3.0 FINANCIAL CAPACITY

3.1 Introduction

CMP is a regulated electric transmission and distribution utility serving approximately 615,000 customers in central, western, and southern Maine. CMP's transmission services are regulated by the Federal Energy Regulatory Commission ("FERC") and its distribution services are regulated by the Maine Public Utilities Commission ("MPUC"). CMP will construct, own, and operate the NECEC Project.

CMP is an experienced and financially strong developer and operator of transmission facilities in Maine, with a proven track record of delivering major transmission Projects on time and on budget. The Company's recent completion of the Maine Power Reliability Program ("MPRP"), a $1.4 billion transmission Project to improve the reliability of the New England Transmission System which included constructing a total of 440 miles of transmission lines, including 184 miles of new 345kV transmission lines, 100 miles of new 115kV transmission lines, 156 miles of rebuilt transmission lines, constructing six new substations, and major expansions to six existing substations, demonstrates CMP's capabilities. In addition, CMP has the full support of its parent companies, AVANGRID, Inc. ("AVANGRID") and Iberdrola S., which together are among the United States' and the world's largest energy companies. CMP has and will continue to draw on its significant experience and expertise developing large transmission Projects and financial strength, to successfully complete the NECEC Project on time and on budget. As required by Chapter 373 sec. 2 (B)(2), CMP provides an overview construction schedule of the NECEC Project components (**Exhibit 3-1**).

3.2 CMP Financial Capacity

The financial strength of CMP and its parent companies ensures that the Company will be able to attract the capital needed to finance the NECEC Project on financially viable and favorable terms. As required by Chapter 373 sec. 2 (B)(5), CMP has provided a Certificate of Good Standing in **Exhibit 3-2**. CMP will use short- and long-term debt financing including AVANGRID'S significant existing credit facilities, and equity funding sourced through retained earnings and capital contributions from AVANGRID, if necessary, to finance the Project. The NECEC RFP response includes a Transmission Service Agreement ("TSA") under which CMP's revenue requirements for the NECEC Transmission Project will be recovered from the Distribution Companies over the Power Purchase Agreement ("PPA") terms. With the firm revenue stream provided under the TSA, these sources of capital will be more than sufficient for CMP to finance the NECEC Project.

CMP Group, Inc. owns 100 percent of outstanding shares of CMP's common stock. CMP Group, Inc. is a wholly-owned subsidiary of Avangrid Networks, Inc., which in turn is a wholly-owned subsidiary of AVANGRID, a New York corporation listed on the New York Stock Exchange (NYSE: AGR). AVANGRID is a diversified energy and utility holding company with more than $30 billion in assets and operations in more than 27 states across the United States.

CMP plans to finance the full cost of the NECEC Transmission Project. The Site Law, Chapter 373, requires that CMP's application include cost estimate information as follows:

> **Cost estimates.** Accurate and complete cost estimates of the development, including all proposed phases. The itemization of major costs may include, but is not limited to, the cost of the following activities: land purchase, erosion control, roads, sewers, structures, water supply, utilities, pollution abatement, landscaping, and restoration of the site, if applicable. [06 096 C.M.R. Ch. 373(1)(B)(1)]

MDEP has determined that the cost estimates provided by CMP in support of this application are protected from disclosure as a trade secret, and are being withheld as such. CMP is filing the required cost estimates simultaneously with its Site Law application, but separately, so that MDEP can protect those cost estimates as confidential information.

CMP's sources for capital and its financial wherewithal to successfully complete the NECEC Transmission Project are set forth below.

CMP owns both distribution and transmission assets and finances them together, without regard to their purpose. CMP's capital structure (excluding the value of goodwill in the common equity balance) at March 31, 2017 is shown in **Figure 3-1**.

Figure 3-1: CMP's Capital Structure ($,000)

Short-term Debt	0	0%
Long-term Debt	1,043,291	42%
Preferred Equity	571	0%
Common Equity	1,444,532	58%
Total Capital	**$2,488,394**	

CMP expects to continue to maintain approximately the same debt and equity capital structure in financing all its operations, including financing of the NECEC Transmission Project. This requires a balanced approach to the use of short- and long-term debt financing and equity funding sourced through retained earnings and capital contributions from CMP's parent, AVANGRID, if necessary. Specific sources of financing for CMP are as follows:

Short-term debt financing: CMP funds short-term liquidity needs through an agreement among AVANGRID's regulated utility subsidiaries (the Virtual Money Pool Agreement), a bi-lateral intercompany credit agreement with AVANGRID (the Bi-Lateral Intercompany Facility), and a bank provided credit facility to which CMP and other affiliated entities are parties (the AVANGRID Credit Facility). The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of AVANGRID under which the parties to the agreement may lend to or borrow from each other. This Agreement allows AVANGRID to optimize cash resources within the regulated utility companies, which are prohibited by regulation from lending to unregulated affiliates. The Bi-Lateral Intercompany Facility provides for borrowing of up to $500 million from AVANGRID. Both the Virtual Money Pool Agreement and the Bi-Lateral Intercompany Facility allow CMP to borrow at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve.

On April 5, 2016, AVANGRID and its investment-grade rated utility subsidiaries, including CMP, entered into the AVANGRID Credit Facility, a revolving credit facility with a syndicate of banks that provides for maximum borrowings of up to $1.5 billion in the aggregate. Under the terms of the AVANGRID Credit Facility, CMP has a maximum sublimit of $250 million. The maturity date for the facility is April 5, 2021.

Long-term debt financing: CMP borrows long-term debt in the investment grade capital markets. CMP's senior unsecured debt ratings are A / A2 / A- from Standard & Poor's, Moody's and Fitch, respectively. Since 2009, CMP has issued $900 million of first mortgage bonds to finance its operations, including construction of the $1.4 billion MPRP Project. The first mortgage bonds are rated A / Aa3 / A by Standard & Poor's, Moody's and Fitch, respectively.

Equity financing: From the commencement of MPRP in 2009 to the present, CMP has received $250 million of equity capital contributions from AVANGRID. This, together with retaining a large portion of earnings, has enabled CMP to maintain a balanced capital structure while funding the construction of the MPRP and other capital Projects.

Parent Company Financial Resources: AVANGRID has an equity market capitalization of approximately $14 billion. AVANGRID's senior unsecured debt is rated BBB / Baa1 / BBB+ by Standard & Poor's, Moody's and Fitch, respectively, giving AVANGRID access to the investment grade debt markets. Under the AVANGRID Credit Facility (described above), AVANGRID has the capacity to borrow up to $1 billion. AVANGRID also has a $1 billion commercial paper facility that is backstopped by the AVANGRID Credit Facility. AVANGRID's commercial paper is rated A-2 / P-2 / F-2 by Standard & Poor's, Moody's and Fitch, respectively.

As discussed above, AVANGRID is 81.5 percent owned by Iberdrola, S.A., one of the world's largest energy companies with an equity market capitalization of approximately $45 billion. Iberdrola, S.A. has approximately $33 billion in consolidated debt outstanding and has ratings of BBB+ / Baa1 / BBB+ from Standard & Poor's, Moody's and Fitch, respectively, giving it access to investment grade debt markets in Europe, the U.S. and Asia.

A Letter of Commitment to Fund is included in **Exhibit 3-3.** A copy of Avangrid Networks, Inc. 2015 and 2016 Combined and Consolidated Financial Statements and a copy of CMP's 2015 and 2016 Consolidated Financial Statement, are included as **Exhibit 3-4** and **Exhibit 3-5**, respectively.

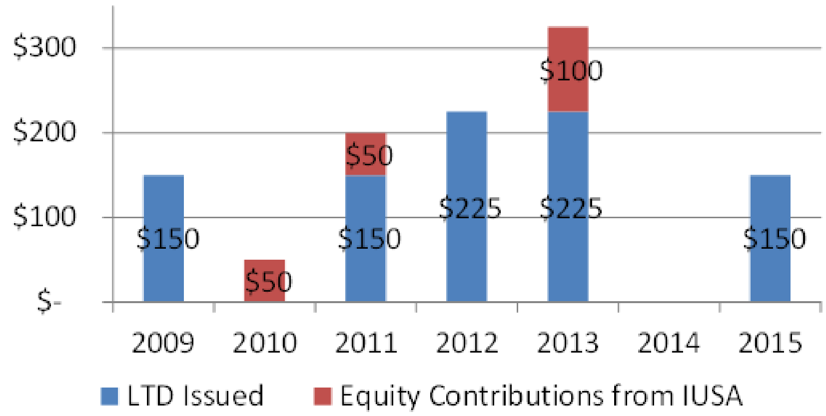
3.3 Financing of Similar Size and Technology

As discussed above, in 2015 CMP completed the $1.4 billion MPRP. During the period from 2009 through 2015, in order to fund the MPRP, as well as its ongoing transmission[6] and distribution operations while maintaining a stable capital structure, CMP retained 100 percent of its net income (i.e., it did not pay dividends). In addition, since 2009, CMP has received $250 million of equity contributions from AVANGRID and has issued $900 million of first mortgage bonds as shown in **Figure 3-2**[7]. CMP used its access to revolving credit to finance its variable working capital needs and to provide a source of bridge financing between its long-term debt financing transactions.

[6] For a list of other transmission projects CMP completed during this time, which it financed through a combination of retained earnings, equity contributions, and short-term and long-term debt, please see **Exhibit 3-6**.

[7] References to "IUSA" in **Figure 3-2** refer to Iberdrola USA. In December 2015, IUSA acquired UIL Holdings to form AVANGRID.

Figure 3-2: 2009-2015 Long-term Debt and Equity Capital Raised by CMP ($MM)



CMP intends to use a similar balanced approach to finance the NECEC Project, with the full support of AVANGRID and Iberdrola, S.A.

Exhibit 3-1: NECEC Schedule

Exhibit 3-1 NECEC Construction Schedule

Construction Activity	Estimated Start	Estimated Completion
Merrill Road HVDC Converter Construction	2/24/2020	6/21/2022
Larrabee Road Construction	8/21/2000	3/17/2022
Maine Yankee Construction	8/21/2020	6/24/2021
Raven Farm - Construction	7/10/2020	3/17/2022
Fickett Road - Construction	7/3/2019	10/16/2020
Coopers Mills Road - Construction	8/21/2020	4/5/2021
Surowiec - Construction	8/24/2020	3/24/2021
HVDC - Section 3006 Construction	12/4/2019	7/31/2022
345kV - Section 3005 Construction	3/24/2021	6/16/2021
345 kV - Section 3027 Construction	4/13/2020	5/25/2021
115kV - Section 62 Construction	5/18/2021	12/30/2021
115kV - Section 64 Construction	4/13/2020	6/9/2021

Exhibit 3-2: Certificate of Good Standing

Information Summary

Subscriber activity report

This record contains information from the CEC database and is accurate as of: Wed Sep 06 2017 11:53:35. Please print or save for your records.

Legal Name	Charter Number	Filing Type	Status
CENTRAL MAINE POWER COMPANY	19050014 D	BUSINESS CORPORATION	GOOD STANDING

Filing Date	Expiration Date	Jurisdiction
07/20/1905	N/A	MAINE

Other Names	(A=Assumed ; F=Former)
MAINEPOWER - CANCELLED	A
MAINE POWER, INC.-CANCELLED	A
COMBINED ENERGIES - CANCELLED	A
THE MESSALONSKEE ELECTRIC COMPANY	F

Clerk/Registered Agent

ERIC N. STINNEFORD
83 EDISON DRIVE
AUGUSTA, ME 04336

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List of Filings	View list of filings	
Obtain additional information:		
Certificate of Existence (more info)	Short Form without amendments ($30.00)	Long Form with amendments ($30.00)

Exhibit 3-3: Letter of Commitment to Fund

CENTRAL MAINE
POWER

September 18, 2017

Mr. Jim Beyer
Regional Licensing and Compliance Manager, Bureau of Land Resources
Eastern Maine Regional Office
Maine Department of Environmental Protection
106 Hogan Road, Suite 6
Bangor, ME 04401

Re: Central Maine Power Company (CMP), Site Location of Development Act Application, New England Clean Energy Connect (NECEC)

Dear Mr. Beyer:

Below, please find information concerning the cost of the NECEC project and CMP's financial strength, access to capital, and commitment to fund the Project.

Project Costs: As stated in the application, the Project cost estimates are a trade secret under the Maine Freedom of Access Act and must be kept confidential.

Financial Strength: CMP is a regulated electric transmission and distribution utility serving approximately 615,000 customers in central, western, and southern Maine. CMP's transmission services are regulated by the Federal Energy Regulatory Commission, and its distribution services are regulated by the Maine Public Utilities Commission. As of June 30, 2017 CMP had total assets of $4.3 billion, net in-service property, plant, and equipment valued at $2.9 billion, cash on hand of $73 million, and a long-term capital base consisting of $1.8 billion of shareholders' equity and $1.0 billion of long-term debt. In 2016 CMP generated $834 million in revenues, $135 million in net income, and $300 million in cash from operations. CMP carries investment grade ratings of A- / A2 / A- from Standard & Poor's, Moody's and Fitch, respectively.

Access to Long-term Capital and Liquidity: Since 2009 CMP has accessed debt capital markets to raise $900 million in long-term debt capital as part of the funding for the $1.4 billion Maine Power Reliability Project ("MPRP"). During the period when MPRP was under construction, CMP received $200 million in equity capital contributions from its parent company, Avangrid, Inc. In addition to the cash on hand on June 30, 2017, CMP can meet its liquidity needs through agreements to borrow from Avangrid, Avangrid's utility subsidiaries, and from a bank-provided, committed credit facility under which CMP's limit is $250 million.

CENTRAL MAINE
POWER

Funds Committed to the Project: The CMP board of directors have approved the NECEC, thereby committing the funding necessary to complete the development, permitting and construction of the Project. CMP plans to finance the full cost of the Project through the use of short- and long-term debt financing and equity funding through retained earnings and capital contributions from CMP's parent, Avangrid, Inc., with the goal of maintaining CMP's existing capital structure (i.e., 42% debt and 58% equity). Specific sources of the debt financing for the Project will include the short-term credit facility discussed above as well the issuance of long-term debt through the investment grade capital markets.

We hope this information meets your needs. Please call me at (207) 629-1280 if you have any questions concerning this letter.

Sincerely,

Howard Coon
Vice President & Treasurer
Avangrid Management Company
On behalf of Central Maine Power Company

Exhibit 3-4: AVANGRID 2015 and 2016 Annual Reports

Avangrid Networks, Inc.
Combined and Consolidated Financial Statements
For the Years Ended December 31, 2016 and 2015

Avangrid Networks, Inc.

Index

Management’s Report on Internal Control Over Financial Reporting

Avangrid Networks, Inc.’s (we, us, our) internal control over financial reporting is a process affected by those charged with governance, management, and other personnel, designed to provide reasonable assurance regarding the preparation of reliable financial statements in accordance with accounting principles generally accepted in the United States of America. An entity’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 entity; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the entity are being made only in accordance with authorizations of management and those charged with governance; and (3) provide reasonable assurance regarding prevention, or timely detection and correction of unauthorized acquisition, use, or disposition of the entity’s assets that could have a material effect on the financial statements.

Management is responsible for establishing and maintaining effective internal control over financial reporting. Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2016, based on the framework set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control—Integrated Framework* (2013). Based on that assessment, management identified certain deficiencies that rose to the level of a material weakness in controls related to (1) the preparation of the consolidated financial statements, specifically the classification and disclosure of financial information and (2) the measurement and disclosure of income taxes. The 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 weaknesses 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 completion of these consolidated financial statements. Based on these procedures, management believes that our consolidated financial statements have been prepared in accordance with generally accepted accounting principles. In addition, we have developed a remediation plan for these material weaknesses, which is described below.

Avangrid Networks’ Independent Auditor, Ernst & Young LLP, has issued an adverse audit report on the effectiveness of Avangrid Networks’ internal control over financial reporting as of December 31, 2016.

Avangrid Networks’ management, with oversight from its Audit and Compliance Committee of the Board of Directors of Avangrid Networks, is actively engaged in remediation efforts to address the material weaknesses identified above. Management has taken and will take a number of actions to remediate the material weaknesses 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;
- 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 weaknesses. 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 weaknesses. However, the material weaknesses in our internal control over financial reporting will not be considered remediated until the controls operate for a sufficient period of time and management has concluded, through testing that these controls operate effectively. We currently expect that the remediation of this material weaknesses will be completed by December 31, 2017.

Avangrid Networks, Inc.
July 7, 2017

Ernst & Young LLP
5 Times Square
New York, NY 10036-6530
Tel: +1 212 773 3000
Fax: +1 212 773 6350
ey.com

Report of Independent Auditors on Financial Statements

To the Board of Directors and Stockholder of Avangrid Networks, Inc.

We have audited the accompanying consolidated financial statements of Avangrid Networks, Inc. which comprise the combined and consolidated balance sheets as of December 31, 2016 and 2015, and the related combined and consolidated statements of income, comprehensive income, changes in equity and cash flows for the years then ended, and the related notes to the combined and 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 U.S. generally accepted accounting principles; 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 audits. We conducted our audits 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. 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 combined and consolidated financial position of Avangrid Networks, Inc. at December 31, 2016 and 2015, and the combined and consolidated results of its operations and its cash flows for the years then ended in conformity with U.S. generally accepted accounting principles.

Report on Internal Control Over Financial Reporting

We also have audited, in accordance with auditing standards generally accepted in the United States, Avangrid Networks, Inc.'s 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 July 7, 2017 expressed an adverse opinion thereon.

Ernst & Young LLP

July 7, 2017

Ernst & Young LLP
5 Times Square
New York, NY 10036-6530

Tel: +1 212 773 3000
Fax: +1 212 773 6350
ey.com

Report of Independent Auditors on Internal Control Over Financial Reporting

To the Board of Directors and Stockholder of Avangrid Networks, Inc.

We have audited Avangrid Networks, Inc.'s 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).

Management's Responsibility for Internal Control Over Financial Reporting

Management is responsible for designing, implementing, and maintaining effective internal control over financial reporting, and for its assessment about the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting.

Auditor's Responsibility

Our responsibility is to express an opinion on the entity's internal control over financial reporting based on our audit. We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects.

An audit of internal control over financial reporting involves performing procedures to obtain evidence about whether a material weakness exists. The procedures selected depend on the auditor's judgement, including the assessment of the risks that a material weakness exists. An audit includes obtaining an understanding of internal control over financial reporting and testing and evaluating the design and operating effectiveness of internal control over financial reporting based on the assessed risk.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our adverse audit opinion.

Definition and Inherent Limitations of Internal Control Over Financial Reporting

An entity's internal control over financial reporting is a process effected by those charged with governance, management, and other personnel, designed to provide reasonable assurance regarding the preparation of reliable financial statements in accordance with accounting principles generally accepted in the United States of America. An entity'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 entity; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the entity are being made only in accordance with authorizations of management and those charged with governance; and (3) provide reasonable assurance regarding prevention, or timely detection and correction, of unauthorized acquisition, use, or disposition of the entity'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 and correct, misstatements. Also, projections of any assessment 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.

Basis for Adverse Opinion

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the entity's financial statements will not be prevented, or detected and corrected, on a timely basis. The following material weaknesses have been identified and included in Management's Report on Internal Control Over Financial Reporting: (a) the preparation of the consolidated financial statements, including disclosures within those consolidated financial statements and (b) the recognition and measurement of income taxes.

Adverse Opinion

In our opinion, because of the effect of the material weaknesses described in the Basis for Adverse Opinion paragraph on the achievement of the objectives of the COSO criteria, Avangrid Networks, Inc. has not maintained effective internal control over financial reporting as of December 31, 2016, based on the COSO criteria.

Report on Financial Statements

We also have audited, in accordance with auditing standards generally accepted in the United States of America, the consolidated balance sheets as of December 31, 2016 and 2015, and the related combined and consolidated statements of income, comprehensive income, changes in equity and cash flows for each of the years then ended of Avangrid Networks, Inc. and our report dated July 7, 2017 expressed an unqualified opinion thereon. We considered the material weaknesses identified above in determining the nature, timing, and extent of audit procedures applied in our audit of the 2016 combined and consolidated financial statements, and this report does not affect such report on the combined and consolidated financial statements.

