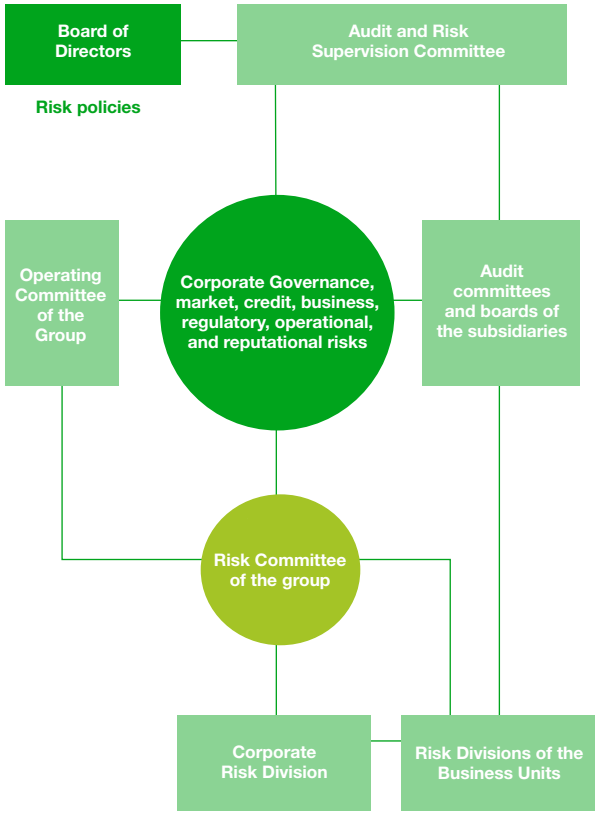
- Acceptable levels of risk tolerance are reviewed and approved *ex ante* on an annual basis through risk policies and limits that establish the qualitative and quantitative risk appetite at the Group level and at each of the main businesses.
- There is then a periodic monitoring *ex post* of significant risks and threats and of compliance with the approved risk policies and limits.

⦿ **Consolidated financial statements**

The essential elements of proper risk management are foresight and control, acting with independence and commitment to the business objectives

Comprehensive risk control and management system

At the operational level, the commitment of the Board of Directors is implemented by means of a comprehensive risk control and management system, supported by a Risk Committee and an independent specialised risk organisation deployed within the main businesses of the Group.



Risks facing Iberdrola's primary businesses / page 42

Duties of the Risk Division

ERM Approach – Integrated Vision

Ensure that the Group's significant risks are adequately identified, measured, managed, and controlled and that they are periodically reported.

Basic instruments:

- Risk policies and limits.
- Reports on key risks

Centralised approach – Active management

Credit risk

- Approval of counterparties and limits and/or establishment of admission criteria in order to minimise credit losses within the Group.

Market risk

- Approval of detailed limits in order to delimit the effects of volatility in the markets in which the Group operates.

Operational risk management through insurance.

5.3 Ethics and social responsibility

Compliance Unit

Iberdrola has a Compliance Unit, as a collective, internal, and permanent body linked to the Corporate Social Responsibility Committee of the Board of Directors.

There are also compliance divisions at the level of the country subholding companies and/or the head of business companies.

Their goals include promoting a culture of ethical behaviour and zero tolerance for the commission of unlawful acts or fraud.

There is a compliance system intended to encourage action by the organisation in accordance with ethics and applicable legal provisions by means of a set of procedures and actions designed to prevent, detect, and react to irregular activities, fraud, or acts contrary to the *Code of Ethics* of the Iberdrola Group or applicable regulations.

Main activities in the area of ethics and compliance

As part of the Compliance System, various programmes, control systems, and activity frameworks are implemented within the Group to encourage the organisation to act in accordance with the most stringent ethical standards and in accordance with applicable laws and regulations.

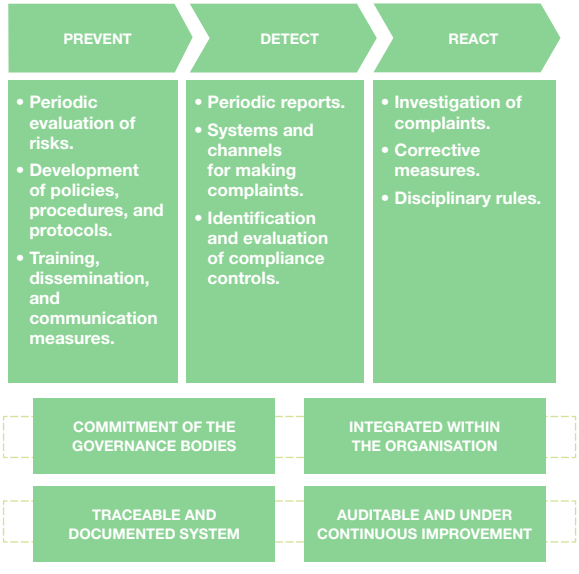
These include the *Crime Prevention Programme*, which is implemented within the framework of the process of reviewing and adapting the duties imposed by the Spanish Criminal Code, without prejudice to the legal provisions applicable in any other jurisdiction in which the Company does business.

In addition to the foregoing, the Compliance Unit has defined an action framework for compliance with the Code of Ethics, the fundamental goal of which is to foster a culture of corporate ethics and transparency, disseminating the principle of "zero tolerance" with respect to fraud and promoting mechanisms and actions to prevent corruption and fraud.

Powers of the Unit

The Compliance Unit has powers related to the *Code of Ethics*, the *Crime Prevention and Anti-Fraud Policy*, the *Internal Regulations for Conduct in the Securities Markets*, legal provisions regarding the separation of activities, and all other powers that may be entrusted thereto by the Corporate Social Responsibility Committee or the Board of Directors of the Company or that are established in Iberdrola's Corporate Governance System.

The Iberdrola Group's ethics and compliance system



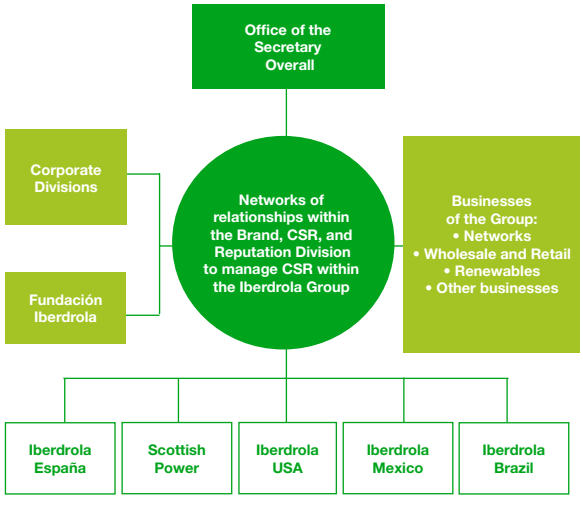
Action framework for compliance with the Code of Ethics

- The *Code of Ethics* is the "cornerstone" upon which this framework and its actions and procedures are implemented, including plans for training and dissemination in this area.
- It is projected **towards third parties** with which the Group works.

Iberdrola regards the commitment to good corporate governance, business ethics, and transparency as “business values”

Organisation of social responsibility within the Group

The Iberdrola Group has an organisational structure designed to promote and manage responsible actions with its stakeholders.



The Corporate CSR and Reputation Committee and the CSR and Reputation Committees of the country subholding companies coordinate the balanced development of these matters within the Iberdrola Group. The CSR Committee of the Board of Directors performs the duties of supervision within its purview.

CSR plans of the group

In 2014, Iberdrola completed the *Social Responsibility Plan* for the 2013-2014 period, which is articulated around the goals of contributing to the generation of a culture of global responsibility within the Group, strengthening trust through the continuous promotion of responsible behaviour, and contributing to the creation of value shared with its stakeholders.

This plan is analysed by the Corporate CSR and Reputation Committee and the CSR Committee of the Board of Directors every six months, and upon the completion thereof, it reached a 96% level of compliance with the established goals.

The CSR Plan for the 2015-2017 period is currently being prepared.

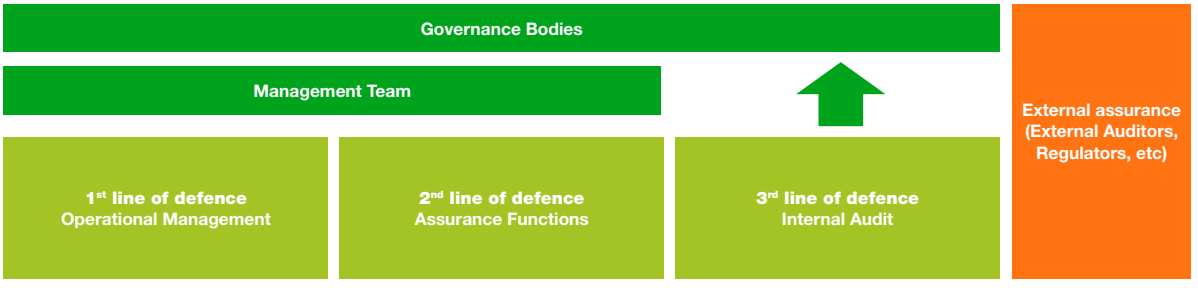
External awards

Dow Jones Sustainability Indices	86 points.
FTSE4Good	First utility with nuclear assets to be selected on the index.
CDP	Carbon Disclosure Leadership Index (CDLI), 99 points.
CDP	Carbon Performance Leadership Index A.
	Iberdrola one of the developers.
Carbon Ranking GLOBAL 800	First Spanish utility.
NYSE EURONEXT	Iberdrola selected.
ROBeCO SAM	Sustainability Yearbook 2014 “*Silver Class*” in the electricity sector.
European Business Awards	Honourable Mention in Environment and Sustainability.
	Iberdrola is leading most sustainable Spanish utility and third worldwide.
merco	Leader among Spanish utilities: electricity, gas, and water.
	Classified as “*Prime*”.
Fundación Compromiso y Transparencia	Leading company on the Ibex 35 in the *Tax Transparency ranking 2014*.

5.4 Triple line of defence

Model of Triple Line of Defence

The *Internal Control System* of Iberdrola and the companies of its Group is configured by reference to international best practices. It is based on a guarantee combined around three lines of defence, providing a comprehensive view of how the different parts of the organisation interact in an effective and coordinated manner, making more efficient the processes for management and internal control of the entity's significant risks.



Based on the document "*Guidance on the 8th EU Company Low Directive, article 41*" ECIIA/FERMA, September 2010

Operational management

As the first line of defence, the Management Team and the professionals of Iberdrola and its Group are the direct managers of the risks of the entity. Thus, the Management of the Company is responsible for maintaining effective control and implementing procedures to control risks on a continuous basis.

Risks facing Iberdrola's primary businesses / page 42

Internal Control Objectives (COSO. May 2013)

- **Operations objectives -** Pertain to the effectiveness and efficiency of the entity's operations, including operational and financial performance goals, and safeguarding assets against loss.
- **Reporting objectives -** Pertain to internal and external financial and non-financial reporting and may encompass reliability, timeliness, transparency, or other terms as set forth by regulators, recognised standard setters, or the entity's policies.
- **Compliance objectives -** Pertain to adherence to laws and regulations to which the entity is subject.

Assurance functions

As the second line of defence, certain duties provide the foundation for the entity's internal control system, proposing guidelines to the Board and monitoring how the first line of defence implements them.

The primary assurance functions within Iberdrola, within their respective areas of responsibility, are (i) the Risk Committee of the Group, within the framework of its duties within the Comprehensive Risk Control and Management System; (ii) the Compliance Unit, which is responsible for the Compliance System; and (iii) the Internal Control Division, which is part of the Administration and Control Division, within its duties relating to the internal control and risk management systems in relation to the issuance of financial information (ICFRS).

Comprehensive risk control and management system / page 77
Compliance unit / page 78

Iberdrola adopts the triple line of defence model to guarantee effective and integrated management of its Internal Control System

Internal Audit

The internal audit function, in its capacity as the third line of defence, supervises the internal control and risk management systems, auditing how the first and second lines carry out their respective duties of management and control.

To ensure its independence, the director of the Internal Audit Area reports hierarchically to the Chairman of the Board of Directors and functionally to the Audit and Risk Supervision Committee.

The internal audit divisions of the various country subholding companies have this same positioning, and are coordinated under the framework of the *Basic Internal Audit Regulations* of Iberdrola and the Companies of its Group.

The 2014 annual activities plans of the Internal Audit Area Division of Iberdrola, S.A. and of the internal audit divisions of the Group responded to the requirements established by the Audit and Risk Supervision Committee of Iberdrola, S.A. and the respective audit and compliance committees of the country subholding companies in their respective regulations, and included work for the Senior Management and the rest of the organisation, including:

- Annual audits of compliance with the *Code of Ethics* at Iberdrola, S.A. and at each of the country subholding companies.
- Audit of the Corporate Risk Policy regarding Treasury Shares.
- Six-month reviews of the operation of the most critical controls of the Internal Control Over Financial Reporting (ICFR) Model, as well as reviews of the various cycles of preparation of the financial information of Iberdrola, S.A. and the various companies of the Group, within the framework of the general goal of reviewing the entire ICFR over a period of 3 years.

Basic Internal Audit Regulations of Iberdrola and the Companies of its Group
• Approved by the Board of Directors of Iberdrola, S.A. upon a proposal of its Audit and Risk Supervision Committee.
• Defines the nature, activities, organisation, operation, basic powers, and duties of Internal Audit.
• Establishes the framework of relations with: i) the Board of Directors, its chairman, and Committees; ii) the internal audit divisions of the other companies of the Group; and iii) the rest of the organisation.
• Disseminates the knowledge of the Internal Audit function among the professionals of the Group.
• Serves as a reference for the management model and the quality system of the Internal Audit Area of the Company and the Internal Audit divisions of the other companies of the Group.

External assurance

The auditors, regulatory bodies, and other entities external to the organisation play a significant role in the general structure of governance, internal control, and risks of Iberdrola, especially in the regulated businesses.

The regulators establish requirements with the intention to strengthen the controls of an organisation and perform a function of independent and separate monitoring.

On the other hand, the auditors provide assurance regarding the true and fair view of the entity's financial information.

Regulatory environment / page 38
Report of the auditor of the consolidated financial statements

About this report

This report, which Iberdrola directs to both its shareholders and investors and all of its stakeholders, has been prepared under the emerging "integrated report" concept, and constitutes one more example of the Group's intention to be innovative in the area of transparency.

Whitelee Wind Farm,
Scotland / United Kingdom

6

6.1 About this report

Integrated report

- This report has been prepared in accordance with the reporting framework published by the International Integrated Reporting Council (IIRC) and in accordance with the recommendations thereof, taking into consideration the individual and consolidated financial statements of the Company formulated by the Board of Directors, audited and pending approval by the shareholders at the General Shareholders' Meeting of Iberdrola, S.A.
- A multi-disciplinary team made up of corporate businesses and areas of the Group was created in order to provide a complete view of the Company, its business model, the challenges and risks it faces, and its social, environmental, financial, and governance performance. The participating organisations guarantee the completeness of the information included.
- This report has been analysed by the Operating Committee of the company and approved by the Board of Directors of Iberdrola at its meeting of 17 February 2015.
- As regards the key issues identified by the IIRC, it is expected that future reports will delve into the establishment of increased interrelation between the Company's objectives and their effects on capital.

Information boundaries

- The information submitted covers Iberdrola, S.A. and its subsidiaries and affiliates. The information boundaries are defined in the Group's *Annual Financial Statements* and *Sustainability Report*.
- The Group's performance over the last years is connected to external corporate transactions and internal management decisions, which the reader should take into account in order to properly interpret this report. These transactions and activities are described in the Group's public information, the following being particularly noteworthy:
  - The acquisition and merger of companies in Brazil (2011) and the nationalisation in Bolivia (2011).
  - Beginning on 1 January 2011, the focus on a Group management model based on global businesses.
  - The application of IFRS 11 to the 2013 and 2014 figures, which mainly affect Brazil.

Material aspects

- Iberdrola has channels of communication and dialogue with its stakeholders, developed in accordance with the principles of the AA1000 Assurance Standard, as described in detail in the *Sustainability Report*.
- In addition, it performs materiality analyses that help identify matters of significance to the Company's stakeholders, bringing to light particularly sensitive financial, environmental, or social issues related to the business in the various communities and geographic areas in which the Group operates.
- The contents of this report have been selected by taking into account the existing channels for dialogue as well as the materiality analyses and the framework defined by the IIRC for this kind of information.

Social and relational capital / page 66

This report has been prepared in accordance with the reporting framework published by the International Integrated Reporting Council (IIRC).

Internal and external verification

- This report has been subject to a process of internal verification, by means of a limited review performed by the Management of the Internal Audit Area of Iberdrola, S.A.
- Although it has not been subject to a process of independent external verification, a significant portion of the information contained herein relating to financial year 2014 and to previous years comes from annual financial reports and sustainability reports, all of which have been the subject of an external audit or verification for which the respective certificates are available. The remaining information comes mainly from other reports or public presentations made by the Company.

Legal disclaimer with respect to forward-looking statements, errors, and omissions

- This document contains forward-looking information and statements about Iberdrola, S.A. Such statements include projections and estimates and their underlying assumptions, statements regarding plans, objectives, and expectations with respect to future transactions, investments, synergies, products, and services, and statements regarding future performance. Forward-looking statements are not historical facts and are generally identified by the words “expects”, “anticipates”, “believes”, “intends”, “estimates”, and similar expressions.
- In this regard, although Iberdrola, S.A. believes that the expectations reflected in such statements are reasonable, investors and holders of Iberdrola, S.A. shares are cautioned that forward-looking information and statements are subject to risks and uncertainties, many of which are difficult to predict and generally beyond the control of Iberdrola, S.A., which risks could cause actual results and developments to differ materially from those expressed in, or implied or projected by, the forward-looking information and statements. These risks and uncertainties include those identified in the documents sent by Iberdrola, S.A. to the National Securities Market Commission (*Comisión Nacional del Mercado de Valores*) and which are accessible to the public.
- Forward-looking statements are not guarantees of future performance and have not been reviewed by the auditors of Iberdrola, S.A. You are cautioned not to place undue reliance on the forward-looking statements, which speak only as of the date they were made. All forward-looking statements included in this report are expressly qualified by the cautionary statement above. All forward-looking statements included in this document are based on information available as of the date of publication hereof. Except as required by applicable law, Iberdrola, S.A. does not undertake any obligation to publicly update its forward-looking statements or to revise any forward-looking information, even if new data are published or new events occur.

Your
energy,
our
energy.

IBERDROLA

OCS-A 0501 MASS USA

VINEYARD WIND

Vineyard Wind

Attachment 5.6-7

(CI II Annual Reports 2015-16)

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Statsautoriseret Revisionspartnerselskab
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2300 Copenhagen S
Phone 36102030
Fax 36102040
www.deloitte.dk

Copenhagen Infrastructure II K/S

Central Business Registration No
36 39 30 92
Nørregade 21
1165 Copenhagen K

Annual report 2014/15

The Annual General Meeting adopted the annual report on 27 May 2016

Chairman of the General Meeting

Name: Mogens Thorninger

Contents

	Side
Fund details	1
Statement by General Partner on the annual report	2
Independent auditor's reports	3
Management commentary	5
Statement of comprehensive income	9
Balance sheet at 31 December 2015	10
Statement of changes in equity for 2015	12
Cash flow statement for 2015	13
Note overview	14
Notes	15

Fund details

Fund

Copenhagen Infrastructure II K/S
Nørregade 21
1165 Copenhagen K

Central Business Registration No: 36 39 30 92
Registered in: Copenhagen
Financial year: 30 September 2014 – 31 December 2015

Telephone: +45 70 70 51 51
Internet: www.cip.dk

General Partner

Copenhagen Infrastructure II GP ApS

Fund Manager

Copenhagen Infrastructure Partners II P/S
Approved Manager of Alternative Investment Funds (FSA number: 23014)

Auditors

Deloitte Statsautoriseret Revisionspartnerselskab
Weidekampsgade 6
2300 Copenhagen S

Statement by General Partner on the annual report

The General Partner has today considered and approved the annual report of Copenhagen Infrastructure II K/S for the financial year 30 September 2014 – 31 December 2015.

The annual report is presented in accordance with International Financial Reporting Standards as adopted by the EU and disclosure requirements of the Danish Financial Statements Act.

In our opinion, the financial statements give a true and fair view of the Limited Partnership's financial position at 31 December 2015 and of the results of its operations and the cash flows for the financial year 30 September 2014 – 31 December 2015.

We believe that the management commentary contains a fair review of the affairs and conditions referred to therein.

We recommend the annual report for adoption at the Annual General Meeting.

Copenhagen, 12 May 2016

On behalf of Copenhagen Infrastructure II GP ApS

Mogens Thorninger

Torben Carlsen

Independent auditor's reports

To the Limited Partners of Copenhagen Infrastructure II K/S

Report on the financial statements

We have audited the financial statements of Copenhagen Infrastructure II K/S for the financial year 30 September 2014 – 31 December 2015, which comprise the statement of comprehensive income, balance sheet, statement of changes in equity, cash flow statement and notes including the accounting policies. The financial statements are prepared in accordance with International Financial Reporting Standards as adopted by the EU and disclosure requirements of the Danish Financial Statements Act.

General Partner's responsibility for the financial statements

The General Partner is responsible for the preparation of the financial statements that give a true and fair view in accordance with International Financial Reporting Standards as adopted by the EU and disclosure requirements of the Danish Financial Statements Act and for such internal control as the General Partner determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

Our responsibility is to express an opinion on the financial statements based on our audit. We conducted our audit in accordance with International Standards on Auditing and additional requirements under Danish audit regulation. This requires that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgement, including the assessment of the risks of material misstatements of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Fund's preparation of financial statements that give a true and fair view in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Fund's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by the General Partner, as well as the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Our audit has not resulted in any qualification.

Independent auditor's reports

Opinion

In our opinion, the financial statements give a true and fair view of the Limited Partnership's financial position at 31 December 2015, and of the results of its operations and cash flows for the financial year 30 September 2014 – 31 December 2015 in accordance with International Financial Reporting Standards as adopted by the EU and disclosure requirements of the Danish Financial Statements Act.

Statement on the management commentary

Pursuant to the Danish Financial Statements Act, we have read the management commentary. We have not performed any further procedures in addition to the audit of the financial statements.

On this basis, it is our opinion that the information provided in the management commentary is consistent with the financial statements.

Copenhagen, 12 May 2016

Deloitte
Statsautoriseret Revisionspartnerselskab
Central Business Registration No 33 96 35 56

Bill Haudal Pedersen
State-Authorised
Public Accountant

Michael Thorø Larsen
State-Authorised
Public Accountant

Management commentary

	2015 DKK'000
Financial highlights	
Key figures	
Profit/loss from ordinary activities (EBIT)	15,692
Profit/loss for the year	18,645
Equity	2,978,645
Balance sheet total	2,985,338
Ratios	
Solvency ratio (%)	99.78

Primary activity

Copenhagen Infrastructure II K/S (CI II) was established in September 2014 and is managed by Copenhagen Infrastructure Partners II P/S (CIP). The General Partner of CI II is Copenhagen Infrastructure II GP ApS.

