CENTRAL MAINE POWER

July 3, 2014

Ms. Heather Hunt
Executive Director
New England States Committee on Electricity
655 Longmeadow Street
Longmeadow, MA 01106

Re: Response to Request for Expression of Interest to Act as a Counterparty

Dear Ms. Hunt:

On June 11, 2014, the New England States Committee on Electricity ("NESCOE") issued a Summary of Stakeholder Input and Request for Further Information on Capacity Management, Other Concepts and Expressions of Interest in Acting as a Counterparty. As part of that memorandum, NESCOE requested that interested parties file expressions of interest in acting as creditworthy counterparties to contracts with gas pipeline companies for gas pipeline capacity. By letter dated June 5, 2014, CMP and Emera Maine expressed interest in working with other stakeholders in New England to achieve a mutually beneficial solution to the existing gas capacity shortage. As noted by CMP in that letter, CMP and other electric distribution companies could potentially serve as counterparties to long-term contracts for gas capacity, subject to agreement on appropriate compensation, which could include equity participation in a gas capacity expansion project.

CMP remains interested in pursuing the opportunity to work with other parties to achieve a mutually beneficial solution to the existing gas capacity shortage in New England. Therefore, in accordance with NESCOE's Request for Expression of Interest to Act as a Counterparty, CMP hereby provides notice of its interest in acting as counterparty to potential contracts for gas pipeline capacity. CMP's interest, of course, would depend on the specifics of any particular contract that is being proposed, as well as appropriate cost recovery assurances. The information required by NESCOE's Request for Expression of Interest to Act as a Counterparty is attached hereto.

Please contact me if you have any questions or require any further information from CMP.

Sincerely,

Thorn C. Dickinson
Vice President - Business Development
Iberdrola USA Management Corporation
On behalf of Central Maine Power Company

RESPONSE TO REQUEST FOR EXPRESSION OF INTEREST TO ACT AS A COUNTERPARTY

CENTRAL MAINE POWER COMPANY

July 3, 2014

A. Executive Summary

Central Maine Power Company ("CMP") is pleased to provide this response to the New England States Committee on Electricity ("NESCOE") Request for Expressions of Interest to Act as a Counterparty to contracts in the expansion of gas transportation to electric generation in New England ("REI"). As described in CMP's June 5, 2014 letter to NESCOE, CMP supports the approach outlined by NESCOE and other electric distribution companies such as Northeast Utilities, National Grid, and UIL Holdings, which contemplates the development of gas pipeline capacity infrastructure funded through a FERC-approved tariff. CMP hereby confirms that it is interested in serving as a Counterparty to a long-term contract for gas pipeline capacity, to facilitate the development of additional gas transportation capacity needed to maintain reliable and cost-effective electric service in New England.

CMP is uniquely qualified to be the Contract Entity. In addition to being highly creditworthy, CMP and its affiliates provide electricity and natural gas service customers in New England and New York. Collectively, CMP and its U.S. affiliates serve 3 million electric and gas customers. A core part of our business is the management of electricity and natural gas delivery and supply to our customers. CMP and its affiliates have a wide range of expertise and strengths necessary assist in the implementation of the New England Governors initiatives being advanced by NESCOE.

As a regulated EDC, CMP should be an acceptable Contract Entity for gas pipeline developers. CMP, its parent companies and affiliates all have high investment grade credit ratings. In addition, CMP and its affiliates presently manage large portfolios of electric and gas supply contracts and possess the expertise to negotiate and manage the contracts required to deliver the infrastructure necessary to implement the Governors Initiative to increase the reliability of gas supply to power generation in New England.

Other than obtaining necessary approvals discussed below, CMP is ready to work with other stakeholders in developing the items necessary to move forward with implementation of the New England Governors initiatives being advanced by NESCOE.

B. Description of Entity

Central Maine Power Company ("CMP") is an electric transmission and distribution utility organized and operating under the laws of the State of Maine. CMP provides retail electric transmission and distribution service to customers in southern, central and western Maine, as well as wholesale customers in the State of Maine. The principal business office of the Company is located at 83 Edison Drive, Augusta, Maine 04336. The contact information for individuals authorized to represent CMP in this REI process are:

Thorn C. Dickinson
Vice President - Business Development
Iberdrola USA Management Corporation
Durham Hall, 52 Farm View Drive
New Gloucester, ME 04260
Telephone 207.688.6362
thorn.dickinson@iberdrolausa.com

CMP's ultimate parent company is Iberdrola, S.A. ("ISA"), which owns CMP though two intermediate holding companies indirectly upstream from CMP. The first intermediate holding company is Iberdrola USA Networks, Inc. ("Networks"), which owns (i) 100% of the stock of CMP Group, Inc., which in turn owns 100% of CMP. Networks also owns 100% of Iberdrola USA Enterprises, Inc. ("Enterprises"), which, in turn owns 100% of Maine Natural Gas Corporation ("MNG"). MNG is a natural gas distribution company providing service in Bath, West Bath, Brunswick, Topsham, Windham, Gorham, Bowdoin, Freeport, Pownal and Augusta, Maine). Networks is a direct, wholly owned subsidiary of Iberdrola USA, Inc. and is responsible for holding all of ISA's regulated electric and gas utilities in the United States (i.e., CMP, MNG, New York State Gas & Electric Corporation ("NYSEG"), Rochester Gas and Electric Corporation ("RG&E"), and New Hampshire Gas Corporation ("NHGC")). The second intermediate holding company is Iberdrola Finance UK Limited ("IBFL"), a direct, wholly owned subsidiary of ISA that owns 100% of the stock of IBUSA. An organization chart showing these relationships is attached hereto as Attachment 1. ISA is one of the world's largest investor owned utilities with a market capitalization of approximately €60 billion, 30,000 employees, 46 GW of installed generation capacity and 32 million points of supply.