Ernst + Young LLP

July 7, 2017

Avangrid Networks, Inc.
Combined and Consolidated Statements of Income

Year ended December 31, (Thousands)	2016	2015
Operating Revenues		
Electricity	**$3,767,029**	$2,785,640
Natural gas	**1,308,268**	600,678
Total Operating Revenues	**5,075,297**	3,386,318
Operating Expenses		
Electricity purchased and fuel used in generation	**707,006**	597,417
Natural gas purchased	**466,507**	223,710
Operations and maintenance	**1,869,353**	1,388,870
Depreciation and amortization	**465,967**	328,258
Other taxes	**467,693**	312,390
Total Operating Expenses	**3,976,526**	2,850,645
Operating Income	**1,098,771**	535,673
Other Income	**45,790**	43,946
Equity earnings from equity method investments	**15,118**	527
Interest Charges, Net	**(253,750)**	(228,244)
Income Before Income Tax	**905,929**	351,902
Income Tax Expense	**429,409**	145,048
Net Income	**476,520**	206,854
Less:		
Preferred Stock Dividends of Subsidiaries, Noncontrolling Interests	**-**	34
Net Income Attributable to Other Noncontrolling Interests	**409**	353
Net Income Attributable to Avangrid Networks, Inc.	**$476,111**	$206,467

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

Avangrid Networks, Inc.
Combined and Consolidated Statements of Comprehensive Income

Year ended December 31, (Thousands)	2016	2015
Net Income	**$476,520**	$206,854
Other Comprehensive Income, Net of Tax		
Net unrealized holding gain on investments	**6**	18
Amortization of pension for nonqualified plans	**719**	2,841
Unrealized gain (loss) on derivatives qualified as hedges:		
Unrealized gain (loss) during period on derivatives qualified as hedges	**190**	(1,617)
Reclassification adjustment for loss included in net income	**1,239**	1,991
Reclassification adjustment for loss on settled cash flow treasury hedges	**4,911**	5,178
Net unrealized gain on derivatives qualified as hedges, Net of Tax	**6,340**	5,552
Other Comprehensive Income	**7,065**	8,411
Comprehensive Income	**483,585**	215,265
Less:		
Preferred Stock Dividends of Subsidiaries, Noncontrolling Interests	**-**	34
Comprehensive Income Attributable to Other Noncontrolling Interests	**409**	353
Comprehensive Income Attributable to Avangrid Networks, Inc.	**$483,176**	$214,878

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

Avangrid Networks, Inc.
Combined and Consolidated Balance Sheets

December 31,	**2016**	**2015**
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	**$16,263**	$31,951
Accounts receivable and unbilled revenues, net	**871,610**	789,616
Accounts receivable from affiliates	**48,975**	32,474
Notes receivable from affiliates	**4,336**	4,990
Fuel and natural gas in storage	**69,175**	99,818
Materials and supplies	**54,285**	41,758
Broker margin accounts	**15,816**	34,766
Prepaid property taxes	**73,424**	116,469
Prepayments and other current assets	**221,974**	121,427
Regulatory assets	**284,532**	218,853
Total Current Assets	**1,660,390**	1,492,122
Property, plant and equipment	**16,024,499**	14,996,424
Less accumulated depreciation	**(3,970,320)**	(3,726,286)
Net Property, Plant and Equipment in Service	**12,054,179**	11,270,138
Construction work in progress	**978,494**	1,094,233
Total Property, Plant and Equipment	**13,032,673**	12,364,371
Equity method investments	**150,914**	110,306
Other Property and Investments	**58,317**	61,050
Regulatory and Other Assets		
Regulatory assets	**3,091,202**	3,313,595
Goodwill	**2,744,416**	2,733,355
Other	**42,889**	30,561
Total Regulatory and Other Assets	**5,878,507**	6,077,511
Total Assets	**$20,780,801**	$20,105,360

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

Avangrid Networks, Inc.
Combined and Consolidated Balance Sheets

December 31,	2016	2015
(Thousands, except share information)		
Liabilities		
Current Liabilities		
Current portion of long-term debt	**$336,403**	$198,039
Notes Payable	**542**	163,000
Notes payable to affiliates	**427,868**	547,126
Accounts payable and accrued liabilities	**824,542**	670,183
Accounts payable to affiliates	**35,806**	5,130
Interest accrued	**56,345**	62,426
Taxes accrued	**37,674**	31,252
Derivative liabilities	**23,273**	30,385
Environmental remediation costs	**33,631**	35,144
Other current liabilities	**208,665**	171,178
Regulatory liabilities	**191,934**	147,133
Total Current Liabilities	**2,176,683**	2,060,996
Regulatory and Other Liabilities		
Regulatory liabilities	**1,752,799**	1,840,712
Deferred income taxes regulatory	**575,303**	518,511
Other Non-current Liabilities		
Deferred income taxes	**2,337,192**	2,164,495
Nuclear plant obligations	**122,579**	122,258
Pension and other postretirement benefits	**1,078,136**	1,172,392
Environmental remediation costs	**398,026**	405,559
Asset retirement obligations	**36,900**	43,210
Derivative liabilities	**71,783**	68,543
Other	**163,928**	177,709
Total Regulatory and Other Liabilities	**6,536,646**	6,513,389
Long-term Debt	**3,970,280**	4,417,804
Total Liabilities	**12,683,609**	12,992,189
Commitments and Contingencies		
Preferred Stock of Subsidiary		
Redeemable preferred stock, noncontrolling interest	**532**	312
Avangrid Networks, Inc. Common Stock Equity		
Common stock ($.01 par value, 100 shares authorized and outstanding at December 31, 2016 and 2015)	**-**	-
Capital in excess of par value	**6,656,988**	5,932,467
Retained earnings	**1,483,664**	1,231,858
Accumulated other comprehensive loss	**(54,238)**	(61,303)
Total Avangrid Networks, Inc. Common Stock Equity	**8,086,414**	7,103,022
Other Noncontrolling Interests	**10,246**	9,837
Total Equity	**8,096,660**	7,112,859
Total Liabilities and Equity	**$20,780,801**	$20,105,360

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

Avangrid Networks, Inc.
Combined and Consolidated Statements of Cash Flows

Year Ended December 31,	2016	2015
(Thousands)		
Cash Flow from Operating Activities		
Net income	**$476,520**	$206,854
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	**465,967**	328,258
Impairment of non-current assets	**-**	6,000
Amortization of regulatory and other assets and liabilities	**49,402**	101,103
Carrying cost of regulatory assets and liabilities	**13,156**	41,109
Deferred income taxes and investment tax credits, net	**352,874**	43,532
Pension cost	**109,959**	112,630
Earnings from equity method investments	**(15,118)**	(527)
Accretion expenses	**1,003**	1,054
Amortization of debt (premium) cost	**(23,733)**	3,727
Other non-cash items	**(17,205)**	(6,575)
Changes in current operating assets and liabilities		
Accounts receivable and unbilled revenues	**(100,533)**	7,386
Inventories	**18,116**	24,283
Cash distribution from equity method investments	**13,925**	-
Accounts payable	**170,876**	108,187
Other assets/liabilities	**(260,399)**	(276,847)
Accrued taxes	**(2,731)**	168
Regulatory assets/liabilities	**(81,100)**	70,648
Net Cash Provided by Operating Activities	**1,170,979**	770,990
Cash Flow from Investing Activities		
Capital expenditures	**(1,175,316)**	(774,413)
Contributions in aid of construction	**80,635**	38,465
Government grants	**-**	16,479
Proceeds from sale of equity method and other investment	**-**	3,047
Proceeds from disposals of property, plant and equipment	**50,001**	-
Deemed cash contribution from transfer of UIL	**-**	47,465
Cash distribution from equity method investments	**5,072**	-
Proceeds/(lending) for notes receivable with affiliates	**653**	(4,990)
Other current and noncurrent investments	**(17,066)**	(2,873)
Net Cash Used in Investing Activities	**(1,056,021)**	(678,820)
Cash Flow from Financing Activities		
Capital contribution from parent	**725,547**	-
Long-term note issuances	**493,160**	350,000
Long-term note repayments	**(832,869)**	(131,726)
Repayments of short-term debt	**(281,716)**	(232,541)
Repayment of capital leases	**(10,435)**	(2,953)
Dividends paid on common stock	**(224,305)**	(59,150)
Capital contribution from noncontrolling interest	**-**	2,164
Net Cash Used in Financing Activities	**(130,618)**	(74,206)
Net (Decrease)/Increase in Cash, Cash Equivalents and Restricted Cash	**(15,660)**	19,964
Cash, Cash Equivalents and Restricted Cash, Beginning of Year	**33,677**	13,713
Cash, Cash Equivalents and Restricted Cash, End of Year	**$18,017**	$33,677

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

Avangrid Networks, Inc.
Combined and Consolidated Statements of Changes in Equity

(Thousands, except share amounts)	Avangrid Networks, Inc. Stockholder: Common Stock Outstanding $.01 Par Value Shares	Amount	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stock Equity	Other Noncontrolling Interests	Total
Balance, January 1, 2015	100	-	$3,078,759	$1,084,541	$(69,714)	$4,093,586	$7,320	$4,100,906
Net income*				206,467		206,467	353	206,820
Other comprehensive income, net of tax					8,411	8,411		8,411
Comprehensive income*								215,231
Capital contribution from noncontrolling interest							2,164	2,164
Deemed dividend			(18,978)			(18,978)		(18,978)
Deemed contribution from transfer of UIL			2,872,686			2,872,686		2,872,686
Cash dividends paid on common stock				(59,150)		(59,150)		(59,150)
Balance, December 31, 2015	100	-	5,932,467	1,231,858	(61,303)	7,103,022	9,837	7,112,859
Net income*				**476,111**		**476,111**	**409**	**476,520**
Other comprehensive income, net of tax					**7,065**	**7,065**		**7,065**
Comprehensive income*								**483,585**
Stock-based compensation			**237**			**237**		**237**
Capital contribution from parent			**706,085**			**706,085**		**706,085**
Deemed capital contribution			**18,199**			**18,199**		**18,199**
Cash dividends paid on common stock				**(224,305)**		**(224,305)**		**(224,305)**
Balance, December 31, 2016	**100**	-	**$6,656,988**	**$1,483,664**	**$(54,238)**	**$8,086,414**	**$10,246**	**$8,096,660**

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

*Amounts do not include Preferred Stock Dividends of Subsidiaries' Noncontrolling Interests of $34 in 2015.

Notes to Combined and Consolidated Financial Statements

Note 1. Significant Accounting Policies

Background: Avangrid Networks, Inc. (Networks, the company, we, our, us) formerly Iberdrola USA Networks, is a public utility holding company operating under the Public Utility Holding Company Act of 2005. Networks is a wholly-owned subsidiary of Avangrid, Inc. (AGR), formerly Iberdrola USA, Inc. which is an 81.5% owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain. We are a super-regional energy services and delivery company 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).

Networks was formed on November 20, 2013, when AGR was reorganized to become the parent company of Networks and Avangrid Renewables Holding, Inc. (ARHI), formerly Iberdrola Renewables Holdings, Inc., another subsidiary of AGR. AGR transferred its investments in CMP Group and RGS to Networks at the time of the reorganization, as well as Iberdrola USA Management Corporation, a company providing management services for the utilities. Also transferred to Networks was Iberdrola USA Enterprises, a holding company that owns Maine Natural Gas.

On December 16, 2015, AGR completed the acquisition of UIL Holdings Corporation (UIL). Immediately following the completion of the acquisition, former UIL shareowners owned 18.5% of the outstanding shares of common stock of AGR, and Iberdrola owned the remaining shares. The acquisition was accounted for as a business combination in AGR's consolidated financial statements (see Note 2, 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. Effective as of April 30, 2016, UIL and its subsidiaries were transferred to a wholly-owned subsidiary of Networks.

Basis of presentation

As a result of the common control transaction that occurred as part of the transfer of the ownership of UIL and its subsidiaries to Networks, we recorded the net assets of UIL in these combined and consolidated financial statements at the historical accounting basis of AGR. The historical accounting basis of AGR includes purchase accounting adjustments related to AGR's acquisition of UIL (See Note 2). As such, these combined and consolidated financial statements were adjusted to reflect the retrospective combination with UIL since the inception of common control, which is the date of the acquisition of UIL by AGR.

***Accounts receivable*:** Accounts receivable at December 31 include unbilled revenues of $257 million for 2016 and $210 million for 2015, and are shown net of an allowance for doubtful accounts at December 31 of $56 million for 2016 and $55 million for 2015. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was $47 million in 2016 and $43 million in 2015.

Notes to Combined and Consolidated Financial Statements

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.

The allowance for doubtful accounts is our best estimate of the amount of probable credit losses in our 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.

Our accounts receivable include amounts due under deferred payment arrangements (DPAs). 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 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 or is otherwise considered to be delinquent. We establish provisions for uncollectible accounts by using both historical average loss percentages to project future losses and by establishing specific provisions for known credit issues. Amounts are written off when reasonable collection efforts have been exhausted. The allowance for doubtful accounts for DPAs at December 31 was $30 million for 2016 and $35 million for 2015. DPA receivable balances at December 31 were $54 million for 2016 and $62 million for 2015.

***Asset retirement obligations*:** We record the fair value of the liability for an asset retirement obligation (ARO) and a conditional ARO in the period in which it is incurred and capitalize the cost by increasing the carrying amount of the related long-lived asset. We adjust the liability periodically to reflect revisions to either the timing or the amount of the original estimated undiscounted cash flows over time. The liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement we will either settle the obligation at its recorded amount or incur a gain or a loss. Our regulated utilities defer any timing differences between rate recovery and depreciation expense and accretion as either a regulatory asset or a regulatory liability.

The term conditional ARO refers to an entity's legal obligation to perform an asset retirement activity in which the timing or method of settlement are conditional on a future event that may or may not be within the control of the entity. 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 ARO at December 31, including our conditional ARO, was $37 million for 2016 and $43 million for 2015. The ARO is associated with our long-lived assets and primarily consists of obligations related to removal or retirement of: asbestos, PCB-contaminated equipment, gas pipeline and cast iron gas mains.

The following table reconciles the beginning and ending aggregate carrying amount of the ARO for the years ended December 31, 2016 and 2015.

Year ended December 31,	2016	2015
(Thousands)		
ARO, beginning of year	**$43,210**	$38,699
Acquisition of UIL	**-**	19,168
Liabilities settled during the year	**(7,313)**	(15,711)
Accretion expense	**1,003**	1,054
ARO, end of year	**$36,900**	$43,210

We have AROs for which we have not recognized a liability because the fair value cannot be reasonably estimated due to indeterminate settlement dates, including: 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.

Accrued removal obligations**:** Our regulated utilities meet the requirements concerning accounting for regulated operations, and recognize a regulatory liability, for the difference between removal costs collected in rates and actual costs incurred. We classify those amounts as accrued removal obligations.

Combined and consolidated statements of cash flows**:** 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 combined and consolidated balance sheets. As of both December 31, 2016 and 2015, the amount of restricted cash was $1.7 million.

Supplemental Disclosure of Cash Flows Information	2016	2015
(Thousands)		
Cash paid during the year ended December 31:		
Interest, net of amounts capitalized	**$222,603**	$126,846
Income taxes paid, net	**$132,042**	$140,682

Interest capitalized was $17.0 million in 2016 and $12.3 million in 2015.

Depreciation and amortization**:** We determine 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. Our depreciation accruals were equivalent to 2.9% of average depreciable property for 2016 and 2.6% in 2015. We amortize our capitalized software cost, which is included in common plant, using the straight line method, based on useful lives of 5 to 18 years. Depreciation expense was $423 million in 2016 and $305 million in 2015. Amortization of capitalized software was $43 million in 2016 and $23 million in 2015.

We charge repairs and minor replacements to operations and maintenance expense, and capitalize renewals and betterments, including certain indirect costs. We charge the original cost of utility plant retired or otherwise disposed of to accumulated depreciation.

Plant	Estimated useful life range (years)	December 31, 2016	December 31, 2015
(thousands)			
Electric	29-90	**10,341,688**	11,505,698
Natural Gas	25-80	**4,803,415**	2,673,438
Common	7-75	**879,396**	817,288
Total Property, Plant and Equipment		**$16,024,499**	$14,996,424

Electric and Natural gas plant includes capital leases of $97 million in 2016 and $64 million in 2015. Accumulated depreciation related to these leases was $43 million in 2016 and $41 million in 2015.

***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.

***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 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.

***Inventory**:* Inventory comprises fuel and gas in storage and materials and supplies. We own natural gas that is stored in 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 natural 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 using the weighted average method and reported on the balance sheet within "Materials and supplies."

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

Government grants: We account for government grants related to depreciable assets in the same way as we account for contributions in aid of construction, that is, the grant amount is credited to the cost of the related property, plant and equipment. In accounting for government grants related to operating and maintenance costs, we recognize amounts receivable as compensation for expenses already incurred in the statements of income in the period in which the expenses are incurred.

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

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 method investment, the carrying value of which was $22 million as of December 31, 2016.

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.

Distributions received from equity method investments amounted to $19 million for the year ended December 31, 2016, which is reflected as either distributions of earnings or as returns of capital in the operating and investing sections of the combined and consolidated statements of cash flows.

Stock-based compensation: Stock-based compensation represents costs related to AGR performance stock units (PSUs) granted to certain officers and employees of Networks under the Avangrid, Inc. Omnibus Incentive Plan in July 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. 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.

New Accounting Standards and Interpretations: New accounting standards issued by the Financial Accounting Standards Board (FASB) that we either adopted or have not yet adopted are explained below. Although we are not a public business entity, our parent company became a registrant in December 2015, and in the future we will adopt new accounting standards based on the effective date for public entities.

(a) Revenue from contracts with customers

In May 2014 the 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. 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 2, 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 collectability of the reported amount. An entity must use judgment in determining the relevant information and estimation methods appropriate in its circumstances. The amendments are effective for public entities that are SEC filers for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, with early adoption permitted. Entities are to apply the amendments on a modified retrospective basis for most instruments. We expect our adoption will not materially affect our 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 had no change in net cash provided by operating activities in the consolidated statements of cash flow, for the year ended December 31, 2015.

***Other Income and Other Deductions*:**

Year Ended December 31,	**2016**	**2015**
(Thousands)		
Interest and dividend income	**$1,631**	$542
Allowance for funds used during construction	**23,906**	20,596
Carrying costs on regulatory assets	**14,374**	28,088
Gain on sale of property	**2,293**	2,014
Miscellaneous	**6,724**	5,619
Total other income	**$48,928**	$56,859
Asset impairment	**-**	(6,000)
Civic donations	**(3,369)**	(4,507)
Miscellaneous	**231**	(2,406)
Total other deductions	**$(3,138)**	$(12,913)

***Principles of consolidation and combination*:** These financial statements consolidate our majority-owned subsidiaries after eliminating intercompany transactions. As a result of the common control transaction that occurred as part of the transfer of the ownership of UIL and its subsidiaries to Networks, these combined and consolidated financial statements were adjusted to reflect the retrospective combination with UIL since the inception of common control, which is the date of the acquisition of UIL by AGR. The balances have been updated to reflect the appropriate tax position within these combined and consolidated financial statements in accordance with the tax sharing agreement with AGR and its subsidiaries. The amounts have been adjusted through equity as a deemed non-cash dividend and deemed non-cash capital contribution for a common control transaction.

Reclassifications: Certain amounts have been reclassified in the combined and consolidated statements of cash flows 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 flows.

***Regulatory assets and liabilities*:** Our public utility subsidiaries currently meet the requirements concerning accounting for regulated operations for their electric and natural gas operations in New York, Maine, Connecticut and Massachusetts; however, we cannot predict what effect the competitive market or future actions of regulatory entities would have on their ability to continue to do so. If our public utility subsidiaries were to no longer meet the requirements concerning accounting for regulated operations for all or a separable part of their operations, they may have to record certain regulatory assets and regulatory liabilities as an expense or as revenue, or include them in accumulated other comprehensive income.

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. Substantially all regulatory assets for which funds have been expended are either included in rate base or are accruing carrying costs. The primary regulatory assets and liabilities that have not yet been included in rates, and are therefore accruing carrying costs until included in rates, are deferred storm costs and various deferrals, both assets and liabilities, that result from reconciliation mechanisms designed to allow recovery of actual costs. Our operating utilities also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs (See Note 4).

Related party transactions: Certain Networks subsidiaries borrow from AGR, through intercompany revolving credit agreements. For NYSEG, RG&E and CMP, the intercompany revolving credit agreements provide access to supplemental liquidity. Other Networks subsidiaries do not have third party borrowing arrangements and rely on AGR as their primary source of financing. Networks incurred financing costs from AGR of $2.7 million in 2016 and $3 million in 2015 recorded as interest expense.

Networks, including its subsidiaries, provides various administrative and other services to AGR. The costs charged to the affiliates are based upon service agreements which include allocation methodologies and vary depending on the type of service provided. Management believes such allocations are reasonable. The cost for services provided by Networks to AGR was $0.7 million and $0.6 million for 2016 and 2015, respectively.Networks received charges from Iberdrola for work on the unified SAP project of $1.4 million in 2015. There are no such charges in 2016 due the completion of the project in 2015. Networks' subsidiaries received services from Iberdrola Engineering Products (IEP) related to capital projects of $0.3 million for 2016 and $2.5 million for 2015. Networks contributed amounts to fund IEP's direct costs associated with these engineering projects.

Of the total balance in accounts payable to affiliates of $36 million at December 31, 2016, $28 million is associated to Iberdrola. The balance in accounts payable to affiliates of $5 million at December 31, 2015, is mostly associated to IEP for capital projects and other miscellaneous affiliate costs, as described above.

Networks incurs a corporate overhead charge from its ultimate parent, Iberdrola. The total amount charged to Networks for management services provided by Iberdrola was approximately $28.6 million for 2016 and $16.6 million for 2015. Networks also receives the charge from Iberdrola for ARHI and passes through ARHI's share on to them. The total amount charged to ARHI in 2016 and 2015 for these management services was approximately $37 million and $31 million.

AGR has provided a guarantee on behalf of RG&E in the amount of $123 million related to RG&E's nuclear plant obligation on the balance sheet. This is a liability that RG&E may have to ultimately pay to the DOE related to spent nuclear fuel from the Ginna Nuclear Power Plant (formerly owned by RG&E). AGR on behalf of Maine Natural Gas, a 100% owned subsidiary of Networks, also guarantees approximately $18.2 million toward natural gas purchases.

Of the total balance in accounts receivable from affiliates of $49 million at December 31, 2016, $37 million is associated to ARHI and $11 million is associated to New York TransCo. The balance in accounts receivable from affiliates of $32 million at December 31, 2015 is mostly associated to ARHI.

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 increased its equity method investment in the New York TransCo by approximately $21 million for a total equity method investment of $22 million. Additionally, 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, $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.

AGR has reciprocal current account agreements with many of its unregulated subsidiaries, including the nonregulated subsidiaries of Networks, which do not have their own bank accounts. This arrangement creates a net receivable or payable position for Networks, with the underlying balance in the form of a note, subject to an interest rate charge for the borrower. The Networks balance in notes receivable from affiliates at December 31, 2016 and 2015, was $4 million and $5 million, respectively. The lending rate as of December 31, 2016 and 2015, was 1.2% and 1.30%, respectively.