At Fund close on 1 July 2015, the Limited Partners had committed DKK 14,659.1m to CI II for infrastructure investments in primarily Europe and North America.

Investment portfolio

At the end of 2015, CI II had completed three transactions, Brite, Veja Mate and Beatrice.

Brite

On 10 March 2015, CI II acquired 100% of the UK biomass power plant project Brite. Brite will be a 39.3 MW wood-fired biomass power plant, located in Templeborough, near Rotherham, in South Yorkshire, Central England. Construction started in March 2015 and COD is expected in 3Q 2017.

The total investment in project Brite is expected to amount to GBP 160.0m. At the end of 2015, CI II had contributed a total of GBP 88.2m to the project. The remaining commitment will be contributed as the project execution progresses over the remaining construction period.

Management commentary (continued)

Veja Mate

On 29 June 2015, CI II provided two tranches of mezzanine debt in total of EUR 250m to finance the construction of the German offshore wind power project Veja Mate.

The total investment in Veja Mate is expected to amount to EUR 1,900m, and will be financed by CI II (mezzanine loans), and equity from Highland Group and Siemens Wind Power, and further a consortium of six banks providing senior debt.

Veja Mate will be a 400 MW offshore wind farm, located in the German North Sea, approx. 94 km from the shore on water depths around 40 meters. COD is expected in 4Q 2017.

Beatrice

On 5 November 2014, CI II acquired 12.5% of the UK offshore wind project, Beatrice.

Beatrice is located in Outer Moray Firth, Scotland and is one of five offshore wind projects in the UK awarded an Investment Contract by the UK government (fixed inflation indexed settlement price for a 15-year period). The project has been substantially developed by SSE and is progressing towards Final Investment Decision (FID). The offshore wind farm is planned to be fully operational in 2019.

On 17 December 2014, CI II entered into an agreement to purchase an additional 5% share of Beatrice from SSE, subject to completion at the end of January 2016.

The total gross commitment to the full project for CI II's 17.5% share, subject to closing in January 2016 and provided FID, is currently expected to be around GBP 300.0m.

Particular risks

Except for the valuation of investments in portfolio investments as mentioned in the following sections, no particular risks for the Fund have been identified.

Management commentary (continued)

Development in activities and finances

Income from investments in 2015 (30 September 2014 – 31 December 2015, i.e. 15 months) amounts to DKK 66.2m.

Net Income for 2015 amounts to a gain of DKK 18.6m, which is in accordance with the expectations. The result reflects income from investments, partly offset by management fee and transaction costs expensed, during the period.

Limited Partners' paid-in capital to the Fund at the end of 2015 amounted to DKK 2,960.0m, equalling 20.2% of the committed capital of DKK 14,659.1m. Of the committed capital, DKK 3,881.7m (including the additional 5% share of Beatrice but excluding the possible commitment to Beatrice at final investment decision) has been committed to investments, equalling 26.5%. Total Limited Partners' capital amounted to DKK 2,978.6m reflecting the Limited Partners' paid-in capital plus accumulated net income since Fund initiation.

Uncertainty relating to recognition and measurement

Copenhagen Infrastructure II K/S develops and invests in infrastructure projects where transferability and cash flows are affected by changes in market conditions. Consequently, the fair value of the investments is based on estimates and a number of assumptions made by the General Partner. Uncertainty attaches to the fair value of the infrastucture investments and to their realisability at any time and under any market conditions at the estimated fair value.

Information according to the Alternative Investment Fund Managers Directive

According to Article 22 of the Alternative Investment Fund Managers Directive, Alternative Investment Funds (AIF) must make certain disclosures to investors in connection with the presentation of financial statements.

During the financial period covered by the financial statements, there have been no changes in the matters below:

- The Fund's Investment strategy;
- The number of shares in the Alternative Investment Fund, which, due to their illiquid nature, are subject to special measures;
- New arrangements for managing the Fund's liquidity;
- The Fund's risk profile and the risk management systems implemented by the Fund Manager used to manage the Fund's risks;
- There have been no amendments to the maximum level of leverage which the Fund Manager can use on behalf of the Fund. Nor has there been any changes in the right to use collateral or any guarantee accordance with the agreement allowing for the leverage.

Management commentary (continued)

Events after the balance sheet date

On 17 December 2015, CI II entered into an agreement to purchase an additional 5% share of Beatrice from SSE plc (SSE). The transaction was completed on 22 January 2016. Thus, CI II now owns 17.5% of the UK offshore wind project, Beatrice.

No other events have occurred after the balance sheet date to this date which would influence the evaluation of this annual report.

Outlook

The outlook for the Limited Partnership is directly derived from the results of the investments.

The number of investments are expected to increase during 2016.

As the Fund is still in the investment period there are no specific return expectations for the Limited Partnership's financial performance for 2016 as the investments mainly will be under construction.

Statement of comprehensive income

	Notes	2015 DKK'000
Operating income		
Interest income		23,578
Net change in urealised gains/(losses) from financial assets and liabilities at fair value		55,703
Net foreign currency gains/(losses)		(13,121)
Total operating income/(loss)		**66,160**
Operating expenses		
Administrative expenses	3	(50,469)
Total operating expenses		**(50,469)**
Operating profit/loss		**15,692**
Financial income	4	4,579
Financial expenses	5	(1,626)
Profit/loss for the year		**18,645**
Other comprehensive income		**0**
Comprehensive income		**18,645**

Balance sheet at 31 December 2015

	Notes	2015 DKK'000
Portfolio investments	6	2,368,908
Receivables from portfolio investments	6	601,820
Portfolio investments		**2,970,728**
Fixed assets		**2,970,728**
Other short-term receivables		733
Receivables		**733**
Cash		**13,877**
Current assets		**14,610**
Assets		**2,985,338**

Balance sheet at 31 December 2015

	Notes	2015 DKK'000
Limited partnership capital	7	2,960,000
Retained earnings		18,645
Equity		**2,978,645**
Other payables	8	6,693
Current laibilities other than provisions		**6,693**
Liabilities other than provisions		**6,693**
Equity and liabilities		**2,985,338**

Statement of changes in equity for 2015

	Limited partnership capital DKK'000	Retained earnings DKK'000	Total DKK'000
Contribution from limited partners	2,960,000	-	2,960,000
Distribution to limited partners	-	-	-
Profit/loss for the year	-	18,645	18,645
Equity end of year	**2,960,000**	**18,645**	**2,978,645**

Cash flow statement for 2015

	Notes	2015 DKK'000
Operating profit/loss		15,692
Income from investments		(66,161)
Working capital changes	9	5,960
Cash flows from ordinary activities		**(44,509)**
Financial income	4	4,579
Financial expenses	5	(1,626)
Cash flows from operating activities		**2,953**
Acquisition in Portfolio investments	6	(2,316,816)
Receivables from Portfolio investments	6	(587,751)
Cash flows from investing activities		**(2,904,567)**
Contribution from Limited Partners		2,960,000
Cash flows from financing activities		**2,960,000**
Increase/decrease in cash		**13,877**
Cash beginning of year		-
Cash end of year		**13,877**

Note overview

1.	Accounting policies	15
2.	Significant accounting estimates, assumptions and uncertainties	21
3.	Administrative expenses	21
4.	Financial income	22
5.	Financial expenses	22
6.	Portfolio investments	23
7.	Limited partnership capital	24
8.	Other payables	24
9.	Working capital changes	24
10.	Financial instruments	24
11.	Financial risk management	25
12.	Financial instruments measured at fair value	28
13.	Related parties	30
14.	Contingent liabilities	31
15.	Investors	31
16.	Events after the balance sheet date	31
17.	Authorisation of the annual report for issue	31

Notes

1. Accounting policies

Reporting class

The financial statements are prepared in accordance with International Financial Reporting Standards (IFRS) as adopted by the EU and disclosure requirements of the Danish Financial Statements Act.

Copenhagen Infrastructure II K/S is a Limited Partnership based in Denmark.

This is the Fund's first financial year.

The financial statements are presented in Danish kroner (DKK), which is the functional currency of the Fund.

The financial statements are presented on the basis of historical cost, except for the portfolio investments and receivables from portfolio investments, which are measured at fair value. Historical cost is based on the fair value of the consideration given in exchange for assets.

Judgements made by the General Partner in the application of IFRSs that have had significant effects on the financial statements are disclosed, where applicable, in the relevant notes to the financial statements.

The principal accounting policies are set out overleaf.

Report on the omission of preparation of consolidated financial statements

CI II has omitted to prepare consolidated financial statements under the provisions of IFRS 10 and IAS 27 as the Limited Partnership qualifies as an investment entity. The definition is as follows:

"An investment entity is defined as an entity which commits to its investors that its business purpose is to invest funds solely for returns from capital appreciation, investment income, or both".

In view of the circumstances described below, the General Partner believes that the Fund satisfies the definition of an investment entity:

1) The Fund has more than one portfolio investment.
2) The Fund has more than one investor, and its investors are not related parties. Please refer to the description in note 14 to the financial statements.
3) The Fund's investments in portfolio investments take the form of equity instruments or similar investments, and the Fund can also exit the investment, if relevant.

Notes

1. Accounting policies (continued)

Standards and Interpretations not yet in force

All the new and amended Standards and Interpretations which are relevant to the Fund and which came into force with effect for financial years beginning 1 January 2014 have been applied when preparing the financial statements.

At the date of the issue of these financial statements, a number of new or amended Standards and Inter-pretations, including IFRS 9 in particular, have not yet entered into force. The General Partner believes that they will not impact significantly on the financial statements for the coming financial years.

Significant accounting policies and estimates

As part of the preparation of the financial statements, the General Partner makes a number of accounting judgements which form the basis of presentation, recognition and measurement of the Fund's assets and liabilities. The most significant accounting judgements are evident from note 2 to the financial statements.

Recognition and measurement

Assets are recognised in the balance sheet when it is probable as a result of a prior event that future economic benefits will flow to the Fund, and the value of the asset can be measured reliably. Assets are derecognised in the balance sheet when it is no longer probable that future economic benefits will flow to the Fund.

Purchase and sale of financial assets and liabilities are recognised in the balance sheet at the commitment date.

Liabilities are recognised in the balance sheet when the Fund has a legal or constructive obligation as a result of an event before or on the balance sheet date, and it is probable that future economic benefits will flow out of the Fund, and the value of the liability can be measured reliably. Liabilities are derecognised in the balance sheet when it is no longer probable that economic benefits will have to be given up to settle the liability.

On initial recognition, assets and liabilities are measured at cost, however, investment assets are measured at fair value on initial recognition, typically equalling cost exclusive of directly incurred expenses (direct transaction costs). Measurement subsequent to initial recognition is effected as described below for each financial statement item. Allowance is made for events occurring from the balance sheet date to the date of presentation of the annual report, and which confirm or invalidate affairs and conditions existing at the balance sheet date.

Income is recognised in the statement of comprehensive income when earned, whereas costs are recognised by the amounts attributable to this financial year.

Notes

1. Accounting policies (continued)

Foreign currency translation

Items included in the financial statemens of the Fund are measured in the curreny of the primary economic environment in which the Fund operates (the "functional currency"). The financial statements of the Fund are presented in the currency unit (DKK, Danish kroner), which is the Fund's functional and presentation currency.

On initial recognition, foreign currency transactions are translated applying the exchange rate at the transaction date. Receivables, payables and other monetary items denominated in foreign currencies that have not been settled at the balance sheet date are translated using the exchange rate at the balance sheet date. Exchange differences that arise between the rate at the transaction date and the one in effect at the payment date or the rate at the balance sheet date are recognised in the income statement as financial income or financial expenses.

Statement of comprehensive income

Revenue recognition

Dividend income is recognised when the Fund's rights to receive the payments have been established, normally being the ex-dividend date.

Interest on receivables from portfolio investments at fair value through profit or loss is accrued on a time-proportionate basis, by reference to the principal receivables from portfolio investments and at the effective interest rate applicable. The interest is calculated based on the net carrying amount on intial recognition.

Income from receivables and portfolio investments

Income from receivables and portfolio investments consists of unrealised fair value adjustments, dividends received, accrued interest and profit or loss from the disposal of portfolio investments.

Income realised from the disposal of portfolio investments is calculated as the difference between net selling price and cost at the time of acquisition. Previously, unrealised fair value adjustments related to portfolio investments disposed of during the year are recycled to the effect that, in net terms, profit for the year is affected by the difference between the selling price and the fair value at the beginning of the financial year. Net gains realised are then disclosed in the income statement.

Administrative expenses

All expenses are recognised in the statement of comprehensive income on the accrual basis.

Notes

1. Accounting policies (continued)

Administrative expenses comprise expenses incurred during the financial year relating to the Fund's investment activities, including fund management and administration, management fee and establishment costs.

General due diligence costs and general administration etc including management fees have been expensed by the amounts attributable to this financial year, whereas part of the development costs have been capitalised in so far as they have been incurred in order to increase the value of the equity investment or receivable.

Financial income and expenses

Financial income and expenses comprise interest income and various expenses, and net capital gain/loss on transactions in foreign currencies.

Interest income and interest expenses are stated on an accruals basis using the principal interest rate.

Income taxes

Under current Danish law governing the Fund, it is not independently taxable because the Fund's profit/loss for the year is included in the Limited Partner's taxable income.

Balance sheet

Receivables from and equity investments in portfolio companies

Financial assets and liabilities are recognised at fair value through profit and loss when the Fund becomes party to the contractual provisions of the instrument. Recognition takes place on the trading day when the Fund purchases or sells an investment under a contract whose terms require delivery of the investment within the time frame established by the market.

On initial recognition, receivables and investments in portfolio companies are measured at fair value.

Financial assets and liablitities are derecognised when the contractual rights to the cash flows from the investments have expired or the Fund has transferred substantially all risks and rewards of ownership.

Notes

1. Accounting policies (continued)

Investments recognised as portfolio investments consist of portfolio equity investments which are measured, on initial recognition, at fair value, and subsequently measured at fair value with recognition of fair value adjustments through profit or loss.

The fair value is calculated equivalent to an estimated fair value that is determined based on market information, IPEV valuation guidelines and accepted valuation techniques, including benchmarking, DCF or other relevant method, which is considered to provide the best estimate of the fair value.

For further information about the measurement of fair values, please refer to note 12.

Notes

1. Accounting policies (continued)

Other short-term receivables

Receivables are measured at amortised cost, usually equalling nominal value less write-downs for bad and doubtful debts.

Cash

Cash comprise cash in bank deposits.

Other financial liabilities

Other financial liabilities are measured at amortised cost, which usually corresponds to nominal value.

Cash flow statement

The cash flow statement of the Fund is presented using the indirect method and shows cash flows from operating, investing and financing activities as well as the Fund's cash equivalents at the beginning and the end of the financial year.

Cash flows from operating activities are calculated as the operating profit/loss adjusted for non-cash operating items and working capital changes.

Cash flows from investing activities comprise payments in connection with acquisition and divestment of portfolio investments.

Cash flows from financing activities comprise changes in the size or composition of the contributed capital and related costs as well as the raising of loans, instalments on interest-bearing debt, and payment of dividend.

Cash comprise cash and short-term securities with an insignificant price risk less short-term bank debt.

Financial highlights

Financial highlights are defined and calculated in accordance with "Recommendations & Ratios 2015" issued by the Danish Society of Financial Analysts.

Ratios		Calculation formula	Ratios reflect
Solvency ratio (%)	=	$\frac{\text{Equity x 100}}{\text{Total assets}}$	The enterprise's financial strength.

Notes

2. Significant accounting estimates, assumptions and uncertainties

The Fund develops and invests in infrastructure assets (unlisted equity investments and receivables), the market price of which depends both on entity-specific affairs and market conditions, including power prices, commodity prices, exchange rates and construction risk within the different investments. The valuation and hence fair value of the long-term receivables are, furthermore, affected by changes in the risk-free interest rate other than the general cost of risk in the market. As a result, income from portfolio investments, including the unrealised value adjustments, accrued interest and the fair value of investments are subject to estimation and uncertainty.

This uncertainty may be higher during periods of high volatility in the financial markets, and economic trends affect earnings of the underlying companies as well. The uncertainty is, furthermore, affected by the construction risk within the different investments, and also the uncertainty related to the construction of the projects taking place within relevant time frames or milestones.

The methods applied in and the assumptions underlying the determination of the fair value in unlisted equity investments are described in note 13 to the financial statements.

3. Administrative expenses

The Fund has no employees.

According to Article 107 of the AIFM Directive, alternative investment funds must disclose information about the total remuneration of the entire staff of the Fund Manager and the number of beneficiaries. Furthermore, remuneration to material risk-takers must be disclosed. For information about remuneration, please refer to the annual report of the Fund Manager.

The Fund Manager must also disclose the information necessary to provide an understanding of the risk profile of the Fund and the measures that the Fund Manager takes to avoid or manage conflicts of interest between the Fund Manager and the Limited Partners. The Board of Directors has adopted a remuneration policy in order to ensure that the employees and Management are remunerated according to the Danish Executive Order on remuneration policy and disclosure requirements on remuneration for managers of alternative investment funds, etc.

Notes

3. Administrative expenses (continued)

The remuneration policy ensures, among other matters, that the following is applied in relation to remuneration at the Fund Manager:

- Promoting of sound and effective risk management, which does not encourage excessive risk-taking.
- Consistency with the principles regarding the protection of the Limited Partners and measures in order to avoid conflicts of interest.

Currently, the Fund Manager only serves as fund manager for Copenhagen Infrastructure II K/S.

No carried interest is paid out by the AIF during the financial period.

	2014/15 DKK'000
4. Financial income	
Currency exchange rate gains	4,460
Interest income from assets not measured at fair value through profit or loss	119
Financial income	**4,579**

	2014/15 DKK'000
5. Financial expenses	
Other interest, currency loss etc	1,617
Risk premium	9
Interest expenses for financial liabilities	**1,626**

Notes

	Capitalized development projects before FID DKK'000	Portfolio investments DKK'000	Receivables from portfolio investments DKK'000
6. Portfolio investments			
Fair value 30.09.2014	-	-	-
Acquisition	-	2,261,976	581,912
Capitalized development projects	-	50,734	5,841
Development projects pre FID*	4,105	-	-
Sales	-	-	-
Interest income	-	-	23,578
Fair value adjustment (including exchange rates)	-	52,093	(9,511)
Fair value 31.12.2015	**4,105**	**2,364,803**	**601,820**

*Development projects pre FID comprise capitalised costs related to the design and development of the infrastructure investments where no equity and loan commitment has been provided.

Portfolio investment	Corporate form	Registered in	Equity interest %	Equity DKK'000	Profit/loss DKK'000
CI Beatrice II *	Ltd.	United Kingdom	99.80	N/A	N/A
CI Brite (UK) Holdings *	Ltd.	United Kingdom	99.80	N/A	N/A
CI-II VM HoldCo	K/S	Copenhagen	99.80	1,870,759	134
CI-II Holdings GP	ApS	Copenhagen	100	46	(4)

*It is the portfolio companies first financial year. The financial statements for 2015 have not been finalized therefore the informations have not been included.

Consistently with the accounting policies, the Fund regularly adjusts the value of the portfolio investments to best estimate of fair value. This means that the proportionate share of profit or loss of the portfolio investments is not recognised in profit or loss of the Fund. Instead, the value adjustment of each portfolio investment's fair value is taken to profit or loss of Fund.

The methods applied by the Fund to measure investments are evident from note 12 to the financial statements.

Notes

6. Portfolio investments (continued)

In accordance with the requirements of IFRS 12, certain disclosures must be provided for an investment company's non-consolidated subsidiaries, and the following information is deemed relevant in this respect:
The Fund's portfolio investments are not classified as investment entities because they are all engaged in developing infrastructure projects. There are no restrictions on the Fund's right to receive dividend from or have loans etc repaid by the portfolio investments, except that distributions from current operating activities of the portfolio investments must be made allowing for debt servicing by such companies. The Fund has not provided its portfolio investments with financial support during the financial year outside the contractual basis.

7. Limited partnership capital

The limited partnership capital has not been divided into classes.

	2014/15 DKK'000
8. Other payables	
Other payables	6,693

The carrying amount of payables relates to legal fees, auditor's fees, travel costs etc. The amount recognised is equal to the fair value of the liabilities.

	2014/15 DKK'000
9. Working capital changes	
Change in receivables	733
Change in payables	(6,693)
	(5,960)

10. Financial instruments

Categories of financial instruments:

Investments in portfolio investments	2,368,908
Receivables from portfolio investments	601,820
Financial assets measured at fair value through profit or loss	**2,953,678**
Other short-term receivables	733
Loans and receivables	**733**

Notes

10. Financial instruments (continued)

Other payables	6,693
Financial liabilities measured at amortised cost	**6,693**

All financial liabilities are due for payment within 12 months.

11. Financial risk management

The Fund pursues an investment strategy approved by the Limited partners and invests in both greenfield and operating infrastructure assets. The Fund is therefore exposed to financial risk. To manage such risk the Fund has implemented a risk management framework comprising the following elements:

a) Risk Management Policy
b) Risk Management Procedures
c) Governance structure
d) Reporting

The Fund's risk management processes include financial risk factor identification, measurement, monitoring, reporting and mitigation.

The risk management framework and processes seek to minimise the potential negative effects arising from financial risks on the Fund's value and financial performance.

The General Partner is ultimately responsible for the overall risk management within the Fund, but has delegated the responsibility to the Fund Manager. According to the Alternative Investment Fund Managers Directive the Fund Manager has appointed a Risk Manager heading the Risk Management function.

The Fund is exposed to a number of financial risk factors including, but not limited to, liquidity risk, credit risk, interest arte risk, currency risk, and commodity and power price risk.

The fund is affected both directly and indirectly to changes in financial risk factors. Direct exposure relates to the value of balance sheet items diretly affected by changes in financial risk factors, and includes (among others) foreign exchange adjustments of investment fair value and non-performance of receivables. Indirect exposure relates to the value of balance sheet items indirectly affected by changes in financial risk factors via the portfolio of infrastructure assets' direct exposure to such risk factors, and includes (among others) the fair value of investments in equity and debt.

Notes

11. Financial risk management (continued)

Financial Risk Factors

The financial risk factors and exposure in regards to the financial statements as of 2015 are identified to be the following:

Liquidity risks

Liquidity risk relates to the risk of having insufficient cash to meet the Fund's payables and commitments to infrastructure investments as they fall due. The amounts specified represent the payable amounts falling due.

	Less than 1 year DKK'000	Between 1 and 5 years DKK'000	After 5 years DKK'000	Total DKK'000
Other payables	6,693	0	0	6,693
31.12.2015	**6,693**	**0**	**0**	**6,693**

The cash position including bank facilities of the Fund is bigger than the payables.

The Fund has no guarantees or contingent liabilities, but has an outstanding investment commitment of DKK 772.5m.

The liquidity risk is considered insignificant as the investors of the Fund are well consolidated pension companies, insurance companies and corporates, which have the ability to provide the capital and liquidity required inside their commitment.

Credit risks

Credit risk relates to the risk of non-performing receivables and impairment of the Fund's loans provided to the infrastructure projects in the portfolio.