As of March 31, 2014 CMP had a capital structure comprised of approximately 60% equity and 40% debt. CMP is subject to a "minimum equity ratio" that mirrors the equity ratio used in its distribution rate structure and it maintains an equity ratio at or above the minimum through dividend payments or capital contributions to its parent. CMP has investment grade ratings and has ready access to the debt capital markets. Since 2009, CMP has issued $750 million of first mortgage bonds to fund the Maine Power Reliability Project and for general corporate purposes. CMP is a party to a committed revolving credit facility under which it may borrow up to $250 million dollars. In addition to capital accessible from third parties, CMP has agreements with IUSA under which it may borrow up to $250 million under a demand note arrangement. IUSA itself is party to a committed credit facility under which it may borrow up to $300 million and IUSA also borrows from affiliated companies within the Iberdrola family. At March 31, 2014, the Iberdrola Group had available liquidity exceeding €10 billion.

CMP's most recent audited financial statements for 2012 and 2013 are attached hereto as Attachment 2.

CMP has served in a similar Contract Entity role with respect to State policy initiatives in Maine. For example, at the direction of the Maine Public Utilities Commission, CMP has acted as a counterparty to several long-term contracts for capacity and energy under 35-A M.R.S. § 3210-C. As stated by the MPUC, the underlying purpose of this statute in Maine is to take advantage of opportunities to use long-term contracts for capacity and energy with utilities as a means to lower capacity and energy costs or otherwise benefit Maine ratepayers. The MPUC also noted in approving these contracts that long-term contracts with a creditworthy counterparty, such as an EDC, can be very valuable to developers or owners of generation resources and may be necessary to obtain financing for new projects. In CMP's opinion, the same is true with respect to long-term contracts for gas pipeline capacity.

CMP is uniquely qualified to be the Contract Entity. In addition to being highly creditworthy, CMP and its affiliates provide electricity and natural gas service customers in New England and New York. Collectively, CMP and its U.S. affiliates serve 3 million electric and gas customers. A core part of our business is the management of electricity and natural gas delivery and supply to our customers. CMP and its affiliates have a wide range of expertise and strengths necessary to deliver on the New England Governors initiatives being implemented by NESCOE.

CMP has not had any complaints alleging misconduct or malfeasance or requesting an investigation filed against it with FERC or any state agency in connection with the provision of any natural gas-related service.

CMP suggests an approach whereby multiple entities would serve as the Contract Entities for gas capacity contracts. Such an approach would minimize risk for each contracting party by spreading this risk among multiple parties. In particular, CMP supports an approach where multiple EDCs and LDCs could act as Contract Entities.

C. Qualifications

CMP is qualified to serve as a Contract Entity due to the fact that it is a creditworthy regulated utility. The ratings on senior unsecured obligations for CMP and its rated parent entities are shown the table below.

	S&P	Moody's	Fitch
CMP	BBB	Baa1	BBB+
IUSA	BBB	Baa1	BBB
Iberdrola, S.A.	BBB+	A3	A-

D. Capacity Manager Selection and Controls

CMP supports the development of a capacity management function to ensure that the value of the released capacity is optimized. CMP's affiliates have had experience in the past utilizing these services as part of managing its gas supply responsibilities. CMP believes that in the coming months the EDC's will need to work together with representatives of the states, NESCOE, ISO New England and other interested parties to ensure that the programs goals are achieved.

CMP believes that the EDCs or other selected Contract Entities should oversee the management of the capacity manager, with input from other parties. This would include issuing the RFP, creating policies and procedures necessary for the appropriate controls of the capacity manager and overseeing the day-to-day operations. CMP believes that as counterparties to the capacity contracts, the EDCs' interests are most aligned with the successful management of the Capacity Manager function.

E. Costs and Other Business Terms

CMP agrees that the construction of pipeline capacity necessary to achieve the goal advocated by NESCOE will require an extraordinary level of investment by a variety of parties. The pipeline companies who have traditionally constructed these projects require long-term contract commitments with highly creditworthy counterparties to support construction. CMP, as well as the other electric distribution companies, could play a significant role in providing the creditworthiness necessary for these long-term contracts provided that their cost recovery is assured. This cost recovery must include the direct costs of the contracts and any indirect costs, such as costs to seek regulatory approvals and the cost to administer the contracts.

As noted in our June 5th letter, electric distribution companies would need to be appropriately compensated for entering into these long-term contract commitments and for lending financial stability in the form of balance sheet and credit-rating qualifications. This compensation could be in the form of equity participation in the capacity expansion project and/or other compensation, depending on the size of the contract commitments and the equity participation opportunity. CMP's preferred outcome would be in the form of equity participation in any resulting gas pipeline capacity expansion project. The specific details associated with this compensation can be evaluated by CMP when it is more clear which projects are identified.

F. FERC Review

The REI requested that Respondents describe how their participation would contribute to the FERC's favorable review and approval of the proposed tariff changes reflecting the IGER approach. CMP and its gas utility affiliates are highly experienced with respect to FERC policies and procedures. CMP anticipates working with NESCOE, ISO New England and other EDCs to contribute to the development of a FERC strategy to achieve any necessary FERC approvals.

G. State Review

The REI requested that Respondents describe how their participation would contribute to state approval of any precedent agreements or other regulatory approvals that may be required at the state public utility commissions and siting board approvals. CMP anticipates that MPUC approval would be necessary in order for CMP to enter into any precedent agreement. As noted in our June 5th letter, there is an open proceeding before the MPUC to consider the parameters under which long-term contracts for gas capacity could be implemented by the MPUC pursuant to The Maine Energy Cost Reduction Act, which provides that the MPUC may direct one or more transmission and distribution utilities, gas utilities or natural gas pipeline utilities to be a counterparty to a contract for natural gas transmission pipeline capacity. In that proceeding, CMP is advocating that any action taken by the MPUC be part of an overall region-wide effort, such as that being undertaken by NESCOE in issuing its REI.

Other than MPUC approval, CMP does not anticipate the need for any other state review on its part.

H. Prerequisites or Impediments to Participation

As noted above, CMP anticipates that MPUC approval would be necessary in order for CMP to enter into any precedent agreement. Given the importance of this issue and the existing MPUC proceeding, CMP anticipates that any required MPUC approval could be obtained in an expeditious manner. Depending on the final form of transaction adopted as part of the REI process, various FERC approvals would also be required.