Of the $132 million income tax paid in 2016, substantially all was paid to AGR under the tax sharing agreement. Included in the income taxes paid in 2015, $133 million was paid to AGR under the tax sharing agreement.

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.

In addition, our regulated utilities accrue revenue pursuant to the various regulatory provisions to record regulatory assets for revenues that will be collected in the future.

Taxes**:** AGR files consolidated federal and state income tax returns including all of the activities of its subsidiaries. Each subsidiary company is treated as a member of the consolidated group and determines its current and deferred taxes based on the separate return with benefits for loss method. Networks is treated as a separate member and calculates its consolidated income tax expense or benefit by combining the current and deferred income tax expense or benefit of each of its subsidiaries and of Networks holding company, which is treated as a separate member. Each member settles its current tax liability or benefit each year directly with AGR pursuant to a tax sharing agreement between AGR and its members.

The aggregate amount of the intercompany income tax receivable balance due from AGR is $144.4 million and $90.7 million at December 31, 2016 and December 31, 2015, respectively.

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 other 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. Uncertain tax positions have been classified as non-current unless expected to be paid within one year. 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 charges, net” and “Other (income)” of the consolidated statements of income.

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.

We account for sales tax collected from customers and remitted to taxing authorities on a net basis.

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 measurement; and (9) earnings sharing mechanism (ESM); (10) environmental remediation liabilities; (11) pension and Other Postretirement Employee Benefit (OPEB) and (12) AROs. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our consolidated financial statements will change as new events occur, as more experience is acquired, as additional information is obtained, and as our operating environment changes. We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside experts to assist in our evaluations, as considered necessary. Actual results could differ from those estimates.

Union bargain agreements: The Company has approximately 56.4% of the company's employees covered by a collective bargaining agreement. Agreements, which will expire within the coming year apply to approximately 7.1% of the employees.

Note 2. Acquisition of UIL

On December 16, 2015 (acquisition date), AGR completed the acquisition of UIL, a diversified energy company with its portfolio of regulated utility companies in Connecticut and Massachusetts that is expected to provide 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 AGR 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 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 AGR, 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, AGR determined that UIL's common stock is more reliably measurable than the common stock of AGR 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 AGR 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 was 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 AGR common stock issued to the UIL shareowners in the business combination represents the purchase consideration in the business combination, which was computed as follows:

		(Thousands, 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	$	2,837,132
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	$	24,808
Total shares of AGR 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	$	10,746
Total consideration	$	2,872,686

(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:

		(Thousands, except share data)
Cash ($10.50 x number of UIL common shares outstanding at the acquisition date-56,629,377)	$	594,608
AGR Equity		2,278,078
Total consideration	$	2,872,686

The following unaudited pro forma financial information presents the combined results of operations as if the acquisition had been completed on January 1, 2015, 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 (Thousands)
Revenue	$4,977,000
Net income	$383,280

The revenue and net (loss) of UIL since the acquisition date included in the combined and 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).

AGR 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**
		(Thousands)	
Current assets, including cash of $48 million	500,443	(7,492)	492,951
Other investments	113,754	22,277	136,031
Property, plant and equipment	3,552,403	(5,371)	3,547,032
Regulatory assets	966,445	36,141	1,002,586
Other assets	51,989	-	51,989
Current liabilities	(493,408)	-	(493,408)
Regulatory liabilities	(493,132)	-	(493,132)
Non-current debt	(1,877,977)	(26,978)	(1,904,955)
Other liabilities	(1,202,082)	(29,684)	(1,231,766)
Total net assets acquired at fair value	1,118,435	(11,107)	1,107,328
Goodwill – consideration transferred in excess of fair value assigned	1,754,251	11,107	1,765,358
Total consideration	**$ 2,872,686**		**$ 2,872,686**

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 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., AGR 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 11, 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 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 combined and 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 AGR determined a fair value of contingent liabilities of approximately $46.0 million relating to certain environmental sites.

The following commitments were 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 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 3. 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 10 - Commitments and Contingencies 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 Federal Power Act (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 Company, Inc. (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 contained 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 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 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 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 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 and the customer average interruption duration index (SAIFI). 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 UIL 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. Collaborative and settlement processes began in 2017 and are expected to continue throughout 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 began in the first quarter of 2017 and is expected to continue through the summer 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 is allowed to 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. The RSSA surcharge continues to remain in place beyond March 31, 2017. The date that the surcharge will cease is dependent on the timing of RG&E’s receipt of the capital recovery balance descussed below. Per the RSSA, Ginna prepared and presented an invoice to RG&E that, in addition to the costs and revenues for March 2017, also covered a one-time payment in the amount of $11.5 million. This payment was made in May 2017 and will be recovered from ratepayers. The RSSA also stated that 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 would pay RG&E a capital recovery balance of up to $20.1 million, plus interest, in quarterly installments until eight calendar quarterly payments have been made or, alternatively, Ginna could pay the $20.1 million as a lump sum amount to avoid interest charges. Ginna paid the lump sum amount in June 2017. 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 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 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.

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 4. 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, plant and 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 $140 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.

Notes to Combined and Consolidated Financial Statements

Current and long-term regulatory assets at December 31, 2016 and 2015 consisted of:

December 31,	2016	2015
(Thousands)		
Current		
Environmental remediation costs	**$14,794**	$37,407
Pension and other postretirement benefits cost deferrals	**21,316**	7,530
Pension and other postretirement benefits	**6,546**	12,365
Hedges losses	**9,842**	36,730
Storm costs	**40,129**	7,544
Transmission revenue reconciliation mechanism	**12,049**	4,809
Non by-passable charges	**332**	6,686
Revenue decoupling mechanism	**15,076**	6,493
Temporary supplemental assessment surcharge	**4,359**	6,545
Contracts for differences	**14,132**	17,959
Reliability support service	**27,000**	-
Hardship programs	**16,060**	13,107
Deferred purchased gas	**14,811**	12,326
Deferred transmission expense	**12,497**	12,169
Electric supply reconciliation	**12,761**	264
Deferred property taxes	**9,766**	491
Other	**53,062**	36,428
Total current regulatory assets	**$284,532**	$218,853
Other long-term		
Federal tax depreciation normalization adjustment	**$161,319**	$157,783
Pension and other postretirement benefits cost deferrals	**133,959**	151,001
Pension and other postretirement benefits	**1,319,382**	1,510,390
Unfunded future income taxes	**542,347**	547,161
Environmental remediation costs	**287,029**	269,760
Debt premium	**150,676**	140,733
Storm costs	**186,184**	251,326
Asset retirement obligation	**18,367**	23,705
Deferred property tax	**32,546**	45,044
Unamortized loss on debt reacquisitions	**19,867**	31,421
Merger capital expense	**11,038**	14,533
Low income programs	**17,270**	28,033
Deferred meter replacement costs	**31,543**	34,077
Contracts for differences	**61,152**	49,746
Other	**118,523**	58,882
Total long-term regulatory assets	**$3,091,202**	$3,313,595

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. 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.

Environmental remediation costs include 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.

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.

Deferred property taxes represent 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.

Notes to Combined and Consolidated Financial Statements

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 long-term regulatory liabilities at December 31, 2016 and 2015 consisted of:

December 31,	**2016**	**2015**
(Thousands)		
Current		
Gas supply charge and deferred natural gas cost	**$5,913**	$6,204
Revenue decoupling mechanism	**8,502**	13,948
Transmission revenue reconciliation mechanisms	**4,764**	5,490
Reliability support services (Cayuga)	**3,163**	15,968
Yankee DOE Phase I	**23,938**	5,234
Non by-passable charges	**21,819**	7,004
Energy supply reconciliation	**-**	7,895
Energy efficiency portfolio standard	**44,850**	32,914
Unfunded future income taxes	**23**	10,104
Rate refund-FERC ROE proceeding	**-**	3,091
Pension & other postretirement benefit cost deferral	**16,812**	-
Carrying cost on deferred income tax bonus depreciation	**15,433**	-
Merger related rate credits	**2,000**	20,000
Other	**44,717**	19,281
Total current regulatory liabilities	**$191,934**	$147,133
Long-term		
Asset sale gain account	**$9,309**	$8,365
Merger capital expense target customer credit	**14,533**	16,800
Carrying costs on deferred income tax bonus depreciation	**94,887**	115,743
Pension and other postretirement benefits	**25,382**	24,760
Positive benefit adjustment	**41,587**	50,928
Pension and other postretirement benefits cost deferral	**49,734**	65,341
Deferred property taxes	**18,870**	14,605
Rate refund-FERC ROE proceeding	**21,738**	45,039
Accrued removal obligations	**1,116,969**	1,084,224
Merger related rate credits	**21,329**	24,000
New York State tax rate change	**8,986**	16,925
Post term amortization	**2,972**	25,332
Spent nuclear fuel	**-**	14,155
Theoretical reserve flow thru impact	**24,170**	31,067
Economic development	**34,893**	35,939
Variable rate debt	**28,290**	17,794
Other taxes	**25,462**	67,763
Other	**213,688**	181,932
Total noncurrent regulatory liabilities	**1,752,799**	1,840,712
Deferred income taxes regulatory	**575,303**	518,511
Total long-term regulatory liabilities	**$2,328,102**	$2,359,223

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.

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.

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.

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 2 for further details. In the year ended December 31, 2016, $20 million of rate credits was applied against customer bills.

Economic development represents the economic development program which enables NYSEG 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 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 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.

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.

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.

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 5. Goodwill

As of December 31, 2016 and 2015, the gross amounts of goodwill were $2,744 million and $2,733 million, respectively, with no accumulated impairment losses. During the year ended December 31, 2015 goodwill 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 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 2 – Acquisition of UIL – for further details).

Goodwill Impairment Assessment

For impairment testing purposes, Networks 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.

We had no impairment of goodwill in 2016 and 2015 as a result of our testing impairment testing.

Provided recent relevant events (acquisition of UIL in December 2015 and approval of the proposal by the NYPSC, see Note 2 and 3, 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.

As a result of our step zero qualitative assessment in 2015, 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.

Note 6. Income Taxes

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

Years Ended December 31,	**2016**	**2015**
(Thousands)		
Current		
Federal	**$55,220**	**$66,957**
State	**21,315**	**34,559**
Current taxes charged to expense	**76,535**	**101,516**
Deferred		
Federal	**319,699**	**48,161**
State	**34,257**	**(4,002)**
Deferred taxes charged to expense	**353,956**	**44,159**
Investment tax credit adjustments	**(1,082)**	**(627)**
Total Income Tax expense	**$429,409**	**$145,048**

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 and 2015 consisted of:

Years Ended December 31,	**2016**	**2015**
(Thousands)		
Tax expense at Federal statutory rate	**$317,075**	$123,166
Depreciation and amortization not normalized	**69,140**	12,390
Allowance for funds used during construction	**-**	(10,901)
Investment tax credit amortization	**(1,082)**	(627)
Tax return related adjustments	**(355)**	137
State taxes, net of federal benefit	**36,123**	19,862
Other, net	**8,508**	1,021
Total Income Tax expense	**$429,409**	$145,048

Income tax expense for the year ended December 31, 2016 was $112.3 million higher than it would have been at the statutory federal income tax rate of 35% due predominately to state taxes, (net of federal benefit), depreciation not normalized, and adjustment of $140 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. This resulted in an effective tax rate of 47.4%. Income tax expense for the year ended December 31, 2015 was $21.9 million higher than it would have been at the statutory federal income tax rate of 35% due predominately to state taxes, (net of federal benefit), and depreciation not normalized, partially offset by allowance for funds used during construction. This resulted in an effective tax rate of 41.2%. State taxes, net of federal benefit, are higher in 2016 than in 2015 due to the benefit in 2015 for a rate reduction in New York from 7.1% to 6.5%

Notes to Combined and Consolidated Financial Statements

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

	2016	2015
Non-current Deferred Income Tax Liabilities (Assets)		
Property related	**$2,715,820**	$2,435,480
Unfunded future income taxes	**218,686**	211,347
Employee Benefits	**69,062**	167,828
Accumulated deferred investment tax credits	**14,658**	15,168
Federal and State NOL's	**-**	(4,897)
Federal and state tax credits	**(51,698)**	(16,652)
Positive benefits adjustments merger order	**(17,565)**	(24,789)
Joint ventures/partnerships	**52,758**	54,184
Non-firm margin	**-**	(17,674)
Storm cost deferral	**88,930**	102,693
Other	**(183,880)**	(248,670)
Non-current Deferred Income Tax Liabilities	**2,906,771**	2,674,018
Add: Valuation allowance	**5,724**	8,988
Total Non-current Deferred Income Tax Liabilities	**2,912,495**	2,683,006
Less amounts classified as regulatory liabilities		
Non-current deferred income taxes	**575,303**	518,511
Non-current Deferred Income Tax Liabilities	**$2,337,192**	$2,164,495
Deferred tax assets	**$253,143**	$312,682
Deferred tax liabilities	**3,165,638**	2,995,688
Net Accumulated Deferred Income Tax Liabilities	**$2,912,495**	$2,683,006

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. The decrease in valuation allowance in 2016 represents 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 and 2015 consisted of:

Years ended December 31,	2016	2015
(Thousands)		
Balance as of January 1	**$26,506**	$31,598
Increases for tax positions related to prior years	**33,187**	-
Reduction for tax position related to settlements with taxing authorities	**-**	(5,092)
Balance as of December 31	**$59,693**	$26,506

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 in the financial statements when it is more likely than not, based on the technical merits, that the position will be sustained upon examination, assuming the position will be audited and the taxing authority has full knowledge of all relevant information.

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.

Accruals for interest and penalties on tax reserves were $1.7 million as of both December 31, 2016 and 2015. If recognized, $0.7 million of the total gross unrecognized tax benefits would affect the effective tax rate. Gross unrecognized tax benefits increased by $33.2 million in 2016 due to tax positions related to prior years.

On December 29, 2014, the Joint Committee on Taxation approved the examination of AGR and its subsidiaries, which includes members of the Networks consolidated group, 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 are closed through 2011.

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.

Note 7. Long-term Debt

As of December 31, (Thousands)	Maturity Dates		2016 Balances	2016 Interest Rates		2015 Balances	2015 Interest Rates
First mortgage bonds [(a)]	2018-2045	$	1,752,362	3.07%-10.60%	$	1,775,345	3.07%-10.06%
Senior unsecured debt	2017-2045	$	2,276,287	3.24%-6.15%	$	2,380,705	2.98%-10.48%
Unsecured pollution control notes – fixed	2020		200,000	2.00%-2.375%		200,000	2.00%-2.375%
Secured pollution control notes – fixed	2016		-	-		39,850	4.75%-5.00%
Unsecured pollution control notes – Variable	2032		62,150	1.32%		219,431	0.195%-1.18%
Obligations under capital leases	2017-2036		46,971			24,451	
Unamortized debt issuance costs and discount			(31,087)			(23,939)	
Total Debt		**$**	**4,306,683**		**$**	**4,615,843**	
Less: debt due within one year, included in current liabilities			336,403			198,039	
Total Non-current Debt		**$**	**3,970,280**		**$**	**$4,417,804**	

(a) The first mortgages bonds are secured by a first mortgage lien on substantially all of Net Utility Plant In Service of RG&E, CMP, SCG and BGC, totaling $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 AGR 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, AGR, its subsidiary, UIL, and The Bank of New York Mellon, entered into a supplemental indenture, pursuant to which AGR 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 AGR.

At December 31, 2016, long-term debt, including sinking fund obligations and capital lease payments (in thousands) that will become due during the next five years is:

2017	2018	2019	2020	2021
$336,403	$176,130	$353,783	$268,280	$304,976

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.

Note 8. Bank Loans and Other Borrowings

Networks had $428 million and $547 million of short-term notes payable to affiliates outstanding at December 31, 2016 and 2015. Networks funds short-term liquidity needs through intercompany agreements with AGR and the AGR Credit Facility described below. All of the outstanding balances to affiliates at December 31, 2016 and December 31, 2015 were borrowed under the intercompany agreements. At December 31, 2015, the balance in notes payable consisted of $160 million of borrowings under the UIL credit facility (terminated in 2016 as described below) and $3 million in other notes payable.

On April 5, 2016, AGR and its investment-grade rate utility subsidiaries (NYSEG, RG&E, CMP, UI, CNG, SCG and BGC) entered into a revolving credit facility with a syndicate of banks, (the AGR Credit Facility), that provides for maximum borrowings of up to $1.5 billion in the aggregate. Under the terms of the AGR 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. AGR'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 AGR 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 AGR Credit Facility is April 5, 2021. None of the Networks companies had borrowed under this agreement as of December 31, 2016.

In the AGR Credit Facility each of the Networks borrowers covenant not to permit, without the consent of the lender, our 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 indebtedness to total capitalization, the facility excludes from net worth the balance of accumulated other comprehensive (loss) as it appears on the balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness each borrower may maintain. Continued un-remedied failure to comply with those covenants for five business days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity. We are not in default as of December 31, 2016.

As a condition of closing on the AGR Credit facility, three existing credit facilities were terminated: i) the AGR 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.

Note 9. Redeemable Preferred Stock of Subsidiary, Noncontrolling Interest

The redeemable preferred stock of CMP is a noncontrolling interest because it contains a feature that allows the holders to elect a majority of CMP's board of directors if preferred stock dividends are in default in an amount equivalent to four full quarterly dividends. Such a potential redemption-triggering event is not solely within the control of CMP.

At December 31, 2016 and 2015, our consolidated redeemable preferred stock, noncontrolling interest was:

Subsidiary and Series	Par Value per Share	Redemption Price per Share	Shares Authorized and Outstanding[(1)]	Amount (Thousands) 2016	2015
CMP, 6% Noncallable	$100	-	1,921	**$192**	$192
CNG, 8% Noncallable	$3.125	-	108,706	**$340**	$120
Total				**$532**	$312

[(1)]At December 31, 2016 and 2015, Network's subsidiaries had 6,755,000 shares of $100 par value preferred stock, 14,800,000 shares of $25 par value preferred stock, 1,000,000 shares of $100 par value preference stock, 5,000,000 shares of $1 par value preference stock and 884,315 shares of $3.125 par value preference stock authorized but unissued.

Note 10. Commitments and Contingencies

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 sought 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 therefore are affected by any FERC order resulting from the filed complaint.

On June 19, 2014, the FERC issued its decision in Complaint I, establishing an ROE methodology and setting an issue for a paper hearing. On October 16, 2014, FERC issued its final decision in Complaint I setting the base ROE at 10.57%, and a maximum total ROE of 11.74% (base plus incentive ROEs) for the October 2011 – December 2012 period as well as prospectively from October 16, 2014 and ordered the NETOs to file a refund report. On November 17, 2014 the NETOs filed the requested refund report.

On March 3, 2015, the FERC issued an order on requests for rehearing of its October 16, 2014 decision. The March order upheld the FERC's June 19, 2014 decision and further clarified that the 11.74% ROE cap will be applied on a project specific basis and not on a transmission owner's total average transmission return. In June 2015 the NETOs and complainants both filed an appeal in the U.S. Court of Appeals for the District of Columbia of the FERC's final order. On April 14, 2017, the Court of Appeals (the Court) issued its decision. The Court vacated FERC's decision on Complaint I and remanded it to FERC. The Court found that FERC, as directed by statute, did not determine first that the existing ROE was unjust and unreasonable before determining a new ROE. The Court ruled that FERC must first determine that the then existing 11.14% base ROE was unjust and unreasonable before selecting the 10.57% as the new base ROE. The Court also found that FERC did not provide reasoned judgment as to why 10.57%, the point ROE at the midpoint of the upper end of the zone of reasonableness, is a just and reasonable ROE as FERC only explained in its order that the midpoint of 9.39% was not just and reasonable and a higher base ROE was warranted. The parties or FERC could appeal the decision to the United State Supreme Court or FERC could provide additional justification and issue a decision on remand. On June 5, 2017 the NETOs made filing with FERC to reinstate transmission tariffs based on the original ROE (11.14% base / 13.50% cap) as a result of the Court decision. The NETOs requested the reinstated ROE be effective June 6, 2017 (effect of Court vacating order), but indicated tariffs would not be put into place until 60 days after the FERC has a quorum of Commissioners. We cannot predict the outcome of an appeal or other action by FERC.

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 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 later 2017, once FERC has enough commissioners to provide a quorum for decision-making.

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. On February 1, 2017, the complainants filed their initial testimony recommending a base ROE of 8.59%. On March 23, 2017, the NETOs filed their answering testimony supporting the continuation of the base ROE from Complaint I of 10.57%. In April 2017, The NETOs filed for a stay in the hearings pending FERC on the Court order described above. That request was denied by the Administrative Law Judge. Hearings are being held later this year with an expected Initial Decision from the Administrative Law Judge in March 2018. A range of possible outcomes is not able to be determined at this time due to the preliminary state of this matter. We cannot predict the outcome of the Complaint IV proceeding.

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 included approximately $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 responded 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 issues identified by the Staff. In the Proposal approved by the NYPSC (see Note 5) the parties agreed that in full and final resolution of all issues identified for 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 of 2013 and 2014 ACFs and no additional issues were identified.

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

At the direction of Governor Andrew Cuomo, on March 11, 2017 the New York State Department of Public Service (the “Department”) commenced an investigation of NYSEG’s and RG&E’s preparation for and response to the March 2017 windstorm, which affected more than 219,000 customers. The Department investigation will include a comprehensive review of NYSEG’s and RG&E’s preparation for and response to the windstorm, including all aspects of the companies’ filed and approved emergency plan. The Department held public hearings on April 12 and 13, 2017. We cannot predict the outcome of this investigation.

Leases

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 $37.8 million and $25.5 million for the years ended December 31, 2016 and 2015. We estimate our expenses will be approximately $19 million in 2017.