The maximum credit risk related to receivables equals the carrying amount. There is no indication of non-performing receivables as of the balance sheet date.

Likewise there is no impairment of loans i.e. at the balance sheet date as it is assessed that the debtors will fulfil the individual facility agreements. The investment projects of which the Fund have provided loans are all under construction. The construction phases progress as planned and no significant delays for completion are currently expected.

The Fund is not exposed to any significant credit risk from a single counterparty as of 31 December 2015.

Notes

11. Financial risk management (continued)

Interest rate risk

Interest rate risk relates to the risk of re-valuation of assets and liabilities with a fixed interest rate due to changes in the yield curve and spreads. Balance sheet items affected include the Fund's loans to infrastructure projects, (if any) the Fund's own debt, and (if any) the Fund's derivatives. In addition, interest rate risk relates to changes in future cash flow from assets and liabilities with a variable interest rate.

The Fund has no external debt as of the balance sheet date, and therefore no interest rate risk connected to the liabilities.

The Fund has provided loans with fixed interest rate to infrastructure projects, and has therefore direct interest rate risk exposure related to the fair value of the loans provided. A significant increase is interest rates will have a negative effect on fair value. However, the Fund aims to hold the loans to maturity.

Further, the Fund is indirectly exposed to interest rate risk in infrastructure projects partly financed by third party project financing. This interest rate risk is normally wholly or partly hedged at project level, hence the indirect interest rate risk is considered low.

Currency risk

Currency risk relates to the value of the portfolio investments and loans to infrastructure projects are denominated in local currency and for reporting purposes converted into DKK. Balance sheet items affected includes the Fund's investments and receivables from portfolio investments.

The Fund is denominated in DKK and invests in multiple currencies e.g. EUR and GBP. This means that the Fund is exposed to currency risk. According to the Limited Partnership Agreement the fund makes its draw downs and distributions from/to LPs in the same currency as the infrastructure project investment is made. In addition, the LPs decide on their own currency hedging strategy and the Fund does therefore not hedge balance sheet FX exposure. As of 31 December 2015 the FX exposure relates to EUR and GBP.

The Fund might use FX forwards to cash flow hedge near term future contributions to infrastructure projects. As of the 31 December 2015 no such derivates are in palce.

Commodity and power prices

The Fund is not directly exposed to commodity and power prices, however, the Fund is indirectly exposed to commodity and power price risks through its investments in energy related infrastructure assets. The Fund's indirect power price exposure is normally partly mitigated via power price agreements and/or instruments in the project's capital structure.

Notes

11. Financial risk management (continued)

The Fund have an limited indirect outright power price exposure, which are considered as low.

When the Fund has an indirect outright power price and commodity price exposure changes in such risk factors impact the fair value of the individual investment.

12. Financial instruments measured at fair value

The fair value of the investments are measured on a quarterly basis, or more frequent if significant changes occur.

The Fund Manager has implemented procedures to ensure that the valuation is carried out based on the consistent procedures across time and the investment portfolio.

Methods applied in and assumptions underlying the determination of fair values of portfolio investments

The fair value of each portfolio investment has been estimated by applying methods that best reflect the risks, and the stage of each investment. In general, the fair value is determined in accordance with IPEV valuation guidelines and accepted valuation techniques, including DCF models, benchmarking or other relevant method.

The valuation techniques have been adapted to the fact that portfolio investments are within infrastructure projects, and because the Fund during the development phase of a project add human capital and specialized knowledge. As a result, the valuation is dependent on at which stage the individual projects are and the placement in the capital structure.

The valuation of equity, loans and receivables in portfolio investments are based on the same techniques because the two types of investments are exposed to the same risks.

Notes

12. Financial instruments measured at fair value (continued)

Fair value hierarchy for financial instruments measured at fair value in the balance sheet
Below, financial instruments measured at fair value are classified using the fair value hierarchy:

- Quoted prices in active markets for identical instruments (Level 1)
- Quoted prices in active markets for similar assets or liabilities or other valuation methods under which all material inputs are based on observable market data (Level 2)
- Valuation techniques under which any material input are not based on observable market data (Level 3)

2014/15	Level 1 DKK'000	Level 2 DKK'000	Level 3 DKK'000	Total DKK'000
Unlisted shares, investments in portfolio investments	0	0	2,368,908	2,368,908
Receivables from portfolio investments	0	0	601,820	601,820
Financial assets measured at fair value through profit or loss	0	0	2,970,728	2,970,728

It is the Fund's policy to incorporate the classification of financial assets (changes/transfers between levels 1 and 3) in the financial statements if their classification changes during the financial year. There have not been any transfers between the levels during the financial year.

Material unobservable inputs for Level 3
Financial instruments measured at fair value in the balance sheet are based on valuation techniques that include material unobservable input as described above.

None of the investments are after COD and are hence not measured based on valutation techniques which require unobservable inputs. As a part of the valuation process, it has, however, been assessed if changes in power prices, inflation rates, technical availability or discount rate should lead to an impairment compared to the estimated internal rate in the business models. The assessment did not give rise to any comments.

Sensitivity analysis
The fair value of the Fund's portfolio investments is affected by development in the factors applied and future earnings expectations for these investments. A decline or increase in the material unobservable inputs stated above changes in macroeconomic conditions might have an direct effect on the valuation of the portfolio investments.

Notes

12. Financial instruments measured at fair value (continued)

No sensitivity analysis is made of the investments fair value end of 2015, as all of the portfolio investments is under construction and thereby measured at cost as best estimate of fair value.

Please refer to note 6 for a specification of fair value investments.

13. Related parties

Related parties with a controlling interest

The Limited Partnership has no investors or related parties with a controlling interest.

	2014/15 DKK'000
Related party transactions	
The General Partner is receiving a fee for its liability towards CI II as per the article of association	
Payment to the General Partner	**9**
Copenhagen Infrastructure Partners II P/S (the Fund Manager) are considered related parties of the Fund due to direct or indirect control and transactions	
Management fee (15 months period)	**60,521**

Receivables from portfolio investments

Loans have been granted to CI Brite (UK) Limited and CI Beatrice II Limited on market terms, which are expected to be settled by future cash payments. The Fund has no guarantees or similar in connection with loans. As shown in note 6, loans are only provided to companies in which the Fund holds the majority of shares.

	2014/15 DKK'000
Comitted loan capital	1,011,190
Contributions during 2014/15	581,912
Outstanding commitment	**429,278**

There are no other key relationships, which are considered material for the financial statements.

Notes

14. Contingent liabilities

The Fund has no guarantees or contingent liabilities, but has an outstanding commitment of DKK 772.5m.

15. Investors

The Limited Partnership has registered the following Limited Partners as holding more than 5% of the voting rights or nominal value of the contributed capital:

PensionDanmark Pensionsforsikringsaktieselskab, Langelinie Allé 43, 2100 Copenhagen
Lægernes Pensionskasse, Dirch Passers Allé 76, 2000 Frederiksberg
Pensionskassen for Børne- og Ungdomspædagoger, Østerfælled Torv 3, 2100 Copenhagen
Juristernes og Økonomernes Pensionskasse, Dirch Passers Allé 76, 2000 Frederiksberg
Lærernes Pension, Forsikringsaktieselskab, Tuborg Boulevard 3, 2900 Hellerup
Kommunal Landspensjonskasse Gjensidig Forsikringsselskap, Bronning Eufemias Gate 10, 0191 Oslo.

16. Events after the balance sheet date

The Fund has entered into an agreement to purchase an additional share of one of the investments. Including development costs, it adds up to GBP 3.6m.

No other events have occurred after the balance sheet date to this date, which would influence the evaluation of this annual report.

17. Authorisation of the annual report for issue

At the meeting held on 12 May 2016, the General Partner authorised this annual report for issue on 12 May 2016. The annual report will be submitted to the Limited Partnership's Limited Partners for adoption at the Annual General Meeting on 27 May 2016.

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Copenhagen Infrastructure II K/S

Central Business Registration No
36 39 30 92
Nørregade 21
1165 Copenhagen K

Annual report 2016

The Annual General Meeting adopted the annual report on 24.05.2017

Chairman of the General Meeting

_____

Name: Mogens Thorninger

Contents

	Side
Fund details	1
Statement by General Partner on the annual report	2
Independent auditor’s reports	3
Management commentary	6
Statement of comprehensive income	9
Balance sheet at 31 December 2016	10
Statement of changes in equity for 2016	12
Cash flow statement for 2016	13
Note overview	14
Notes	15

Fund details

Fund

Copenhagen Infrastructure II K/S
Nørregade 21
1165 Copenhagen K

Central Business Registration No: 36 39 30 92
Founded: 30.09.2014
Registered in: Copenhagen
Financial year: 1 January 2016 - 31 December 2016

Telephone: +45 70 70 51 51
Internet: www.cip.dk

General Partner

Copenhagen Infrastructure II GP ApS

Fund Manager

Copenhagen Infrastructure Partners II P/S
Approved Manager of Alternative Investment Funds (FSA number: 23014)

Auditors

Deloitte Statsautoriseret Revisionspartnerselskab
Weidekampsgade 6
2300 Copenhagen S

Statement by General Partner on the annual report

The General Partner has today considered and approved the annual report of Copenhagen Infrastructure II K/S for the financial year 1 January 2016 - 31 December 2016.

The annual report is presented in accordance with International Financial Reporting Standards as adopted by the EU and disclosure requirements of the Danish Financial Statements Act.

In our opinion, the financial statements give a true and fair view of the Limited Partnership's financial position at 31 December 2016 and of the results of its operations and the cash flows for the financial year 1 January 2016 - 31 December 2016.

We believe that the management commentary contains a fair review of the affairs and conditions referred to therein.

We recommend the annual report for adoption at the Annual General Meeting.

Copenhagen, 10 May 2017

On behalf of Copenhagen Infrastructure II GP ApS

Mogens Thorninger Torben Carlsen

Independent auditor's reports

To the shareholders of Copenhagen Infrastructure II K/S

Opinion

We have audited the financial statements of Copenhagen Infrastructure II K/S for the financial year 01.01.2016 - 31.12.2016, which comprise the statement of comprehensive income, balance sheet, statement of changes in equity, cash flow statement and notes, including a summary of significant accounting policies. The financial statements are prepared in accordance with International Financial Reporting Standards as adopted by the EU and additional requirements of the Danish Financial Statements Act.

In our opinion, the financial statements give a true and fair view of the Entity's financial position at 31.12.2016 and of the results of its operations for the financial year 01.01.2016 - 31.12.2016 in accordance with International Financial Reporting Standards as adopted by the EU and additional requirements of the Danish Financial Statements Act.

Basis for opinion

We conducted our audit in accordance with International Standards on Auditing (ISAs) and additional requirements applicable in Denmark. Our responsibilities under those standards and requirements are further described in the *Auditor's responsibilities for the audit of the financial statements* section of this auditor's report. We are independent of the Entity in accordance with the International Ethics Standards Board of Accountants' Code of Ethics for Professional Accountants (IESBA Code) and the additional requirements applicable in Denmark, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

General Partner's responsibilities for the financial statements

The General Partner is responsible for the preparation of financial statements that give a true and fair view in accordance with International Financial Reporting Standards as adopted by the EU and additional requirements of the Danish Financial Statements Act, and for such internal control as the General Partner determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, the General Partner is responsible for assessing the Entity's ability to continue as a going concern, for disclosing, as applicable, matters related to going concern, and for using the going concern basis of accounting in preparing the financial statements unless the General Partner either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISAs and the additional requirements applicable in Denmark will always detect a material misstatement

when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit conducted in accordance with ISAs and the additional requirements applicable in Denmark, we exercise professional judgement and maintain professional scepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by the General Partner.
- Conclude on the appropriateness of Management's use of the going concern basis of accounting in preparing the financial statements, and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures in the notes, and whether the financial statements represent the underlying transactions and events in a manner that gives a true and fair view.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Statement on the management commentary

The General Partner is responsible for the management commentary.

Our opinion on the financial statements does not cover the management commentary, and we do not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the management commentary and, in doing so, consider whether the management commentary is materially inconsistent with the financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated.

Moreover, it is our responsibility to consider whether the management commentary provides the information required under the Danish Financial Statements Act.

Based on the work we have performed, we conclude that the management commentary is in accordance with the financial statements and has been prepared in accordance with the requirements of the Danish Financial Statements Act. We did not identify any material misstatement of the management commentary.

Copenhagen, 10.05.2017

Deloitte
Statsautoriseret Revisionspartnerselskab
Business Registration No 33 96 35 56

Bill Haudal Pedersen	Michael Thorø Larsen
State-Authorised	State-Authorised
Public Accountant	Public Accountant

Management commentary

	2016 DKK'000	2015 DKK'000
Financial highlights		
Key figures		
Profit/loss from ordinary activities (EBIT)	480,955	15,692
Profit/loss for the year	472,463	18,645
Equity	5,448,234	2,978,645
Balance sheet total	5,470,212	2,985,338
Ratios		
Solvency ratio (%)	99,60	99.78

Primary activity

Copenhagen Infrastructure II K/S (CI II) was established in September 2014 and is managed by Copenhagen Infrastructure Partners II P/S (CIP). The General Partner of CI II is Copenhagen Infrastructure II GP ApS.

Investments

End of 2016, CI II had completed five investments, Brite, Veja Mate, Beatrice, Kent and Fluvanna

Brite

CI II has acquired 100% of the UK biomass power plant project Brite. Brite will be a 39.3 MW wood-fired biomass power plant, located in Templeborough, near Rotherham, in South Yorkshire, Central England. Brite is currently under construction.

Veja Mate

CI II has provided two tranches of mezzanine debt to finance the construction of the German offshore wind power project Veja Mate.

Veja Mate will be a 400 MW offshore wind farm, located in the German North Sea, approx. 94 km from the shore on water depths around 40 meters. Veja Mate is currently under construction

Beatrice

CI II has in total acquired 12.7% of the UK offshore wind project, Beatrice. Beatrice is located in Outer Moray Firth, Scotland.Beatrice is currently under construction.

Management commentary (continued)

Kent

CI II has invested in a UK biomass power plant project, Kent. Kent will be a 27.8 MW wood fired plant located in Kent, UK. Kent is currently under construction.

Fluvanna

CI II has provided a mezzanine debt facility to finance the construction of a US onshore wind project, Fluvanna. Fluvanna will be a 155MW onshore wind farm located in Texas. Fluvanna is currently under construction.

Development in activities and finances

Income from investments in 2016 amounts to DKK 539.8m.

Net Income for 2016 amounts to a gain of DKK 472.4m, which is in accordance with the expectations. The result reflects income from investments, partly offset by management fee and transaction costs expensed, during the period.

Limited Partners' paid-in capital to the Fund at the end of 2016 amounted to DKK 4,957.1m, equalling 35.9% of the committed capital of DKK 13,794.1m. Total Limited Partners' capital amounted to DKK 5,448.2m reflecting the Limited Partners' paid-in capital plus accumulated net income since Fund initiation.

Uncertainty relating to recognition and measurement

Copenhagen Infrastructure II K/S develops and invests in infrastructure projects where transferability and cash flows are affected by changes in market conditions structured to be stable. Consequently, the fair value of the investments is based on estimates and a number of assumptions made by the General Partner on the balance sheet date.

Management commentary (continued)

Information according to the Alternative Investment Fund Managers Directive

According to Article 22 of the Alternative Investment Fund Managers Directive, Alternative Investment Funds (AIF) must make certain disclosures to investors in connection with the presentation of financial statements.

During the financial year covered by the financial statements, there have been no changes in the matters below:

- The Fund's Investment strategy;
- The number of shares in the Alternative Investment Fund, which, due to their illiquid nature, are subject to special measures;
- New arrangements for managing the Fund's liquidity;
- The Fund's risk profile and the risk management systems implemented by the Fund Manager used to manage the Fund's risks;
- There have been no amendments to the maximum level of leverage which the Fund Manager can use on behalf of the Fund. Nor has there been any changes in the right to use collateral or any guarantee accordance with the agreement allowing for the leverage.

Events after the balance sheet date

No events have occurred after the balance sheet date to this date, which would influence the evaluation of this annual report.

Outlook

The outlook for the Limited Partnership depends on the results of the investments.

The number of investments are expected to increase during 2017.

There are no specific return expectations for the Limited Partnership's financial performance for 2017 as the investments mainly will be under construction.

Statement of comprehensive income

	Notes	2016 DKK'000	2015 DKK'000
Interest income		77,230	23,578
Realised losses		(2,281)	-
Net change in urealised gains/(losses) from financial assets and liabilities at fair value		639,643	55,703
Net foreign currency losses		(174,807)	(13,121)
Operating income		**539,785**	**66,160**
Administrative expenses	3	(58,830)	(50,469)
Operating expenses		**(58,830)**	**(50,469)**
Operating profit (EBIT)		**480,955**	**15,692**
Financial income	4	1,390	4,579
Financial expenses	5	(9,881)	(1,626)
Profit for the year		**472,463**	**18,645**
Other comprehensive income		**0**	**0**
Comprehensive income		**472,463**	**18,645**

Balance sheet at 31 December 2016

	Notes	2016 DKK'000	2015 DKK'000
Investments	6	4,007,997	2,368,908
Receivables from investments	6	1,192,992	601,820
Investments		**5,200,989**	**2,970,728**
Fixed assets		**5,200,989**	**2,970,728**
Other short-term receivables		21,862	733
Receivables		**21,862**	**733**
Cash		**247,361**	**13,877**
Current assets		**269,223**	**14,610**
Assets		**5,470,212**	**2,985,338**

Balance sheet at 31 December 2016

	Notes	2016 DKK'000	2015 DKK'000
Limited partnership capital	7	4,957,125	2,960,000
Retained earnings		491,109	18,645
Equity		**5,448,234**	**2,978,645**
Other payables	8	21,978	6,693
Current laibilities other than provisions		**21,978**	**6,693**
Liabilities other than provisions		**21,978**	**6,693**
Equity and liabilities		**5,470,212**	**2,985,338**

Statement of changes in equity for 2016

	Limited partnership capital DKK'000	Retained earnings DKK'000	Total DKK'000
Equity beginning of the year	2,960,000	18,645	2,978,645
Contribution from limited partners	2,175,072	-	2,175,072
Distribution to limited partners	(177,947)	-	(177,947)
Profit for the year	-	472,463	472,463
Equity end of year	**4,957,125**	**(491,109)**	**5,448,234**

Cash flow statement for 2016

	Notes	2016 DKK'000	2015 DKK'000
Operating profit		480,955	15,692
Income from investments		(539,785)	(66,161)
Working capital changes	9	(5,844)	5,960
Cash flows from ordinary activities		**(64,674)**	**(44,509)**
Financial income	4	1,390	4,579
Financial expenses	5	(9,881)	(1,626)
Cash flows from operating activities		**(8,491)**	**2,953**
Acquisition of investments	6	(1,051,898)	(2,316,816)
Receivables from investments	6	(934,554)	(587,751)
Distributions from receivables from investments	6	295,976	-
Cash flows from investing activities		**(1,690,476)**	**(2,904,567)**
Contribution from Limited Partners		2,175,072	2,960,000
Distributions to Limited Partners		(177,947)	-
Cash flows from financing activities		**1,997,125**	**2,960,000**
Increase/decrease in cash		**233,485**	**13,877**
Cash beginning of year		13,877	-
Cash end of year		**247,361**	**13,877**

Note overview

1.	Accounting policies	15
2.	Significant accounting estimates, assumptions and uncertainties	20
3.	Administrative expenses	20
4.	Financial income	21
5.	Financial expenses	21
6.	Investments	22
7.	Limited partnership capital	23
8.	Other payables	23
9.	Working capital changes	23
10.	Financial instruments	23
11.	Financial risk management	24
12.	Financial instruments measured at fair value	26
13.	Related parties	28
14.	Contingent liabilities	29
15.	Investors	29
16.	Events after the balance sheet date	29
17.	Authorisation of the annual report for issue	29

Notes

1. Accounting policies

Reporting class

The financial statements are prepared in accordance with International Financial Reporting Standards (IFRS) as adopted by the EU and disclosure requirements of the Danish Financial Statements Act.

Copenhagen Infrastructure II K/S is a Limited Partnership based in Denmark.

The accounting policies applied to these financial statements are consistent with those applied last year.

The financial statements are presented in Danish kroner (DKK), which is the functional currency of the Fund.

The financial statements are presented on the basis of historical cost, except for the investments and receivables from investments, which are measured at fair value. Historical cost is based on the fair value of the consideration given in exchange for assets.

Judgements made by the General Partner in the application of IFRSs that have had significant effects on the financial statements are disclosed, where applicable, in the relevant notes to the financial statements.

The principal accounting policies are set out overleaf.

Report on the omission of preparation of consolidated financial statements

CI II has omitted to prepare consolidated financial statements under the provisions of IFRS 10 and IAS 27 as the Limited Partnership qualifies as an investment entity. The definition is as follows:

”An investment entity is defined as an entity which commits to its investors that its business purpose is to invest funds solely for returns from capital appreciation, investment income, or both”.

In view of the circumstances described below, the General Partner believes that the Fund satisfies the definition of an investment entity:

1) The Fund has more than one investment.
2) The Fund has more than one investor, and its investors are not related parties. Please refer to the description in note 15 of the financial statements.
3) The Fund’s investments take the form of equity instruments or similar investments, and the Fund can also exit the investment, if relevant.

Notes

1. Accounting policies (continued)

Standards and Interpretations not yet in force

All the new and amended Standards and Interpretations which are relevant to the Fund and which came into force with effect for financial years beginning 1 January 2016 have been applied when preparing the financial statements.

At the date of the issue of these financial statements, a number of new or amended Standards and Inter-pretations, including IFRS 9 in particular, have not yet entered into force. The General Partner believes that they will not impact significantly on the financial statements for the coming financial years.

Significant accounting policies and estimates

As part of the preparation of the financial statements, the General Partner makes a number of accounting judgements which form the basis of presentation, recognition and measurement of the Fund's assets and liabilities. The most significant accounting judgements are evident from note 2 to the financial statements.

Recognition and measurement

Assets are recognised in the balance sheet when it is probable as a result of a prior event that future economic benefits will flow to the Fund, and the value of the asset can be measured reliably. Assets are derecognised in the balance sheet when it is no longer probable that future economic benefits will flow to the Fund.

Purchase and sale of financial assets and liabilities are recognised in the balance sheet at the commitment date.

Liabilities are recognised in the balance sheet when the Fund has a legal or constructive obligation as a result of an event before or on the balance sheet date, and it is probable that future economic benefits will flow out of the Fund, and the value of the liability can be measured reliably. Liabilities are derecognised in the balance sheet when it is no longer probable that economic benefits will have to be given up to settle the liability.

On initial recognition, assets and liabilities are measured at cost, however, investment assets are measured at fair value on initial recognition, typically equalling cost exclusive of directly incurred expenses (direct transaction costs). Measurement subsequent to initial recognition is effected as described below for each financial statement item. Allowance is made for events occurring from the balance sheet date to the date of presentation of the annual report, and which confirm or invalidate affairs and conditions existing at the balance sheet date.