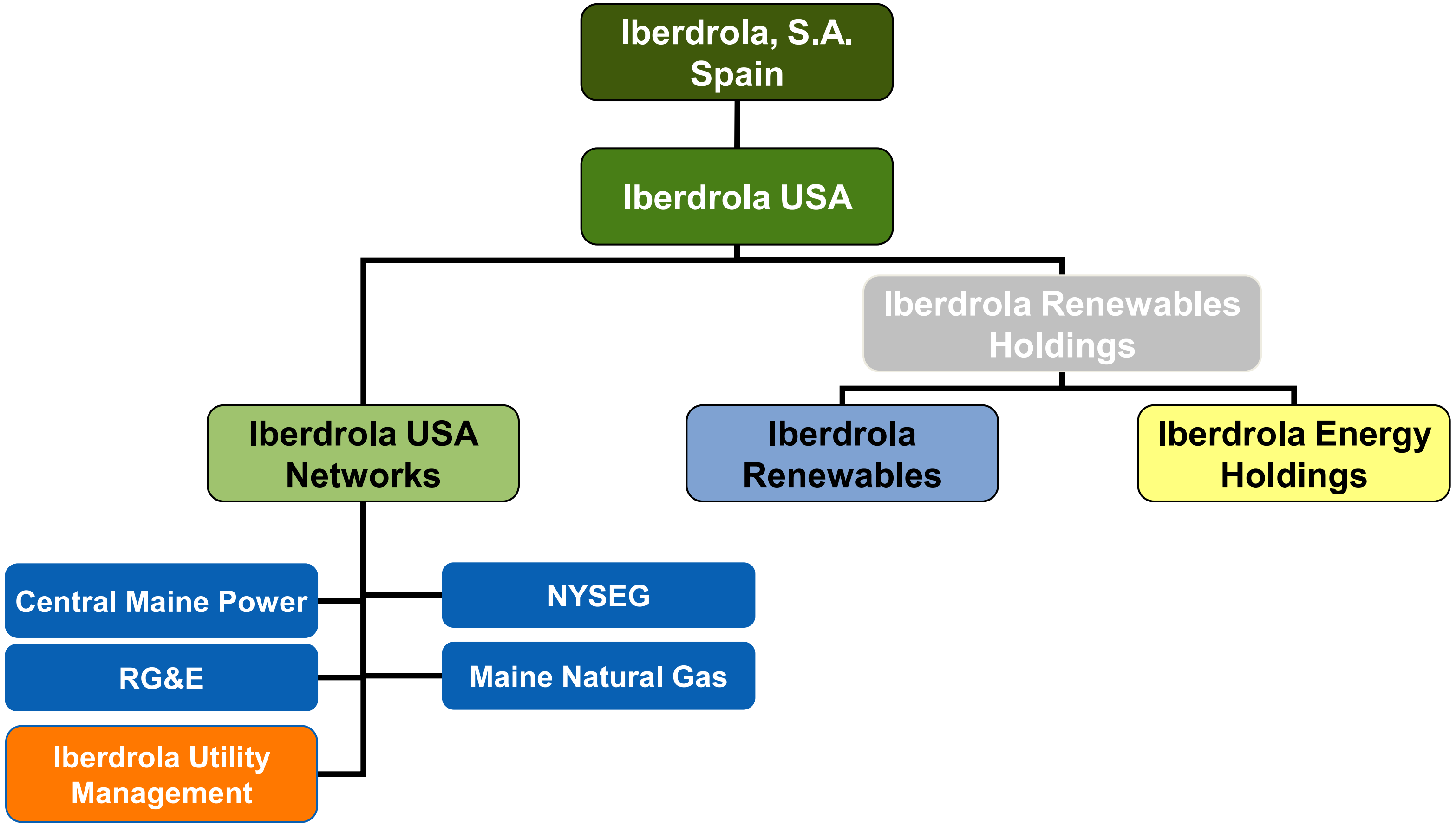
Internal corporate approvals would also need to be obtained, which may take up to [how long?] to receive once final contracts are submitted for approval. Also, as noted above, as a prerequisite to agreeing to be a Contract Entity, CMP would need to be appropriately compensated for entering into such a long-term contract commitment and for lending financial stability in the form of balance sheet and credit rating qualifications.

Other than these prerequisites, CMP sees no impediments its participation as a Contract entity.

I. Conflicts of Interest

CMP has not identified any specific conflict of interest that would be created as a result of its undertaking the role of a Contract entity. To the extent that any such conflict is determined to exist, CMP and its affiliated are experienced in managing such potential conflicts through appropriate internal and regulatory controls. In addition, the selection of an independent third party Capacity Manager would be an effective means to avoid potential conflicts of related to the management, release and use of gas transportation capacity.

ATTACHMENT 1 – ISA ORG CHART



ATTACHMENT 2 – CMP AUDITED FINANCIALS

Central Maine Power Company
and Subsidiaries
Consolidated Financial Statements
For the Years Ended December 31, 2013 and 2012

Central Maine Power Company and Subsidiaries

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Consolidated Financial Statements for the Years Ended December 31, 2013 and 2012

Independent Auditor's Report

To the Shareholder and Board of Directors
of Central Maine Power Company and Subsidiaries:

We have audited the accompanying consolidated financial statements of Central Maine Power Company and its subsidiaries, which comprise the consolidated balance sheets as of December 31, 2013 and December 31, 2012, and the related consolidated statements of income, of comprehensive income, of cash flows and of changes in equity for the years then ended.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on the consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Company's preparation and fair presentation of the consolidated 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 Company'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 consolidated 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Central Maine Power Company and its subsidiaries at December 31, 2013 and December 31, 2012, and the results of their operations and their cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

PricewaterhouseCoopers LLP

March 31, 2014

PricewaterhouseCoopers LLP, 125 High Street, Boston, MA 02110
T: (617) 530 5000, F: (617) 530 5001, www.pwc.com/us