On October 21, 2015, RG&E, GNPP and multiple interveners 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. We estimate our expenses will be approximately $57 million in 2017.

Other operating leases: We recognized expenses of approximately $12.0 million related to our operating leases in 2016 and $6.0 million in 2015. We estimate our expenses will be approximately $10.0 million in 2017, $9.0 million in 2018 and 2019, $8.0 million in 2020 and 2021 and $81.0 million thereafter.

***Purchase power and gas contracts, including nonutility generators*:** 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.

We recognized expenses of approximately $190 million for these contracts including NUG power in 2016 and $197 million in 2015. We estimate that our power, gas purchases and other arrangements will total $317 million in 2017, $280 million in 2018, $223 million in 2019, $187 million in 2020, $157 million in 2021 and $895 million thereafter.

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 $384 million as of December 31, 2016.

Note 11. Environmental Liability

From time to time environmental laws, regulations and compliance programs may require changes in our operations and facilities and may increase the cost of electric and natural gas service.

Waste sites

The EPA 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 25 waste sites. The 25 sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the 25 sites, 15 sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites, six are included in Maine's Uncontrolled Sites Program, one is included on the Massachusetts Non-Priority Confirmed Disposal Site list and nine sites are also included on the National Priorities list.

Any liability may be joint and several for certain of those sites. We have recorded an estimated liability of $6 million related to ten of the 25 sites. We have paid remediation costs related to the remaining 15 sites, and do not expect to incur any additional liability. We have recorded an estimated liability of $8 million related to another 10 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 are regulated under State Resource Conservation and Recovery Act (RCRA) programs. It is possible the ultimate cost to remediate the 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 attributed to us.

Manufactured gas plants

We have a program to investigate and perform necessary remediation at our 53 sites where gas was manufactured in the past. Eight sites are included in the New York State Registry, 11 sites are included in the New York Voluntary Cleanup Program, three sites are part of Maine's Voluntary Response Action Program and of those, and two sites are part of Maine's Uncontrolled Sites Program. We have entered into consent orders with various environmental agencies to investigate and, where necessary, remediate 49 of the 53 sites.

Our estimate for all costs related to investigation and remediation of the 53 sites ranges from a minimum of $221 million to $465 million at December 31, 2016. Our estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial action, 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, as necessary, at the known inactive gas manufacturing sites was $388 million at December 31, 2016 and $397 million at December 31, 2015. We recorded a corresponding regulatory asset, net of insurance recoveries and the amount collected from FirstEnergy 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 (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 $60 million if the decision is upheld on appeal. FirstEnergy appealed the decision to the Second Circuit Court of Appeals. 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 expenses at nine MPG Energy sites. Based on current projections, FirstEnergy's share is estimated at approximately $22 million. This amount is being treated as a contingent asset and has not been recorded as either a receivable or a decrease to the environmental provision. Any recovery will be flowed through to NYSEG ratepayers.

Century Indemnity and OneBeacon

On August 14, 2013, NYSEG filed suit in federal court against two excess insurers, Century Indemnity and OneBeacon, who provided excess liability coverage to NYSEG. NYSEG seeks payment for clean-up costs associated with contamination at twenty-two former manufactured gas plants. Based on estimated clean-up costs of $282 million, the carriers' allocable share is approximately $89 million, excluding pre-judgment interest. 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. On March 31, 2017, the District Court granted motions filed by Century Indemnity and One Beacon dismissing all of NYSEG's claims against both defendants on the grounds of late notice. NYSEG filed a motion with the District Court on April 14, 2017 seeking reconsideration of the Court's decision and is researching grounds for further appeal if the reconsideration motion is denied. We cannot predict the outcome of this matter; however, any recovery will be flowed through to NYSEG ratepayers.

English Station

In January 2012, Evergreen Power, LLC (Evergreen Power) and Asnat Realty LLC (Asnat), then and current owners of a former generation site on the Mill River in New Haven (the English Station site) that UI sold to Quinnipiac Energy in 2000, filed a lawsuit in federal district court in Connecticut against UI seeking, among other things: (i) an order directing UI to reimburse the plaintiffs for costs they have incurred and will incur for the testing, investigation and remediation of hazardous substances at the English Station site and (ii) an order directing UI to investigate and remediate the site. This proceeding had been stayed in 2014 pending resolutions of other proceedings before 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 for July 6, 2017. On July 5, 2017, Asnat filed a pretrial memorandum claiming damages of $10 million for "environmental remediation activities" and lost use of the property; the memorandum also provides that Asnat intends to amend its complaint to update allegations and name additional parties, including former UIL officers and employees and "other UI officers".

On April 8, 2013, DEEP issued an administrative order addressed to UI, Evergreen Power, Asnat and others, ordering the parties to take certain actions related to investigating and remediating the English Station site. Mediation of the matter began in the fourth quarter of 2013 and concluded unsuccessfully in April 2015. This proceeding was stayed while DEEP and UI continue to work through the remediation process pursuant to the consent order described below. Status reports are periodically filed with the DEEP. The last report was filed in July 2017 and the next status report is due in September 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 UIL acquisition. The difference of $7.8 million 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 combined and 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 12. Accounting for Derivative Instruments and Hedging Activities

We are exposed to certain risks relating to our ongoing business operations. The primary risk we manage by using derivative instruments is commodity price risk. In accordance with the accounting requirements concerning derivative instruments and hedging activities, we recognize all derivative instruments as either assets or liabilities at fair value on our balance sheet.

The financial instruments we hold or issue are not for trading or speculative purposes.

Commodity price risk: Commodity price risk, due to volatility experienced in the wholesale energy markets, is a significant issue for the electric and natural gas utility industries. We manage this 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. Owned electric generation and long-term supply contracts reduce our exposure to market fluctuations.

We have electricity commodity purchases and sales contracts for both capacity and energy (physical contracts) that have been designated and qualify for the normal purchases and normal sales exception in accordance with the accounting requirements concerning derivative instruments and hedging 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 and $46.9 million for the years ended December 31, 2016 and 2015, respectively.

NYSEG and RG&E have purchased gas adjustment clauses that allow them to recover through rates any changes in the market price of purchased natural gas, substantially eliminating their exposure to natural gas price risk. NYSEG and RG&E use natural gas futures and forwards to manage fluctuations in natural gas commodity prices to provide price stability to customers. We include the cost or benefit of natural gas futures and forwards in the commodity cost that is passed on to customers when the related sales commitments are fulfilled. We record changes in the fair value of natural gas hedge contracts to derivative assets and or liabilities with an offset to regulatory assets and or regulatory liabilities in accordance with the accounting requirements for regulated operations.

The amount recognized in regulatory assets for natural gas hedges was a 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 and $6.3 million for the years ended December 31, 2016 and 2015, 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:

	Year Ended December 31, 2016	Period from December 17, 2015 to December 31, 2015
(thousands)		
Regulatory Assets - Derivative liabilities	$ 7,578	$ 548
Regulatory Liabilities - Derivative assets	$ 739	$ 33

Our derivative volumes by commodity type that are expected to settle each year are:

	Electricity Contracts	Natural Gas Contracts	Fleet Fuel Contracts
Year to settle	**Mwhs**	**Dths**	**Gals**
As of December 31, 2016			
2017	**3,844,900**	**4,790,000**	**2,325,200**
2018	**1,793,750**	**960,000**	**-**
As of December 31, 2015			
2016	4,507,500	3,850,000	2,500,100
2017	2,158,400	920,000	1,260,000

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

As of December 31, 2016	Current Assets	Noncurrent Assets	Current Liabilities	Noncurrent Liabilities
(Thousands)				
Not designated as hedging instruments				
Derivative assets	**$18,971**	**$15,609**	**$6,792**	**$4,624**
Derivative liabilities	**(6,792)**	**(4,624)**	**(39,551)**	**(78,903)**
	12,179	**10,985**	**(32,759)**	**(74,279)**
Designated as hedging instruments				
Derivative assets	**18**	**-**	**18**	**-**
Derivative liabilities	**(18)**	**-**	**(374)**	**-**
	-	**-**	**(356)**	**-**
Total derivatives before offset of cash collateral	**12,179**	**10,985**	**(33,115)**	**(74,279)**
Cash collateral receivable	**-**	**-**	**9,842**	**2,496**
Total derivatives as presented in the balance sheet	**$12,179**	**$10,985**	**$(23,273)**	**$(71,783)**

As of December 31, 2015	Current Assets	Noncurrent Assets	Current Liabilities	Noncurrent Liabilities
(Thousands)				
Not designated as hedging instruments				
Derivative assets	$10,507	$18,557	$-	$-
Derivative liabilities	-	-	(28,466)	(67,764)
	10,507	18,557	(28,466)	(67,764)
Designated as hedging instruments				
Derivative assets	3,260	6,225	3,260	6,225
Derivative liabilities	(3,260)	(6,045)	(41,909)	(7,275)
	-	180	(38,649)	(1,050)
Total derivatives before offset of cash collateral	10,507	18,737	(67,115)	(68,814)
Cash collateral receivable	-	-	36,730	271
Total derivatives as presented in the balance sheet	$10,507	$18,737	$(30,385)	$(68,543)

The effect of hedging instruments on other comprehensive income (OCI) and income was:

Year Ended December 31,	**Gain (Loss) Recognized in OCI on Derivatives**	**Location of Gain (Loss) Reclassified from Accumulated OCI into Income**	**Gain (Loss) Reclassified from Accumulated OCI into Income**
Derivatives in Cash Flow Hedging Relationships	**Effective Portion**	**Effective Portion**	
(Thousands)			
2016			
Interest rate contracts	**$-**	Interest expense	**$(8,048)**
Commodity contracts:	**311**	Other operating expenses	**(2,031)**
Total	**$311**		**$(10,079)**
2015			
Interest rate contracts	-	Interest expense	(8,618)
Commodity contracts:	(2,696)	Other operating expenses	(3,318)
Total	$(2,696)		$(11,936)

The amounts in AOCI related to previously settled forward starting swaps, and accumulated amortization, as of December 31, 2016, is a net loss of $76.7 million as compared to a net loss of $84.9 million for 2015. For the year ended December 31, 2016 and 2015, we recorded $8.0 and $8.6 million, respectively in net derivative losses related to discontinued cash flow hedges. We will amortize approximately $8.0 million of discontinued cash flow hedges in 2017. There was no ineffective portion of hedge during the years ended December 31, 2016 and 2015.

As of December 31, 2016, the unrealized losses of $0.4 million are reported in OCI because the forecasted transaction is considered to be probable. We expect that those losses will be reclassified into earnings within the next 12 months, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted energy transactions.

We 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 a counterparty's or the counterparty 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 one contract. For financial statement presentation, 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.

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, it 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 on December 31, 2016, is $12.7 million for which we have posted collateral.

Note 13. Fair Value of Financial Instruments and Fair Value Measurements

The estimated fair value of debt amounted to $4,640 million and $4,929 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 for the fair value of debt is considered as Level 2, except for unsecured pollution control notes-variable with a fair value of $61 million as of December 31, 2016 and $204 million as of December 31, 2015, 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.

Assets and liabilities measured at fair value on a recurring basis

The financial instruments measured at fair value as of December 31, consist of:

Description (Thousands)	(Level 1)	(Level 2)	(Level 3)	Netting	Total
2016					
Assets					
Noncurrent investments available for sale, primarily money market funds	**$39,825**	**$-**	**$-**	**$-**	**$39,825**
Derivatives					
Commodity contracts:					
Electricity	**11,416**	**-**	**-**	**$(11,416)**	**-**
Natural gas	**3,550**				**3,550**
Contracts for differences	**-**	**-**	**19,614**	**-**	**19,614**
Other	**-**	**-**	**18**	**(18)**	**-**
Total	**$54,791**	**$-**	**$19,632**	**$(11,434)**	**$62,989**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	**$(23,754)**	**-**	**-**	**$23,754**	**-**
Contracts for differences	**-**	**-**	**(94,700)**	**-**	**(94,700)**
Other	**-**	**-**	**(374)**	**18**	**(356)**
Total	**$(23,754)**	**$-**	**$(95,074)**	**$23,772**	**$(95,056)**
2015					
Assets					
Noncurrent investments, available for sale primarily money market funds	$38,782	$-	$-	$-	$38,782
Derivatives					
Commodity contracts:					
Electricity	9,665	-	-	$(9,485)	180
Contracts for differences	-	-	29,264	-	29,264
Total	$48,447	$-	29,264	$(9,485)	$68,226
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	$(43,326)	$-	$-	$43,326	$-
Natural gas	(3,160)	-	-	3,160	-
Contracts for differences	-	-	(96,230)	-	(96,230)
Other	-	-	(2,698)	-	(2,698)
Total	$(46,486)	$-	$(98,928)	$46,486	$(98,928)

Valuation techniques: We measure the fair value of our noncurrent investments available for sale using quoted market prices in active markets for identical assets and include the measurements in

Level 1. The investments which are Rabbi Trusts for deferred compensation plans primarily consist of money market funds.

We determine the fair value of our derivative assets and liabilities utilizing market approach valuation techniques:

- We enter into electric energy derivative contracts to hedge the forecasted purchases required to serve their electric load obligations. We hedge their electric load obligations using derivative contracts that are settled based upon Locational Based Marginal Pricing published by the NYISO. We have a combination of Level 1 and Level 2 fair values for our 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 these 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 our 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.
- We enter into natural gas derivative contracts to hedge the forecasted purchases required to serve our natural gas load obligations. The forward market prices used to value our open natural gas derivative contracts are exchange-based prices for the identical derivative contracts traded actively on the New York Mercantile Exchange. Because we use prices quoted in an active market, we include those fair value measurements in Level 1.
- We enter into fuel derivative contracts to hedge our unleaded and diesel fuel requirements for our fleet vehicles. Exchange based forward market prices are used but because a 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.

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.

Instruments measured at fair value on a recurring basis using significant unobservable inputs

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)	
	Derivatives, Net	
Year Ended December 31,	**2016**	**2015**
(Thousands)		
Beginning balance	**$69,664**	$3,320
Acquisition of UIL	**-**	66,966
Net change recognized on regulatory assets and liabilities	**8,120**	-
Included in earnings	**(2,031)**	(3,318)
Included in other comprehensive income	**(311)**	2,696
Ending balance	**$75,442**	$69,664

The gains and losses included in earnings for the periods above are reported in Operations and maintenance of the combined and consolidated statements of income.

Note 14. Accumulated Other Comprehensive Loss

(Thousands)	Balance January 1, 2015	2015 Change	Balance December 31, 2015	2016 Change	Balance December 31, 2016
Net unrealized holding gain on investments, net of income tax expense of $11 for 2015 and $4 for 2016	$17	$18	$35	$6	$41
Amortization of pension cost for nonqualified plans, net of income tax expense of $1,577 for 2015 and $392 for 2016	(11,405)	2,841	(8,564)	719	(7,845)
Unrealized (loss) gain on derivatives qualified as hedges:					
Unrealized (loss) gain during period on derivatives qualified as hedges, net of income tax (benefit)expense of $(1,079) for 2015 and of $121 for 2016		(1,617)		190	
Reclassification adjustment for loss included in net income, net of income tax expense of $1,327 for 2015 and $792 for 2016		1,991		1,239	
Reclassification adjustment for loss on settled cash flow treasury hedges, net of income tax expense of $3,441 for 2015 and $3,137 for 2016		5,178		4,911	
Net unrealized (loss) gain on derivatives qualified as hedges	$(58,326)	$5,552	$(52,774)	$6,340	$(46,434)
Accumulated Other Comprehensive Loss	$(69,714)	$8,411	$(61,303)	$7,065	$(54,238)

No Accumulated Other Comprehensive Loss is attributable to the noncontrolling interests for the above periods.

Note 15. Retirement Benefits

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 has 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.

Notes to Combined and Consolidated Financial Statements

Obligations and funded status of Networks as of December 31, 2016 and 2015 consisted of:

***Obligations and funded status*:**

	Pension Benefits		Postretirement Benefits	
	2016	**2015**	**2016**	**2015**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	**$3,453,536**	$2,564,092	**$510,109**	$411,456
Service cost	**44,150**	35,689	**4,930**	4,176
Interest cost	**139,489**	96,656	**20,474**	15,137
Plan participants' contributions	**-**	-	**6,935**	4398
Plan amendments	**-**	-	**-**	(914)
Actuarial (gain) loss	**(43,118)**	(105,255)	**(22,616)**	(22,671)
Special termination benefits	**-**	1,602	**-**	-
Benefits paid	**(198,960)**	(158,537)	**(37,680)**	(23,993)
Acquisition of UIL	**-**	1,019,289	**-**	122,516
Federal subsidy on benefits paid	**-**	-	**-**	4
Benefit obligation at December 31	**$3,395,097**	$3,453,536	**$482,152**	$510,109
Change in plan assets				
Fair value of plan assets at January 1	**$2,622,483**	$2,097,242	**$160,440**	$127,865
Actual return on plan assets	**166,988**	(29,723)	**10,401**	(4,624)
Employer contributions	**43,902**	26,651	**30,498**	20,595
Plan participants' contributions	**-**	-	**6,935**	3,398
Benefits paid	**(198,960)**	(158,537)	**(37,680)**	(23,993)
Withdrawal from VEBA	**-**	-	**(10,506)**	(2,223)
Acquisition of UIL	**-**	686,850	**-**	39,422
Fair value of plan assets at December 31	**$2,634,413**	$2,622,483	**$160,088**	$160,440
Funded status at December 31	**$(760,684)**	$(831,053)	**$(322,064)**	$(349,669)

Amounts recognized in the balance sheet	**Pension Benefits**		**Postretirement Benefits**	
December 31,	**2016**	**2015**	**2016**	**2015**
(Thousands)				
Current liabilities	-	-	**$(5,450)**	$(5,274)
Noncurrent liabilities	**$(760,684)**	$(831,053)	**(316,614)**	(344,395)
	$(760,684)	$(831,053)	**$(322,064)**	$(349,669)

We have determined that all of our operating companies are allowed to defer as regulatory assets or regulatory liabilities items that would otherwise be recorded in accumulated other comprehensive income pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans. Amounts recognized as regulatory assets or regulatory liabilities consist of:

	Pension Benefits		**Postretirement Benefits**	
December 31,	**2016**	**2015**	**2016**	**2015**
(Thousands)				
Net loss	**$859,301**	$993,958	**$44,233**	$76,365
Prior service cost (credit)	**$7,354**	$9,122	**$(39,862)**	$(48,880)

Our accumulated benefit obligation for all defined benefit pension plans was $3.2 billion at December 31, 2016, and $3.2 billion at December 31, 2015.CMP's and NYSEG's postretirement benefits were partially funded at December 2016 and 2015.

The projected benefit obligation and the accumulated benefit obligation exceeded the fair value of pension plan assets for all plans as of December 31, 2016 and for all plans as of December 31, 2016. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets for the companies' plans for the relevant periods.

December 31,	Projected Benefit Obligation Exceeds Fair Value of Plan Assets 2016	2015	Accumulated Benefit Obligation Exceeds Fair Value of Plan Assets 2016	2015
(Thousands)				
Projected benefit obligation	**$3,395,097**	$3,453,536	**$3,395,097**	$3,453,536
Accumulated benefit obligation	**$3,162,796**	$3,206,430	**$3,162,796**	$3,206,430
Fair value of plan assets	**$2,634,413**	$2,622,483	**$2,634,413**	$2,622,483

***Components of net periodic benefit cost and other amounts recognized in regulatory assets and regulatory liabilities*:**

Year ended December 31,	Pension Benefits 2016	2015	Postretirement Benefits 2016	2015
(Thousands)				
Net periodic benefit cost				
Service cost	**$44,150**	$35,689	**$4,930**	$4,176
Interest cost	**139,489**	96,656	**20,474**	15,137
Expected return on plan assets	**(198,687)**	(156,141)	**(8,683)**	(7,128)
Amortization of prior service cost (benefit)	**1,767**	2,907	**(9,018)**	(8,851)
Amortization of net loss	**123,240**	129,987	**7,978**	6,911
Settlement charge	**-**	1,602	**-**	-
Amortization of transition obligation	**-**	1,930	**-**	-
Net periodic benefit cost	**$109,959**	$112,630	**$15,681**	$10,245
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net (gain)/loss	**$(11,417)**	$69,204	**$(24,333)**	$(12,342)
Settlement	**-**	(1,930)	**-**	-
Amortization of net (loss)	**(123,240)**	(129,987)	**(7,978)**	(6,911)
Current year prior service cost	**-**	-	**-**	(914)
Amortization of prior service (cost)	**(1,767)**	(2,907)	**9,018**	8,851
Total recognized in regulatory assets and regulatory liabilities	**(136,424)**	(65,620)	**(23,293)**	(11,316)
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$(26,465)**	$47,010	**$(7,612)**	**$**(1,071)

We include the net periodic benefit cost in other operating expenses net of capitalized portion. The net periodic benefit cost for postretirement benefits represents the amount expensed for providing health care benefits to retirees and their eligible dependents.

Amounts expected to be amortized from regulatory assets or regulatory liabilities into net periodic benefit cost for the fiscal year ending December 31, 2017	Pension Benefits	Postretirement Benefits
(Thousands)		
Estimated net loss	**$125,858**	**$4,690**
Estimated prior service cost (benefit)	**$1,580**	**$(9,018)**

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

Weighted-average assumptions used to determine benefit obligations at December 31,	Pension Benefits 2016	Pension Benefits 2015	Postretirement Benefits 2016	Postretirement Benefits 2015
Discount rate	**4.12%/4.24%**	4.10%/4.24%	**4.12%4.24%**	4.10%/4.24%
Rate of compensation increase	**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 rate by developing a yield curve derived from a portfolio of high grade noncallable bonds with yields that closely matches the duration of the expected cash flows of our benefit obligations.