Income is recognised in the statement of comprehensive income when earned, whereas costs are recognised by the amounts attributable to this financial year.

Notes

1. Accounting policies (continued)

Foreign currency translation

Items included in the financial statemens of the Fund are measured in the curreny of the primary economic environment in which the Fund operates (the "functional currency"). The financial statements of the Fund are presented in the currency unit (DKK, Danish kroner), which is the Fund's functional and presentation currency.

On initial recognition, foreign currency transactions are translated applying the exchange rate at the transaction date. Receivables, payables and other monetary items denominated in foreign currencies that have not been settled at the balance sheet date are translated using the exchange rate at the balance sheet date. Exchange differences that arise between the rate at the transaction date and the one in effect at the payment date or the rate at the balance sheet date are recognised in the income statement as financial income or financial expenses.

Statement of comprehensive income

Revenue recognition

Dividend income is recognised when the Fund's rights to receive the payments have been established, normally being the ex-dividend date.

Interest on receivables from investments at fair value through profit or loss is accrued on a time-proportionate basis, by reference to the principal receivables from investments and at the effective interest rate applicable. The interest is calculated based on the net carrying amount on intial recognition.

Income from receivables and investments

Income from receivables and investments consists of unrealised fair value adjustments, dividends, accrued interest and profit or loss from the disposal of portfolio investments.

Income realised from the disposal of investments is calculated as the difference between net selling price and cost at the time of acquisition. Previously, unrealised fair value adjustments related to investments disposed of during the year are recycled to the effect that, in net terms, profit for the year is affected by the difference between the selling price and the fair value at the beginning of the financial year.

Administrative expenses

All expenses are recognised in the statement of comprehensive income on the accrual basis.

Administrative expenses comprise expenses incurred during the financial year not directly related to the Fund's investment activities.

Notes

1. Accounting policies (continued)

General due diligence costs and general administration etc including management fees have been expensed by the amounts attributable to this financial year, whereas certain development costs have been capitalised in order to increase the value of the equity investments or receivables from investments.

Financial income and expenses

Financial income and expenses comprise interest income and various expenses, and net exchange rate adjustments on transactions in foreign currencies.

Interest income and interest expenses are stated on an accruals basis using the principal interest rate.

Income taxes

Under current Danish law governing the Fund, it is not independently taxable because the Fund's profit/loss for the year is included in the Limited Partner's taxable income.

Balance sheet

Investments and receivables from investments

Financial assets and liabilities are recognised at fair value through profit and loss when the Fund becomes party to the contractual provisions of the instrument. Recognition takes place on the trading day when the Fund purchases or sells an investment under a contract whose terms require delivery of the investment within the time frame established by the market.

On initial recognition, investments and receivables from investments are measured at fair value.

Financial assets and liablitities are derecognised when the contractual rights to the cash flows from the investments have expired or the Fund has transferred substantially all risks and rewards of ownership.

Investments consist of equity investments and receivables from investments consist of loans and shareholder loans. Both type of investment are measured, on initial recognition, at fair value, and subsequently measured at fair value with recognition of fair value adjustments through profit or loss.

The fair value is calculated equivalent to an estimated fair value that is determined based on market information, IPEV valuation guidelines and accepted valuation techniques, including benchmarking, DCF or other relevant method, which is considered to provide the best estimate of the fair value.

For further information about the measurement of fair values, please refer to note 12.

Notes

1. Accounting policies (continued)

Other short-term receivables

Receivables are measured at amortised cost, usually equalling nominal value less write-downs for bad and doubtful debts.

Cash

Cash comprise cash in bank deposits.

Other financial liabilities

Other financial liabilities are measured at amortised cost, which usually corresponds to nominal value.

Cash flow statement

The cash flow statement of the Fund is presented using the indirect method and shows cash flows from operating, investing and financing activities as well as the Fund's cash equivalents at the beginning and the end of the financial year.

Cash flows from operating activities are calculated as the operating profit/loss adjusted for non-cash operating items and working capital changes.

Cash flows from investing activities comprise payments in connection with acquisition and divestment of investments.

Cash flows from financing activities comprise changes in the size or composition of the contributed capital and payment of distributions to Limited Partners.

Cash comprise cash and short-term securities with an insignificant price risk less short-term bank debt.

Financial highlights

Financial highlights are defined and calculated in accordance with "Recommendations & Ratios 2015" issued by the Danish Society of Financial Analysts.

Ratios		Calculation formula	Ratios reflect
Solvency ratio (%)	=	$\frac{\text{Equity x 100}}{\text{Total assets}}$	The enterprise's financial strength.

Notes

2. Significant accounting estimates, assumptions and uncertainties

The Fund develops and invests in infrastructure assets (unlisted equity investments and receivables), the market price of which depends both on entity-specific affairs and market conditions, including power prices, commodity prices, exchange rates and construction risk within the different investments. The valuation and hence fair value of the long-term receivables are, furthermore, affected by changes in the risk-free interest rate other than the general cost of risk in the market. As a result, income from investments, including the unrealised value adjustments, accrued interest and the fair value of investments are subject to estimation and uncertainty.

This uncertainty may be higher during periods of high volatility in the financial markets, and economic trends affect earnings of the underlying companies as well. The uncertainty is, furthermore, affected by the construction risk within the different investments, and also the uncertainty related to the construction of the projects taking place within relevant time frames or milestones.

The methods applied in and the assumptions underlying the determination of the fair value in unlisted equity investments are described in note 12 to the financial statements.

3. Administrative expenses

The Fund has no employees.

According to Article 107 of the AIFM Directive, alternative investment funds must disclose information about the total remuneration of the entire staff of the Fund Manager and the number of beneficiaries. Furthermore, remuneration to material risk-takers must be disclosed. For information about remuneration, please refer to the annual report of the Fund Manager.

The Fund Manager must also disclose the information necessary to provide an understanding of the risk profile of the Fund and the measures that the Fund Manager takes to avoid or manage conflicts of interest between the Fund Manager and the Limited Partners. The Board of Directors has adopted a remuneration policy in order to ensure that the employees and Management are remunerated according to the Danish Executive Order on remuneration policy and disclosure requirements on remuneration for managers of alternative investment funds, etc.

Notes

3. Administrative expenses (continued)

The remuneration policy ensures, among other matters, that the following is applied in relation to remuneration at the Fund Manager:

- Promoting of sound and effective risk management, which does not encourage excessive risk-taking.
- Consistency with the principles regarding the protection of the Limited Partners and measures in order to avoid conflicts of interest.

Currently, the Fund Manager serves as fund manager for Copenhagen Infrastructure II K/S, CI II US AIV Non-QFPF K/S and CI II US AIV QFPF K/S.

No carried interest is paid out by the AIF during the financial period.

	2016 DKK'000	2014/15 DKK'000
4. Financial income		
Currency exchange rate gains	1,323	4,460
Interest income from assets not measured at fair value through profit or loss	67	119
Financial income	**1,390**	**4,579**
5. Financial expenses		
Other interest, currency loss etc	(9,875)	(1,617)
General Partner fee	(6)	(9)
Interest expenses for financial liabilities	**(9,881)**	**(1,626)**

Notes

	Capitalized development projects before FID* DKK'000	Investments DKK'000	Receivables from investments DKK'000
6. Investments			
Fair value 31.12.2015	4,105	2,364,803	601,820
Acquisitions and development costs	14,950	1,036,948	934,554
Distributions	-	-	(295,976)
Value adjustment	(2,281)	589,472	(47,406)
Fair value 31.12.2016	**16,774**	**3,991,223**	**1,192,992**

	Capitalized development projects before FID* DKK'000	Investments DKK'000	Receivables from investments DKK'000
Investments			
Fair value 30.09.2014	-	-	-
Acquisitions and development costs	4,105	2,312,710	587,753
Value adjustment	-	52,093	14,067
Fair value 31.12.2015	**4,105**	**2,364,803**	**601,820**

*****Development projects before FID comprise capitalised costs related to the design and development of the infrastructure investments where no equity and loan commitment has been provided.

Investment	Corporate form	Registered in	Equity interest %
CI Beatrice II	Ltd.	United Kingdom	99.80
CI Brite (UK) Holdings	Ltd.	United Kingdom	99.80
CI-II VM HoldCo	K/S	Copenhagen	99.80
CI-II Holdings GP	ApS	Copenhagen	100.00
CI II Fluvanna B	K/S	Copenhagen	99.80
CI Procurement	Inc.	United States	99.80
CI-II US Project Services	Inc.	United States	100.00
CI-II NY	Inc.	United States	100.00

Notes

6. Investments (continued)

Consistently with the accounting policies, the Fund regularly adjusts the value of the investments to best estimate of fair value. This means that the proportionate share of profit or loss of the investments is not recognised in profit or loss of the Fund. Instead, the value adjustment of each investment's fair value is taken to profit or loss of Fund.

The methods applied by the Fund to measure investments are evident from note 12 to the financial statements.

In accordance with the requirements of IFRS 12, certain disclosures must be provided for an investment company's non-consolidated subsidiaries, and the following information is deemed relevant in this respect:

The Fund's investments are not classified as investment entities because they are all engaged in developing infrastructure projects. There are no restrictions on the Fund's right to receive dividend from or have loans etc repaid by the investments, except that distributions from current operating activities of the investments must be made allowing for debt servicing by such companies. The Fund has not provided its investments with financial support during the financial year outside the contractual basis.

7. Limited partnership capital

The limited partnership capital has not been divided into classes.

	2016 DKK'000	2014/15 DKK'000

8. Other payables

Other payables	21,978	6,693

The carrying amount of payables relates to legal fees, auditor's fees, travel costs etc. The amount recognised is equal to the fair value of the liabilities.

9. Working capital changes

Change in receivables	21,129	733
Change in payables	(15,285)	(6,693)
	5,844	**(5,960)**

10. Financial instruments

Categories of financial instruments:

Investments	4,007,997	2,368,908
Receivables from investments	1,192,992	601,820
Financial assets measured at fair value through profit or loss	**5,200,989**	**2,970,728**

Notes

10. Financial instruments (continued)

	2016 DKK'000	2014/15 DKK'000
Other short-term receivables	21,862	733
Loans and receivables	**21,862**	**733**
Other payables	21,978	6,693
Financial liabilities measured at amortised cost	**21,978**	**6,693**

All financial liabilities are due for payment within 12 months.

11. Financial risk management

The General Partner is ultimately responsible for the overall risk management within the Fund, but has delegated the responsibility to the Fund Manager.

The Fund pursues an investment strategy approved by the Limited partners and invests in both greenfield and operating infrastructure assets.

The Fund's risk management processes includes identification, measurement, monitoring, reporting and mitigation of the identified risks to minimize the potential negative effects at fund level.

Key financial risk factors and exposure in regards to the financial statements as of 2016 can be categorised as follows:

Notes

11. Financial risk management (continued)

Financial Risk Factors

	Less than 1 year DKK'000	Between 1 and 5 years DKK'000	After 5 years DKK'000	Total DKK'000
Other payables	21,978	0	0	21,978
31.12.2016	**21,978**	**0**	**0**	**21,978**

	Less than 1 year DKK'000	Between 1 and 5 years DKK'000	After 5 years DKK'000	Total DKK'000
Other payables	6,693	0	0	6,693
31.12.2015	**6,693**	**0**	**0**	**6,693**

The cash position in the Fund is bigger than the payables.

The Fund has no guarantees or contingent liabilities, but has an outstanding investment commitment of DKK 2,928m.

The liquidity risk is considered insignificant. No indication of the limited partners ability to contribute the remaining fund commitment occurs.

Credit risks

Credit risk relates to the risk of non-performing receivables and impairment of the Fund's loans provided to the infrastructure projects.

The maximum credit risk related to receivables equals the carrying amount. There is no indication of non-performing receivables as of the balance sheet date.

Likewise there is no impairment of receivables i.e. at the balance sheet date as it is assessed that the debtors will fulfil the individual facility agreements. The investment projects of which the Fund have provided loans are currently under construction. The construction phases progress as planned and no significant delays for completion are currently expected.

The Fund is not exposed to any significant credit risk from a single counterparty as of 31 December 2016.

Notes

11. Financial risk management (continued)

Interest rate risk

The Fund has no external debt as of the balance sheet date, and therefore no interest rate risk connected to the liabilities.

Currency risk

The Fund is denominated in DKK. However, all cash flows, including draw downs and distributions, are made in investment specific currencies, consequently, the limited partner is not exposed to currency risk through the fund.

Commodity and power prices

The Fund's indirect power price exposure is mitigated via power price agreements and/or instruments in the project's capital structure. The Fund's indirect outright power price exposure are considered as low.

When the Fund has an indirect outright power price and commodity price exposure changes in such risk factors impact the fair value of the individual investment.

12. Financial instruments measured at fair value

The fair value of the investments are measured on a quarterly basis, or more frequent if significant changes occur.

The Fund Manager has implemented procedures and methodology to ensure that the valuation is carried out consistent over time and across investments.

Methods applied in and assumptions underlying the determination of fair values of investments

The fair value of each investment and receivables from investment has been estimated by applying methods that best reflect the risks, and the stage of each investment.

In general, the fair value is determined in accordance with IPEV valuation guidelines and accepted valuation techniques, including DCF models, benchmarking or other relevant method. For projects which is before the state of COD (Commissioning Operating Date) cost is however considered as best estimate for fair value.

The valuation of investments and receivables from investments are based on the same methods, as investments and receivables from investments are exposed to the same risks.

Fair value hierarchy for financial instruments measured at fair value in the balance sheet

Below, financial instruments measured at fair value are classified using the fair value hierarchy:

Notes

12. Financial instruments measured at fair value (continued)

- Quoted prices in active markets for identical instruments (Level 1)
- Quoted prices in active markets for similar assets or liabilities or other valuation methods under which all material inputs are based on observable market data (Level 2)
- Valuation techniques under which any material input are not based on observable market data (Level 3)

It is the Fund's policy to incorporate the classification of financial assets (changes/transfers between levels 1 and 3) in the financial statements if their classification changes during the financial year. There have not been any transfers between the levels during the financial year and all investments are classified as Level 3 investments.

Material unobservable inputs for Level 3

Financial instruments measured at fair value in the balance sheet are based on valuation techniques that include material unobservable input as described above.

None of the investments are after COD and are hence not measured based on valutation techniques which require unobservable inputs. As a part of the valuation process, it has, however, been assessed if changes in power prices, inflation rates, technical availability or discount rate should lead to an impairment compared to the estimated internal rate in the business models. The assessment did not give rise to any comments.

2016	**Level 1 DKK'000**	**Level 2 DKK'000**	**Level 3 DKK'000**	**Total DKK'000**
Unlisted shares, investments	0	0	4,007,997	4,007,997
Receivables from investments	0	0	1,192,992	1,192,992
Financial assets measured at fair value through profit or loss	**0**	**0**	**5,200,989**	**5,200,989**

2014/15	**Level 1 DKK'000**	**Level 2 DKK'000**	**Level 3 DKK'000**	**Total DKK'000**
Unlisted shares, investments	0	0	2,368,908	2,368,908
Receivables from investments	0	0	601,820	601,820
Financial assets measured at fair value through profit or loss	**0**	**0**	**2,970,728**	**2,970,728**

Notes

12. Financial instruments measured at fair value (continued)

Sensitivity analysis

The fair value of the Fund's investments is affected by development in the applied discount rate and future earnings expectations for these investments. A decline or increase in the material unobservable inputs stated above and changes in macroeconomic conditions might have an direct effect on the valuation of the investments.

No sensitivity analysis is made of the investments fair value end of 2016, as all of the portfolio investments is under construction and thereby measured at cost as best estimate of fair value.

Please refer to note 6 for a specification of fair value investments.

13. Related parties

Related parties with a controlling interest

The Limited Partnership has no investors or related parties with a controlling interest.

	2016 DKK'000	2014/15 DKK'000
Related party transactions		
The General Partner is receiving a fee for its liability towards CI II as per the article of association		
Payment to the General Partner	**6**	**9**
Copenhagen Infrastructure Partners II P/S (the Fund Manager) is considered related parties of the Fund due to direct or indirect control and transactions		
Management fee (15 months period for 2014/15)	**30,599**	**60,521**

Receivables from investments

Loans have been granted on market terms, which are expected to be settled by future cash payments. The Fund has no guarantees or similar in connection with loans. As shown in note 6, loans are only provided to companies in which the Fund holds the majority of shares.

	2016 DKK'000	2014/15 DKK'000
Comitted loan capital	3,224,500	1,011,190
Contributions	933,092	581,912
Outstanding commitment	**2,291,408**	**429,278**

There are no other key relationships, which are considered material for the financial statements.

Notes

14. Contingent liabilities

The Fund has no guarantees or contingent liabilities, but has an outstanding commitments of DKK 2,928m.

15. Investors

The Limited Partnership has registered the following Limited Partners as holding more than 5% of the voting rights or nominal value of the contributed capital:

PensionDanmark Pensionsforsikringsaktieselskab, Langelinie Allé 43, 2100 Copenhagen
Lægernes Pensionskasse, Dirch Passers Allé 76, 2000 Frederiksberg
Pensionskassen for Børne- og Ungdomspædagoger, Østerfælled Torv 3, 2100 Copenhagen
Juristernes og Økonomernes Pensionskasse, Dirch Passers Allé 76, 2000 Frederiksberg
Lærernes Pension, Forsikringsaktieselskab, Tuborg Boulevard 3, 2900 Hellerup
Kommunal Landspensjonskasse Gjensidig Forsikringsselskap, Bronning Eufemias Gate 10, 0191 Oslo.

16. Events after the balance sheet date

No events have occurred after the balance sheet date to this date, which would influence the evaluation of this annual report.

17. Authorisation of the annual report for issue

At the meeting held on , the General Partner authorised this annual report for issue on . The annual report will be submitted to the Limited Partnership's Limited Partners for adoption at the Annual General Meeting on .

OCS-A 0501 MASS USA

VINEYARD WIND

Vineyard Wind

Attachment 5.6-8

(CI II US AIV Non-QFPF Annual Report 2016)

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CI II US AIV Non-QFPF K/S

Central Business Registration No
37 78 94 10
Nørregade 21
1165 Copenhagen K

Annual report 2016

The Annual General Meeting adopted the annual report on 24.05.2017

Chairman of the General Meeting

_____

Name: Mogens Thorninger

Contents

	Side
Fund details	1
Statement by General Partner on the annual report	2
Independent auditor's report	3
Management commentary	6
Statement of comprehensive income	8
Balance sheet at 31 December 2016	9
Statement of changes in equity for 2016	11
Cash flow statement for 2016	12
Note overview	13
Notes	14

Fund details

Fund

CI II US AIV Non-QFPF K/S
Nørregade 21
1165 Copenhagen K

Central Business Registration No: 37 78 94 10
Founded: 13.06.2016
Registered in: Copenhagen
Financial year: 13 June 2016 - 31 December 2016

Telephone: +45 70 70 51 51
Internet: www.cip.dk

General Partner

Copenhagen Infrastructure II GP ApS

Fund Manager

Copenhagen Infrastructure Partners II P/S
Approved Manager of Alternative Investment Funds (FSA number: 23014)

Auditors

Deloitte Statsautoriseret Revisionspartnerselskab
Weidekampsgade 6
2300 Copenhagen S

Statement by General Partner on the annual report

The General Partner has today considered and approved the annual report of CI II US AIV Non-QFPF K/S for the financial year 13 June 2016 – 31 December 2016.

The annual report is presented in accordance with International Financial Reporting Standards as adopted by the EU and disclosure requirements of the Danish Financial Statements Act.

In our opinion, the financial statements give a true and fair view of the Limited Partnership's financial position at 31 December 2016 and of the results of its operations and the cash flows for the financial year 13 June 2016 – 31 December 2016.

We believe that the management commentary contains a fair review of the affairs and conditions referred to therein.

We recommend the annual report for adoption at the Annual General Meeting.

Copenhagen, 10 May 2017

On behalf of Copenhagen Infrastructure II GP ApS

Mogens Thorninger Torben Carlsen

Independent auditor's report

To the shareholders of CI II US AIV Non-QFPF K/S

Opinion

We have audited the financial statements of CI II US AIV Non-QFPF K/S for the financial year 13.06.2016 - 31.12.2016, which comprise the statement of comprehensive income, balance sheet, statement of changes in equity, cash flow statement and notes, including a summary of significant accounting policies. The financial statements are prepared in accordance with International Financial Reporting Standards as adopted by the EU and additional requirements of the Danish Financial Statements Act.

In our opinion, the financial statements give a true and fair view of the Entity's financial position at 31.12.2016 and of the results of its operations for the financial year 13.06.2016 - 31.12.2016 in accordance with International Financial Reporting Standards as adopted by the EU and additional requirements of the Danish Financial Statements Act.

Basis for opinion

We conducted our audit in accordance with International Standards on Auditing (ISAs) and additional requirements applicable in Denmark. Our responsibilities under those standards and requirements are further described in the *Auditor's responsibilities for the audit of the financial statements* section of this auditor's report. We are independent of the Entity in accordance with the International Ethics Standards Board of Accountants' Code of Ethics for Professional Accountants (IESBA Code) and the additional requirements applicable in Denmark, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

General Partner's responsibilities for the financial statements

The General Partner is responsible for the preparation of financial statements that give a true and fair view in accordance with International Financial Reporting Standards as adopted by the EU and additional requirements of the Danish Financial Statements Act, and for such internal control as the General Partner determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, the General Partner is responsible for assessing the Entity's ability to continue as a going concern, for disclosing, as applicable, matters related to going concern, and for using the going concern basis of accounting in preparing the financial statements unless the General Partner either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISAs and the additional requirements applicable in Denmark will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit conducted in accordance with ISAs and the additional requirements applicable in Denmark, we exercise professional judgement and maintain professional scepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by the General Partner.
- Conclude on the appropriateness of Management's use of the going concern basis of accounting in preparing the financial statements, and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures in the notes, and whether the financial statements represent the underlying transactions and events in a manner that gives a true and fair view.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Statement on the management commentary

The General Partner is responsible for the management commentary.

Our opinion on the financial statements does not cover the management commentary, and we do not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the management commentary and, in doing so, consider whether the management commentary is materially inconsistent with the financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated.

Moreover, it is our responsibility to consider whether the management commentary provides the information required under the Danish Financial Statements Act.

Based on the work we have performed, we conclude that the management commentary is in accordance with the financial statements and has been prepared in accordance with the requirements of the Danish Financial Statements Act. We did not identify any material misstatement of the management commentary.

Copenhagen, 10.05.2017

Deloitte
Statsautoriseret Revisionspartnerselskab
Business Registration No 33 96 35 56

Bill Haudal Pedersen	Michael Thorø Larsen
State-Authorised	State-Authorised
Public Accountant	Public Accountant

Management commentary

	2016 DKK'000
Financial highlights	
Key figures	
Profit/loss from ordinary activities (EBIT)	(2,067)
Profit/loss for the year	(305)
Equity	49,327
Balance sheet total	74,160
Ratios	
Solvency ratio (%)	66,51

Primary activity

CI II US AIV Non-QFPF K/S (CI II) was established in June 2016 and is managed by Copenhagen Infrastructure Partners II P/S (CIP). The General Partner of CI II US AIV Non-QFPF K/S is Copenhagen Infrastructure II GP ApS.