Central Maine Power Company and Subsidiaries
Consolidated Statements of Income

Year Ended December 31,	2013	2012
(Thousands)		
Operating Revenues		
Sales and services	**$701,384**	$627,961
Operating Expenses		
Electricity purchased	**65,059**	64,939
Other operating expenses	**223,973**	225,263
Maintenance	**77,275**	65,703
Depreciation and amortization	**66,053**	51,039
Other taxes	**28,466**	22,565
Total Operating Expenses	**460,826**	429,509
Operating Income	**240,558**	198,452
Other (Income)	**(5,803)**	(8,413)
Other Deductions	**1,070**	944
Interest Charges, Net	**54,279**	47,146
Income Before Income Tax	**191,012**	158,775
Income Tax Expense	**54,363**	54,954
Net Income	**136,649**	103,821
Less: Net (Loss) Income Attributable to Other Noncontrolling Interest	**(39)**	205
Net Income Attributable to CMP	**136,688**	103,616
Preferred Stock Dividends	**34**	101
Earnings Available for CMP Common Stock	**$136,654**	$103,515

Central Maine Power Company and Subsidiaries
Consolidated Statements of Comprehensive Income

Year ended December 31,	2013	2012
(Thousands)		
Net Income	**$136,649**	$103,821
Other Comprehensive (Loss) Income, Net of Tax		
Amortization of pension cost for nonqualified plans	**(1,889)**	-
Unrealized (loss) gain on derivatives qualified as hedges:		
Unrealized (loss) during period on derivatives qualified as hedges	**(104)**	(235)
Reclassification adjustment for loss included in net income	**149**	193
Reclassification adjustment for loss on settled cash flow treasury hedges	**1,299**	1,288
Net unrealized gain on derivatives qualified as hedges	**1,344**	1,246
Other Comprehensive (Loss) Income	**(545)**	1,246
Comprehensive Income	**136,104**	105,067
Less:		
Comprehensive (Loss) Income Attributable to Other Noncontrolling Interests	**(39)**	205
Comprehensive Income	**$136,143**	$104,862

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

Central Maine Power Company and Subsidiaries
Consolidated Balance Sheets

December 31, (Thousands)	2013	2012
Assets		
Current Assets		
Cash and cash equivalents	**$3,176**	$2,309
Accounts receivable and unbilled revenues, net	**148,322**	142,220
Accounts receivable from affiliates	**2,100**	1,599
Notes receivable from affiliates	**15,750**	-
Materials and supplies, at average cost	**17,151**	21,173
Accumulated deferred income taxes	**3,867**	13,524
Prepayments and other current assets	**43,400**	5,134
Regulatory assets	**17,790**	27,966
Deferred income taxes regulatory	**9,194**	-
Total Current Assets	**260,750**	213,925
Utility Plant, at Original Cost		
Electric	**2,758,894**	2,340,980
Less accumulated depreciation	**700,462**	656,972
Net Utility Plant in Service	**2,058,432**	1,684,008
Construction work in progress	**577,047**	617,893
Total Utility Plant	**2,635,479**	2,301,901
Other Property and Investments	**8,960**	9,446
Regulatory and Other Assets		
Regulatory assets		
Advance metering infrastructure	**39,225**	37,499
Pension and other postretirement benefits	**150,792**	223,229
Unfunded future income taxes	**274,161**	238,214
Other	**39,652**	25,786
Total regulatory assets	**503,830**	524,728
Other assets		
Goodwill	**324,938**	324,938
Other	**24,068**	21,845
Total other assets	**349,006**	346,783
Total Regulatory and Other Assets	**852,836**	871,511
Total Assets	**$3,758,025**	$3,396,783

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

Central Maine Power Company and Subsidiaries
Consolidated Balance Sheets

December 31,	2013	2012
(Thousands)		
Liabilities		
Current Liabilities		
Current portion of long-term debt	**$22,426**	$38,570
Notes payable	**-**	157,177
Notes payable to affiliates	**-**	47,490
Accounts payable and accrued liabilities	**68,942**	80,329
Accounts payable, construction	**130,723**	86,868
Accounts payable to affiliates	**10,828**	5,041
Accounts payable, electricity purchased	**26,246**	23,486
Interest accrued	**18,285**	13,994
Taxes accrued	**645**	8,245
Other current liabilities	**77,436**	60,464
Regulatory liabilities	**40,321**	27,751
Deferred income taxes regulatory	**-**	88
Total Current Liabilities	**395,852**	549,503
Regulatory and Other Liabilities		
Regulatory liabilities		
Accrued removal obligations	**79,165**	82,431
Deferred income taxes	**165,274**	174,896
Other	**6,240**	10,715
Total regulatory liabilities	**250,679**	268,042
Other liabilities		
Deferred income taxes	**511,142**	364,040
Nuclear plant obligations	**-**	4,998
Pension and other postretirement benefits	**151,354**	217,026
Other	**38,744**	22,606
Total other liabilities	**701,240**	608,670
Total Regulatory and Other Liabilities	**951,919**	876,712
Long-term debt	**943,528**	740,982
Total Liabilities	**2,291,299**	2,167,197
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, 2013 and 2012)	**156,057**	156,057
Capital in excess of par value	**713,893**	613,893
Retained earnings	**603,827**	467,173
Accumulated other comprehensive loss	**(10,650)**	(10,105)
Total CMP Common Stock Equity	**1,463,127**	1,227,018
Other Noncontrolling Interest	**3,028**	1,997
Total Equity	**1,466,155**	1,229,015
Total Liabilities and Equity	**$3,758,025**	$3,396,783