Weighted-average assumptions used to determine net periodic benefit cost for year ended December 31,	Pension Benefits 2016	Pension Benefits 2015	Postretirement Benefits 2016	Postretirement Benefits 2015
Discount rate	**4.12%/4.24%**	3.80%/4.24%	**4.12%/4.24%**	3.80%/4.24%
Expected long-term return on plan assets	**7.40%/7.75%**	7.5%	**7.16%**	-
Expected long-term return on plan assets - nontaxable trust	**-**	-	**7.00%**	7.50%
Expected long-term return on plan assets - taxable trust	**-**	-	**4.50%**	5.00%
Rate of compensation increase	**3.50%-4.20%**	4.10%	**-**	-

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

Assumed health care cost trend rates to determine benefit obligations at December 31,	2016	2015
Health care cost trend rate assumed for next year	**7.00%/9.00%**	7.50%/7.00%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	**4.50%**	4.50%
Year that the rate reaches the ultimate trend rate	**2026/2028**	2027

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
(Thousands)		
Effect on total of service and interest cost	**$730**	**$(607)**
Effect on postretirement benefit obligation	**$13,132**	**$(11,004)**

Contributions**:** In accordance with our funding policy we make annual contributions of not less than the minimum required by applicable regulations. We expect to contribute $33 million to our pension benefit plans in 2017.

Estimated future benefit payments**:** Our expected benefit payments and expected Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) subsidy receipts, which reflect expected future service, as appropriate, are:

	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
(Thousands)			
2017	$205,588	$33,019	$289
2018	$208,097	$33,049	$302
2019	$212,218	$33,175	$311
2020	$215,266	$33,299	$319
2021	$219,792	$33,256	$329
2022 – 2026	$1,108,549	$164,442	$2,264

Plan assets**:** Our pension benefits plan assets are held in a master trust providing for a single trustee/custodian, a uniform investment manager lineup, and an efficient, cost-effective means of allocating expenses and investment performance to each plan under the master trust. Our primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our tolerance for risk. 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 trust's investments while avoiding significant concentrations of risk in any one area of the securities markets. Within each asset group, further diversification is achieved through utilizing multiple asset managers and systematic allocation to various asset classes; 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.

Networks maintains a 401(k) Savings and Retirement Plan (the Plan) for all eligible employees as defined in the Plan agreement. Participants in the Plan may contribute a percentage of their compensation and the company may match a predetermined percentage of the participant contributions. Expenses under the Plan for Networks totaled approximately $24.4 million for 2016 and $12.6 million for 2015.

The fair values of our pension benefits plan assets at December 31, 2016 and 2015, by asset category are:

		Fair Value Measurements at December 31, Using		
Asset Category	**Total**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
(Thousands)				
2016				
Cash and cash equivalents	**$48,645**	**$-**	**$48,645**	**$-**
U.S. government securities	**171,736**	**171,736**	**-**	**-**
Common stocks	**120,301**	**120,301**	**-**	**-**
Registered investment companies	**92,152**	**92,152**	**-**	**-**
Corporate bonds	**357,773**		**357,773**	**-**
Preferred stocks	**4,078**	**262**	**3,816**	**-**
Common/collective trusts	**1,193,500**		**371,831**	**821,669**
Partnership/joint venture interests	**-**	**-**	**-**	**-**
Real estate investments	**60,995**	**-**	**-**	**60,995**
Other investments, principally annuity and fixed income	**585,233**		**310,785**	**274,448**
Total	**$2,634,413**	**$384,451**	**$1,092,850**	**$1,157,112**
2015				
Cash and cash equivalents	$57,797	$3,561	$54,236	$-
U.S. government securities	171,024	171,024	-	-
Common stocks	661,639	661,639	-	-
Registered investment companies	81,308	81,308	-	-
Corporate bonds	323,900	-	323,900	-
Preferred stocks	4,926	295	4,631	-
Common/collective trusts	511,504	-	21,476	490,028
Partnership/joint venture interests	78,519	-	-	78,519
Real estate investments	88,865	-	-	88,865
Other investments, principally annuity and fixed income	643,001	324,733	-	318,268
Total	$2,622,483	$1,242,560	$404,243	$975,680

Valuation techniques

We value our pension benefits plan assets as follows:

- Cash and cash equivalents – Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities, Common stocks and Registered investment companies - at the closing price reported in the active market in which the security is traded.
- Corporate bonds – based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks – at the closing price reported in the active market in which the individual investment is traded.
- Common/collective trusts and Partnership/joint ventures – using the Net Asset Value (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:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)				
(Thousands)	**Common/ Collective Trusts**	**Partner-ship/ Joint Venture Interests**	**Real Estate Invest-ments**	**Other Invest-ments**	**Total**
Balance, December 31, 2014	$450,141	$79,489	$74,871	$341,685	$946,186
Actual return on plan assets:					
Relating to assets still held at the reporting date	(5,873)	18,518	10,235	(20,169)	2,711
Relating to assets sold during the year	(3,115)	(19,488)	-	904	(21,699)
Purchases, sales and settlements	48,875	-	3,759	(4,152)	48,482
Balance, December 31, 2015	$490,028	$78,519	$88,865	$318,268	$975,680
Actual return on plan assets:					
Relating to assets held at the reporting date	**50,752**	**-**	**1,710**	**(7,534)**	**44,928**
Relating to assets sold during the year	**5,542**	**(18,519)**	**478**	**686**	**(11,813)**
Purchases, sales and settlements	**275,347**	**(60,000)**	**(30,058)**	**(36,972)**	**148,317**
Balance, December 31, 2016	**$821,669**	**$-**	**$60,995**	**$274,448**	**$1,157,112**

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 46%-66% for equity securities, 30%-31% for fixed income, and 3%-23% for 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 and 2015 of:

		Fair Value Measurements at December 31, Using		
Asset Category	**Total**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
(Thousands)				
2016				
Money market funds	**$5,786**	**$3,582**	**$2,204**	**$-**
Mutual funds, fixed	**40,856**	**38,496**	**2,360**	**-**
Government & corporate bonds	**1,651**	**-**	**1,651**	**-**
Mutual funds, equity	**71,031**	**41,687**	**29,344**	**-**
Common stocks	**22,896**	**22,896**	**-**	**-**
Mutual funds, other	**17,868**	**9,961**	**7,907**	**-**
Total assets measured at fair value	**$160,088**	**$116,622**	**$43,466**	**$-**
2015				
Money market funds	$4,163	$4,163	$-	$-
Mutual funds, fixed	35,438	35,438	-	-
Government & corporate bonds	1,703	-	1,703	-
Mutual funds, equity	45,679	45,679	-	-
Common stocks	22,939	22,793	-	146
Mutual funds, other	50,518	43,400	7,118	-
Total assets measured at fair value	$160,440	$151,473	$8,821	$146

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.

Note 16. Subsequent events

The company has performed a review of subsequent events through July 7, 2017, which is the date these financial statements were available to be issued, and no material subsequent events have occurred from January 1, 2017 through such date that have not been disclosed within these financial statements.

On March 13, 2017, the board of directors of Networks declared a dividend of $24 million. This dividend was payable on March 29, 2017 to Avangrid, Inc.

On May 1, 2017, the board of directors of Networks declared a dividend of $134.4 million. This dividend was payable on May 3, 2017 to Avangrid, Inc.

On May 24, 2017, RG&E issued $300 million of 10 year first mortgage bonds.

On June 30, 2017, SCG filed an application for approval of a three-year rate plan of amended rate schedules with PURA.

Exhibit 3-5: CMP 2015 and 2016 Consolidated Financial Statements

Central Maine Power Company
and Subsidiaries
Consolidated Financial Statements
For the Years Ended December 31, 2016 and 2015

Central Maine Power Company
and Subsidiaries

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Consolidated Financial Statements for the Years Ended December 31, 2016 and 2015

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Report of Independent Auditors

To the Shareholders and Board of Directors
Central Maine Power Company

We have audited the accompanying consolidated financial statements of Central Maine Power Company and subsidiaries, which comprise the consolidated balance sheets as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, changes in equity and cash flows for the years 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 U.S. generally accepted accounting principles; 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 audits. We conducted our audits 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 Central Maine Power Company and subsidiaries at December 31, 2016 and 2015, and the consolidated results of their operations and their cash flows for the years then ended in conformity with U.S. generally accepted accounting principles.

Ernst & Young LLP

March 31, 2017

Central Maine Power Company and Subsidiaries
Consolidated Statements of Income

Year Ended December 31,	2016	2015
(Thousands)		
Operating Revenues		
Sales and services	**$833,938**	$819,716
Operating Expenses		
Electricity purchased	**59,201**	57,165
Operations and maintenance	**352,244**	377,423
Depreciation and amortization	**102,786**	98,654
Other taxes	**54,536**	47,482
Total Operating Expenses	**568,767**	580,724
Operating Income	**265,171**	238,992
Other Income	**6,416**	7,629
Other Deductions	**(1,711)**	(391)
Interest Charges, Net	**(52,985)**	(54,751)
Income Before Income Tax	**216,891**	191,479
Income Tax Expense	**81,071**	77,038
Net Income	**135,820**	114,441
Less: Net Income Attributable to Noncontrolling Interest	**409**	353
Net Income Attributable to CMP	**135,411**	114,088
Preferred Stock Dividends	**-**	34
Net Income Available for CMP Common Stock	**$135,411**	$114,054

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

Central Maine Power Company and Subsidiaries
Consolidated Statements of Comprehensive Income

Year ended December 31,	2016	2015
(Thousands)		
Net Income	**$135,820**	$ 114,441
Other Comprehensive Income (Loss), Net of Tax		
Amortization of pension cost for nonqualified plans	**75**	163
Unrealized gain (loss) on derivatives qualified as hedges:		
Unrealized gain (loss) during period on derivatives qualified as hedges	**81**	(562)
Reclassification adjustment for loss included in net income	**388**	623
Reclassification adjustment for loss on settled cash flow treasury hedges	**1,323**	1,315
Net unrealized gain on derivatives qualified as hedges	**1,792**	1,376
Other Comprehensive Income, Net of Tax	**1,867**	1,539
Comprehensive Income	**137,687**	115,980
Less:		
Comprehensive Income Attributable to Noncontrolling Interests	**409**	353
Comprehensive Income Attributable to CMP	**$137,278**	$115,627

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

Central Maine Power Company and Subsidiaries
Consolidated Balance Sheets

December 31,	2016	2015
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	**$7,968**	$5,360
Accounts receivable and unbilled revenues, net	**161,725**	149,281
Accounts receivable from affiliates	**1,671**	1,762
Notes receivable from affiliates	**32,100**	23,437
Materials and supplies	**15,018**	15,828
Prepayments and other current assets	**79,170**	121,095
Regulatory assets	**18,198**	22,032
Total Current Assets	**315,850**	338,795
Utility plant, at original cost	**3,828,993**	3,675,772
Less accumulated depreciation	**(893,117)**	(826,309)
Net Utility Plant in Service	**2,935,876**	2,849,463
Construction work in progress	**160,459**	152,707
Total Utility Plant	**3,096,335**	3,002,170
Other Property and Investments	**1,297**	1,506
Regulatory and Other Assets		
Regulatory assets	**489,765**	521,482
Goodwill	**324,938**	324,938
Other	**19,027**	5,304
Total Regulatory and Other Assets	**833,730**	851,724
Total Assets	**$4,247,212**	$4,194,195

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

Central Maine Power Company and Subsidiaries
Consolidated Balance Sheets

December 31,	2016	2015
(Thousands, except share information)		
Liabilities		
Current Liabilities		
Current portion of long-term debt	**$5,154**	$41,312
Accounts payable and accrued liabilities	**145,653**	123,070
Accounts payable to affiliates	**35,844**	32,893
Interest accrued	**17,851**	18,671
Taxes accrued	**3,154**	7,454
Other current liabilities	**54,008**	59,781
Regulatory liabilities	**36,801**	44,799
Total Current Liabilities	**298,465**	327,980
Regulatory and Other Liabilities		
Regulatory liabilities	**109,941**	100,228
Deferred income taxes regulatory	**149,232**	165,119
Other Non-current liabilities		
Deferred income taxes	**660,090**	626,868
Pension and other postretirement benefits	**194,716**	226,560
Other	**56,096**	54,678
Total Regulatory and Other Liabilities	**1,170,075**	1,173,453
Long-term debt	**1,042,310**	1,043,512
Total Liabilities	**2,510,850**	2,544,945
Commitments and Contingencies		
Preferred Stock		
Preferred stock	**571**	571
CMP Common Stock Equity		
Common stock ($5 par value, 80,000 shares authorized and 31,211 shares outstanding at December 31,2016 and 2015)	**156,057**	156,057
Capital in excess of par value	**764,014**	713,893
Retained earnings	**812,121**	777,406
Accumulated other comprehensive loss	**(6,647)**	(8,514)
Total CMP Common Stock Equity	**1,725,545**	1,638,842
Noncontrolling Interest	**10,246**	9,837
Total Equity	**1,735,791**	1,648,679
Total Liabilities and Equity	**$4,247,212**	$4,194,195

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

Central Maine Power Company and Subsidiaries
Consolidated Statements of Cash Flows

Year Ended December 31,	2016	2015
(Thousands)		
Cash Flow from Operating Activities		
Net income	**$135,820**	**$114,441**
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	**102,786**	**98,654**
Amortization of regulatory assets and liabilities	**(17,548)**	**(14,835)**
Carrying cost of regulatory assets and liabilities	**942**	**1,195**
Deferred taxes	**14,942**	**70,198**
Other non-cash items	**2,925**	**(673)**
Pension expense	**22,433**	**26,274**
Changes in operating assets and liabilities		
Accounts receivable and unbilled revenues, net	**(14,392)**	**(134)**
Materials and supplies	**810**	**11,648**
Accounts payable and accrued liabilities	**14,652**	**30,052**
Other assets and other liabilities	**15,958**	**(101,804)**
Changes in regulatory assets and liabilities	**20,912**	**19,775**
Net Cash Provided by Operating Activities	**300,240**	**254,791**
Cash Flow from Investing Activities		
Utility plant additions	**(220,257)**	**(280,224)**
Contributions in aid of construction	**25,001**	**16,565**
Issuance of notes receivable with affiliates	**(8,663)**	**(22,747)**
Proceeds from sale of property, plant and equipment	**284**	**-**
Changes in other investments	**(20)**	**166**
Net Cash Used in Investing Activities	**(203,655)**	**(286,240)**
Cash Flow from Financing Activities		
Capital contributions from parent	**50,000**	**-**
Repayment of debts and capital leases	**(43,281)**	**(2,152)**
Long-term note issuance	**-**	**150,000**
Repayments of notes payable with affiliates	**-**	**(118,192)**
Dividends paid on common stock	**(100,696)**	**-**
Dividends paid on preferred stock	**-**	**(34)**
Capital contribution from noncontrolling interests	**-**	**2,164**
Net Cash (Used in) Provided by Financing Activities	**(93,977)**	**31,786**
Net Increase in Cash and Cash Equivalents	**2,608**	**337**
Cash and Cash Equivalents, Beginning of Year	**5,360**	**5,023**
Cash and Cash Equivalents, End of Year	**$7,968**	**$5,360**

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

Central Maine Power Company and Subsidiaries
Consolidated Statements of Changes in Equity

	CMP Stockholder							
(Thousands, except per share amounts)	**Shares**	**Common Stock Outstanding $5 Par Value Amount**	**Capital in Excess of Par Value**	**Retained Earnings**	**Accumulated Other Comprehensive Loss**	**Total Common Stock Equity**	**Noncon-trolling Interest**	**Total**
Balance, January 1, 2015	31,211	$156,057	$713,893	$663,352	$(10,053)	$1,523,249	$7,320	$1,530,569
Net income				114,088		114,088	353	114,441
Other comprehensive income, net of tax					1,539	1,539		1,539
Comprehensive income								115,980
Capital contribution from noncontrolling interests							2,164	2,164
Dividends paid, preferred stock				(34)		(34)		(34)
Balance, December 31, 2015	31,211	156,057	713,893	777,406	(8,514)	1,638,842	9,837	1,648,679
Net income				**135,411**		**135,411**	**409**	**135,820**
Other comprehensive income net of tax					**1,867**	**1,867**		**1,867**
Comprehensive income								**137,687**
Stock-based compensation			**121**			**121**		**121**
Capital contribution from parent			**50,000**			**50,000**		**50,000**
Dividends paid				**(100,696)**		**(100,696)**		**(100,696)**
Balance, December 31, 2016	**31,211**	**$156,057**	**$764,014**	**$812,121**	**$(6,647)**	**$1,725,545**	**$10,246**	**$1,735,791**

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

Notes to Consolidated Financial Statements

Note 1. Significant Accounting Policies

Background: Central Maine Power Company and subsidiaries (CMP, the company, we, our, us) conduct regulated electricity transmission and distribution operations in Maine serving approximately 619,000 customers in a service territory of approximately 11,000 square miles with a population of approximately one million people. The service territory is located in the southern and central areas of Maine and contains most of Maine's industrial and commercial centers, including the city of Portland and the Lewiston-Auburn, Augusta-Waterville, Saco-Biddeford and Bath-Brunswick areas.

CMP is the principal operating utility of CMP Group, Inc. (CMP Group), a wholly-owned subsidiary of Avangrid Networks, Inc. (Networks), which is a wholly-owned subsidiary of Avangrid, Inc. (AGR), formerly Iberdrola USA, which is a 81.5% owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation, organized under the law of the Kingdom of Spain.

Networks was formed on November 20, 2013, when AGR was reorganized to become the parent company of Networks. 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).

On December 16, 2015, AGR completed the acquisition of UIL Holdings Corporation (UIL). Immediately following the completion of the acquisition, former UIL shareowners owned 18.5% of the outstanding shares of common stock of AGR, and Iberdrola owned the remaining shares. The acquisition was accounted for as a business combination in AGR's consolidated financial statements. 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. Effective as of April 30, 2016, UIL and its subsidiaries were transferred to a wholly-owned subsidiary of Networks.

***Accounts receivable*:** Accounts receivable at December 31 include unbilled revenues of $27 million for 2016 and $23 million for 2015, and are shown net of an allowance for doubtful accounts at December 31 of $3 million for both 2016 and 2015. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was $4 million in 2016 and $3 million in 2015.

Unbilled revenues represent estimates of receivables for energy provided but not yet billed. The estimates are determined based on various assumptions, such as current month energy load requirements, billing rates by customer class and delivery loss factors. Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

The allowance for doubtful accounts is our best estimate of the amount of probable credit losses in our existing accounts receivable, determined based on experience. Each month we review our allowance for doubtful accounts and past due accounts by age. When we believe that a receivable will not be recovered, we charge 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.

Our accounts receivable include amounts due under deferred payment arrangements (DPAs). When a residential customer becomes delinquent in making payments, the MPUC requires us to allow the customer to enter into a 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, we 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 or is otherwise considered to be delinquent. We establish provisions for uncollectible accounts by using both historical average loss percentages to project future losses and by establishing specific provisions for known credit issues. Amounts are written off when reasonable collection efforts have been exhausted. The allowance for doubtful accounts for DPAs at December 31 was $1 million for 2016 and $2 million in 2015. DPA receivable balances at December 31 were $9 million in 2016 and $10 million in 2015.

***Asset retirement obligations*:** We record the fair value of the liability for an asset retirement obligation (ARO) and a conditional ARO in the period in which it is incurred and capitalize the cost by increasing the carrying amount of the related long-lived asset. We adjust the liability periodically to reflect revisions to either the timing or the amount of the original estimated undiscounted cash flows over time. The liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement we will either settle the obligation at its recorded amount or incur a gain or a loss. Our regulated utilities defer any timing differences between rate recovery and depreciation expense and accretion as either a regulatory asset or a regulatory liability.

The term conditional ARO refers to an entity’s legal obligation to perform an asset retirement activity in which the timing or method of settlement are conditional on a future event that may or may not be within the control of the entity. 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 ARO at December 31, including our conditional ARO, was less than $1 million for both 2016 and 2015. The ARO is associated with our long-lived assets and primarily consists of obligations related to removal or retirement of asbestos and PCB-contaminated equipment.

We have AROs for which we have not recognized a liability because the fair value cannot be reasonably estimated due to indeterminate settlement dates, including the removal of property upon termination of an easement, right-of-way or franchise.

Accrued removal obligations: We meet the requirements concerning accounting for regulated operations, and recognize a regulatory liability, for the difference between removal costs collected in rates and actual costs incurred. We classify those amounts as accrued removal obligations.

Consolidated statements of cash flows: 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. As of both December 31, 2016 and 2015, we did not have restricted cash.

Notes to Consolidated Financial Statements

Supplemental Disclosure of Cash Flows Information	2016	2015
(Thousands)		
Cash paid during the year ended December 31:		
Interest, net of amounts capitalized	**$50,892**	$48,889
Income taxes paid, net	**$19,018**	$46,696

Interest capitalized was $1.5 million in 2016 and $2.1 million in 2015.

Depreciation and amortization: We determine depreciation expense using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Our depreciation accruals were equivalent to 2.5% of average depreciable property for both 2016 and 2015. We amortize our capitalized software cost which is included in other plant, using the straight line method, based on useful lives of 5 to 10 years. Capitalized software costs of approximately $94 million as of December 31, 2016 and $87 million as of December 31, 2015. Depreciation expense was $95 million in 2016 and $91 million in 2015. Amortization of capitalized software was $8 million in 2016 and 2015.

We charge repairs and minor replacements to operation and maintenance expense, and capitalize renewals and betterments, including certain indirect costs. We charge the original cost of utility plant retired or otherwise disposed of to accumulated depreciation.

Our balances of major classes of assets and the associated useful lives are shown below.