Investments

End of 2016, CI II had not yet made any transactions, which have had financial investment decision.

Development in activities and finances

Income from investments in 2016 (13 June 2016 – 31 December 2016, i.e. 6.5 months) amounts to DKK 0 m.

Net Income for 2016 amounts to a loss of DKK 0.3m, which is in accordance with the expectations. The result reflects administration costs and transaction costs expensed, during the period.

Limited Partners' paid-in capital to the Fund at the end of 2016 amounted to DKK 49.6m, equalling 18.1% of the committed capital of DKK 273.5m. Of the committed capital. Total Limited Partners' capital amounted to DKK49.3m reflecting the Limited Partners' paid-in capital plus accumulated net loss since Fund initiation.

Management commentary (continued)

Uncertainty relating to recognition and measurement

CI II develops and invests in infrastructure projects structured to provide stable cash flows, but where transferability and cash flows to a certain extend still may be affected by changes in market conditions. Consequently, the fair value of the investments is based on estimates and a number of assumptions made by the General Partner on the balance sheet date.

Information according to the Alternative Investment Fund Managers Directive

According to Article 22 of the Alternative Investment Fund Managers Directive, Alternative Investment Funds (AIF) must make certain disclosures to investors in connection with the presentation of financial statements.

Since the establishment of the fund of 13 June 2016, there have been no significant changes in the matters below:

- The Fund’s Investment strategy;
- Valuation principles of the Fund’s investments;
- New arrangements for managing the Fund’s liquidity;
- The Fund's risk profile and the risk management systems implemented by the Fund Manager used to manage the Fund's risks;
- There have been no amendments to the maximum level of leverage which the Fund Manager can use on behalf of the Fund. Nor has there been any changes in the right to use collateral or any guarantee accordance with the agreement allowing for the leverage.

Events after the balance sheet date

End of March 2017 CI II announced the Bearkat I investment, an onshore wind farm with a total expected capacity of 197.7 MW located in Glasscock County, Texas. The construction have now commenced.

No other events have occurred after the balance sheet date to this date which would influence the evaluation of this annual report.

Outlook

The outlook for the Limited Partnership is expected to be positive.

The number of investments is expected to increase during 2017.

Statement of comprehensive income

	Notes	2016 DKK'000
Administrative expences	3	(2,067)
Operating expenses		**(2,067)**
Operating loss (EBIT)		**(2,067)**
Financial items		1,762
Loss for the year		**(305)**
Other comprehensive income		**0**
Comprehensive income		**(305)**

Balance sheet at 31 December 2016

	Notes	2016 DKK'000
Equity investments	4	45,618
Investments		**45,618**
Fixed assets		**45,618**
Other short-term receivables		1,569
Prepayments		53
Receivables		**1,622**
Cash		**26,921**
Current assets		**28,542**
Assets		**74,160**

Balance sheet at 31 December 2016

	Notes	2016 DKK'000
Limited partnership capital	5	49,632
Reatined earnings		(305)
Equity		**49,327**
Other payables	6	24,833
Current laibilities other than provisions		**24,833**
Liabilities other than provisions		**24,833**
Equity and liabilities		**74,160**

Statement of changes in equity for 2016

	Limited partnership-capital DKK'000	Retained earnings DKK'000	Total DKK'000
Contributions from limited partners	49,632	-	49,632
Profit/loss for the year	-	(305)	(305)
Equity end of year	**49,632**	**(305)**	**49,327**

Cash flow statement for 2016

	Notes	2016 DKK'000
Operating loss		(2,067)
Income from investments		-
Working capital changes	7	23,212
Cash flows from ordinary activities		**21,145**
Financial items		1,762
Cash flows from operating activities		**1,762**
Acquisition of equity investments	4	(45,618)
Cash flows from investing activities		**(45,618)**
Contribution from Limited Partners		49,632
Cash flows from financing activities		**49,632**
Increase/decrease in cash		**26,921**
Cash beginning of year		-
Cash end of year		**26,921**

Note overview

1.	Accounting policies	14
2.	Significant accounting estimates, assumptions and uncertainties	19
3.	Administrative expenses	19
4.	Investments	20
5.	Limited partnership capital	21
6.	Other payables	22
7.	Working capital changes	22
8.	Financial instruments	22
9.	Financial risk management	23
10.	Financial instruments measured at fair value	24
11.	Related parties	26
12.	Contingent liabilities	26
13.	Investors	26
14.	Events after the balance sheet date	27
15.	Authorisation of the annual report for issue	27

Notes

1. Accounting policies

Reporting class

The financial statements are prepared in accordance with International Financial Reporting Standards (IFRS) as adopted by the EU and disclosure requirements of the Danish Financial Statements Act.

CI II US AIV Non-QFPF K/S is a Limited Partnership based in Denmark.

This is the Fund's first financial year and comprise the period 13 June 2016 – 31 December 2016, and hence no comparetiv figures have been presented.

The financial statements are presented in Danish kroner (DKK), which is the functional currency of the Fund.

The financial statements are presented on the basis of historical cost, except for the equity investments, which are measured at fair value. Historical cost is based on the fair value of the consideration given in exchange for assets.

Judgements made by the General Partner in the application of IFRSs that have had significant effects on the financial statements are disclosed, where applicable, in the relevant notes to the financial statements.

The principal accounting policies are set out overleaf.

Report on the omission of preparation of consolidated financial statements

CI II US AIV Non-QFPF K/S has omitted to prepare consolidated financial statements under the provisions of IFRS 10 and IAS 27 as the Limited Partnership qualifies as an investment entity. The definition is as follows:

"An investment entity is defined as an entity which commits to its investors that its business purpose is to invest funds solely for returns from capital appreciation, investment income, or both".

In view of the circumstances described below, the General Partner believes that the Fund satisfies the definition of an investment entity:

1) The Fund has more than one investment.
2) The Fund has more than one investor, and its investors are not related parties. Please refer to the description in note 13 to the financial statements.
3) The Fund's investments in investments take the form of equity instruments or similar investments, and the Fund can also exit the investment, if relevant.

Notes

1. Accounting policies (continued)

Standards and Interpretations not yet in force

All the new and amended Standards and Interpretations which are relevant to the Fund and which came into force with effect for financial years beginning 1 January 2016 have been applied when preparing the financial statements.

At the date of the issue of these financial statements, a number of new or amended Standards and Inter-pretations, including IFRS 9 in particular, have not yet entered into force. The General Partner believes that they will not impact significantly on the financial statements for the coming financial years.

Significant accounting policies and estimates

As part of the preparation of the financial statements, the General Partner makes a number of accounting judgements which form the basis of presentation, recognition and measurement of the Fund's assets and liabilities. The most significant accounting judgements are evident from note 2 to the financial statements.

Recognition and measurement

Assets are recognised in the balance sheet when it is probable as a result of a prior event that future economic benefits will flow to the Fund, and the value of the asset can be measured reliably. Assets are derecognised in the balance sheet when it is no longer probable that future economic benefits will flow to the Fund.

Purchase and sale of financial assets and liabilities are recognised in the balance sheet at the commitment date.

Liabilities are recognised in the balance sheet when the Fund has a legal or constructive obligation as a result of an event before or on the balance sheet date, and it is probable that future economic benefits will flow out of the Fund, and the value of the liability can be measured reliably. Liabilities are derecognised in the balance sheet when it is no longer probable that economic benefits will have to be given up to settle the liability.

On initial recognition, assets and liabilities are measured at cost, however, investment assets are measured at fair value on initial recognition, typically equalling cost exclusive of directly incurred expenses (direct transaction costs). Measurement subsequent to initial recognition is effected as described below for each financial statement item. Allowance is made for events occurring from the balance sheet date to the date of presentation of the annual report, and which confirm or invalidate affairs and conditions existing at the balance sheet date.

Income is recognised in the statement of comprehensive income when earned, whereas costs are recognised by the amounts attributable to this financial year.

Notes

1. Accounting policies (continued)

Foreign currency translation

Items included in the financial statemens of the Fund are measured in the curreny of the primary economic environment in which the Fund operates (the "functional currency"). The financial statements of the Fund are presented in the currency unit (DKK, Danish kroner), which is the Fund's functional and presentation currency.

On initial recognition, foreign currency transactions are translated applying the exchange rate at the transaction date. Receivables, payables and other monetary items denominated in foreign currencies that have not been settled at the balance sheet date are translated using the exchange rate at the balance sheet date. Exchange differences that arise between the rate at the transaction date and the one in effect at the payment date or the rate at the balance sheet date are recognised in the income statement as financial income or financial expenses.

Statement of comprehensive income

Administrative expenses

All expenses are recognised in the statement of comprehensive income on the accrual basis.

Administrative expenses comprise expenses incurred during the financial year not directly related to the Fund's investment activities.

General due diligence costs and general administration etc including management fees have been expensed by the amounts attributable to this financial year, whereas certain development costs have been capitalised in order to increase the value of the equity investments.

Financial income and expenses

Financial income and expenses comprise interest income and various expenses, and net capital gain/loss on transactions in foreign currencies.

Interest income and interest expenses are stated on an accruals basis using the principal interest rate.

Income taxes

Under current Danish law governing the Fund, it is not independently taxable because the Fund's profit/loss for the year is included in the Limited Partner's taxable income.

Notes

1. Accounting policies (continued)

Balance sheet

Investments

Financial assets and liabilities are recognised at fair value through profit and loss when the Fund becomes party to the contractual provisions of the instrument. Recognition takes place on the trading day when the Fund purchases or sells an investment under a contract whose terms require delivery of the investment within the time frame established by the market.

On initial recognition, equity investments are measured at fair value.

Financial assets and liablitities are derecognised when the contractual rights to the cash flows from the investments have expired or the Fund has transferred substantially all risks and rewards of ownership.

Investments consist of equity investments in infrastructure companies (projects) and are measured, on initial recognition, at fair value, and subsequently measured at fair value with recognition of fair value adjustments through profit or loss.

The fair value is calculated equivalent to an estimated fair value that is determined based on market information, IPEV valuation guidelines and accepted valuation techniques, including benchmarking, DCF or other relevant method, which is considered to provide the best estimate of the fair value.

For further information about the measurement of fair values, please refer to note 10.

Other short-term receivables

Receivables are measured at amortised cost, usually equalling nominal value less write-downs for bad and doubtful debts.

Prepayments

Prepayments comprise incurred cost relating to subsequent financial years. Prepayments are measured at cost.

Cash

Cash comprise cash in bank deposits.

Other financial liabilities

Other financial liabilities are measured at amortised cost, which usually corresponds to nominal value.

Notes

1. Accounting policies (continued)

Cash flow statement

The cash flow statement of the Fund is presented using the indirect method and shows cash flows from operating, investing and financing activities as well as the Fund's cash equivalents at the beginning and the end of the financial year.

Cash flows from operating activities are calculated as the operating profit/loss adjusted for non-cash operating items and working capital changes.

Cash flows from investing activities comprise payments in connection with acquisition and divestment of investments.

Cash flows from financing activities comprise changes in the size or composition of the contributed capital and related costs as well as the raising of loans, instalments on interest-bearing debt, and payment of dividend.

Cash comprise cash and short-term securities with an insignificant price risk less short-term bank debt.

Financial highlights

Financial highlights are defined and calculated in accordance with "Recommendations & Ratios 2015" issued by the Danish Society of Financial Analysts.

Ratios		Calculation formula	Ratios reflect
Solvency ratio (%)	=	$\frac{\text{Equity x 100}}{\text{Total assets}}$	The enterprise's financial strength.

Notes

2. Significant accounting estimates, assumptions and uncertainties

The Fund develops and invests in infrastructure assets (unlisted equity investments), the market price of which depends both on entity-specific affairs and market conditions, including to a certain extent power prices, commodity prices, exchange rates and construction risk within the different investments. The valuation and hence fair value of equity investments may also be affected by changes in the risk-free interest rate other than the general cost of risk in the market As a result, income from investments, including the unrealised value adjustments and the fair value of investments are subject to estimation and uncertainty.

The methods applied in and the assumptions underlying the determination of the fair value in unlisted equity investments are described in note 10 to the financial statements.

3. Administrative expenses

The Fund has no employees.

According to Article 107 of the AIFM Directive, alternative investment funds must disclose information about the total remuneration of the entire staff of the Fund Manager and the number of beneficiaries. Furthermore, remuneration to material risk-takers must be disclosed. For information about remuneration, please refer to the annual report of the Fund Manager.

The Fund Manager must also disclose the information necessary to provide an understanding of the risk profile of the Fund and the measures that the Fund Manager takes to avoid or manage conflicts of interest between the Fund Manager and the Limited Partners. The Board of Directors has adopted a remuneration policy in order to ensure that the employees and Management are remunerated according to the Danish Executive Order on remuneration policy and disclosure requirements on remuneration for managers of alternative investment funds, etc.

Notes

3. Administrative expenses (continued)

The remuneration policy ensures, among other matters, that the following is applied in relation to remuneration at the Fund Manager:

- Promoting of sound and effective risk management, which does not encourage excessive risk-taking.
- Consistency with the principles regarding the protection of the Limited Partners and measures in order to avoid conflicts of interest.

Currently, the Fund Manager serves as fund manager for Copenhagen Infrastructure II K/S, CI II US AIV Non-QFPF K/S and CI II US AIV QFPF K/S.

No carried interest is paid out by the AIF during the financial period.

	Development projects DKK'000	Equity investments DKK'000
4. Investments		
Fair value 13.06.2016	-	-
Acquisition and development costs	26,337	19,281
Fair value 31.12.2016	**26,337**	**19,281**

Projects are considered as development projects until final investment decision is made, and is comprising costs related to project rights, the design and development of the infrastructure investments.

Notes

4. Investments (continued)

Investment	Corporate form	Registered in	Equity interest %
CI-II Bearkat Non-QFPF	Inc.	United States	100
CI-II Bearkat II Non-QFPF	Inc.	United States	100
CI Alice II	Inc.	United States	100
CI-II Blue Cloud Non-QFPF	Inc.	United States	100
CI II Mitchell Non-QFPF	Inc.	United States	100
CI II Fluvanna Non-QFPF	Inc.	United States	100
CI-II Bearkat III Non-QFPF	Inc.	United States	100

Consistently with the accounting policies, the Fund regularly adjusts the value of the investments to best estimate of fair value. This means that the proportionate share of profit or loss of the investments is not recognised in profit or loss of the Fund. Instead, the value adjustment of each investment’s fair value is taken to profit or loss of Fund.

The methods applied by the Fund to measure investments are evident from note 12 to the financial statements

In accordance with the requirements of IFRS 12, certain disclosures must be provided for an investment company's non-consolidated subsidiaries, and the following information is deemed relevant in this respect:

The Fund’s investments are not classified as investment entities under IFRS 10 because they are all engaged in developing or owning infrastructure projects. There are no restrictions on the Fund's right to receive dividend from or have loans etc repaid by the investments, except that distributions from current operating activities of the equity investments must be made allowing for debt servicing by such companies. The Fund has not provided its investments with financial support during the financial year outside the contractual basis.

5. Limited partnership capital

The limited partnership capital has not been divided into classes.

Notes

	2016 DKK'000
6. Other payables	
Other payables	24,833

The carrying amount of payables relates to Investments, legal fees, auditor's fees, travel costs etc. The amount recognised is equal to the fair value of the liabilities.

7. Working capital changes	
Change in receivables	1,622
Change in payables	(24,833)
	(23,212)

8. Financial instruments	
Categories of financial instruments:	
Equity investments	45,618
Financial assets measured at fair value through profit or loss	**45,618**
Other short-term receivables	1,569
Prepayments	53
Receivables at amortised cost	**1,622**
Other payables	24,833
Financial liabilities measured at amortised cost	**24,833**

All financial liabilities are due for payment within 12 months.

Notes

9. Financial risk management

The General Partner is ultimately responsible for the overall risk management within the Fund, but has delegated the responsibility to the Fund Manager.

The Fund pursues an investment strategy approved by the Limited partners and invests in infrastructure projects.

The Fund's risk management processes includes identification, measurement, monitoring, reporting and mitigation of the identified risks to minimize the potential negative effects at fund level.

Key financial risk factors and exposure in regards to the financial statements as of 2016 can be categorised as follows:

Financial Risk Factors

Liquidity risks

	Less than 1 year DKK'000	Between 1 and 5 years DKK'000	After 5 years DKK'000	Total DKK'000
Other payables	24,833	0	0	24,833
31.12.2016	**24,833**	**0**	**0**	**24,833**

The cash position including bank facilities of the Fund is larger than the payables.

The Fund has no guarantees or contingent liabilities.

This liquidity risk is currently related to the limited partners ability to contribute the remaining fund commitment. The liquidity risk is considered highly unlikely to materialise.

Credit risks

The Fund is not exposed to significant credit risk as of 31 December 2016.

Interest rate risk

The Fund has no external debt as of the balance sheet date, and therefore no interest rate risk connected to the liabilities.

Currency risk

The Fund is denominated in DKK. However, all investments, including draw downs and distributions, are made in investment specific currencies. No hedging is made at fund level.

Notes

9. Financial risk management (continued)

Commodity and power prices

The Fund's market price exposure is limited as it is significant mitigated through fixed price agreements, hedges and capital structure protection. However, major changes in certain market prices may to some extent impact certain investments. Though, the overall market price exposure are considered as low.

When the Fund has an market price and/or commodity price exposure changes in such risk factors impact the fair value of the individual investment.

10. Financial instruments measured at fair value

The fair value of the investments are measured on a quarterly basis, or more frequent if significant changes occur.

The Fund Manager has implemented procedures and methodology to ensure that the valuation is carried out consistent over time and across investments.

Methods applied in and assumptions underlying the determination of fair values of investments

The fair value of each equity investment has been estimated by applying methods that best reflect the risks, and the stage of each investment.

In general, the fair value is determined in accordance with IPEV valuation guidelines and accepted valuation techniques, including DCF models, benchmarking or other relevant method.

Fair value hierarchy for financial instruments measured at fair value in the balance sheet

Below, financial instruments measured at fair value are classified using the fair value hierarchy:

- Quoted prices in active markets for identical instruments (Level 1)
- Quoted prices in active markets for similar assets or liabilities or other valuation methods under which all material inputs are based on observable market data (Level 2)
- Valuation techniques under which any material input are not based on observable market data (Level 3)

It is the Fund's policy to incorporate the classification of financial assets (changes/transfers between levels 1 and 3) in the financial statements if their classification changes during the financial year. There have not been any transfers between the levels during the financial year and all investments are classified as Level 3 investments.

Notes

10. Financial instruments measured at fair value (continued)

Material unobservable inputs for Level 3

Financial instruments measured at fair value in the balance sheet are based on valuation techniques that include material unobservable input for instance assumptions related to power prices, inflation rates, technical availability and discount rate. Due to the nature of the investments and that none of the investments are after COD (Commercial Operating Day) end of 2016 only a immaterial part of the valutation requires material unobservable inputs.

2016	Level 1 DKK'000	Level 2 DKK'000	Level 3 DKK'000	Total DKK'000
Unlisted shares, investments in investments	0	0	45,618	45,618
Financial assets measured at fair value through profit or loss	**0**	**0**	**45,618**	**45,618**

Sensitivity analysis

The fair value of the Fund's investments is affected by development in the applied discount rate and future earnings expectations for these investments. A decline or increase in the material unobservable inputs stated above and changes in macroeconomic conditions might have an direct effect on the valuation of the investments. Due to that no investments are after COD no sensitivity analysis have been made.

Please refer to note 4 for a specification of fair value investments.

Notes

11. Related parties

Related parties with a controlling interest

The Limited Partnership has no investors or related parties with a controlling interest.

	2016 DKK'000
Related party transactions	
The General Partner is receiving a fee for its liability towards CI II as per the article of association	
Payment to the General Partner	**0**
Copenhagen Infrastructure Partners II P/S (the Fund Manager) are considered related parties of the Fund due to direct or indirect control and transactions	
Management fee (6 months period)	**569**

12. Contingent liabilities

The Fund has no guarantees or contingent liabilities.

13. Investors

The Limited Partnership has registered the following Limited Partners as holding more than 5% of the voting rights or nominal value of the contributed capital:

Kommunal Landspensjonskasse Gjensidig Forsikringsselskap, Dronning Eufemias Gate 10, 0191 Oslo
European Investment Bank, Boulevard Konrad Adenauer 98-100, L-2950 Luxembourg
PFA Pension, Forsikringsaktieselskab, Sundkrogsgade 4, 2100 Copenhagen
Kapitalforeningen Nykredit Alpha afdeling Alternativer, Otto Mønsteds Plads 9 , 1780 København V
Nordea Liv & Pension, Livsforsikringsselskab A/S, Klausdalsbrovej 615 , 2750 Ballerup
SEB Pensionsforsikring A/S, Bernstorffsgade 50, 1577 København V

Notes

14. Events after the balance sheet date

End of March 2017 CI II announced the Bearkat I investment, an onshore wind farm currently under construction, with a total expected capacity of 197.7 MW located in Glasscock County, Texas.

No other events have occurred after the balance sheet date to this date, which would influence the evaluation of this annual report.

15. Authorisation of the annual report for issue

At the meeting held on , the General Partner authorised this annual report for issue on . The annual report will be submitted to the Limited Partnership's Limited Partners for adoption at the Annual General Meeting on

OCS-A 0501 MASS USA

VINEYARD WIND

Vineyard Wind

Attachment 5.6-9

(CI II US AIV QFPF Annual Report 2016)

Deloitte
Statsautoriseret Revisionspartnerselskab
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CI II US AIV QFPF K/S

Central Business Registration No
37 78 93 72
Nørregade 21
1165 Copenhagen K

Annual report 2016

The Annual General Meeting adopted the annual report on 24.05.2017

Chairman of the General Meeting

_____

Name: Mogens Thorninger

Contents

	Side
Fund details	1
Statement by General Partner on the annual report	2
Independent auditor’s reports	3
Management commentary	6
Statement of comprehensive income	8
Balance sheet at 31 December 2016	9
Statement of changes in equity for 2016	11
Cash flow statement for 2016	12
Note overview	13
Notes	14

Fund details

Fund

CI II US AIV QFPF K/S
Nørregade 21
1165 Copenhagen K

Central Business Registration No: 37 78 93 72
Founded: 13.06.2016
Registered in: Copenhagen
Financial year: 13 June 2016 - 31 December 2016

Telephone: +45 70 70 51 51
Internet: www.cip.dk

General Partner

Copenhagen Infrastructure II GP ApS

Fund Manager

Copenhagen Infrastructure Partners II P/S
Approved Manager of Alternative Investment Funds (FSA number: 23014)

Auditors

Deloitte Statsautoriseret Revisionspartnerselskab
Weidekampsgade 6
2300 Copenhagen S

Statement by General Partner on the annual report

The General Partner has today considered and approved the annual report of CI II US AIV QFPF K/S for the financial year 13 June 2016 – 31 December 2016.

The annual report is presented in accordance with International Financial Reporting Standards as adopted by the EU and disclosure requirements of the Danish Financial Statements Act.