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,	2013	2012
(Thousands)		
Cash Flow from Operating Activities		
Net income	**$136,649**	$103,821
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	**70,512**	52,948
Amortization of regulatory and other assets and liabilities	**(7,546)**	(17,667)
Carrying cost of regulatory assets and liabilities	**(2,229)**	(4,939)
Deferred income taxes and investment tax credits, net	**102,195**	62,889
Pension expense	**13,309**	16,162
Transmission revenue	**14,702**	41,477
Changes in current operating assets and liabilities		
Accounts receivable and unbilled revenues, net	**(6,602)**	38,756
Materials and supplies	**4,022**	(9,319)
Prepayments and other current assets	**(1,522)**	951
Accounts payable and accrued liabilities	**(14,429)**	(26,767)
Interest accrued	**4,291**	3,656
Taxes accrued	**(34,306)**	499
Pension and other postretirement benefits contributions	**(8,052)**	(26,928)
VEBA withdrawal	**3,450**	-
Changes in other assets		
Department of Energy – Yankee settlement received	**12,903**	-
Payment to Efficiency Maine	**(5,787)**	-
Deferred storm costs	**(23,764)**	(3,997)
Funded deferred income tax	**(6,081)**	-
Advanced metering infrastructure	**(2,357)**	(7,484)
Stranded costs	**10,876**	3,095
Other	**14,248**	(11,031)
Net Cash Provided by Operating Activities	**274,482**	216,122
Cash Flow from Investing Activities		
Utility plant additions	**(341,502)**	(572,536)
Grants received from governmental entities	**1,013**	9,475
Notes receivable from affiliate	**(15,750)**	-
Investments, net	**11**	330
Net Cash Used in Investing Activities	**(356,228)**	(562,731)
Cash Flow from Financing Activities		
Repurchase of preferred stock	**-**	(2,090)
Issuance of first mortgage bonds	**225,000**	225,000
Costs associated with debt issuance	**(219)**	(1,872)
Long-term note repayments	**(38,537)**	(55,256)
Notes payable three months or less, net	**(157,177)**	137,378
Notes payable with affiliates	**(47,490)**	42,765
Equity contribution from parent	**100,000**	-
Dividends paid on preferred stock	**(34)**	(101)
Other noncontrolling interest	**1,070**	(21)
Net Cash Provided by Financing Activities	**82,613**	345,803
Net Increase (Decrease) in Cash and Cash Equivalents	**867**	(806)
Cash and Cash Equivalents, Beginning of Year	**2,309**	3,115
Cash and Cash Equivalents, End of Year	**$3,176**	$2,309

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

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

(Thousands, except per share amounts)	CMP Stockholder Shares	Common Stock Outstanding $5 Par Value Amount	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive (Loss)	Noncontrolling Interest	Comprehensive Income	Total
Balance, January 1, 2012	31,211	$156,057	$613,893	$363,658	$(11,351)	$1,813		$1,124,070
Net income				103,616		205	$103,821	103,821
Other comprehensive income, net of tax					1,246		1,246	1,246
Comprehensive income							105,067	105,067
Dividends paid, preferred stock				(101)				(101)
Dividends to other noncontrolling interest						(21)		(21)
Balance, December 31, 2012	31,211	156,057	613,893	467,173	(10,105)	1,997		1,229,015
Net income				**136,688**		**(39)**	**$136,649**	**136,649**
Other comprehensive income, net of tax					**(545)**		**(545)**	**(545)**
Comprehensive income							**136,104**	**136,104**
Equity contribution from parent			**100,000**					**100,000**
Additional paid in capital						**1,086**		**1,086**
Dividends paid, preferred stock				**(34)**				**(34)**
Dividends to other noncontrolling interest						**(16)**		**(16)**
Balance, December 31, 2013	**31,211**	**$156,057**	**$713,893**	**$603,827**	**$(10,650)**	**$3,028**		**$1,466,155**

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 612,000 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 Iberdrola USA Networks, Inc. (Networks) which is a wholly-owned subsidiary of Iberdrola USA, Inc. (IUSA) which is a wholly-owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the law of the Kingdom of Spain. Networks' wholly-owned subsidiaries, and their principal operating companies, include: CMP Group, Inc.– Central Maine Power Company (CMP), and RGS Energy Group, Inc. - New York State Electric & Gas Corporation (NYSEG) and Rochester Gas and Electric Corporation (RG&E). We operate under the authority of the Maine Public Utility Commission (MPUC) in Maine and are also subject to regulation by the Federal Energy Regulatory Commission (FERC).

The financial statements of Networks are derived from these financial statements. Networks issued its annual financial statements on February 7, 2014. Accordingly, the Company has evaluated transactions for consideration as recognized subsequent events in the annual financial statements through the date of February 7, 2014. Additionally, the Company has evaluated transactions that occurred as of the issuance of these financial statements, March 31, 2014, for purposes of disclosure of unrecognized subsequent events.

Accounts receivable**:** Accounts receivable at December 31 include unbilled revenues of $21 million for 2013 and $15 million for 2012, and are shown net of an allowance for doubtful accounts at December 31 of $9 million for 2013 and $11 million for 2012. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was $5 million in 2013 and $10 million in 2012.

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 classification and delivery loss factors. Changes in those assumptions could significantly affect the estimates 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.

DPA receivable balances, net of the applicable reserve, at December 31 were: $11 million for 2013 and $15 million for 2012.

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 to its present value periodically over time, and depreciate the capitalized cost 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. We 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 2013 and 2012. 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.

Supplemental Disclosure of Cash Flows Information	**2013**	**2012**
(Thousands)		
Cash paid (received) during the year ended December 31:		
Interest, net of amounts capitalized	**$44,533**	$37,871
Income taxes (received), net	**$(20,123)**	$(6,846)

Interest capitalized was $724 thousand in 2013 and $325 thousand in 2012. We have decreased utility plant additions by $61 million for the change in amounts payable as of December 31, 2013 and increased them by $56 million as of December 31, 2012.

Preliminary survey costs**:** Consolidated preliminary survey costs included in Other assets at December 31 totaled approximately $10 million for 2013 and $14 million for 2012. Preliminary survey costs represent expenditures incurred for the purpose of determining the feasibility of utility projects under contemplation which are probable of being placed into service. When construction begins on such projects, the amounts are moved to Construction work in progress (CWIP), and then eventually to Utility plant when construction is completed and the asset is placed in service. If a project is abandoned, the costs incurred for that project are charged to expense.