Plant	Estimated useful life (years)	2016	2015
(thousands)			
Electric			
Transmission	47.2	**$2,192,851**	$2,136,532
Distribution	47.0	**1,295,277**	1,316,746
Vehicles	7	**58,621**	52,168
Other	34.8	**282,244**	170,326
Total Utility Plant		**$3,828,993**	$3,675,772

Electric plant includes capital leases of $46 million for 2016 and $40 million for 2015. Accumulated depreciation related to these leases was $37 million for 2016 and 2015.

***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.

***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 initially measured at cost, being the excess of the aggregate of the consideration transferred the fair value of any non-controlling 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.

Inventory: Inventory comprises materials and supplies 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”.

Government grants: We account for government grants related to depreciable assets in the same way as we account for contributions in aid of construction (CIAC), that is, the grant amount is credited to the cost of the related property, plant and equipment. In accounting for government grants related to operating and maintenance costs, we recognize amounts receivable as compensation for expenses already incurred in the statements of income in the period in which the expenses are incurred.

Stock-based compensation: Stock-based compensation represents costs related to AGR performance stock units (PSUs) granted to certain officers and employees of CMP under the Avangrid, Inc. Omnibus Incentive Plan in July 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. 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.

New Accounting Standards and Interpretations: New accounting standards issued by the Financial Accounting Standards Board (FASB) that we either adopted or have not yet adopted are explained below. Although we are not a public business entity, our parent company became a registrant in December 2015, and in the future we will adopt new accounting standards based on the effective date for public entities.

(a) Revenue from contracts with customers

In May 2014 the 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. 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.

Notes to Consolidated Financial Statements

(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) 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.

(f) 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.

(g) 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.

(h) 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.

(i) 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.

(j) 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. The adoption of the amendment did not have any impact on the consolidated statements of cash flows for the year ended December 31, 2015 as we did not have restricted cash as of the beginning and end of 2015.

Other Income and Other Deductions:

Year Ended December 31,	2016	2015
(Thousands)		
Gain on sale of property	**$1,409**	$160
Interest and dividends income	**139**	953
Allowance for funds used during construction	**3,759**	5,763
Carrying costs on regulatory assets	**500**	581
Miscellaneous	**609**	172
Total other income	**$6,416**	$7,629
Donations	**($500)**	($390)
Miscellaneous	**(1,211)**	(1)
Total other deductions	**($1,711)**	($391)

***Principles of consolidation*:** These financial statements consolidate our majority-owned subsidiaries after eliminating intercompany transactions.

***Regulatory assets and liabilities*:** We currently meet the requirements concerning accounting for regulated operations for our electric operations in Maine; however, we cannot predict what effect the competitive market or future actions of regulatory entities would have on our ability to continue to do so. If we were to no longer meet the requirements concerning accounting for regulated operations for all or a separable part of our operations, we may have to record certain regulatory assets and regulatory liabilities as an expense or as revenue, or include them in accumulated other comprehensive income.

Pursuant to the requirements concerning accounting for regulated operations we capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric rates. Substantially all regulatory assets for which funds have been expended are either included in rate base or are accruing carrying costs. The primary regulatory assets and liabilities that have not yet been included in rates, and are therefore accruing carrying costs until included in rates, are deferred storm costs and various deferrals, both assets and liabilities, that result from reconciliation mechanisms designed to allow recovery of actual costs. We also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs (See Note 3).

Related party transactions: Certain Networks subsidiaries, including CMP borrow from AGR, the parent of Networks, through intercompany revolving credit agreements. For CMP, the intercompany revolving credit agreements provide access to supplemental liquidity. See Note 7 for further detail on the credit facility with AGR.

Avangrid Service Company provides administrative and management services to Networks operating utilities, including CMP, pursuant to service agreements. The cost of those services is allocated in accordance with methodologies set forth in the service agreements. The cost allocation methodologies vary depending on the type of service provided. Management believes such allocations are reasonable. The charge for operating and capital services provided to CMP by Avangrid Service Company was $35 million and $32 million for 2016 and 2015, respectively. Charge for services provided by CMP to AGR and its subsidiaries were approximately $2.9 million for 2016 and 4 million for 2015. All charges for services are at cost. The balance in accounts payable to affiliates of $36 million at December 31, 2016 and $32 million at December 31, 2015 is payable to Avangrid Service Company.

Notes to Consolidated Financial Statements

The balance in notes receivable from affiliates of $32 million and $23 million, respectively, at December 31, 2016 and 2015, is mainly receivable from RG&E.

Of the $19 million paid for income taxes, substantially all was paid to AGR under the tax sharing agreement.

***Revenue recognition*:** We recognize revenues upon delivery of energy and energy-related products and services to our 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 New England Inc. (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 (NUG) and other purchase power contracts to unrelated third parties under bilateral contracts. If the Maine Public Utilities Commission (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.

CMP's electric rates each contain a revenue decoupling mechanism 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 (See Note 2).

In addition we accrue revenue pursuant to the various regulatory provisions to record regulatory assets for revenues that will be collected in the future.

Taxes: AGR files consolidated federal and state income tax returns including all of the activities of its subsidiaries. Each subsidiary company is treated as a member of the consolidated group and determines its current and deferred taxes based on the separate return with benefits for loss method. As a member, CMP settles its current tax liability or benefit each year directly with AGR pursuant to a tax allocation agreement between AGR and its members.

The aggregate amount of the intercompany income tax receivable balance due from AGR is $45.5 million and $92.5 million at December 31, 2016 and December 31, 2015, respectively.

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. 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 other 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 charges, net” and “Other (income)” of the consolidated statements of income. Uncertain tax positions have been classified as non-current unless expected to be paid within one year.

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.

We account for sales tax collected from customers and remitted to taxing authorities on a net basis.

***Use of estimates and assumptions*: ** The preparation of our consolidated financial statements in conformity with generally accepted accounting principles 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) environmental remediation liability; (9) pension and Other Postretirement Employee Benefit (OPEB); (10) fair value measurements 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 experts to assist in our evaluations, as considered necessary. Actual results could differ from those estimates.

Union bargain agreements: The company has approximately 68% of the company’s employees are covered by a collective bargaining agreement. CMP has no agreements which will expire within the coming year.

Reclassifications: Certain amounts have been reclassified in the consolidated statements of cash flow to conform to the 2016 presentation.

Note 2. Industry Regulation

Our revenues are regulated, being based on tariffs established in accordance with administrative procedures set by the various regulatory bodies. Distribution rates are established by the Maine Public Utilities Commission (MPUC) and transmission rates are established by the Federal Energy Regulatory Commission (FERC). The tariffs applied based on the cost of providing service and 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 return on equity (ROE).

Transmission - FERC ROE Proceeding

See Note 9 - Commitments and Contingent Liabilities - for a further discussion.

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, 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 Federal Power Act (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 Maine Electric Power Company, Inc. (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.

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.

Minimum Equity Requirements for Regulated Subsidiaries

CMP is subject to a minimum equity ratio requirement that is tied to the capital structure assumed in establishing revenue requirements. Pursuant to these requirements CMP 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 CMP 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. CMP is prohibited by regulation from lending to unregulated affiliates. CMP has also agreed to minimum equity ratio requirements in certain short-term borrowing agreements. These requirements are lower than the regulatory requirements.

Note 3. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations we capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric 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. We also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs. Of the total regulatory assets net of regulatory liabilities, approximately $459 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

Details of other regulatory assets and other regulatory liabilities are shown in the tables below. They 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.

Current and long-term regulatory assets at December 31, 2016 and 2015 consisted of:

December 31,	**2016**	**2015**
(Thousands)		
Current		
Storm costs	**$-**	$7,544

Transmission revenue reconciliation mechanism	**12,049**	4,136
Deferred meter replacement costs	**2,548**	2,216
Merger related	**-**	1,666
Stranded costs	**-**	2,808
Environmental remediation costs	**1,240**	2,616
Other	**2,361**	1,046
Total current regulatory assets	**$18,198**	$22,032
Long-term		
Federal tax depreciation normalization adjustment	**11,920**	10,349
Merger related	**-**	1,000
Storm costs	**2,051**	4,393
Unamortized losses on reacquired debt	**722**	1,021
Pension and other postretirement benefit costs	**210,394**	243,458
Unfunded future income taxes	**230,851**	225,166
Deferred meter replacement costs	**31,543**	34,077
Other	**2,284**	2,018
Total long-term regulatory assets	**$489,765**	$521,482

Environmental remediation costs include spending that has occurred and is eligible for future recovery in customer rates. The amortization period will be established in future proceedings and will depend upon the timing of spending for the remediation costs.

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. Because no funds have yet been expended for this regulatory asset, it does not accrue carrying costs and is not included within the rate base.

Storm costs are allowed in rates based on an estimate of the routine costs of service restoration. CMP is also allowed to defer unusually high levels of service restoration costs resulting from major storms when they meet certain criteria for severity and duration. CMP's total deferral, including carrying costs was $2 million at December 31, 2016 and $12 million at December 31, 2015.

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 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.

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.

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Current and long-term regulatory liabilities at December 31, 2016 and 2015 consisted of:

December 31,	2016	2015
(Thousands)		
Current		
Accrued removal obligations	**$2,251**	$2,251
Transmission revenue reconciliation mechanism	**4,764**	5,490
Yankee DOE refund	**23,938**	5,234
Stranded cost	**238**	7,004
Unfunded future income taxes	**-**	10,104
Rate refund-FERC ROE proceeding	**-**	3,092
Revenue decoupling mechanism	**4,507**	10,143
Other	**1,103**	1,481
Total current regulatory liabilities	**$36,801**	$44,799
Long-term		
Environmental remediation costs	**3,131**	4,934
Rate refund-FERC ROE proceeding	**21,738**	21,039
Accrued removal obligations	**78,286**	71,188
Other	**6,786**	3,067
Total non-current regulatory liabilities	**109,941**	100,228
Deferred income taxes regulatory	**149,232**	165,119
Total long-term regulatory liabilities	**$259,173**	$265,347

Accrued removal obligations represent the differences between asset removal costs incurred 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.

Other includes the 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 4. Goodwill

We do not amortize goodwill, but perform a goodwill impairment assessment at least annually as described in Note 1. 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. 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.

We had no impairment of goodwill in 2016 and in 2015 as a result of our annual impairment assessment, which we performed as of October 1. For 2016 as a result of our step one testing and for 2015 as a result of our step zero qualitative analysis, no impairment was indicated within any of the ranges of assumptions analyzed. There were no events or circumstances subsequent to our annual impairment assessment for 2016 or for 2015 that required us to update the assessment.

The carrying amount of goodwill was $325 million at both December 31, 2016 and 2015 with no accumulated impairment losses and no changes during 2016 and 2015.

Note 5. Income Taxes

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

Years Ended December 31,	2016	2015
(Thousands)		
Current		
Federal	**$52,923**	$(15,058)
State	**13,206**	21,898
Current taxes charged to expense	**66,129**	6,840
Deferred		
Federal	**9,611**	75,273
State	**5,331**	(5,075)
Deferred taxes charged to expense	**14,942**	70,198
Total Income Tax Expense	**$81,071**	$77,038

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 and 2015 consisted of:

Years Ended December 31,	2016	2015
(Thousands)		
Tax expense at federal statutory rate	**$76,033**	$67,018
Depreciation and amortization not normalized	**(5,221)**	(178)
Tax return and audit adjustments	**(597)**	(34)
State taxes, net of federal benefit	**12,069**	10,935
Other, net	**(1,213)**	(703)
Total Income Tax Expense	**$81,071**	$77,038

Income tax expense for the year ended December 31, 2016 was $5.2 million higher than it would have been at the statutory federal income tax rate of 35% due predominately to state taxes, (net of federal benefit), and depreciation and amortization not normalized. This resulted in an effective tax rate of 37.4%. Income tax expense for the year ended December 31, 2015 was $10 million higher than it would have been at the statutory federal income tax rate of 35% due predominately to state taxes, (net of federal benefit). This resulted in an effective tax rate of 40.2%.

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

December 31,	2016	2015
(Thousands)		
Noncurrent Deferred Income Tax Liabilities (Assets)		
Property related	**$721,444**	$685,724
Unfunded future income taxes	**92,946**	91,541
Employee benefits	**3,768**	14,957
Derivative assets	**(3,365)**	(4,567)
Other	**(11,196)**	(4,656)
Noncurrent Deferred Income Tax Liabilities	**803,597**	782,999
Add: Valuation allowance	**5,725**	8,988
Total Noncurrent Deferred Income Tax Liabilities	**809,322**	791,987
Less amounts classified as regulatory liabilities		
Noncurrent deferred income taxes	**149,232**	165,119
Noncurrent Deferred Income Tax Liabilities	**$660,090**	$626,868
Deferred tax assets	**$14,561**	$9,224
Deferred tax liabilities	**823,883**	801,211
Net Accumulated Deferred Income Tax Liabilities	**$809,322**	$791,987

CMP has $8.5 million of federal and state research and development credits offset by $5.7 million of valuation allowance.

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

Years Ended December 31, (Thousands)	2016	2015
Balance as of January 1	**$20,077**	$20,760
Increases for tax positions related to prior years	**19,717**	-
Reduction for tax positions related to settlements with taxing authorities	**-**	(683)
Balance as of December 31	**$39,794**	$20,077

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 in the financial statements when it is more likely than not based on the technical merits that the position will be sustained upon examination, assuming the position will be audited and the taxing authority has full knowledge of all relevant information.

There were no additional accruals for interest and penalties on tax reserves as of December 31, 2016 and as of December 31, 2015. If recognized, $3 million of the total gross unrecognized tax benefits would affect the effective tax rate. Gross unrecognized tax benefits increased $19.7 million in 2016 due to tax positions related to prior years.

On December 29, 2014, the Joint Committee on Taxation approved the examination of AGR and its subsidiaries, which includes members of the Central Maine Power Group, for the tax years 1998 through 2009. The results of these audits, net of reserves already provided, were immaterial. Maine state returns are closed through 2011.

Note 6. Long-term Debt

At December 31, 2016 and 2015, our long-term debt was:

As of December 31,		2016		2015	
(Thousands)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
First mortgage bonds [(a)]	2019-2045	$ 900,000	3.07%-5.70%	$ 900,000	3.07%-5.70%
Senior unsecured notes	2025-2037	140,000	5.38%-6.40%	180,000	5.27%-6.40%
Chester: Promissory and Senior Notes[(b)]	2020	4,542	7.05%-10.48%	5,725	7.05%-10.48%
Obligations under capital leases	2017-2036	7,424		4,187	
Unamortized debt issuance costs and discount		(4,502)		(5,088)	
Total Debt		**$1,047,464**		**$ 1,084,824**	
Less: debt due within one year, included in current liabilities		5,154		41,312	
Total Non-current Debt		**$1,042,310**		**$ 1,043,512**	

(a) The first mortgages bonds are secured by a first mortgage lien on substantially all of Net Utility Plant In Service.
(b) Chester SVC Partnership notes are secured by the assets of this partnership.

At December 31, 2016, long-term debt, including sinking fund obligations and capital lease payments (in thousands) that will become due during the next five years are:

2017	2018	2019	2020	2021
$5,154	$2,022	$152,042	$1,937	$150,299

We have no debt covenant requirements related to the maintenance of financial ratios in our long term debt agreements at December 31, 2016 and 2015.

Note 7. Bank Loans and Other Borrowings

CMP had no short-term debt outstanding at December 31, 2016 or December 31, 2015. CMP funds short-term liquidity needs through an agreement among Avangrid's regulated utility subsidiaries (the "Virtual Money Pool Agreement"), a bi-lateral intercompany credit agreement with Avangrid (the "Bi-Lateral Intercompany Facility") and a bank provided credit facility to which CMP is a party (the "Avangrid Credit Facility"), each of which are described below.

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. CMP has a lending/borrowing limit of $100 million under this agreement. There were no balances outstanding under this agreement as of December 31, 2016.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $500 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. There were no balances outstanding under this agreement as of December 31, 2016 and December 31, 2015, respectively.

On April 5, 2016, AGR and its investment-grade rate utility subsidiaries (NYSEG, RG&E, CMP, UI, CNG, SCG and BGC) entered into a revolving credit facility with a syndicate of banks, (the AGR Credit Facility), that provides for maximum borrowings of up to $1.5 billion in the aggregate. Under the terms of the AGR 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. AGR'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 AGR 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 AGR Credit Facility is April 5, 2021. CMP had not borrowed under this agreement as of December 31, 2016.

As a condition of closing on the AGR Credit facility, three existing credit facilities were terminated: i) the AGR 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.

Note 8. Redeemable Preferred Stock

We have redeemable preferred stock that contains a feature that could lead to potential redemption-triggering events that are not solely within our control.

At December 31, 2016 and 2015, our redeemable preferred stock was:

Series	Par Value per Share	Redempti on Price per Share	Shares Authorized and Outstanding[1]	Amount (Thousands) 2016	2015
CMP, 6% Noncallable	$100	-	5,713	**$571**	$571
Total				**$571**	$571

[1] At December 31, 2016 CMP had 2,300,000 shares of $100 par value preferred stock authorized but unissued.

CMP Group owns 3,792 shares of the 5,713 shares outstanding.

Note 9. Commitments and Contingencies

CMP Transmission - ROE Complaint

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 reserved for refunds for Complaints I, II and III consistent with the FERC's March 3, 2015 final decision in Complaint I. The CMP total reserve associated with Complaints II and III is $21.7 million 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 will be 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. 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.

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.

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, upon FERC approval, and will reduce retail customer charges or otherwise as specified by law. CMP will receive its 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 received its proportionate share of $2.5 million of the Phase III damage awards, based on percentage ownership, and 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.

Power purchase contracts including nonutility generator

We recognized expense of approximately $58 million for NUG power in 2016 and $57 million in 2015. We estimate that our power purchases will total $12 million in 2017, $15 million in 2018, $18 million in 2019, 2020 and 2021 and $247 million thereafter.

Note 10. Environmental Liability

From time to time environmental laws, regulations and compliance programs may require changes in our operations and facilities and may increase the cost of electric service.

Waste sites

The EPA 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 six waste sites. The six sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the six sites, five sites are included in Maine's Uncontrolled Sites Program, one is included on the Massachusetts Non-Priority Confirmed Disposal Site list and two sites are also included on the National Priorities list. Any liability may be joint and several for certain of those sites. We have recorded an estimated liability of $1.4 million related to the six sites at December 31, 2016.

We have recorded an estimated liability of $2.3 million at December 31, 2016, related to four additional 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 are regulated under State Resource Conservation and Recovery Act (RCRA) program. It is reasonably possible the ultimate cost to remediate the sites may be significantly more than the accrued amount. Our estimate for costs to remediate these sites ranges from $2.7 million to $8.9 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 attributed to us. We recorded a corresponding regulatory asset, net of insurance recoveries, because we expect to recover the net costs in rates.

Manufactured gas plants

We have a program to investigate and perform necessary remediation at our three sites where gas was manufactured in the past. All three sites are part of Maine's Voluntary Response Action Program and two are on the Maine's Uncontrolled Sites Program.

Our estimate for all costs related to investigation and remediation of the three sites range from $0.3 million to $1.2 million at December 31, 2016. The estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial action, changes in technology relating to remedial alternatives and changes to current laws and regulations.

The liability to investigate and perform remediation, as necessary, at the known inactive gas manufacturing sites was $0.7 million at December 31, 2016, and $2.1, million at December 31, 2015. We recorded a corresponding regulatory asset, net of insurance recoveries, because we expect to recover the net costs in rates.

Our environmental liabilities are recorded on an undiscounted basis. We have received insurance settlements during the last two years, which we accounted for as reductions in our related regulatory asset.

Note 11. Accounting for Derivative Instruments and Hedging Activities

We are exposed to certain risks relating to our ongoing business operations. The primary risk we manage by using derivative instruments is commodity price risk. In accordance with the accounting requirements concerning derivative instruments and hedging activities, we recognize all derivative instruments as either assets or liabilities at fair value on our balance sheet. For financial statement presentation, 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 financial instruments we hold or issue are not for trading or speculative purposes.

Cash flow hedging: Our fleet fuel hedges are designated as cash flow hedging instruments. We record changes in the fair value of the cash flow hedging instruments in other comprehensive income (OCI), to the extent they are considered effective, and reclassify those gains or losses into earnings in the same period or periods during which the hedged transactions affect earnings.

Our derivatives designated as hedging instruments, which are other commodity contracts (fleet fuel), had a fair value of $(0.2) million as of December 31, 2016, and $(0.9) million as of December 31, 2015, and are included in current liabilities.

The effect of hedging instruments on OCI and income was:

Year Ended December 31,	Gain (Loss) Recognized in OCI on Derivatives	Location of Gain (Loss) Reclassified from Accumulated OCI into Income	Gain(Loss) Reclassified from Accumulated OCI into Income
Derivatives in Cash Flow Hedging Relationships	**Effective Portion**	**Effective Portion**	
(Thousands)			
2016			
Interest rate contracts	**$-**	Interest expense	**$(2,175)**
Commodity contracts:			
Fleet Fuel	**$133**	Other operating expenses	**(638)**
Total	**$133**		**$(2,813)**
2015			
Interest rate contracts	$-	Interest expense	$(2,222)
Commodity contracts:			
Fleet Fuel	$(950)	Other operating expenses	(1,053)
Total	$(950)		$(3,275)

The amount in OCI related to previously settled interest rate hedging contracts, after tax and accumulated amortization, at December 31 is a net loss of $8.0 million for 2016 and a net loss of $10.1 million for 2015. For the year ended December 31, 2016, we recorded $0.2 million in net derivative losses related to discontinued cash flow hedges. We will amortize approximately $2.2 million of discontinued cash flow hedges in 2017.