In our opinion, the financial statements give a true and fair view of the Limited Partnership's financial position at 31 December 2016 and of the results of its operations and the cash flows for the financial year 13 June 2016 – 31 December 2016.

We believe that the management commentary contains a fair review of the affairs and conditions referred to therein.

We recommend the annual report for adoption at the Annual General Meeting.

Copenhagen, 10 May 2017

On behalf of Copenhagen Infrastructure II GP ApS

Mogens Thorninger Torben Carlsen

Independent auditor's report

To the shareholders of CI II US AIV QFPF K/S

Opinion

We have audited the financial statements of CI II US AIV QFPF K/S for the financial year 13.06.2016 - 31.12.2016, which comprise the statement of comprehensive income, balance sheet, statement of changes in equity, cash flow statement and notes, including a summary of significant accounting policies. The financial statements are prepared in accordance with International Financial Reporting Standards as adopted by the EU and additional requirements of the Danish Financial Statements Act.

In our opinion, the financial statements give a true and fair view of the Entity's financial position at 31.12.2016 and of the results of its operations for the financial year 13.06.2016 - 31.12.2016 in accordance with International Financial Reporting Standards as adopted by the EU and additional requirements of the Danish Financial Statements Act.

Basis for opinion

We conducted our audit in accordance with International Standards on Auditing (ISAs) and additional requirements applicable in Denmark. Our responsibilities under those standards and requirements are further described in the *Auditor's responsibilities for the audit of the financial statements* section of this auditor's report. We are independent of the Entity in accordance with the International Ethics Standards Board of Accountants' Code of Ethics for Professional Accountants (IESBA Code) and the additional requirements applicable in Denmark, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

General Partner's responsibilities for the financial statements

The General Partner is responsible for the preparation of financial statements that give a true and fair view in accordance with International Financial Reporting Standards as adopted by the EU and additional requirements of the Danish Financial Statements Act, and for such internal control as the General Partner determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, the General Partner is responsible for assessing the Entity's ability to continue as a going concern, for disclosing, as applicable, matters related to going concern, and for using the going concern basis of accounting in preparing the financial statements unless the General Partner either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISAs and the additional requirements applicable in Denmark will always detect a material misstatement

Independent auditor's report

when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit conducted in accordance with ISAs and the additional requirements applicable in Denmark, we exercise professional judgement and maintain professional scepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity’s internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by the General Partner.
- Conclude on the appropriateness of Management’s use of the going concern basis of accounting in preparing the financial statements, and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity’s ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor’s report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor’s report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures in the notes, and whether the financial statements represent the underlying transactions and events in a manner that gives a true and fair view.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Statement on the management commentary

The General Partner is responsible for the management commentary.

Our opinion on the financial statements does not cover the management commentary, and we do not express any form of assurance conclusion thereon.

Independent auditor's report

In connection with our audit of the financial statements, our responsibility is to read the management commentary and, in doing so, consider whether the management commentary is materially inconsistent with the financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated.

Moreover, it is our responsibility to consider whether the management commentary provides the information required under the Danish Financial Statements Act.

Based on the work we have performed, we conclude that the management commentary is in accordance with the financial statements and has been prepared in accordance with the requirements of the Danish Financial Statements Act. We did not identify any material misstatement of the management commentary.

Copenhagen, 10.05.2017

Deloitte
Statsautoriseret Revisionspartnerselskab
Business Registration No 33 96 35 56

Bill Haudal Pedersen	Michael Thorø Larsen
State-Authorised	State-Authorised
Public Accountant	Public Accountant

Management commentary

	2016 DKK'000
Financial highlights	
Key figures	
Profit/loss from ordinary activities (EBIT)	(4,444)
Profit/loss for the year	(587)
Equity	106,521
Balance sheet total	122,730
Ratios	
Solvency ratio (%)	86.79

Primary activity

CI II US AIV QFPF K/S (CI II) was established in June 2016 and is managed by Copenhagen Infrastructure Partners II P/S (CIP). The General Partner of CI II is Copenhagen Infrastructure II GP ApS.

Investments

End of 2016, CI II had not yet made any transactions, which have had financial investment decision.

Development in activities and finances

Income from investments in 2016 (13 June 2016 – 31 December 2016, i.e. 6.5 months) amounts to DKK 2.5 m.

Net Income for 2016 amounts to a loss of DKK 0.6 m, which is in accordance with the expectations. The result reflects income from investments, partly offset by administration costs and transaction costs expensed, during the period.

Limited Partners' paid-in capital to the Fund at the end of 2016 amounted to DKK 107.1m, equalling 18.1% of the committed capital of DKK 592m. Total Limited Partners' capital amounted to DKK106.5m reflecting the Limited Partners' paid-in capital plus accumulated net loss since Fund initiation.

Management commentary (continued)

Uncertainty relating to recognition and measurement

CI II develops and invests in infrastructure projects structured to provide stable cash flows, but where transferability and cash flows to a certain extend still may be affected by changes in market conditions. Consequently, the fair value of the investments is based on estimates and a number of assumptions made by the General Partner on the balance sheet date.

Information according to the Alternative Investment Fund Managers Directive

According to Article 22 of the Alternative Investment Fund Managers Directive, Alternative Investment Funds (AIF) must make certain disclosures to investors in connection with the presentation of financial statements.

During the financial period covered by the financial statements, there have been no significant changes in the matters below:

- The Fund’s Investment strategy;
- Valuation principles of the Fund’s investments;
- New arrangements for managig the Fund’s liquidity;
- The Fund's risk profile and the risk management systems implemented by the Fund Manager used to manage the Fund's risks;
- There have been no amendments to the maximum level of leverage which the Fund Manager can use on behalf of the Fund. Nor has there been any changes in the right to use collateral or any guarantee accordance with the agreement allowing for the leverage.

Events after the balance sheet date

End of March 2017 CI II announced the Bearkat I investment, an onshore wind farm with a total expected capacity of 197.7 MW located in Glasscock County, Texas. The construction have now commenced.

No other events have occurred after the balance sheet date to this date which would influence the evaluation of this annual report.

Outlook

The outlook for the Limited Partnership is expected to be positive.

The number of investments is expected to increase during 2017.

Statement of comprehensive income

	Notes	2016 DKK'000
Net foreign currency gains		2,546
Operating income		**2,546**
Administrative expenses	3	(4,444)
Total operating expenses		**(4,444)**
Operating loss (EBIT)		**(1,898)**
Financial items		1,312
Loss for the year		**(587)**
Other comprehensive income		**0**
Comprehensive income		**(587)**

Balance sheet at 31 December 2016

	Notes	2016 DKK'000
Equity investments	4	99,030
Investments		**99,030**
Fixed assets		**99,030**
Other short-term receivables		33
Prepayments		115
Receivables		**148**
Cash		**23,552**
Current assets		**23,700**
Assets		**122,730**

Balance sheet at 31 December 2016

	Notes	2016 DKK'000
Limited partnership capital	5	107,108
Retained earnings		(587)
Equity		**106,521**
Other payables	6	16,209
Current laibilities other than provisions		**16,209**
Liabilities other than provisions		**16,209**
Equity and liabilities		**122,730**

Statement of changes in equity for 2016

	Limited partnership capital DKK'000	Retained earnings DKK'000	Total DKK'000
Contribution from limited partners	107,108		107,108
Loss for the year		(587)	(587)
Equity end of year	**107,108**	**(587)**	**106,521**

Cash flow statement for 2016

	Notes	2016 DKK'000
Operating loss		(4,444)
Income from investments		(2.546)
Working capital changes	7	16,061
Cash flows from ordinary activities		**11,617**
Financial items		1,312
Cash flows from operating activities		**1,312**
Acquisition of equity investments	4	(96,484)
Cash flows from investing activities		**(96,484)**
Contribution from Limited Partners		107,108
Cash flows from financing activities		**107,108**
Increase/decrease in cash		**23,552**
Cash beginning of year		-
Cash end of year		**23,552**

Note overview

1.	Accounting policies	14
2.	Significant accounting estimates, assumptions and uncertainties	19
3.	Administrative expenses	19
4.	Investments	20
5.	Limited partnership capital	21
6.	Other payables	22
7.	Working capital changes	22
8.	Financial instruments	22
9.	Financial risk management	23
10.	Financial instruments measured at fair value	24
11.	Related parties	26
12.	Contingent liabilities	26
13.	Investors	26
14.	Events after the balance sheet date	27
15.	Authorisation of the annual report for issue	27

Notes

1. Accounting policies

Reporting class

The financial statements are prepared in accordance with International Financial Reporting Standards (IFRS) as adopted by the EU and disclosure requirements of the Danish Financial Statements Act.

CI II US AIV QFPF K/S is a Limited Partnership based in Denmark.

This is the Fund's first financial year and comprise the period 13 June 2016 – 31 December 2016, and hence no comparetiv figures have been presented.

The financial statements are presented in Danish kroner (DKK), which is the functional currency of the Fund.

The financial statements are presented on the basis of historical cost, except for the equity investments, which are measured at fair value. Historical cost is based on the fair value of the consideration given in exchange for assets.

Judgements made by the General Partner in the application of IFRSs that have had significant effects on the financial statements are disclosed, where applicable, in the relevant notes to the financial statements.

The principal accounting policies are set out overleaf.

Report on the omission of preparation of consolidated financial statements

CI II US AIV QFPF K/S has omitted to prepare consolidated financial statements under the provisions of IFRS 10 and IAS 27 as the Limited Partnership qualifies as an investment entity. The definition is as follows:

"An investment entity is defined as an entity which commits to its investors that its business purpose is to invest funds solely for returns from capital appreciation, investment income, or both".

In view of the circumstances described below, the General Partner believes that the Fund satisfies the definition of an investment entity:

1) The Fund has more than one investment.
2) The Fund has more than one investor, and its investors are not related parties. Please refer to the description in note 13 to the financial statements.
3) The Fund's investments in investments take the form of equity instruments or similar investments, and the Fund can also exit the investment, if relevant.

Notes

1. Accounting policies (continued)

Standards and Interpretations not yet in force

All the new and amended Standards and Interpretations which are relevant to the Fund and which came into force with effect for financial years beginning 1 January 2016 have been applied when preparing the financial statements.

At the date of the issue of these financial statements, a number of new or amended Standards and Inter-pretations, including IFRS 9 in particular, have not yet entered into force. The General Partner believes that they will not impact significantly on the financial statements for the coming financial years.

Significant accounting policies and estimates

As part of the preparation of the financial statements, the General Partner makes a number of accounting judgements which form the basis of presentation, recognition and measurement of the Fund's assets and liabilities. The most significant accounting judgements are evident from note 2 to the financial statements.

Recognition and measurement

Assets are recognised in the balance sheet when it is probable as a result of a prior event that future economic benefits will flow to the Fund, and the value of the asset can be measured reliably. Assets are derecognised in the balance sheet when it is no longer probable that future economic benefits will flow to the Fund.

Purchase and sale of financial assets and liabilities are recognised in the balance sheet at the commitment date.

Liabilities are recognised in the balance sheet when the Fund has a legal or constructive obligation as a result of an event before or on the balance sheet date, and it is probable that future economic benefits will flow out of the Fund, and the value of the liability can be measured reliably. Liabilities are derecognised in the balance sheet when it is no longer probable that economic benefits will have to be given up to settle the liability.

On initial recognition, assets and liabilities are measured at cost, however, investment assets are measured at fair value on initial recognition, typically equalling cost exclusive of directly incurred expenses (direct transaction costs). Measurement subsequent to initial recognition is effected as described below for each financial statement item. Allowance is made for events occurring from the balance sheet date to the date of presentation of the annual report, and which confirm or invalidate affairs and conditions existing at the balance sheet date.

Income is recognised in the statement of comprehensive income when earned, whereas costs are recognised by the amounts attributable to this financial year.

Notes

1. Accounting policies (continued)

Foreign currency translation

Items included in the financial statemens of the Fund are measured in the curreny of the primary economic environment in which the Fund operates (the "functional currency"). The financial statements of the Fund are presented in the currency unit (DKK, Danish kroner), which is the Fund's functional and presentation currency.

On initial recognition, foreign currency transactions are translated applying the exchange rate at the transaction date. Receivables, payables and other monetary items denominated in foreign currencies that have not been settled at the balance sheet date are translated using the exchange rate at the balance sheet date. Exchange differences that arise between the rate at the transaction date and the one in effect at the payment date or the rate at the balance sheet date are recognised in the income statement as financial income or financial expenses.

Statement of comprehensive income

Revenue recognition

Dividend income is recognised when the Fund's rights to receive the payments have been established, normally being the ex-dividend date.

Income from investments

Income from investments consists of unrealised fair value adjustments

Administrative expenses

All expenses are recognised in the statement of comprehensive income on the accrual basis.

Administrative expenses comprise expenses incurred during the financial year not directly related to the Fund's investment activities.

General due diligence costs and general administration etc including management fees have been expensed by the amounts attributable to this financial year, whereas certain development costs have been capitalised in order to increase the value of the equity investments.

Financial income and expenses

Financial income and expenses comprise interest income and various expenses, and net capital gain/loss on transactions in foreign currencies.

Interest income and interest expenses are stated on an accruals basis using the principal interest rate.

Income taxes

Under current Danish law governing the Fund, it is not independently taxable because the Fund's profit/loss for the year is included in the Limited Partner's taxable income.

Notes

1. Accounting policies (continued)

Balance sheet

Investments

Financial assets and liabilities are recognised at fair value through profit and loss when the Fund becomes party to the contractual provisions of the instrument. Recognition takes place on the trading day when the Fund purchases or sells an investment under a contract whose terms require delivery of the investment within the time frame established by the market.

On initial recognition, equity investments are measured at fair value.

Financial assets and liablitities are derecognised when the contractual rights to the cash flows from the investments have expired or the Fund has transferred substantially all risks and rewards of ownership.

Investments consist of equity investments in infrastructure companies (projects) and are measured, on initial recognition, at fair value, and subsequently measured at fair value with recognition of fair value adjustments through profit or loss.

The fair value is calculated equivalent to an estimated fair value that is determined based on market information, IPEV valuation guidelines and accepted valuation techniques, including benchmarking, DCF or other relevant method, which is considered to provide the best estimate of the fair value.

For further information about the measurement of fair values, please refer to note 10.

Other short-term receivables

Receivables are measured at amortised cost, usually equalling nominal value less write-downs for bad and doubtful debts.

Cash

Cash comprise cash in bank deposits.

Other financial liabilities

Other financial liabilities are measured at amortised cost, which usually corresponds to nominal value.

Notes

1. Accounting policies (continued)

Cash flow statement

The cash flow statement of the Fund is presented using the indirect method and shows cash flows from operating, investing and financing activities as well as the Fund's cash equivalents at the beginning and the end of the financial year.

Cash flows from operating activities are calculated as the operating profit/loss adjusted for non-cash operating items and working capital changes.

Cash flows from investing activities comprise payments in connection with acquisition and divestment of investments.

Cash flows from financing activities comprise changes in the size or composition of the contributed capital and related costs as well as the raising of loans, instalments on interest-bearing debt, and payment of dividend.

Cash comprise cash and short-term securities with an insignificant price risk less short-term bank debt.

Financial highlights

Financial highlights are defined and calculated in accordance with "Recommendations & Ratios 2015" issued by the Danish Society of Financial Analysts.

Ratios		Calculation formula	Ratios reflect
Solvency ratio (%)	=	$\frac{\text{Equity x 100}}{\text{Total assets}}$	The enterprise's financial strength.

Notes

2. Significant accounting estimates, assumptions and uncertainties

The Fund develops and invests in infrastructure assets (unlisted equity investments), the market price of which depends both on entity-specific affairs and market conditions, including to a certain extent power prices, commodity prices, exchange rates and construction risk within the different investments. The valuation and hence fair value of equity investments may also be affected by changes in the risk-free interest rate other than the general cost of risk in the market As a result, income from investments, including the unrealised value adjustments and the fair value of investments are subject to estimation and uncertainty.

The methods applied in and the assumptions underlying the determination of the fair value in unlisted equity investments are described in note 10 to the financial statements.

3. Administrative expenses

The Fund has no employees.

According to Article 107 of the AIFM Directive, alternative investment funds must disclose information about the total remuneration of the entire staff of the Fund Manager and the number of beneficiaries. Furthermore, remuneration to material risk-takers must be disclosed. For information about remuneration, please refer to the annual report of the Fund Manager.

The Fund Manager must also disclose the information necessary to provide an understanding of the risk profile of the Fund and the measures that the Fund Manager takes to avoid or manage conflicts of interest between the Fund Manager and the Limited Partners. The Board of Directors has adopted a remuneration policy in order to ensure that the employees and Management are remunerated according to the Danish Executive Order on remuneration policy and disclosure requirements on remuneration for managers of alternative investment funds, etc.

Notes

3. Administrative expenses (continued)

The remuneration policy ensures, among other matters, that the following is applied in relation to remuneration at the Fund Manager:

- Promoting of sound and effective risk management, which does not encourage excessive risk-taking.
- Consistency with the principles regarding the protection of the Limited Partners and measures in order to avoid conflicts of interest.

Currently, the Fund Manager serves as fund manager for Copenhagen Infrastructure II K/S, CI II US AIV Non-QFPF K/S and CI II US AIV QFPF K/S.

No carried interest is paid out by the AIF during the financial period.

	Development projects DKK'000	**Equity investments DKK'000**
4. Investments		
Fair value 13.06.2016	-	-
Acquisition and development costs	57.319	39,165
Fair value adjustment	-	2,546
Fair value 31.12.2016	**57,319**	**41,711**

Projects are considered as development projects until final investment decision is made, and is comprising costs related to project rights, the design and development of the infrastructure investments.

Notes

5. Investments (continued)

Investment	Corporate form	Registered in	Equity interest %
Offshore Wind	LLC	United States	100
CI-II Bearkat QFPF	LLC	United States	100
CI-II Bearkat II QFPF	LLC	United States	100
CI-II Blue Cloud QFPF	LLC	United States	100
CI-II Mitchell QFPF	LLC	United States	100
CI II Fluvanna QFPF	LLC	United States	100
CI-II Bearkat III QFPF	LLC	United States	100

Consistently with the accounting policies, the Fund regularly adjusts the value of the investments to best estimate of fair value. This means that the proportionate share of profit or loss of the investments is not recognised in profit or loss of the Fund. Instead, the value adjustment of each investment’s fair value is taken to profit or loss of Fund.

The methods applied by the Fund to measure investments are evident from note 10 to the financial statements.

In accordance with the requirements of IFRS 12, certain disclosures must be provided for an investment company's non-consolidated subsidiaries, and the following information is deemed relevant in this respect:

The Fund’s investments are not classified as investment entities under IFRS 10 because they are all engaged in developing or owning infrastructure projects. There are no restrictions on the Fund's right to receive dividend from or have loans etc repaid by the investments, except that distributions from current operating activities of the equity investments must be made allowing for debt servicing by such companies. The Fund has not provided its investments with financial support during the financial year outside the contractual basis.

5. Limited partnership capital

The limited partnership capital has not been divided into classes.

Notes

	2016 DKK'000

6. Other payables

Other payables	16,209

The carrying amount of payables relates to Investments, legal fees, auditor's fees, travel costs etc. The amount recognised is equal to the fair value of the liabilities.

7. Working capital changes

Change in receivables	148
Change in payables	(16,209)
	(16,061)

8. Financial instruments

Categories of financial instruments:

Equity investments	99,030
Financial assets measured at fair value through profit or loss	**99,030**
Other short-term receivables	33
Prepayments	115
Receivables measured at amortised cost	**148**
Other payables	16,209
Financial liabilities measured at amortised cost	**16,209**

All financial liabilities are due for payment within 12 months.

Notes

9. Financial risk management

The General Partner is ultimately responsible for the overall risk management within the Fund, but has delegated the responsibility to the Fund Manager.

The Fund pursues an investment strategy approved by the Limited partners and invests in infrastructure projects.

The Fund's risk management processes includes identification, measurement, monitoring, reporting and mitigation of the identified risks to minimize the potential negative effects at fund level.

Key financial risk factors and exposure in regards to the financial statements as of 2016 can be categorised as follows:

Financial Risk Factors

Liquidity risks

	Less than 1 year DKK'000	Between 1 and 5 years DKK'000	After 5 years DKK'000	Total DKK'000
Other payables	16,209	0	0	16,209
31.12.2016	**16,209**	**0**	**0**	**16,209**

The cash position including bank facilities of the Fund is bigger than the payables.

The Fund has no guarantees or contingent liabilities.

This liquidity risk is currently related to the limited partners ability to contribute the remaining fund commitment. The liquidity risk is considered highly unlikely to materialise.

Credit risks

The Fund is not exposed to any significant credit risk as of 31 December 2016.

Interest rate risk

The Fund has no external debt as of the balance sheet date, and therefore no interest rate risk connected to the liabilities.

Currency risk

The Fund is denominated in DKK. However, all investments, including draw downs and distributions, are made in investment specific currencies. No hedging is made at fund level.

Notes

9. Financial risk management (continued)

Commodity and power prices

The Fund's market price exposure is limited as it is significant mitigated through fixed price agreements, hedges and capital structure protection. However, major changes in certain market prices may to some extent impact certain investments. Though, the overall market price exposure are considered as low.

When the Fund has an market price and/or commodity price exposure changes in such risk factors impact the fair value of the individual investment.

10. Financial instruments measured at fair value

The fair value of the investments are measured on a quarterly basis, or more frequent if significant changes occur.

The Fund Manager has implemented procedures and methodology to ensure that the valuation is carried out consistent over time and across investments.

Methods applied in and assumptions underlying the determination of fair values of investments

The fair value of each equity investment has been estimated by applying methods that best reflect the risks, and the stage of each investment.

In general, the fair value is determined in accordance with IPEV valuation guidelines and accepted valuation techniques, including DCF models, benchmarking or other relevant method.

Fair value hierarchy for financial instruments measured at fair value in the balance sheet

Below, financial instruments measured at fair value are classified using the fair value hierarchy:

- Quoted prices in active markets for identical instruments (Level 1)
- Quoted prices in active markets for similar assets or liabilities or other valuation methods under which all material inputs are based on observable market data (Level 2)
- Valuation techniques under which any material input are not based on observable market data (Level 3)

It is the Fund's policy to incorporate the classification of financial assets (changes/transfers between levels 1 and 3) in the financial statements if their classification changes during the financial year. There have not been any transfers between the levels during the financial year and all investments are classified as Level 3 investments.

Notes

10. Financial instruments measured at fair value (continued)

Material unobservable inputs for Level 3

Financial instruments measured at fair value in the balance sheet are based on valuation techniques that include material unobservable input for instance assumptions related to power prices, inflation rates, technical availability and discount rate. Due to the nature of the investments and that none of the investments are after COD (Commercial Operating Day) end of 2016 only a immaterial part of the valutation requires material unobservable inputs.