Depreciation: 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 2.6% of average depreciable property for 2013 and 2012.

We charge repairs and minor replacements to operating 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)	2013	2012
(thousands)			
Electric			
Transmission	43	**$1,324,432**	$967,033
Distribution	45	**1,158,766**	1,109,828
Other	29	**275,696**	264,119
Total Electric Plant		**$2,758,894**	$2,340,980

***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 2040.

***Goodwill*:** We are required to perform an annual goodwill impairment assessment at the same time each year and, accordingly, we perform our annual impairment assessment of goodwill as of August 31st. We update our goodwill assessment during interim periods if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value.

An entity is allowed to first assess qualitative factors – also referred to as step zero – to determine if there are events or circumstances that indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount, including goodwill. If it is not more likely than not that the fair value is less than the carrying amount, then it is not necessary to perform the two-step quantitative goodwill impairment test. An entity has the option to bypass step zero for any reporting unit in any period and proceed directly to performing step one of the goodwill impairment test, and may resume performing the step zero qualitative assessment in any subsequent period.

If step zero indicates that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, the entity would perform step one of the two-step impairment test. Step one of the impairment test involves comparing the fair value of a reporting unit with its carrying value, including goodwill. If the carrying value of a reporting unit exceeds the reporting unit's fair value, step two must be performed to determine the amount, if any, of goodwill impairment loss. If the carrying amount is less than fair value, further testing for goodwill impairment is not performed.

Step two of the goodwill impairment test involves comparing the implied fair value of the reporting unit's goodwill against the carrying value of the goodwill. In step two, determining the implied fair value of goodwill requires the valuation of a reporting unit's identifiable tangible and intangible assets and liabilities as if the reporting unit had been acquired in a business combination on the testing date. The difference between the fair value of the entire reporting unit as determined in step one and the net fair value of all identifiable assets and liabilities represents the implied fair value of goodwill. A goodwill impairment charge, if any, would be the difference between the carrying amount of goodwill and the implied fair value of goodwill upon the completion of step two.

We may be required to recognize an impairment of goodwill in the future due to market conditions or other factors related to our performance. Those market events could include a decline in the forecasted results in our business plan, significant adverse rate case results, changes in capital investment budgets or changes in interest rates that could permanently impair the fair value of a reporting unit. Recognition of impairments of a significant portion of goodwill would negatively affect our reported results of operations and total capitalization, the effect of which could be material and could make it more difficult to maintain our credit ratings, secure financing on attractive terms, maintain compliance with debt covenants and meet expectations of our regulators.

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 profit or loss in the period in which the expenses are incurred.

New accounting standards adopted: We have adopted new accounting standards issued by the Financial Accounting Standards Board (FASB) as explained below.

Disclosures about Offsetting Assets and Liabilities: In December 2011 the FASB amended the requirements concerning disclosures about offsetting assets and liabilities. The amendments do not change the FASB's current offsetting model but will require enhanced disclosures and provide for converged FASB and International Accounting Standards Board disclosures about financial instruments and derivative instruments that are either offset on the balance sheet or subject to an enforceable master netting arrangement or similar agreement. The disclosures are meant to enable users of an entity's financial statements to understand the effect of offsetting and related arrangements on the entity's financial position. Entities are required to provide both net and gross information about assets and liabilities so as to enhance comparability between entities that prepare their financial statements either based on accounting principles generally accepted in the United States of America (U.S. GAAP) or based on International Financial Reporting Standards (IFRS). The amendments are effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods.

In January 2013 the FASB issued amended guidance to clarify the scope of the required disclosures described in the above paragraph. The required disclosures about offsetting assets and liabilities apply to derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset in accordance with certain sections of the FASB's Accounting Standards Codification™ (ASC) or subject to an enforceable master netting arrangement or similar agreement. Other types of financial assets or financial liabilities are no longer subject to the disclosure requirements. The effectiveness of the amended guidance is the same as for the amendments issued in December 2011, explained above.

The disclosures required by the amendments are to be provided retrospectively for all comparative periods presented. Our adoption of the amendments did not affect our results of operation, financial position or cash flows.

New accounting standards issued but not yet adopted: New accounting standards issued by the FASB that we have not yet adopted in these financial statements are as explained below.

Technical Corrections and Improvements: In October 2012 the FASB issued amendments to make certain technical corrections to a wide variety of Topics in its ASC. The amendments are generally not substantive, and include amendments that identify when the use of *fair value* should be linked to the definition of fair value in Topic 820, *Fair Value Measurement*, as well as conforming amendments to reflect the measurement and disclosure requirements of Topic 820. The amendments are not expected to significantly affect current accounting practice, and are not expected to create any new differences between U.S. GAAP and IFRS. The amendments not subject to the transition guidance were effective upon issuance for both public entities and nonpublic entities, and our adoption of those amendments does not affect our results of operation, financial position or cash flows. For nonpublic entities, the amendments that are subject to the transition guidance are effective for fiscal periods beginning after December 15, 2013. Our adoption of the amendments subject to the transition guidance will not affect our results of operation, financial position or cash flows.

Comprehensive Income: In February 2013 the FASB issued its final update for the amendments concerning improving the reporting of amounts reclassified out of AOCI, including information an entity is to provide and present parenthetically on the face of the financial statements or in a single note. The amendments are effective for nonpublic entities prospectively for reporting periods beginning after December 15, 2013. Our adoption of the amendments will not affect our results of operation, financial position or cash flows.

Presentation of an Unrecognized Tax Benefit: In July 2013 the FASB issued amendments intended to eliminate diversity in practice on the financial statement presentation of an unrecognized tax benefit when a net operating loss (NOL) carryforward, a similar tax loss, or a tax credit carryforward exists. An unrecognized tax benefit, or a portion of an unrecognized tax benefit, is to be presented as a reduction to a deferred tax asset for an NOL carryforward, a similar tax loss, or a tax credit carryforward, with certain exceptions. The unrecognized tax benefit is to be presented as a liability and should not be combined with deferred tax assets to the extent that an NOL carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date under the tax law of the applicable jurisdiction to settle any additional income taxes that would result from the disallowance of a tax position or the tax law of the applicable jurisdiction does not require the entity to use, and the entity does not intend to use, the deferred tax asset for such purpose. No new recurring disclosures are required. The amendments are effective for nonpublic entities for fiscal years, and interim periods within those years, beginning after December 15, 2014, with early adoption allowed. The amendments are to be applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application is allowed. Our adoption of the amendments will not affect our results of operation, financial position or cash flows.