At December 31, 2016, $0.2 million in losses are reported in OCI because the forecasted transaction is considered to be probable. We expect that those losses in OCI will be reclassified into earnings within the next 12 months, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted energy transactions. There was no ineffective portion of the hedge recognized during the year ended December 31, 2016.

Note 12. Fair Value of Financial Instruments and Fair Value Measurements

The estimated fair value of debt amounted to $1,144 million and $1,171 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 for the fair value of debt is considered as Level 2.

Notes to Consolidated Financial Statements

Assets and liabilities measured at fair value on a recurring basis

		Fair Value Measurements at December 31, Using		
Description	**Total**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
(Thousands)				
2016				
Assets				
Noncurrent investments available for sale	**$698**	**$698**	**$-**	**$-**
Total	**$698**	**$698**	**$-**	**$-**
Liabilities				
Derivatives	**$164**	**$-**	**$-**	**$164**
Total	**$164**	**$-**	**$-**	**$164**
2015				
Assets				
Noncurrent investments available for sale	$415	$415	$-	$-
Total	$415	$415	$-	$-
Liabilities				
Derivatives	$935	$-	$-	$935
Total	$935	$-	$-	$935

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2016 and 2015. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

Valuation techniques: We measure the fair value of our noncurrent investments available for sale using quoted market prices in active markets for identical assets and include the measurements in Level 1. The investments primarily consist of money market funds.

We enter into fuel derivative contracts to hedge our unleaded and diesel fuel requirements for our fleet vehicles. Exchange based forward market prices are used but because a basis adjustment is added to the forward prices, we include the fair value measurement for these contracts in level 3.

Instruments measured at fair value on a recurring basis using significant unobservable inputs

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)	
	Derivatives, Net	
Year ended December 31,	**2016**	**2015**
(Thousands)		
Beginning balance	**$935**	$1,038
Total gain or loss for the period		
Included in earnings	**(638)**	(1,053)
Included in other comprehensive income	**(133)**	950
Ending balance	**$164**	$935

The amounts of realized and unrealized gain and loss included in earnings for the period (above) are reported in Operations and maintenance of the consolidated statements of income.

Note 13. Accumulated Other Comprehensive Loss

(Thousands)	Balance January 1, 2015	2015 Change	Balance December 31, 2015	2016 Change	Balance December 31, 2016
Amortization of pension cost for nonqualified plans, net of income tax expense of $112 for 2015 and $48 for 2016	$(2,122)	$163	$(1,959)	**$75**	**$(1,884)**
Unrealized (loss) /gain on derivatives qualified as hedges:					
Unrealized (loss) during period on derivatives qualified as hedges, net of income tax (benefit) expense of ($388) for 2015 and $52 for 2016		(562)		**81**	
Reclassification adjustment for loss included in net income, net of income tax expense of $430 for 2015 and of $250 for 2016		623		**388**	
Reclassification adjustment for loss on settled cash flow treasury hedge, net of income tax expense of $907 for 2015 and $852 for 2016		1,315		**1,323**	
Net unrealized (loss) gain on derivatives qualified as hedges	$(7,931)	$1,376	$(6,555)	**$1,792**	**$(4,763)**
Accumulated Other Comprehensive Loss	$(10,053)	$1,539	$(8,514)	**$1,867**	**$(6,647)**

No Accumulated Other Comprehensive Loss is attributable to the noncontrolling interest for the above periods.

Note 14. Retirement Benefits

We have funded noncontributory defined benefit pension plans that cover all eligible 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 benefits accumulate based on a percentage of annual salary and credited interest. During 2013 the company announced that we would freeze the benefits for all non-union employees covered under the cash balance plans effective December 31, 2013. CMP union employees covered under the cash balance plans ceased accruals as of December 31, 2014. 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 these 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.

The company maintains a 401(k) Savings and Retirement Plan (the Plan) for all eligible employees as defined in the Plan agreement. Participants in the Plan may contribute a percentage of their compensation and the company may match a predetermined percentage of the participant contributions. Expenses under the Plan for the Company totaled approximately $3 million for both 2016 and 2015.

We also have other postretirement health care benefit plans covering substantially all of our employees. The health care plans are contributory with participants' contributions adjusted annually.

***Obligations and funded status*:**

	Pension Benefits 2016	Pension Benefits 2015	Postretirement Benefits 2016	Postretirement Benefits 2015
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	**$405,281**	$419,710	**$113,861**	$117,567
Service cost	**7,846**	7,711	**712**	835
Interest cost	**16,267**	15,620	**4,523**	4,331
Plan participants' contributions	**-**	-	**528**	399
Actuarial loss (gain)	**(12,059)**	(20,756)	**(5,520)**	(3,320)
Special termination benefits	**-**	824	**-**	-
Medicare subsidies received	**-**	-	**48**	-
Benefits paid	**(20,812)**	(17,828)	**(7,173)**	(5,950)
Benefit obligation at December 31	**$396,523**	$405,281	**$106,979**	$113,862
Change in plan assets				
Fair value of plan assets at January 1	**$256,948**	$254,164	**$35,635**	$38,787
Actual return on plan assets	**15,773**	(4,070)	**2,117**	(929)
Employer contributions	**20,736**	24,682	**6,597**	5,551
Withdrawal from VEBA	**-**	-		(2,223)
Employer and plan participants' contributions	**-**	-	**528**	399
Benefits paid	**(20,812)**	(17,828)	**(8, 784)**	(5,950)
Medicare subsidies received	**-**	-	**48**	-
Fair value of plan assets at December 31	**$272,645**	$256,948	**$36,141**	$35,635
Funded status at December 31	**(123,878)**	(148,333)	**(70,838)**	$(78,227)

Amounts recognized in the balance sheet December 31,	Pension Benefits 2016	Pension Benefits 2015	Postretirement Benefits 2016	Postretirement Benefits 2015
(Thousands)				
Noncurrent liabilities	**$(123,878)**	$(148,333)	**$(70,838)**	$(78,227)

We have determined that we are allowed to defer as regulatory assets or regulatory liabilities items that would otherwise be recorded in accumulated other comprehensive income pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans.

Amounts recognized as regulatory assets or regulatory liabilities, consist of:

December 31,	Pension Benefits 2016	Pension Benefits 2015	Postretirement Benefits 2016	Postretirement Benefits 2015
(Thousands)				
Net loss	**$179,114**	**$205,258**	**$41,974**	**$50,898**
Prior service cost (credit)	**$7**	**$16**	**$(10,701)**	**$(12,713)**

Our accumulated benefit obligation for all defined benefit pension plans at December 31 was $360 million for 2016 and $363 million for 2015.

Our postretirement benefits were partially funded at December 31, 2016 and 2015.

The projected benefit obligation and accumulated benefit obligation exceeded the fair value of pension plan assets for our plans as of December 31, 2016 and 2015. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets for the relevant periods.

December 31,	2016	2015
(Thousands)		
Projected benefit obligation	$396,523	$405,281
Accumulated benefit obligation	$359,747	$362,643
Fair value of plan assets	$272,645	$256,948

***Components of net periodic benefit cost and other amounts recognized in regulatory assets and regulatory liabilities*:**

	Pension Benefits		Postretirement Benefits	
Years ended December 31,	**2016**	**2015**	**2016**	**2015**
(Thousands)				
Net periodic benefit cost				
Service cost	**$7,846**	$7,710	**$712**	$835
Interest cost	**16,267**	15,621	**4,523**	4,331
Expected return on plan assets	**(19,963)**	(18,742)	**(2,292)**	(2,674)
Amortization of prior service cost (credit)	**9**	117	**(2,013)**	(2,049)
Special termination benefit charge	**-**	824	**-**	-
Amortization of net loss	**18,274**	20,744	**3,579**	3,656
Net periodic benefit cost	**$22,433**	$26,274	**$4,509**	$4,099
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net loss/(gain)	**$(7,870)**	$2,056	**$(5,345)**	$283
Amortization of net (loss)	**(18,274)**	(20,744)	**(3,579)**	(3,656)
Amortization of prior service (cost) credit	**(9)**	(117)	**2,013**	2,049
Total recognized in regulatory assets and regulatory liabilities	**(26,153)**	(18,805)	**(6,911)**	(1,324)
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$(3,720)**	$7,469	**$(2,402)**	$2,775

We include the net periodic benefit cost in other operating expenses. The net periodic benefit cost for postretirement benefits represents the amount expensed for providing health care benefits to retirees and their eligible dependents.

Amounts expected to be amortized from regulatory assets or regulatory liabilities into net periodic benefit cost for the fiscal year ending December 31, 2017	Pension Benefits	Postretirement Benefits
(Thousands)		
Estimated net loss	$15,918	$2,833
Estimated prior service cost (credit)	$6	$(2,013)

We expect that no pension benefit or postretirement benefit plan assets will be returned to us during the fiscal year ending December 31, 2017.

Weighted-average assumptions used to determine benefit obligations at December 31,	Pension Benefits		Postretirement Benefits	
	2016	**2015**	**2016**	**2015**
Discount rate	**4.12%**	4.10%	**4.12%**	4.10%
Rate of compensation increase	**3.80%/4.20%**	4.10%	**N/A**	N/A

The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rate by developing a yield curve derived from a portfolio of high grade non-callable bonds with above median yields that closely matches the duration of the expected cash flows of our benefit obligations.

Weighted-average assumptions used to determine net periodic benefit cost for Years ended December 31,	Pension Benefits 2016	Pension Benefits 2015	Postretirement Benefits 2016	Postretirement Benefits 2015
Discount rate	**4.10%**	3.80%	**4.10%**	3.80%
Expected long-term return on plan assets	**7.40%**	7.50%	**-**	-
Expected long-term return on plan assets - nontaxable trust	**-**	-	**7.00%**	7.50%
Expected long-term return on plan assets - taxable trust	**-**	-	**4.50%**	5.00%
Rate of compensation increase (Union/Non-Union	**3.80%/4.20%**	4.30%	**N/A**	N/A

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. That analysis considered current capital market conditions and projected conditions. Our policy is to calculate the expected return on plan assets using the market related value of assets. We amortize unrecognized actuarial gains and losses using the standard amortization methodology, under which amounts in excess of 10% 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 to determine benefit obligations at December 31,	2016	2015
Health care cost trend rate (pre 65/post 65)	**7.00%9.00%**	7.00%/9.00%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	**4.50%**	4.50%
Year that the rate reaches the ultimate trend rate	**2026/2028**	2026

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plan. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
(Thousands)		
Effect on total of service and interest cost	**$238**	**$(199)**
Effect on postretirement benefit obligation	**$5,773**	**$(4,835)**

Contributions**:** In accordance with our funding policy we make annual contributions of not less than the minimum required by applicable regulations. We expect to contribute $15.7 million to our pension benefit plans in 2017.

Estimated future benefit payments**:** Our expected benefit payments and expected Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) subsidy receipts, which reflect expected future service, as appropriate, are:

(Thousands)	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
2017	$17,680	$7,017	$151
2018	$18,266	$7,037	$167
2019	$19,064	$7,083	$184
2020	$19,847	$7,097	$203
2021	$20,656	$7,040	$223
2022 - 2026	$116,582	$26,869	$1,426

***Plan assets*:** Our pension benefits plan assets are held in a master trust providing for a single trustee/custodian, a uniform investment manager lineup, and an efficient, cost-effective means of allocating expenses and investment performance to each plan under the master trust. Our primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our tolerance for risk. 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 trust's investments while avoiding significant concentrations of risk in any one area of the securities markets. Within each asset group, further diversification is achieved through utilizing multiple asset managers and systematic allocation to various asset classes; 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.

The fair values of Networks' pension benefits plan assets at December 31, 2016 and 2015, by asset category are shown in the following table. CMP's share of the total consolidated assets is approximately 10% for both 2016 and 2015.

Asset Category	Total	Fair Value Measurements at December 31, Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(Thousands)				
2016				
Cash and cash equivalents	**$48,645**	**$-**	**$48,645**	**$-**
U.S. government securities	**171,736**	**171,736**	**-**	**-**
Common stocks	**120,301**	**120,301**	**-**	**-**
Registered investment companies	**92,152**	**92,152**	**-**	**-**
Corporate bonds	**357,773**		**357,773**	**-**
Preferred stocks	**4,078**	**262**	**3,816**	**-**
Common/collective trusts	**1,193,500**		**371,831**	**821,669**
Partnership/joint venture interests	**-**	**-**	**-**	**-**
Real estate investments	**60,995**	**-**	**-**	**60,995**
Other investments, principally annuity and fixed income	**585,233**	**-**	**310,785**	**274,448**
Total	**$2,634, 413**	**$384,451**	**$1,092,850**	**$1,157,112**
2015				
Cash and cash equivalents	$57,797	$3,561	$54,236	$-
U.S. government securities	171,024	171,024	-	-
Common stocks	661,639	661,639	-	-
Registered investment companies	81,308	81,308	-	-
Corporate bonds	323,900	-	323,900	-
Preferred stocks	4,926	295	4,631	-
Common/collective trusts	511,504	-	21,476	490,028
Partnership/joint venture interests	78,519	-	-	78,519
Real estate investments	88,865	-	-	88,865
Other investments, principally annuity and fixed income	643,001	324,733	-	318,268
Total	$2,622,483	$1,242,560	$404,243	$975,680

Valuation techniques: We value our pension benefits plan assets as follows:

- Cash and cash equivalents – Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities, Common stocks and registered investment companies - at the closing price reported in the active market in which the security is traded.
- Corporate bonds – based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks – at the closing price reported in the active market in which the individual investment is traded.
- Common/collective trusts and Partnership/joint ventures – using the Net Asset Value (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:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)				
(Thousands)	Common/ Collective Trusts	Partner-ship/ Joint Venture Interests	Real Estate Invest-ments	Other Invest-ments	Total
Balance, December 31, 2014	$450,141	$79,489	$74,871	$341,685	$946,186
Actual return on plan assets:					
Relating to assets still held at the reporting date	(5,873)	18,518	10,235	(20,169)	2,711
Relating to assets sold during the year	(3,115)	(19,488)	-	904	(21,699)
Purchases, sales and settlements	48,875	-	3,759	(4,152)	48,482
Balance, December 31, 2015	$490,028	$78,519	$88,865	$318,268	$975,680
Actual return on plan assets:					
Relating to assets held at the reporting date	**50,752**	**-**	**1,710**	**(7,534)**	**44,928**
Relating to assets sold during the year	**5,542**	**(18,519)**	**478**	**686**	**(11,813)**
Purchases, sales and settlements	**275,347**	**(60,000)**	**(30,058)**	**(36,972)**	**148,317**
Balance, December 31, 2016	**$821,669**	**$-**	**$60,995**	**$274,448**	**$1,157,112**

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.

We 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. 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 Networks' other postretirement benefits plan assets, by asset category, as of December 31, 2016 and 2015, by asset category are shown in the following table. CMP's share of the total consolidated assets was approximately 22% for both 2016 and 2015.

		Fair Value Measurements at December 31, Using		
Asset Category	**Total**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
(Thousands)				
2016				
Money market funds	**$5,786**	**$3,582**	**$2,204**	**$-**
Mutual funds, fixed	**40,856**	**38,496**	**2,360**	**-**
Government & corporate bonds	**1,651**	**-**	**1,651**	**-**
Mutual funds, equity	**71,031**	**41,687**	**29,344**	**-**
Common stocks	**22,896**	**22,896**	**-**	**-**
Mutual funds, other	**17,868**	**9,961**	**7,907**	**-**
Total assets measured at fair value	**$160,088**	**$116,622**	**$43,466**	**$-**
2015				
Money market funds	$4,163	$4,163	$-	$-
Mutual funds, fixed	35,438	35,438	-	-
Government & corporate bonds	1,703	-	1,703	-
Mutual funds, equity	45,679	45,679	-	-
Common stocks	22,939	22,793	-	146
Mutual funds, other	50,518	43,400	7,118	-
Total assets measured at fair value	$160,440	$151,473	$8,821	$146

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 the 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 AGR and Iberdrola common stock as of both December 31, 2016 and 2015.

Note 15. Subsequent events

The company has performed a review of subsequent events through March 31, 2017, which is the date these financial statements were available to be issued, and no subsequent events have occurred from January 1, 2017 through such date.

Exhibit 3-6: AVANGRID / Iberdrola Project Portfolio

AVANGRID / IBERDROLA - Portfolio of Projects under construction or recently energized — *Updated:* *22-Jun-17*

Name	Investment	Location	Project Type, Size and Technology	Commercial Operation Date	References
AVANGRID					
Central Maine Power (CMP)					
Maine Power Reliability Program (MPRP)	$1,405M	75 Municipalities between Elliot and Orrington, Maine	436 miles of new and rebuild Transmission Lines (345 and 115 kV): Overhead, Wood and Steel Poles, Fiber Optic, 1590 MCM and 1113 MCM Conductor; 6 new substations, 7 major expansions, 43 remote ends: Breaker and a Half, IEC-61850 protocol.	2015	Sara Burns, President – Central Maine Power; 83 Edison Dr., Augusta, ME 04330; (207) 623-3521
Lewiston Loop	$71M	Lewiston/Auburn, Maine	A 115 kV expansion into Lewiston from Larrabee Rd SS to Lewiston Lower: New Middle St SS 115/34/12 kV; 4.3 miles of New 115 kV Overhead Line; 1.1 miles of New 115 kV Underground Line; Additional expansions.	2018	Sara Burns, President – Central Maine Power; 83 Edison Dr., Augusta, ME 04330; (207) 623-3521
Lakewood Project	$18M	Madison, Maine	Rebuild the Lakewood Substation by adding a 115kv ring bus, a second 115/34.5kV transformer and replace the 34.5kV structures and breakers. This project also involved the construction of new line Section 264, rebuild of existing line Section 241B.	2015	Sara Burns, President – Central Maine Power; 83 Edison Dr., Augusta, ME 04330; (207) 623-3521
Berwick Reinforcements Project	$13M	York County, Maine	Adding 2.3-mile 34kV transmission line. Constructing new Bassett Substation; Adding a new 34kV bay at the existing Quaker Hill Substation to receive Section 117. One 34.5-12.47kV outdoor power transformer, two 12.47kV distribution circuits.	2013 & 2017	Sara Burns, President – Central Maine Power; 83 Edison Dr., Augusta, ME 04330; (207) 623-3521
34kV Rebuilds Project	$32M	Cumberland, Knox and Penobscot Counties, Maine	Rebuild of 30 miles of 34.5kV transmission lines, including Sections 5A, 48, 172 and 187.	2014 & 2015	Sara Burns, President – Central Maine Power; 83 Edison Dr., Augusta, ME 04330; (207) 623-3521
NERC Alert	$38M	Entire service territory	Twenty-six transmission lines required a total of 408 structure replacements or raises to meet clearance requirements. Nine were 345 kV structures and 17 were 115kV. PhaseRaiser used for 108 structures and remaining were mostly replacements and a few midspans. MPRP covered an additional 121 corrections to eight lines (three 345kV and five 115kV).	2012, 2013 and 2014	Sara Burns, President – Central Maine Power; 83 Edison Dr., Augusta, ME 04330; (207) 623-3521
Blue Sky West Project	$18M	Central Maine	New generation lead into Guilford Substation. Guilford Substation upgrade new 115kV bay and reconfiguration of ring bus. 27 miles of re-rate 115kV line section to Detroit Substation. SVC installed adjacent to Detroit Substation and connected in at Detroit.	2016	Sara Burns, President – Central Maine Power; 83 Edison Dr., Augusta, ME 04330; (207) 623-3521
Saco Bay	$36.9 M	Saco and Old Orchard Beach, Maine	Addition of seven miles radial 115kV transmission line and associated infrastructure, including substations; two new sections of 115kV transmission lines; six relocated sections of 34.5 kV transmission lines; two new "green-field" 115kV transmission lines; two modified "brown-field" substations, 34.5 & 115kV; removal of two 34.5kV substations.	2012	Sara Burns, President – Central Maine Power; 83 Edison Dr., Augusta, ME 04330; (207) 623-3521
South Gorham	$27.2M	Gorham, Maine	Installation of 345kV autotransformer with remote end work and control house expansion / relay updates.	2010	Sara Burns, President – Central Maine Power; 83 Edison Dr., Augusta, ME 04330; (207) 623-3521
Section 241	$39.1M	Winslow, Maine	Phase I included re-rating two segments, Section 38 (completed in 2014) and Section 38B (completed in 2014:) and a complete re-build of Section 242 between the Winslow S/S and the Heywood S/S. Completed November, 2015.	2015	Sara Burns, President – Central Maine Power; 83 Edison Dr., Augusta, ME 04330; (207) 623-3521
Coopers Mill Statcom	$51.7M	Windsor, Maine	Coopers Mills has been chosen by ISO-NE as a site for a new STATCOM based on the Greater Boston Needs Assessment study. The addition of this STATCOM will require expansions to the 345kV breaker and a half bus involving the construction of a new breaker and a half rung, rework Section 3024 conductor onto new deadend structure, and the installation among others of two 362kV IPO circuit breakers, eight 345kV switches, and steel structures.	2018	Sara Burns, President – Central Maine Power; 83 Edison Dr., Augusta, ME 04330; (207) 623-3521
NERC Alert (II)	$105M	Entire service territory (ME, NY)	The target of the program is to evaluate Priority III 115kV Lines and determine facility ratings based on the actual field conditions. If issues are found, the program will correct them.	2021	Sara Burns, President – Central Maine Power; 83 Edison Dr., Augusta, ME 04330; (207) 623-3521
Substation Modernizations	$45M	Entire service territory (ME)	This project is a substation rebuild project to replace several distribution substations in CMP's territory that have age/condition issues that are in need of attention.	2020	Sara Burns, President – Central Maine Power; 83 Edison Dr., Augusta, ME 04330; (207) 623-3521
Rochester Gas and Electric (RGE)					
Rochester Area Reliability Program (RARP)	$254M	Rochester, New York (USA)	20 miles of new and rebuild Transmission Lines (345 and 115 kV) Overhead & Underground; 1 new substation, 3 major expansions, 2 remote ends; Breaker and a Half, IEC-61850 protocol, GIS Switchyard	2017	Carl Taylor, President – Rochester Gas & Electric; 89 East Avenue, Rochester NY 14604; (800) 743-2110
Station 56	$21M	Rochester, New York (USA)	1 new Transformer (22MV 115/12kV) and upgrade of the 12kV yard, including the relocation of the existing transformer, new 12kV GIS and new Power Room. IEC-61850 protocol. Rebuild of the distribution lines (C267, C268 and C402) to convert from 4kV to 12kV.	2015 Phase 1 2016 Phase 2	Carl Taylor, President – Rochester Gas & Electric; 89 East Avenue, Rochester NY 14604; (800) 743-2110
Station 23	$145M	Rochester, New York (USA)	Rebuild the existing Station 23. Build the new 34.5kV lines 802 and 803, two new 115kV/34kV Transformers and switchgear at Station 23. Upgrade line 901 from 210 MVA to 400 MVA. Install a 115kV 230 MVA PST at Station 42. New fiber optic. DNP 3 protocol.	2018	Carl Taylor, President – Rochester Gas & Electric; 89 East Avenue, Rochester NY 14604; (800) 743-2110
Station 80 1T, 3T Replacements	$13M	Rochester, New York (USA)	This project encompasses replacing two 345/115 kV, 200 MVA transformers with new 420MVA units including oil containment, circuit breakers, switches, protection equipment and 2,000 ft. of aluminum bus. 1T placed in service on 5/6/13.	2013	Carl Taylor, President – Rochester Gas & Electric; 89 East Avenue, Rochester NY 14604; (800) 743-2110
Station 136 Add Transformer and 12kV Circuits	$7.3M	Rochester, New York (USA)	ST 136 is an existing substation located east of the city of Rochester in the Town of Webster. The scope of the project is to install a new 22.4MVA transformer, new 34.5kV and 12kV switchgear and expand the existing control house. Associated with this project is the installation on three new 12kV lines in the Webster area.	2013	Carl Taylor, President – Rochester Gas & Electric; 89 East Avenue, Rochester NY 14604; (800) 743-2110
Webster East New 12kV Source	$6.6M	Rochester, New York (USA)	Webster East New 12kV Source: Install a 34/12kV, 22 MVA transformer. 3 new 12kV circuits, & the conversions of three existing 4kV is part of the project. Establish a new 12kV source in the eastern area of the Town of Webster. Install a 34.5-12kV, 22 MVA transformer at Station 424 and install three new 12kV circuit positions. The 12kV bus will be established after the completion of the 115kV expansion that is planned for Station 424, and then the necessary conversions of three existing 4kV circuits will be undertaken. The project includes both substation work at Station 424 and distribution work for three circuits. A portion of the substation construction was completed in 2008. Work was stopped in January 2009. The engineering resumed in late Fall of 2010. The original Team NY standards are being used for this project.	2012	Carl Taylor, President – Rochester Gas & Electric; 89 East Avenue, Rochester NY 14604; (800) 743-2110
Station 124 SVC	$23.6M	Rochester, New York (USA)	Expand existing Station 124 eastward to install a 115kV +200/-100 Mvar Static VAR Compensator (SVC) to provide dynamic voltage support during system contingencies, improve transfer capability across the transmission system and prevent overvoltage during light load conditions due to the capacitance of nearby 115kV cables and area generation.	2013	Carl Taylor, President – Rochester Gas & Electric; 89 East Avenue, Rochester NY 14604; (800) 743-2110