2016	Level 1 DKK'000	Level 2 DKK'000	Level 3 DKK'000	Total DKK'000
Equity investments	0	0	99,030	99,030
Financial assets measured at fair value through profit or loss	**0**	**0**	**99,030**	**99,030**

Sensitivity analysis

The fair value of the Fund's investments is affected by development in the applied discount rate and future earnings expectations for these investments. A decline or increase in the material unobservable inputs stated above and changes in macroeconomic conditions might have an direct effect on the valuation of the investments. Due to that no investments are after COD no sensitivity analysis have been made.

Please refer to note 4 for a specification of fair value investments.

Notes

11. Related parties

Related parties with a controlling interest

The Limited Partnership has no investors or related parties with a controlling interest.

	2016 DKK'000
Related party transactions	
The General Partner is receiving a fee for its liability towards CI II as per the article of association	
Payment to the General Partner	**0**
Copenhagen Infrastructure Partners II P/S (the Fund Manager) are considered related parties of the Fund due to direct or indirect control and transactions	
Management fee (6 months period)	**4,123**

There are no other key relationships, which are considered material for the financial statements.

12. Contingent liabilities

The Fund has no guarantees or contingent liabilities.

13. Investors

The Limited Partnership has registered the following Limited Partners as holding more than 5% of the voting rights or nominal value of the contributed capital:

PensionDanmark Pensionsforsikringsaktieselskab, Langelinie Allé 43, 2100 Copenhagen
Lægernes Pensionskasse, Dirch Passers Allé 76, 2000 Frederiksberg
Pensionskassen for Børne- og Ungdomspædagoger, Østerfælled Torv 3, 2100 Copenhagen
Juristernes og Økonomernes Pensionskasse, Dirch Passers Allé 76, 2000 Frederiksberg
Lærernes Pension, Forsikringsaktieselskab, Tuborg Boulevard 3, 2900 Hellerup
Danske Civil- og Akademiingeniørers Pensions-kasse, Dirch Passers Allé 76, 2000 Frederiksberg

Notes

14. Events after the balance sheet date

End of March 2017 CI II announced the Bearkat I investment, an onshore wind farm currently under construction, with a total expected capacity of 197.7 MW located in Glasscock County, Texas.

No other events have occurred after the balance sheet date to this date, which would influence the evaluation of this annual report.

15. Authorisation of the annual report for issue

At the meeting held on , the General Partner authorised this annual report for issue . The annual report will be submitted to the Limited Partnership's Limited Partners for adoption at the Annual General Meeting on

OCS-A 0501 MASS USA

VINEYARD WIND

Vineyard Wind

Attachment 5.10-1

CCA Letter Confirming T/E Treatment

CCAGroup

December 15, 2017

Lars T. Pedersen
Vineyard Wind LLC
700 Pleasant Street, Suite 510
New Bedford, MA 02740

Re: Vineyard Wind Project

Dear Mr. Pedersen:

CCA is a leading advisor in the renewable energy sector and the preeminent tax equity advisor in the wind sector. Since March 2006, CCA and its affiliates have advised the sponsor or tax equity investor in connection with the financing of over 100 wind energy projects in 19 states and the Commonwealth of Puerto Rico representing over 15,000 MW of nameplate capacity. We have also represented sponsors or tax equity investors in connection with the financing of over $5.0 billion of domestic utility scale and distributed generation solar projects. CCA and its affiliates provide advisory services to some of the most prominent sponsors of, institutional tax equity investors in and debt providers to, renewable energy projects in the United States.

CCA is writing this letter in connection with the approximately 400 MW off-shore wind project (the "***Project***") that Vineyard Wind LLC ("***Vineyard Wind***") is developing 15 miles south of Martha's Vineyard, Massachusetts. We are familiar with the Vineyard Wind team and their development and financing capabilities. We have reviewed and participated in the development of the Project's financial proforma, financing structure and associated financing timeline. We believe the Project has the ability to obtain tax equity financing consistent with the structure and underlying assumptions incorporated in Vineyard Wind's financial proforma. We also believe that the assumed financing timeline is both achievable and appropriate given the Project's projected commercial operation date.

This letter is for discussion purposes only and is not an offer of financing or any commitment on our part, nor is intended to be legally binding and shall not be relied on by any persons without the express written consent of CCA Group, LLC.

CCA looks forward to continuing our discussions with respect to the financing of the Project. Please do not hesitate to contact me should you have any questions.

Very truly yours,

Martin J. Pasqualini
Managing Director

ONE BOSTON PLACE SUITE 3825 BOSTON, MA 02108 PH: 617.570.2300 FAX: 617.570.2350

OCS-A 0501 MASS USA

VINEYARD WIND

Vineyard Wind

Attachment 5.15-1

Avangrid Renewables Affiliate Companies

AVANGRID, Inc. and subsidiaries

1. Aeolus Wind Power II, LLC
2. Aeolus Wind Power III, LLC
3. Aeolus Wind Power IV, LLC
4. Atlantic Renewable Energy Corporation
5. Atlantic Renewable Projects II, LLC
6. Atlantic Renewable Projects, LLC
7. Atlantic Wind, LLC
8. Aurora Solar, LLC
9. Avangrid Arizona Renewables, LLC
10. Avangrid Enterprises, Inc.
11. Avangrid, Inc.
12. Avangrid Logistic Services, LLC
13. Avangrid Management Company, LLC
14. Avangrid Networks, Inc.
15. Avangrid New York Transco, LLC
16. Avangrid Renewables Holdings, Inc.
17. Avangrid Renewables, LLC
18. Avangrid Service Company
19. Avangrid Solutions, Inc.
20. Avangrid Texas Renewables, LLC
21. Avangrid Vineyard Wind, LLC
22. Bakeoven Wind, LLC
23. Barton Windpower, LLC
24. Berkshire Energy Resources, Inc.
25. Big Horn II Wind Project, LLC
26. Big Horn Wind Project, LLC
27. Blue Creek Wind Farm, LLC
28. Buffalo Ridge I, LLC
29. Bufallo Ridge II, LLC
30. Buffalo Ridge III, LLC
31. Caledonia Energy Partners, LLC
32. Casselman Windpower, LLC
33. Cayuga Energy, Inc.
34. Central Maine Power Company
35. Chester SVC Partnership
36. CMP Group, Inc.
37. CNE Energy Services Group, LLC
38. CNE Peaking, LLC
39. Colorado Green Holdings, LLC
40. Colorado Wind Ventures, LLC
41. Connecticut Energy Corporation

42. Connecticut Natural Gas Corporation
43. Connecticut Yankee Atomic Power Company
44. CTG Resources, Inc.
45. Deerfield Wind, LLC
46. Desert Wind Farm, LLC
47. Dillon Wind, LLC
48. El Cabo Wind Holdings, LLC
49. El Cabo Wind, LLC
50. El Cabo Partners, LLC
51. Elk River Windfarm, LLC
52. Elm Creek Wind II, LLC
53. Elm Creek Wind, LLC
54. Enstor Energy Services, LLC
55. Enstor Gas, LLC
56. Enstor Grama Ridge Storage and Transportation, LLC
57. Enstor Houston Hub Storage and Transportation, L.P.
58. Enstor Katy Storage and Transportation, L.P.
59. Enstor Louisiana, LLC
60. Enstor Operating Company, LLC
61. Enstor Sundance Storage and Transportation, LLC
62. Enstor Waha Storage and Transportation, L.P.
63. Enstor, Inc.
64. E.O. Resources, LLC
65. Farmers City Wind, LLC
66. Flat Rock Windpower II, LLC
67. Flat Rock Windpower, LLC
68. Flying Cloud Power Partners, LLC
69. Freebird Assets Inc.
70. Freebird Gas Storage, LLC
71. GCE Holding, LLC
72. Gemini Capital, LLC
73. GenCon Devon, LLC
74. GenConn Energy, LLC
75. GenConn Middletown, LLC
76. Goodland Wind, LLC
77. Groton Wind, LLC
78. Hardscrabble Wind Power, LLC
79. Hay Canyon Wind, LLC
80. Hazelwood Australia, Inc. (in process of liquidation)
81. Hazelwood Ventures, Inc. (in process of liquidation)
82. Heartland Wind, LLC
83. Helix Wind Power Facility, LLC
84. Juniper Canyon Wind Power II, LLC
85. Juniper Canyon Wind Power, LLC
86. Klamath Energy, LLC
87. Klamath Generation, LLC

88. Klondike Wind Power II, LLC
89. Klondike Wind Power III, LLC
90. Klondike Wind Power, LLC
91. Lakeview Cogeneration LLC
92. Leaning Juniper Wind Power II, LLC
93. Leipsic Wind, LLC
94. Lempster Wind, LLC
95. Locust Ridge II, LLC
96. Locust Ridge Wind Farm, LLC
97. Loma Vista, LLC
98. Maine Electric Power Company, Inc.
99. Maine Natural Gas Corporation
100. Maine Yankee Atomic Power Company
101. MaineCom Services
102. Manzana Power Services, Inc.
103. Manzana Wind, LLC
104. Midland Wind, LLC
105. Minndakota Wind LLC
106. Montague Wind Power Facility, LLC
107. Moraine Wind II, LLC
108. Moraine Wind, LLC
109. Mount Pleasant Wind, LLC
110. Mountain View Power Partners III, LLC
111. New England Wind, LLC
112. New York State Electric & Gas Corporation
113. New Harvest Wind Project, LLC
114. New York Transco, LLC
115. Northern Iowa Windpower II, LLC
116. NORVARCO
117. Nth Power Technologies Fund I, L.P.
118. Otter Creek Wind Farm, LLC
119. Pacific Harbor Capital, Inc.
120. Pacific Solar Investments, Inc.
121. Pacific Wind Development, LLC
122. Pebble Springs Wind, LLC
123. Phoenix Wind Power, LLC
124. PPM Colorado Wind Ventures, Inc.
125. PPM Roaring Brook, LLC
126. PPM Technical Services, Inc.
127. PPM Wind Energy, LLC
128. Providence Heights Wind, LLC
129. RGS Energy Group, Inc.
130. Rochester Gas and Electric Corporation
131. Rugby Wind, LLC
132. San Luis Solar, LLC
133. Scotishpower Hazelwood Ptw, Ltd.

134. Scottish Power Financial Services, Inc. (in process of liquidation)
135. Scottish Power Group Holdings Company
136. ScottishPower International Group Holdings Company (in process of liquidation)
137. Shiloh I Wind Project, LLC
138. South Chestnut, LLC
139. South Glens Falls Energy, LLC
140. Star Point Wind Project, LLC
141. Streator Deer Run Wind Farm, LLC
142. Streator-Cayuga Ridge Wind Power, LLC
143. TEN Transmission Company
144. The Berkshire Gas Company
145. The Southern Connecticut Gas Company
146. The Union Water-Power Company
147. The United Illuminating Company
148. Thermal Energies, Inc.
149. Total Peaking Services, LLC
150. Trimont Wind I, LLC
151. Tule Wind, LLC
152. Twin Buttes Wind II, LLC
153. Twin Buttes Wind, LLC
154. UIL Distributed Resources, LLC
155. UIL Group, LLC
156. UIL Holdings Corporation
157. United Capital Investments, Inc.
158. United Resources, Inc.
159. Vineyard Wind, LLC
160. Wy'East Solar, LLC
161. West Valley Leasing Company, LLC
162. WGP Acquisition, LLC
163. Winnebago Windpower II, LLC
164. Winnebago Windpower, LLC
165. Xcel Services, Inc.
166. Xcelcom, Inc.
167. Yankee Atomic Electric Company

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OCS-A 0501 MASS USA

VINEYARD WIND

Vineyard Wind

Attachment 5.15-2

Iberdrola S.A.'s Subsidiary Companies

Iberdrola, S.A. group companies, jointly controlled companies and associated companies of the Iberdrola, S.A. group (not including AVANGRID, Inc. and its subsidiaries)

DEREGULATED BUSINESS

Spain and Portugal

Cobane, A.I.E.	Spain
Cogeneración Gequisa, S.A.	Spain
Enercrisa, S.A.	Spain
Energía Portátil Cogeneración, S.A.	Spain
Energyworks Aranda, S.L.	Spain
Energyworks Carballo, S.L.	Spain
Energyworks Cartagena, S.L.	Spain
Energyworks Fonz, S.L.	Spain
Energyworks Milagros, S.L.	Spain
Energyworks Monzón, S.L.	Spain
Energyworks San Millán, S.L.	Spain
Energyworks Villarrobledo, S.L.	Spain
Energyworks Vit-Vall, S.L.	Spain
Fudepor, S.L.	Spain
Fuerzas Eléctricas de Navarra, S.A.	Spain
Hidroeléctrica Ibérica, S.L.U.	Spain
Iberdrola Clientes, S.A.U.	Spain
Iberdrola Cogeneración, S.L.U.	Spain
Iberdrola Comercialización de Último Recurso, S.A.U.	Spain
Iberdrola Generación España, S.A.U.	Spain
Iberdrola Generación Nuclear, S.A.U.	Spain
Iberdrola Generación, S.A.U.	Spain
Iberdrola Operación y Mantenimiento, S.A.U.	Spain
Iberdrola Servicios Energéticos, S.A.U.	Spain
Iberduero, S.L.U.	Spain
Intermalta Energía, S.A.	Spain
Nuclenor, S.A.	Spain
Peninsular Cogeneración, S.A.	Spain
Productos y Servicios de Confort, S.A.	Spain
S.E.D.A. Cogeneración, S.A.	Spain
Subgrupo Tirme	Spain
Tarragona Power, S.L.U.	Spain
Tecnatom, S.A. (5)	Spain
Iberdrola Clientes Portugal, Unipessoal Ltda.	Portugal

United Kingdom

Manweb Energy Consultants, Ltd.	United Kingdom
Scotash, Ltd.	United Kingdom
Scottish Power Generation Holdings Ltd.	United Kingdom
ScottishPower (DCL), Ltd.	United Kingdom
ScottishPower (DCOL), Ltd.	United Kingdom
ScottishPower (SCPL), Ltd.	United Kingdom
ScottishPower Energy Management (Agency), Ltd.	United Kingdom
ScottishPower Energy Management, Ltd.	United Kingdom
ScottishPower Energy Retail, Ltd.	United Kingdom
ScottishPower Generation, Ltd.	United Kingdom

SMW, Ltd.	United Kingdom
SP Dataserve, Ltd.	United Kingdom
SP Gas Transportation Cockenzie, Ltd.	United Kingdom
SP Gas Transportation Hatfield, Ltd.	United Kingdom
SP Smart Meter Assets, Ltd.	United Kingdom

Rest of Europe

Iberdrola Energie Deutschland, GmbH.	Germany
Iberdrola Energie France, S.A.S.	France
Iberdrola Clienti Italia, S.R.L. (previously Iberdrola Energía Italia, S.R.L.)	Italy

Mexico

Hidrola I, S.L.U.	Spain
Cinergy, S.R.L. de C.V.	Mexico
Electricidad de Veracruz, S.A. de C.V.	Mexico
Enertek, S.A. de C.V.	Mexico
Iberdrola Clientes, S.A. de C.V.	Mexico
Iberdrola Cogeneración Altamira, S.A. de C.V.	Mexico
Iberdrola Cogeneración Bajío, S.A. de C.V.	Mexico
Iberdrola Cogeneración Ramos, S.A. de C.V.	Mexico
Iberdrola Energía Altamira de Servicios, S.A. de C.V.	Mexico
Iberdrola Energía Altamira, S.A. de C.V.	Mexico
Iberdrola Energía Baja California, S.A. de C.V.	Mexico
Iberdrola Energía del Golfo, S.A. de C.V.	Mexico
Iberdrola Energía Escobedo, S.A. de C.V.	Mexico
Iberdrola Energía La Laguna, S.A. de C.V.	Mexico
Iberdrola Energía Monterrey, S.A. de C.V.	Mexico
Iberdrola Energía Norte, S.A. de C.V.	Mexico
Iberdrola Energía Noroeste, S.A. de C.V.	Mexico
Iberdrola Energía Tamazunchale, S.A. de C.V.	Mexico
Iberdrola Generación, S.A. de C.V.	Mexico
Iberdrola Generación Mexico, S.A. de C.V.	Mexico
Iberdrola Mexico, S.A. de C.V.	Mexico
Iberdrola Servicios Corporativos, S.A. de C.V.	Mexico
Servicios Administrativos Tamazunchale, S.A. de C.V.	Mexico
Servicios de Operación La Laguna, S.A. de C.V.	Mexico
Servicios Industriales y Administrativos del Noreste, S.R.L. de C.V.	Mexico
Iberdrola Energia Topolobampo, S.A. de C.V.	Mexico

United States and Canada

Iberdrola Canadá Energy Services, Ltd.	Canada

RENEWABLE BUSINESS

Spain

Anselmo León Hidráulica, S.L.	Spain
Biocantaber, S.L.	Spain
Bionor Eólica, S.A.	Spain
Biovent Energía, S.A.	Spain
Cantaber Generación Eólica, S.L.	Spain
Ciener, S.A.U.	Spain
Desarrollo de Energías Renovables de La Rioja, S.A.	Spain
Ecobarcial, S.A.	Spain
Electra de Malvana, S.A.	Spain
Electra Sierra de los Castillos, S.L.	Spain

Electra Sierra de San Pedro, S.A.	Spain
Eléctricas de la Alcarria, S.L.	Spain
Eme Hueneja Cuatro, S.L.	Spain
Energía de Castilla y León, S.A.	Spain
Energías Ecológicas de Tenerife, S.A.	Spain
Energías Eólicas de Cuenca, S.A.U.	Spain
Energías Renovables de la Región de Murcia, S.A.U.	Spain
Eólica Campollano, S.A.	Spain
Eólica 2000, S.L.	Spain
Eólicas de Euskadi, S.A.U.	Spain
Iberdrola Energía Solar de Puertollano, S.A.	Spain
Iberdrola Renewables Solutions, S.A.U.	Spain
Iberdrola Renovables Galicia, S.A.U.	Spain
Iberdrola Renovables Andalucía, S.A.U.	Spain
Iberdrola Renovables Aragón, S.A.U.	Spain
Iberdrola Renovables Canarias, S.A.U.	Spain
Iberdrola Renovables Castilla – La Mancha, S.A.U.	Spain
Iberdrola Renovables Castilla y León, S.A.	Spain
Iberdrola Renovables Energía, S.A.U.	Spain
Iberdrola Renovables La Rioja, S.A.	Spain
Iberenova Promociones, S.A.U.	Spain
Iberjalón, S.A.	Spain
Minicentrales del Tajo, S.A.	Spain
Molinos de La Rioja, S.A.	Spain
Molinos del Cidacos, S.A.	Spain
Parque Eólico Cruz del Carrutero, S.L.	Spain
Peache Energías Renovables, S.A.	Spain
Producciones Energéticas Asturianas, S.L.	Spain
Producciones Energéticas de Castilla y León, S.A.	Spain
Renovables de la Ribera, S.L.	Spain
Sistemas Energéticos Altamira, S.A.U.	Spain
Sistemas Energéticos Chandrexa, S.A.	Spain
Sistemas Energéticos del Moncayo, S.A.	Spain
Sistemas Energéticos La Gomera, S.A.U.	Spain
Sistemas Energéticos La Higuera, S.A.	Spain
Sistemas Energéticos de la Linera, S.A.U.	Spain
Sistemas Energéticos La Muela, S.A.	Spain
Sistemas Energéticos Mas Garullo, S.A.	Spain
Sistemas Energéticos Nacimiento, S.A.U.	Spain
Sistemas Energéticos Tacica de Plata, S.A.U.	Spain
Sistemas Energéticos Torralba, S.A.	Spain
Sistemes Energetics Savalla del Comtat, S.A.U.	Spain
Sociedad Gestora de Parques Eólicos de Andalucía, S.A.	Spain
Sotavento Galicia, S.A.	Spain

United Kingdom	
Celtpower, Ltd.	United Kingdom
Coldham Windfarm, Ltd.	United Kingdom
East Anglia Offshore Wind, Ltd.	United Kingdom
East Anglia One, Ltd.	United Kingdom
East Anglia Three, Ltd.	United Kingdom
Morecambe Wind, Ltd.	United Kingdom
ScottishPower Renewable Energy, Ltd.	United Kingdom
ScottishPower Renewables (WODS), Ltd.	United Kingdom
ScottishPower Renewables UK, Ltd.	United Kingdom

Rest of the World	
Iberdrola Renovables Offshore Deutschland, GmbH.	Germany

Iberdrola Renovables Deutschland, GmbH.	Germany
Baltic Eagle, GmbH.	Germany
Iberdrola Renewables Bulgaria, EOOD.	Bulgaria
Iberdrola Renewables Canadá, Ltd.	Canada
Rokas Aeoliki Cyprus, Ltd.	Cyprus
Ailes Marine, S.A.S.	France
Iberdrola Renovables France, S.A.S.	France
C. Rokas Industrial Commercial Company, S.A.	Greece
PPC Renewables Rokas, S.A.	Greece
Rokas Aeoliki Achladotopos, S.A.	Greece
Rokas Aeoliki Macedonia I, S.A.	Greece
Rokas Aeoliki Macedonia II, S.A.	Greece
Rokas Aeoliki Peloponnisos I, S.A.	Greece
Rokas Aeoliki Peloponnisos II, S.A.	Greece
Rokas Aeoliki Thraki III, S.A.	Greece
Rokas Aeoliki Vorios Ellas I, S.A.	Greece
Rokas Aeoliki Vorios Ellas II, S.A.	Greece
Rokas Aeolos, Ltd.	Greece
Rokas Construction, S.A.	Greece
Rokas Energy, S.A.	Greece
Rokas Hydroelectric, S.A.	Greece
Iberdrola Renovables Magyarorszag, KFT.	Hungary
Eólica Lucana, S.R.L.	Italy
Iberdrola Renovables Italia, S.p.A.	Italy
Societa Energie Rinnovabili 2, S.p.A.	Italy
Uppm-Rokas Cranes, S.I.A.	Letonia
Iberdrola Renewables Portugal, S.A.	Portugal
Parque Eólico da Serra do Alvao, S.A.	Portugal
Eolica Dobrogea One, S.R.L.	Romania
Iberdrola Renewables Romania, S.R.L.	Romania

Mexico	
BII NEE Stipa Energía Eólica, S.A. de C.V.	Mexico
Corporativo Iberdrola Renovables Mexico, S.A. de C.V.	Mexico
Energías Renovables Venta III, S.A. de C.V.	Mexico
Eólica Dos Arbolitos S.A.P.I. de C.V.	Mexico
Iberdrola Renovables Centro, S.A. de C.V.	Mexico
Iberdrola Renovables del Bajío, S.A. de C.V.	Mexico
Impulsora de Generacion Fotovoltaica de Mexico, S.A. de C.V. (formerly, Iberdrola Renovables del Irapuato, S.A. de C.V.)	Mexico
Infraestructuras de Generacion Electrica, S.A. de C.V. (formerly, Iberdrola Renovables del Zacatecas, S.A. de C.V.)	Mexico
Iberdrola Renovables Mexico, S.A. de C.V.	Mexico
Iberdrola Renovables Noroeste, S.A. de C.V.	Mexico
Iberdrola Renovables Norte, S.A. de C.V.	Mexico
Parque Industrial de Energía Renovables, S.A. de C.V.	Mexico
Parques Ecológicos de Mexico, S.A. de C.V.	Mexico
Pier II Quecholac Felipe Ángeles, S.A. de C.V.	Mexico
Pier IV, S.A. de C.V.	Mexico
Proyecto Alternativa Energética de Mexico, S.A. de C.V.	Mexico
Servicios de Operación Eoloeléctrica de Mexico, S.A. de C.V.	Mexico