Other (Income) and Other Deductions:

Year Ended December 31,	**2013**	**2012**
(Thousands)		
Interest and dividend income	**$(298)**	$(189)
Allowance for funds used during construction	**(1,794)**	(503)
Earnings from equity investments	**(47)**	(44)
Carrying costs on regulatory assets	**(3,664)**	(7,122)
Miscellaneous	**-**	(555)
Total other (income)	**$(5,803)**	$(8,413)
Miscellaneous	**$1,070**	$944
Total other deductions	**$1,070**	$944

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

***Reclassifications*:** Certain amounts have been reclassified in our consolidated statements of cash flows to conform to the 2013 presentation which have not affected the operating, investing, and financing activity sections.

During the year ended December 31, 2013, we identified certain revisions related to the classification of regulatory assets and regulatory liabilities that affected the December 31, 2012 consolidated balance sheet. The misclassifications of regulatory assets resulted in a $28 million overstatement of long-term regulatory assets, which also resulted in an overstatement of total regulatory and other assets by the same amount, and a corresponding understatement of current regulatory assets, which also resulted in an understatement of total current assets by the same amount. The misclassifications of regulatory liabilities also resulted in a $28 million overstatement of long-term regulatory liabilities, which also resulted in an overstatement of total regulatory and other liabilities by the same amount, and a corresponding understatement of current regulatory liabilities, which also resulted in an understatement of total current liabilities by the same amount. The revisions did not affect net income or total cash flows from operating, investing or financing activities. Although we have determined that the misclassifications were not material to any prior period financial statements, we have revised the December 31, 2012 consolidated balance sheet included in our December 31, 2013 annual financial statements, to correct the misclassifications.

During the year ended December 31, 2013, we identified certain revisions related to prepaid property taxes and accrued future property taxes that affected the December 31, 2012 consolidated balance sheet. In our balance sheet as of December 31, 2012, we presented $9.5 million of accrued property tax for future periods in taxes accrued with the offsetting entry to prepayments and other current assets. The gross up of property taxes resulted in a $9.5 million overstatement of prepayments and other current assets, which also resulted in an overstatement of total current assets by the same amount, as well as a $9.5 million overstatement of taxes accrued, which also resulted in an overstatement of total current liabilities by the same amount. The revisions did not affect net income or total cash flows from operating, investing or financing activities. Although we have determined that the amounts were not material to any prior period financial statements, we have revised the December 31, 2012 consolidated balance sheet included in our December 31, 2013 annual financial statements, to correct the misstated amounts.

***Regulatory assets and regulatory 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 14).

Related party transactions: Certain Networks subsidiaries, including CMP borrow from IUSA, the parent of Networks, through intercompany revolving credit agreements. For CMP, the intercompany revolving credit agreements provide access to supplemental liquidity. See Note 5 for further detail on the credit facility with IUSA.

Iberdrola USA Management Corporation (IUMC) 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 cost for services provided to CMP by Iberdrola USA and its subsidiaries was approximately $40 million for 2013 and $28 million for 2012 and cost for services provided by CMP to Iberdrola USA and its subsidiaries were approximately $3 million for 2013 and 2012.

***Revenue recognition*:** We recognize revenues upon delivery of energy and energy-related products and services to our customers.

Pursuant to a Maine state law, we earn revenues for the delivery of energy to our retail customers, but we are prohibited from selling power to them. We generally do 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. We generally sell all of our power entitlements under our nonutility generator (NUG) and other purchase power contracts to unrelated third parties under bilateral contracts. If the MPUC does not approve the terms of bilateral contracts, it can direct us to sell power entitlements that we receive from those contracts on the spot market through ISO-NE.

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: Iberdrola USA, the parent company of Networks, 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 IUSA pursuant to a tax sharing agreement between IUSA and its members.

Deferred income taxes are recorded for the temporary differences between the financial statement and tax basis of assets and liabilities using currently enacted tax rates. Valuation allowances are established against deferred tax assets whenever circumstances indicate that it is more likely than not that such assets will not be realized in future periods. We amortize investment tax credits over the estimated lives of the related assets.

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

We classify all interest related to uncertain tax positions as interest expense. The gross interest accrued is $1.9 million as of December 31, 2013 and $1.2 million as of December 31, 2012. Penalties are recorded in other deductions.

***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) and (10) fair value measurements. 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.

Note 2. Goodwill

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

We had no impairment of goodwill in 2013 or in 2012 as a result of our annual impairment assessment, which we performed as of August 31st. For 2013 and 2012, as a result of our step zero qualitative assessment, it was not more likely than not that the fair value of each reporting unit was less than its carrying amount and it was not necessary to perform the two-step goodwill impairment test. There were no events or circumstances subsequent to our annual impairment testing for 2013 or 2012 that required us to update the assessment.

The carrying amount of goodwill was $325 million at December 31, 2013 and 2012.

Note 3. Income Taxes

Year Ended December 31,	2013	2012
(Thousands)		
Current		
Federal	**$(50,611)**	$(20,245)
State	**2,779**	12,310
Current taxes charged (benefits) charged to expense	**(47,832)**	(7,935)
Deferred		
Federal	**93,579**	71,851
State	**9,331**	(8,247)
Deferred taxes charged to expense	**102,910**	63,604
Investment tax credit adjustments	**(715)**	(715)
Total	**$54,363**	$54,954

The significant decrease in current income tax expense in 2013, and corresponding increase in deferred income tax expense as compared to 2012, is primarily as a result of an increase in tax depreciation deduction, an increase in capitalized repairs deduction, and 2012 provision to return adjustments booked in 2013. The $47.8 million effect on current tax expense for 2013 is primarily a result of a favorable 2012 provision to return adjustment booked in 2013. The $7.9 million effect on current tax expense for 2012 is primarily a result of a favorable 2011 provision to return adjustment booked in 2012.