New York State Electric & Gas (NYSEG)					
Agro Farma	$15.1M	Binghamton, New York (USA)	New 46 kV Line Position in County Line Substation and build a new 46kV Transmission line#834, a brand new 46/15 kV Columbus Substation and modify existing Distribution lines; Dismantling of the existing South Edmeston substation and relocation of the existing 46 kV Transmission Line#830 to the new Columbus Substation.	2013	
Auburn Transmission Project	$105M	Cayuga and Onondaga Counties, New York	NYSEG's ability to ensure reliable service to customers in its Auburn Division is dependent on at least one of the generating units at the Cayuga Generating Facility in Lansing, owned by a subsidiary of AES Corporation ("AES"), being available to operate. This dependency exists only because of limitations on transmission to the area. To eliminate these transmission limitations and enable NYSEG to maintain adequate normal and single contingency service throughout the Auburn Division during extended outages (planned or forced) of a single unit at the Cayuga Generating Facility, NYSEG to reinforce its electric transmission system in the Auburn Division by constructing a new approximately 14.5 mile, 115kV transmission line from National Grid's Elbridge Substation to NYSEG's State Street Substation. This new line not only addresses the above transmission limitations, but it also increases the short circuit and strengthen the transmission system throughout the Auburn Division and lessen NYSEG's dependency on the aged National Grid 115kV trunk lines. The Project also addresses rebuilding portions of NYSEG and National Grid 115kV L971 and L972.	2017	Carl Taylor, President – Rochester Gas & Electric; 89 East Avenue, Rochester NY 14604; (800) 743-2110
New York Transco -Marcy South Series Compensation-	$69M	Fraser, New York (USA)	The overall scope of the Marcy South Series Compensation project involves the installation of series capacitor banks and upgrades to the 345kV lines connecting the Marcy, Edic, Fraser, and Coopers Corner substations, in order to increase the transmission line capacity of this portion of the network. For NYSEG, the Marcy South Series Compensation (MSSC) project built a 240 MVAR capacitors bank "station", in the vicinity of Fraser substation, connected in series compensation to the NYSEG-owned 345 kV FCC-33 Transmission Line, as well as re-conductor 22 miles long section, from structure #17 to #177, of the 46.6 miles long NYSEG-owned 345 kV FCC-33 single circuit, between Fraser and Coopers Corners substations (replacing the existing single 2156 ACSR conductor) . These improvements increase the thermal transfer limits of the FCC-33 circuit to an ampacity of approximately 2500A, and all under rated equipment upgraded to handle the new nominal rating, as well as all line relaying and communications equipment associated with the affected remote ends also upgraded at NYSEG owned Fraser, Coopers Corners and Oakdale substations.	2016	Carl Taylor, President – Rochester Gas & Electric; 89 East Avenue, Rochester NY 14604; (800) 743-2110
NERC Alert	$14.8 M	Binghamton, New York (USA)	The scope of the project is to analyze the 230 kV and 345 kV NYSEG-owned Transmission Lines in its service territory in order to identify the clearance violation points according to National Electric Safety Code (NESC) and execute a solution to eliminate the violations.	2013	
SGIG/DOE Cap Bank Installations	$14.0 M	Binghamton, New York (USA)	Add DOE Stimulus capacitor banks at Morgan, Amawalk, Ridge Road, Big Tree, Mountaindale and Ashley Rd. The Smart Grid Capacitor Bank Program comprises the installation of 13 new 115KV switched capacitor banks, 13-115KV Independent Pole Operated circuit breakers, associated motor operated disconnect switches, relay protection equipment and several new control houses or control house additions at six existing NYSEG substations. Total reactive capability of the NYSEG system will increase by approximately 410 MVars. Ridge road was placed in service 3/28/13.	2014	

United Illuminating (UI)					
Grand Avenue Infrastructure Replacement	$55M	New Haven, CT	This project was undertaken to address several asset condition and operation issues with meeting short circuit equipment capability requirements. This included the installation of a 4 bay breaker and a half 115kV GIS station with associated protection systems, line terminations, and remote end protection and control upgrades. This project was constructed bringing the station up to BPS compliance.	2012	Tony Marone, President & CEO – UIL 180 Marsh Hill Road, Orange CT 06477 (203) 499-2032
Baird Substation Infrastructure Replacement	$30M	Stratford, CT	This project is a 115kV to 13.8kV substation rebuild of an existing substation that was constructed in 1964. The rebuild will address limited clearances to energized equipment, National Electric Safety Code (NESC) requirements overly-congested control house; fixed tap transformers replacements with LTC transformers; & the 115 kV and 13.8 kV bus nearing its thermal capacity.	2018	Tony Marone, President & CEO – UIL 180 Marsh Hill Road, Orange CT 06477 (203) 499-2032
New Trumbull 115 kV/13.8kV Substation	$26M	Trumbull, CT	The construction of Trumbull 115/13.8 kV Substation was completed in 2008 to alleviate a capacity deficiency in Trumbull region. The substation provides approximately 58 MVA of capacity in the Trumbull area. This project consisted of an outdoor, air-insulated, 115/13.8 kV switchyard with two 24/32/40 MVA, 115/13.8 kV transformers with load tap changers and three 115 kV circuit breakers in a ring bus configuration.	2008	Tony Marone, President & CEO – UIL 180 Marsh Hill Road, Orange CT 06477 (203) 499-2032
Pootatuck 115/13.8 kV Substation	$40M	Shelton, CT	The construction of Pootatuck 115/13.8 kV Substation was completed in 2015 to alleviate a capacity deficiency in Shelton region. The substation provides approximately 72 MVA of capacity in the Trumbull area. This project consisted of an outdoor, air-insulated, 115/13.8 kV switchyard with two 30/40/50 MVA, 115/13.8 kV transformers with load tap changers and one 115 kV circuit breaker.	2015	Tony Marone, President & CEO – UIL 180 Marsh Hill Road, Orange CT 06477 (203) 499-2032
Singer Substation	$130M	Bridgeport, CT	This project was done to address transmission congestion issues and improve the reliability of Connecticuts transmission infrastructure. It consisted of - 345kV GIS, (16) circuit breakers,(2) 600 MVA auto-Transformers, (4) 50-100 MVAr Shunt Reactors, 115KV UG XLPE circuits to Bridgeport Energy and Pequonnock, Building and control room. (1) Spare 600 MVA Auto-Transformer, (1) Spare 50-100 Shunt Reactor.	2008	Tony Marone, President & CEO – UIL 180 Marsh Hill Road, Orange CT 06477 (203) 499-2032
Middle Town to Norwalk	$196M	Bridgeport, CT	This project was done to address transmission congestion issues and improve the reliability of Connecticuts transmission infrastructure. It consisted of - 345KV Underground – 6.1 miles of double circuit 345kV UG XLPE, 36 splice chambers including fiber optics.	2008	Tony Marone, President & CEO – UIL 180 Marsh Hill Road, Orange CT 06477 (203) 499-2032
Housatonic River Crossing Transmission Line Replacement	$20M	Milford, CT	This project was done to address aging infrastructure and NESC loading criteria. A conceptual design assessment has been initiated for replacing the Housatonic River transmission structures which carry two 115 kV transmission circuits along the railroad corridor from New Haven to Bridgeport, CT. These structures were built in 1912 and have shown signs of corrosion, and do not meet current NESC loading criteria. Concerns have also been raised if a structural failure occurred there would be significant transmission system impacts and issues related to the close proximity to the Moses Wheeler Bridge.	2017	Tony Marone, President & CEO – UIL 180 Marsh Hill Road, Orange CT 06477 (203) 499-2032
Baird-Congress Transmission Line Rebuild	$58M	Bridgeport, CT	In coordination with ISO-NE and Northeast Utilities, a long-term transmission planning reliability assessment of Southwest Connecticut ("SWCT Needs Assessment") was completed in 2011 which identified unacceptable thermal overloads on the 8809A and 8909B 115 kV line sections between Congress and Baird Substations. This project addresses the thermal upgrades to the 8809A and 8909B 115 kV line sections between Congress and Baird Substations (4.6 circuit miles).	2019	Tony Marone, President & CEO – UIL 180 Marsh Hill Road, Orange CT 06477 (203) 499-2032
Milvon-Devon Tie Transmission Line Rebuild	$25M	Milford, CT	In coordination with ISO-NE and Northeast Utilities, a long-term transmission planning reliability assessment of Southwest Connecticut ("SWCT Needs Assessment") was completed in 2011 which identified unacceptable thermal overloads on the 88005A and 89005B 115 kV line sections between Devon Tie and Milvon Substations. This project reconductored/rebuilt the 88005A and 89005B 115 kV line sections between Devon Tie and Milvon Substations (2.6 circuit miles)	2016	Tony Marone, President & CEO – UIL 180 Marsh Hill Road, Orange CT 06477 (203) 499-2032
Mix Ave Cap & Reactor Addition	$22M	Hamden, CT	The Southwest Connecticut Transmission planning study indicated that capacitor banks are needed at Mix Avenue 115 kV substation to mitigate low voltages in the Mix Ave. - Sackett 115 kV corridor. The series reactor is needed to help restrict power flow in the Sackett - Mix Ave. 115 kV corridor. This restriction will help keep power flow within the thermal ratings of the corridor. Refer to ISO-NE "SWCT Area Transmission Needs Assessment" report dated July 13, 2011 and "SWCT Preferred Solution - New Haven and Bridgeport Areas" PAC presentation dated June 19, 2012.	2016	Tony Marone, President & CEO – UIL 180 Marsh Hill Road, Orange CT 06477 (203) 499-2032
Grand Ave 8300 Line Rebuild	$16M	New Haven, CT	Nature and Characteristics of Needs: The recently completed SWCT Needs Analysis study identified a number of thermal and voltage needs including many in the New Haven area. To address this need the 8300 line terminal was reconfigured	2013	Tony Marone, President & CEO – UIL 180 Marsh Hill Road, Orange CT 06477 (203) 499-2032
East Shore TXF / PDC / Bus replacement	$24M	New Haven, CT	The East Shore 115/13.8 kV Substation Capacity Upgrade Project completed in 2013 brought the region capacity level below 95% addressing the projected capacity deficiency. East Shore 115/13.8 kV Substation Capacity Upgrade in 2013 will provide additional regional capacity. The East Shore 115/13.8 kV Substation Capacity Upgrade project includes replacing the non-load tap changing substation transformers with load tap changing units and increasing the rating of these transformers.	2013	Tony Marone, President & CEO – UIL 180 Marsh Hill Road, Orange CT 06477 (203) 499-2032
NERC FAC-008 Compliance	$19 M	Various locations across CT	As a result of this NERC alert, UI engaged GeoDigital to perform a LiDAR survey of all of UI's OH transmission lines to identify potential line clearance violations that could impact UI's line ratings. This project remediated all of the identified clearance violations.	2016	Tony Marone, President & CEO – UIL 180 Marsh Hill Road, Orange CT 06477 (203) 499-2032

Scottish Power Energy Networks					
Western HVDC Link	$736M	West Scotland (Irish sea) (UK)	New 400 kV double busbar substation at Hunterston (6L+Bus Bar Coupler and Bus Bar Section); New HVDC converter station at Hunterston, capacity 2250MW; Onshore and offshore HVDC cable to SPT/NGET boundary. 2200MW Cable route length between Hunterston and Scottish Territorial Waters Boundary is approximately 4km onshore and 90km offshore i.e. 94km total. (approx. 35% of total cable length).	2017	Pearse Murray, Director of Scottish Power Transmission Ochil House, Technology Park, High Blantyre, South Lanarkshire, G72 0FD Pearse.Murray@ScottishPower.com Tel: (+44) 7753621585
Beauly – Denny 400kV	$278M	Denny (North East Scotland) (UK)	Install 20km of new 400kV overhead line from Denny North to SPT / SHETL boundary; Remove 17km of existing 132kV overhead line to SPT / SHETL boundary and underground sections of existing 132kV overhead network in the Stirling area. Install a new two bay 400kV double busbar substation at Denny North (1L + 1T). Install a new nine bay 275kV double busbar at Denny North (5L, 2T + Bus Coupler + Section). Install new transformation: 1 x 400/275kV 1000MVA and 1 x 275/132kV 240MVA at Denny North.	2017	Pearse Murray, Director of Scottish Power Transmission Ochil House, Technology Park, High Blantyre, South Lanarkshire, G72 0FD Pearse.Murray@ScottishPower.com Tel: (+44) 7753621585
Renewable Generation in South West Scotland	$430M	South West Scotland (UK)	Develop New Infrastructure to facilitate renewable generation (9 Wind Farms). 5 New "Collector" Substations (1 * 275/132kV; 4 * 132/33kV). 2 New 132/33kV Substations for individual connections 14km of new 275kV overhead line. 13 New Transformers (3 * 275/132kV 240MVA SGTs; 10 * 132/33kV 90MVA) 60kM of new 132kV overhead line. Extend Coylton 275kV Substation in a six bay single busbar configuration (5L + Bus Section). Reconductor 14kM 275kV OHL (Coylton-Kilmarnock).	2017	Pearse Murray, Director of Scottish Power Transmission Ochil House, Technology Park, High Blantyre, South Lanarkshire, G72 0FD Pearse.Murray@ScottishPower.com Tel: (+44) 7753621585
Shunt Compensation of the Scotland – England Interconnection (Part of Upgrade from 2800MW to 3300MW Secure Export Capability from Scotland)	$30M	Southern Scotland (UK)	Install five Mechanically Switched Capacitor Damping Networks (MSCDN's) totaling 1050MVAr at the following locations: Install 1 x 275kV 150MVAr MSCDN at Windyhill 275kV Substation Install 1 x 400kV 225MVAr MSCDN at Elvanfoot 400kV Substation Install 1 x 400kV 225MVAr MSCDN at Moffat 400kV Substation Install 2 x 275kV 225MVAr MSCDN's at Longannet 275kV Substation Install a wide area MSCDN control scheme	2015	Pearse Murray, Director of Scottish Power Transmission Ochil House, Technology Park, High Blantyre, South Lanarkshire, G72 0FD Pearse.Murray@ScottishPower.com Tel: (+44) 7753621585
Series and Shunt Compensation of the Scotland – England Interconnection (Part of Upgrade from 3300MW to 4400MW Secure Export Capability from Scotland)	$82M	Southern Scotland (UK)	Install four 400kV Series Capacitors totaling 2004MVAr, each equipped with passive damping filters for Sub-Synchronous Resonance (SSR) mitigation, at the following locations: Install 1 x 400kV 560MVAr Series Capacitor at Gretna 400kV Substation Install 1 x 400kV 560MVAr Series Capacitor at Moffat 400kV Substation Install 2 x 400kV 442MVAr Series Capacitors at Eccles 400kV Substation Install a wide area Series Capacitor control scheme Install Sub-Synchronous Oscillation (SSO) monitoring / detection equipment Install 1 x 275kV 225MVAr MSCDN at Cockenzie 275kV Substation	2015	Pearse Murray, Director of Scottish Power Transmission Ochil House, Technology Park, High Blantyre, South Lanarkshire, G72 0FD Pearse.Murray@ScottishPower.com Tel: (+44) 7753621585
Iberdrola Spain					
Plan Murcia	38,9 MM€	Murcia Capital	Construction a new compact GIS substation (ST Murcia) with a new 220/20 kV transformer module (2x50 MVA installed) and a new very high voltage underground transmission line ST El Palmar-ST Murcia (8 km long, 220 kV, double circuit)	2016	Nekane Dorronsoro Paulis ndorronsoro@iberdrola.es Tel: (+34) 630923500 Iberdrola Distribución Eléctrica Avda. Los Pinos 7, A1P01C013 30009 Murcia - Spain
Plan Valencia	78,2 MM€	Valencia Capital	Construction four new compact GIS substations (ST Beniferri, Aqua, Parque Central, Fuente San Luis), two of them underground, with 220/132 kV (450 MVA) and 220/20 kV (600 MVA) transformer modules, and a new very high voltage underground transmission line Fuente San Luis-Parque Central-Aqua-Beniferri (12.9 km long, 220 kV, single circuit and 3.7 km long, 220 kV, double circuit)	2011 - 2017	Nekane Dorronsoro Paulis ndorronsoro@iberdrola.es Tel: (+34) 630923500 Iberdrola Distribución Eléctrica Avda. Los Pinos 7, A1P01C013 30009 Murcia - Spain
Plan Madrid (Fase 1)	60 MM€	Madrid Capital	Construction four new compact GIS substations (ST Ventas, Melancolicos, Palafox, La Estrella), with 220/132 kV (450 MVA) and 220/20 kV (600 MVA) transformer modules, and a new very high voltage underground transmission line Ventas-Melancolicos-Palafox-La Estrella (40 km long, 220 kV, single circuit)	2007-2010	Amaya Campini Jiménez acampini@iberdrola.es Tel: (+34) 618777428 Iberdrola Distribución Eléctrica Tomás Redondo 1, A1P4C029 28033 Madrid - Spain
Plan Madrid (Fase 2)	52,9 MM€	Madrid Capital	Construction three new compact GIS substations (ST Parque Ingenieros, Antonio Leyva, Arganzuela), with 220/20 kV (400 MVA) transformer modules, and a new very high voltage underground transmission line Villaverde-Parque Ingenieros-Antonio Leyva-Arganzuela-Melancolicos (15,2 km long, 220 kV, single circuit)	2009-2012	Amaya Campini Jiménez acampini@iberdrola.es Tel: (+34) 618777428 Iberdrola Distribución Eléctrica Tomás Redondo 1, A1P4C029 28033 Madrid - Spain
Plan Madrid (Fase 3)	46,9 MM€	Madrid Capital	Construction two new compact GIS substations (ST Aguacate y Poligono C), one of them underground, with 220/45 kV and 220/20 kV transformer modules, and a new very high voltage underground transmission line Parque Ingenieros-Aguacate-Poligono C-Ventas (15.5 km long, 220 kV, single circuit)	2009-2014	Amaya Campini Jiménez acampini@iberdrola.es Tel: (+34) 618777428 Iberdrola Distribución Eléctrica Tomás Redondo 1, A1P4C029 28033 Madrid - Spain