Brazil	
Arizona 1 Energia Renovável, S.A.	Brazil
Caetité 1 Energia Renovável, S.A.	Brazil
Caetité 2 Energia Renovável, S.A.	Brazil
Caetité 3 Energia Renovável, S.A.	Brazil
Calango 1 Energia Renovável, S.A.	Brazil

Calango 2 Energia Renovável, S.A.	Brazil
Calango 3 Energia Renovável, S.A.	Brazil
Calango 4 Energia Renovável, S.A.	Brazil
Calango 5 Energia Renovável, S.A.	Brazil
Calango 6 Energia Renovável, S.A.	Brazil
Canoas Energia Renovável, S.A.	Brazil
Elektro Renováveis do Brasil, S.A. (previously Iberdrola Renováveis do Brasil, S.A.)	Brazil
Energias Renováveis do Brasil, S.A.	Brazil
FE Participaçoes, S.A.	Brazil
Força Eolica do Brasil 1, S.A.	Brazil
Força Eolica do Brasil 2, S.A.	Brazil
Força Eolica do Brasil, S.A.	Brazil
Lagoa I, S.A.	Brazil
Lagoa II, S.A.	Brazil
Mel 2 Energia Renovável, S.A.	Brazil
Santana 1, Energia Renovável, S.A.	Brazil
Santana 2, Energia Renovável, S.A.	Brazil

Innovation	
Algaenergy, S.A.	Spain
Arborea Intellbird, S.L.	Spain
Atten2 Advanced Monitoring Technologies, S.L.	Spain
GDES Tecnology for services, S.L.	Spain
Iberdrola Servicios de Innovación, S.L.	Spain
Inversiones Financieras Perseo, S.L.	Spain
Oceantec Energías Marinas, S.L.	Spain
Iberdrola QSTP, LLC	Qatar

NETWORK BUSINESS

Spain	
Anselmo León Distribución, S.L	Spain
Anselmo León, S.A.U.	Spain
Bidelek Sareak, A.I.E.	Spain
Distribuidora de Energía Eléctrica Enrique García Serrano, S.L.	Spain
Distribuidora Eléctrica Navasfrías, S.L.	Spain
Eléctrica Conquense Distribución, S.A.	Spain
Eléctrica Conquense, S.A.	Spain
Electro-Distribuidora Castellano-Leonesa, S.A.	Spain
Empresa Eléctrica del Cabriel, S.L.	Spain
Herederos María Alonso Calzada – Venta de Baños, S.L.	Spain
San Cipriano de Rueda Distribución, S.L. (previously Hidroeléctrica de San Cipriano de Rueda, S.L.)	Spain
Iberdrola Distribución Eléctrica, S.A.U.	Spain
Iberdrola Infraestructuras y Servicios de Redes, S.A.	Spain
Iberdrola Redes España, S.A.U.	Spain
Sociedad Distribuidora de Electricidad de Elorrio, S.A.	Spain

United Kingdom	
Manweb Services, Ltd.	United Kingdom
NGET/SPT Upgrades, Ltd.	United Kingdom
Scottish Power Energy Networks Holdings, Ltd.	United Kingdom
SP Distribution, Plc.	United Kingdom
SP Gas, Ltd.	United Kingdom

SP Manweb, Plc.	United Kingdom
SP Network Connections, Ltd.	United Kingdom
SP Power Systems, Ltd.	United Kingdom
SP Transmission, Plc.	United Kingdom

Brazil	
Afluente Transmissao de Energia Elétrica, S.A.	Brazil
Baguari Geraçao de Energia Eléctrica, S.A.	Brazil
Bahia PCH II, S.A. Bahía Pequeña C. Hidroeléctrica	Brazil
Bahia PCH III, S.A. Bahía Geraçao de Energia	Brazil
Belo Monte Participaçoes, S.A.	Brazil
Companhia de Eletricidade do Estado do Bahia, S.A.	Brazil
Companhia Energética de Pernambuco, S.A.	Brazil
Companhia Energetica do Rio Grande do Norte, S.A.	Brazil
Companhia Hidrelétrica Teles Pires, S.A.	Brazil
EKTT 12-A Serviços de Transmissão de Energia Elétrica SPE S/A	Brazil
EKTT 13-A Serviços de Transmissão de Energia Elétrica SPE S/A	Brazil
EKTT 14-A Serviços de Transmissão de Energia Elétrica SPE S/A	Brazil
EKTT 15-A Serviços de Transmissão de Energia Elétrica SPE S/A	Brazil
Elektro Comercializadora de Energia Ltda.	Brazil
Elektro Holding, S.A. (antes Iberdrola Brasil, S.A.)	Brazil
Elektro Operaçao e Manutençao, Ltda. (previously Iberdrola Operaçao e Manutençao, Ltda.)	Brazil
Elektro Redes, S.A. (previously Elektro Electricidade e Serviços, S.A.)	Brazil
Energetica Aguas da Pedra, S.A.	Brazil
Energética Corumba III, S.A.	Brazil
Geraçao Ceu Azul, S.A.	Brazil
Geraçao CIII, S.A.	Brazil
Itapebí Geraçao de Energia, S.A.	Brazil
Lanmóvil Amara Celular da Bahia Ltd. (Lanmara)	Brazil
Meridiano 1 Energia renovavel, S.A.	Brazil
Meridiano 2 Energia renovavel, S.A.	Brazil
Meridiano 3 Energia renovavel, S.A.	Brazil
Meridiano 4 Energia renovavel, S.A.	Brazil
Meridiano 5 Energia renovavel, S.A.	Brazil
Meridiano 6 Energia renovavel, S.A.	Brazil
NC Energia, S.A.	Brazil
Neoenergia Investimentos, S.A.	Brazil
Neoenergia Operaçao e Manuitençao, S.A.	Brazil
Neoenergia Servicios, Ltd.	Brazil
Neoenergia, S.A.	Brazil
Norte Energia, S.A.	Brazil
PCH Alto do Rio Grande, S.A.	Brazil
Potiguar Sul Transmissao de Energia, S.A.	Brazil
S.E. Narandiba, S.A.	Brazil
Sever RJ Participacoes S.A.	Brazil
Soumaya RJ Participacoes S.A.	Brazil
Tacca RJ Participacoes S.A.	Brazil
Titanum RJ Participacoes S.A.	Brazil
Teles Pires Participaçoes, S.A.	Brazil
Termopernambuco, S.A.	Brazil
Garter Properties, Inc.	British Virgin Islands

OTHER BUSINESSES

Engineering	
Adícora Servicios de Ingeniería, S.L.U.	Spain
Empresarios Agrupados Internacional, S.A.	Spain
Empresarios Agrupados, A.I.E.	Spain
Ghesa Ingeniería y Tecnología, S.A.	Spain
Iberdrola Ingeniería de Explotación, S.A.U.	Spain
Iberdrola Ingeniería y Construcción, S.A.U.	Spain
Ingeniería, Estudios y Construcciones, S.A.	Spain
Iberdrola Engineering and Construction Saudi Arabia, LLC	Saudi Arabia
Iberdrola Construçao e Serviços, Ltd.	Brazil
Iberdrola Energy Proyects Canada Corporation	Canada
Iberdrola Ingenieria y Construcción Costa Rica, S.A.	Costa Rica
Iberdrola Energy Project, Inc.	United States
Iberinco Hellas Techniki kai Kataskevastiki EPE	Greece
Iberdrola Ingegnieria e Costruzioni Italia, SRL.	Italy
Enermón S.A. de C.V.	Mexico
Iberdrola Ingeniería y Construcción Mexico, S.A. de C.V.	Mexico
Iberservicios, S.A. de C.V.	Mexico
Iberdrola Engineering and Construction Poland, SP. Z.O.O.	Poland
Iberdrola Engenharia e Construçao Portugal, Unipessoal Lda.	Portugal
Iberdrola Engineering and Construction Networks, Ltd.	United Kingdom
Iberdrola Engineering and Construction UK, Ltd.	United Kingdom
Iberdrola Engineering and Construction Ro, SRL.	Romania
Iberdrola Inzhiniring I Stroiteistvo, LLC	Russia
Iberdrola Engineering and Construction South Africa	South Africa
Iberdrola Ingeniería y Construcción Venezuela, S.A.	Venezuela

Real Estate	
Arrendamiento de Viviendas Protegidas Siglo XXI, S.L.	Spain
Camarate Golf, S.A.	Spain
Fiuna, S.A.	Spain
Iberdrola Inmobiliaria Patrimonio, S.A.U.	Spain
Iberdrola Inmobiliaria, S.A.	Spain
Promotora la Castellana de Burgos, S.A.	Spain
Urbanizadora Marina de Cope, S.L.	Spain
Iberdrola Inmobiliaria Real State Investment, EOOD	Bulgaria
Desarrollos Inmobiliarias Laguna del Mar, S.A. de C.V.	Mexico
Promociones La Malinche, S.A. de C.V.	Mexico

Other Businesses	
Subgrupo Corporación IBV Participaciones Empresariales	Spain
Gamesa Corporación Tecnológica, S.A.	Spain
Iberdrola Inversiones 2010, S.A.U.	Spain
Iberdrola Participaciones, S.A.U. (previously Iberdrola Redes, S.A.)	Spain
Investigación y Desarrollo de Equipos Avanzados, S.A.U.	Spain
Keytech Sistemas Integrales, S.A.	Spain

CORPORATION	
CarteraPark, S.A.U.	Spain
Iberdrola Corporación, S.A.	Spain
Iberdrola España, S.A.U.	Spain
Iberdrola Energía, S.A.U.	Spain
Iberdrola Financiación, S.A.U.	Spain
Iberdrola Finanzas, S.A.U.	Spain
Iberdrola International, B.V.	Netherlands
Iberdrola Finance Ireland, DAC	Irland

Iberdrola Re, S.A.	Luxemburg
Demon Internet, Ltd.	United Kingdom
Manweb Nominees, Ltd.	United Kingdom
Manweb Pensions Trustee, Ltd.	United Kingdom
Manweb Share Scheme Trustees, Ltd.	United Kingdom
Scottish Power UK Holdings, Ltd.	United Kingdom
Scottish Power UK, Plc	United Kingdom
Scottish Power, Ltd.	United Kingdom
ScottishPower Investments, Ltd.	United Kingdom
ScottishPower Overseas Holdings, Ltd.	United Kingdom
SPW Investments Ltd.	United Kingdom

Joint operations of Iberdrola, S.A. group companies structured through an independent vehicle (not including subsidiaries of AVANGRID, Inc.)

DEREGULATED BUSINESS	
Asociación Nuclear Ascó – Vandellós, A.I.E.	Spain
Centrales Nucleares Almaraz – Trillo, A.I.E.	Spain
RENEWABLE BUSINESS	
Infraestructuras de Medinaceli, S.L.	Spain
Sistema Eléctrico de Conexión Hueneja, S.L.	Spain
OTHER BUSINESSES	
Torre Iberdrola, A.I.E.	Spain

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VINEYARD WIND

Vineyard Wind

Attachment 5.15-3

CI II US AIV Company 3Q 2017 Affiliates

CI II US AIV QFPF K/S and CI II US AIV Non-QFPF K/S - Subsidiaries and Affiliates, Q3 2017

Company Name	Country	Relation
CI Alice II Inc.	Wilmington, Delaware, USA	CI II US AIV Non-QFPF K/S, 100%
Offshore Wind LLC	Wilmington, Delaware, USA	CI II US AIV QFPF K/S, 100%
CI II Alice Holding LLC	Wilmington, Delaware, USA	CI II Alice Inc., 31.55% , Offshore Wind LLC, 68.25%
Vineyard Wind LLC (formerly Offshore MW LLC)	Wilmington, Delaware, USA	CI II Alice Holding LLC, 100%
CI-II Bearkat Non-QFPF Inc.	Wilmington, Delaware, USA	CI II US AIV Non-QFPF K/S, 100%
CI-II Bearkat QFPF LLC	Wilmington, Delaware, USA	CI II US AIV QFPF K/S, 100%
CI-II Bearkat Holding LLC	Wilmington, Delaware, USA	CI-II Bearkat Non-QFPF Inc., 31.55%, CI-II Bearkat QFPF LLC, 68.25%
CI-II Bearkat Holding B LLC	Wilmington, Delaware, USA	CI-II Bearkat Non-QFPF Inc., 31.55%, CI-II Bearkat QFPF LLC, 68.25%
Sponsor Bearkat I HoldCo LLC	Wilmington, Delaware, USA	CI-II Bearkat Holding LLC, 100%
Bearkat I TE Partnership LLC	Wilmington, Delaware, USA	Sponsor Bearkat I HoldCo LLC, 95%, CI-II Bearkat Holding B LLC, 5%
Bearkat Wind Energy I LLC	Wilmington, Delaware, USA	Bearkat I TE Partnership LLC, 100%
CI-II Bearkat II Non-QFPF Inc.	Wilmington, Delaware, USA	CI II US AIV Non-QFPF K/S, 100%
CI-II Bearkat II QFPF LLC	Wilmington, Delaware, USA	CI II US AIV QFPF K/S, 100%
CI-II Bearkat II Holding LLC	Wilmington, Delaware, USA	CI-II Bearkat II Non-QFPF Inc., 31.55%, CI-II Bearkat II QFPF LLC, 68.25%
Bearkat Wind Energy II LLC	Wilmington, Delaware, USA	CI-II Bearkat II Holding LLC, 100%
CI-II Bearkat III Non-QFPF Inc.	Wilmington, Delaware, USA	CI II US AIV Non-QFPF K/S, 100%
CI-II Bearkat III QFPF LLC	Wilmington, Delaware, USA	CI II US AIV QFPF K/S, 100%
CI-II Bearkat III Holding LLC	Wilmington, Delaware, USA	CI-II Bearkat III Non-QFPF Inc., 31.55%, CI-II Bearkat III QFPF LLC, 68.25%
Bearkat Wind Energy III LLC	Wilmington, Delaware, USA	CI-II Bearkat III Holding LLC, 100%
CI-II Blue Cloud Non-QFPF Inc.	Wilmington, Delaware, USA	CI II US AIV Non-QFPF K/S, 100%
CI-II Blue Cloud QFPF LLC	Wilmington, Delaware, USA	CI II US AIV QFPF K/S, 100%
CI-II Blue Cloud Holding LLC	Wilmington, Delaware, USA	CI-II Blue Cloud Non-QFPF Inc., 31.55%, CI-II Blue Cloud QFPF LLC, 68.25%
CI II Blue Cloud Holding B LLC	Wilmington, Delaware, USA	CI-II Blue Cloud Non-QFPF Inc., 31.55%, CI-II Blue Cloud QFPF LLC, 68.25%
Sponsor Blue Cloud HoldCo LLC	Wilmington, Delaware, USA	CI-II Blue Cloud Holding LLC, 100%
Blue Cloud TE Partnership LLC	Wilmington, Delaware, USA	Sponsor Blue Cloud HoldCo LLC, 95%; CI II Blue Cloud Holding B LLC, 5%
Blue Cloud Wind Energy LLC	Wilmington, Delaware, USA	Blue Cloud TE Partnership LLC, 100%
CI II Fluvanna Non-QFPF Inc.	Wilmington, Delaware, USA	CI II US AIV Non-QFPF K/S, 100%
CI II Fluvanna QFPF LLC	Wilmington, Delaware, USA	CI II US AIV QFPF K/S, 100%
CI II Fluvanna A LLC	Wilmington, Delaware, USA	CI II Fluvanna Non-QFPF Inc., 31.55%, CI II Fluvanna QFPF LLC, 68.25%
CI II Mitchell Non-QFPF Inc.	Wilmington, Delaware, USA	CI II US AIV Non-QFPF K/S, 100%
CI II Mitchell QFPF LLC	Wilmington, Delaware, USA	CI II US AIV QFPF K/S, 100%
CI II Mitchell Holding LLC	Wilmington, Delaware, USA	CI II Mitchell Non-QFPF Inc., 31.55%, CI II Mitchell QFPF LLC, 68.25%
1001 Ebenezer Church Solar LLC	Raleigh, North Carolina, USA	CI II Mitchell Holding LLC, 100%
1003 Whitney Solar LLC	Raleigh, North Carolina, USA	CI II Mitchell Holding LLC, 100%
1008 Matthews Solar LLC	Raleigh, North Carolina, USA	CI II Mitchell Holding LLC, 100%
1025 Traveller Solar LLC	Raleigh, North Carolina, USA	CI II Mitchell Holding LLC, 100%
1031 Winthrow Creek Solar LLC	Raleigh, North Carolina, USA	CI II Mitchell Holding LLC, 100%
1034 Catherine Lake Solar LLC	Raleigh, North Carolina, USA	CI II Mitchell Holding LLC, 100%
Suncaster LLC	Raleigh, North Carolina, USA	CI II Mitchell Holding LLC, 100%
Glenfield Solar LLC	Raleigh, North Carolina, USA	CI II Mitchell Holding LLC, 100%
Grays Mill Solar LLC	Raleigh, North Carolina, USA	CI II Mitchell Holding LLC, 100%
Pitt County Solar LLC	Raleigh, North Carolina, USA	CI II Mitchell Holding LLC, 100%
Williams Solar LLC	Raleigh, North Carolina, USA	CI II Mitchell Holding LLC, 100%
Acme Solar LLC	Raleigh, North Carolina, USA	CI II Mitchell Holding LLC, 100%
Solar Lee LLC	Raleigh, North Carolina, USA	CI II Mitchell Holding LLC, 100%
1073 Onslow Solar LLC	Raleigh, North Carolina, USA	CI II Mitchell Holding LLC, 100%
Ennis Solar LLC	Raleigh, North Carolina, USA	CI II Mitchell Holding LLC, 100%
1051 Lucky Solar LLC	Raleigh, North Carolina, USA	CI II Mitchell Holding LLC, 100%
Sykes Solar LLC	Raleigh, North Carolina, USA	CI II Mitchell Holding LLC, 100%
Brewington Solar LLC	Raleigh, North Carolina, USA	CI II Mitchell Holding LLC, 100%
1047 Little Mountain Solar LLC	Raleigh, North Carolina, USA	CI II Mitchell Holding LLC, 100%
Union Chapel Solar LLC	Raleigh, North Carolina, USA	CI II Mitchell Holding LLC, 100%
1035 Lee Landing Solar LLC	Raleigh, North Carolina, USA	CI II Mitchell Holding LLC, 100%
1045 Tomlin Mill Solar LLC	Raleigh, North Carolina, USA	CI II Mitchell Holding LLC, 100%
Elk Solar LLC	Charlotte, North Carolina, USA	CI II Mitchell Holding LLC, 100%
Gray Fox Solar LLC	Charlotte, North Carolina, USA	CI II Mitchell Holding LLC, 100%
Apple Pie Solar LLC	Asheville, North Carolina, USA	CI II Mitchell Holding LLC, 100%
Burgaw Solar LLC	Raleigh, North Carolina, USA	CI II Mitchell Holding LLC, 100%
Carolina Lily Solar LLC	Asheville, North Carolina, USA	CI II Mitchell Holding LLC, 100%
Swansboro Solar LLC	Asheville, North Carolina, USA	CI II Mitchell Holding LLC, 100%
Sweet Tea Solar LLC	Asheville, North Carolina, USA	CI II Mitchell Holding LLC, 100%

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VINEYARD WIND

Vineyard Wind

Attachment 5.15-4

CI III US Company List 3Q 2017 Affiliates

CI III Non-QFPF Blocker K/S - Subsidiaries and affiliates, Q3 2017

Company Name	Country	Relation
CI III VK I Non-QFPF Inc.	Wilmington, Delaware, USA	CI III Non-QFPF Blocker K/S, 100%
CI III VK I Top Holding LLC	Wilmington, Delaware, USA	CI III VK I Non-QFPF Inc., 99.57%
CI III VK I Holding LLC	Wilmington, Delaware, USA	CI III VK I Top Holding LLC, 100%
Sage Solar I LLC	Utah, USA	CI III VK I Holding LLC, 100%
Sage Solar II LLC	Utah, USA	CI III VK I Holding LLC, 100%
Sage Solar III LLC	Utah, USA	CI III VK I Holding LLC, 100%
MTSun LLC	Montana, USA	CI III VK I Holding LLC, 100%
Broadview Solar LLC	Montana, USA	CI III VK I Holding LLC, 100%
Broadview Solar 2 LLC	Montana, USA	CI III VK I Holding LLC, 100%
CI III Alice Non-QFPF Inc.	Wilmington, Delaware, USA	CI III Non-QFPF Blocker K/S, 100%
CI III Alice Holding LLC	Wilmington, Delaware, USA	CI III Alice Non-QFPF Inc., 99.57%
Vineyard Wind LLC (formerly Offshore MW LLC)	Wilmington, Delaware, USA	CI II Alice Holding LLC, 25%
CI III Non-QFPF Mariah I Inc.	Wilmington, Delaware, USA	CI III Non-QFPF Blocker K/S, 100%
CI III Mariah I Holding LLC	Wilmington, Delaware, USA	CI III Non-QFPF Mariah I Inc., 99.57%
CI III Mariah Wind Energy I LLC	Wilmington, Delaware, USA	CI III Mariah I Holding LLC, 100%
CI III Kontiki Wind Non-QFPF Inc.	Wilmington, Delaware, USA	CI III Non-QFPF Blocker K/S, 100%
CI III Kontiki Wind Holding LLC	Wilmington, Delaware, USA	CI III Kontiki Wind Non-QFPF Inc., 99.57%
CI III Kontiki Wind Energy LLC	Wilmington, Delaware, USA	CI III Kontiki Wind Holding LLC, 100%
CI III Blue Cloud II Non-QFPF Inc.	Wilmington, Delaware, USA	CI III Non-QFPF Blocker K/S, 100%;
CI III Blue Cloud II Holding LLC	Wilmington, Delaware, USA	CI III Blue Cloud II Non-QFPF Inc. 99,57%
CI III Blue Cloud Wind Energy II LLC	Wilmington, Delaware, USA	CI III Blue Cloud II Holding LLC 100%
CI III Non-QFPF Sunwind Inc	Wilmington, Delaware, USA	CI III Non-QFPF Blocker K/S, 100%;
CI III Sunwind Holding LLC	Wilmington, Delaware, USA	CI III Non-QFPF Sunwind Inc., 99,57%
CI III Sunwind Wind Energy LLC	Wilmington, Delaware, USA	CI III Sunwind Holding LLC, 100%
CI III Non-QFPF Upper Badlands Inc	Wilmington, Delaware, USA	CI III Non-QFPF Blocker K/S, 100%;
CI III Upper Badlands Holding LLC	Wilmington, Delaware, USA	CI III Non-QFPF Upper Badlands Inc, 99,57%
CI III Upper Badlands Wind Energy LLC	Wilmington, Delaware, USA	CI III Upper Badlands Holding LLC, 100%