Our tax expense differed from the expense at the federal statutory rate of 35% due to the following:

Year Ended December 31, (Thousands)	2013	2012
Tax expense at federal statutory rate	**$66,854**	$55,315
Depreciation and amortization not normalized	**(4,260)**	(2,378)
Investment tax credit amortization	**(715)**	(715)
Impairment of unfunded deferred tax regulatory assets	**(947)**	-
Tax return and audit adjustments	**(11,538)**	365
State taxes, net of federal benefit	**7,871**	2,641
Other, net	**(2,902)**	(274)
Total	**$54,363**	$54,954

Income taxes were $12.5 million less in 2013 than they would have been at the federal statutory rate of 35% and $0.4 million less in 2012. The 2013 effective tax rate was lower than the statutory rate primarily due to 2012 tax return flow through benefits of tax basis repairs and early retirement of assets booked in 2013 and depreciation and amortization not normalized, offset by state taxes. The 2012 effective tax rate was lower than the statutory rate primarily due to depreciation and amortization not normalized offset by state taxes. The variance in tax return and audit adjustments in 2013 as compared to 2012 is primarily driven by the flow-through impact of tax basis repairs and early retirements taken on the 2012 tax return filed in 2013. The variance in state taxes, net in 2013 as compared to 2012 is primarily driven by the increase in pretax income and state provision to return adjustments.

Our consolidated deferred tax assets and liabilities consisted of:

December 31, (Thousands)	2013	2012
Federal Net Operating Loss Carryforwards	**-**	$6,117
Regulatory	**$9,194**	-
Other	**3,867**	7,407
Current Deferred Income Tax Assets	**13,061**	13,524
Noncurrent Deferred Income Tax Liabilities (Assets)		
Property related	**$573,130**	$454,698
Unfunded future income taxes	**111,832**	97,218
Accumulated deferred investment tax credits	**499**	1,214
Pension	**18,742**	21,834
Other postretirement benefits	**(20,115)**	(26,179)
Derivative assets	**(5,951)**	(6,966)
Other	**(1,721)**	(2,795)
Total Noncurrent Deferred Income Tax Liabilities	**676,416**	539,024
Less amounts classified as regulatory liabilities		
Current deferred income taxes	**-**	88
Deferred income taxes	**165,274**	174,896
Noncurrent Deferred Income Tax Liabilities	**$511,142**	$364,040
Deferred tax assets	**$40,848**	$49,464
Deferred tax liabilities	**704,203**	574,964
Net Accumulated Deferred Income Tax Liabilities	**$663,355**	$525,500

CMP has $16.1 million of credits offset by $14.3 million of valuation allowance and $1.8 million of uncertain tax position.

Reconciliation of Gross Income Tax Reserves	2013	2012
(Thousands)		
Balance as of January 1	**$5,923**	$1,235
Increases for tax positions related to prior years	**10,225**	6,084
Reduction for tax positions related to settlements with taxing authorities	**-**	(1,396)
Balance as of December 31	**$16,148**	$5,923

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.

Unrecognized income tax benefits represent income tax positions taken on income tax returns but not yet recognized in the consolidated financial statements. The company has unrecognized income tax benefits of $16.1 million as of December 31, 2013, and $5.9 million as of December 31, 2012. Accruals for interest and penalties on tax reserves were $1.9 million as of December 31, 2013 and $1.2 million as of December 31, 2012. If recognized, $1.1 million of the total gross unrecognized tax benefits would affect the effective tax rate.

We have been audited through 2005 for federal income taxes. Our federal returns for 2006 through 2009 are currently under review. We anticipate that the review will be completed in 2014. The statute of limitations in all state jurisdictions has expired for all years through 2009. It is reasonably possible that other events will occur during the next 12 months that would cause the total amount of unrecognized tax benefits to increase or decrease.

Safe Harbor Method for capitalizing expenditures: In 2011 the Internal Revenue Service issued a revenue procedure to provide a safe harbor method of accounting that taxpayers may use to determine whether expenditures to maintain, replace or improve electric transmission and distribution property must be capitalized under Section 263(a) of the Internal Revenue Code. The revenue procedure also provides procedures to obtain automatic consent to change to the safe harbor method of accounting. We used the safe harbor method in accounting for our 2012 and 2013 results.

Capitalization of tangible assets: In December 2012 the Internal Revenue Service amended the temporary capitalization of tangible assets regulations previously issued in 2011, to be applicable to tax years beginning on or after January 1, 2014, unless the taxpayer elects to apply them in tax years beginning on or after January 1, 2012. We intend to review and comply with the final regulations, however we did not elect to apply these regulations in 2013. In September 2013, the Internal Revenue Service issued final regulations addressing when costs incurred to acquire, produce or improve tangible property must be capitalized or may be deducted as incurred. The final repair regulations must be applied to taxable years beginning on or after January 1, 2014. We are presently reviewing and analyzing the final repair regulations to determine the impact upon adoption in 2014.

***Bonus depreciation*:** As a result of the passage of The Small Business Jobs Act in September 2010 and the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 in December 2010, certain capital additions qualify for 50% bonus depreciation and 100% expensing, respectively, for tax purposes. Iberdrola USA and its affiliates have elected to apply the 50% bonus and 100% expensing to the additions it has determined qualify for accelerated tax depreciation. There is no effect on earnings related to this election because the accelerated tax depreciation creates a temporary difference that requires the establishment of a deferred tax liability.

Note 4. Long-term Debt

At December 31, 2013 and 2012, our consolidated long-term debt was:

	Interest Rates	Maturity	Amount (Thousands) 2013	2012
First mortgage bonds [1]	3.07% to 5.70%	2019 to 2043	**$750,000**	$525,000
Pollution control notes, fixed	5.375%	2014	**19,500**	19,500
Medium-term notes, fixed	5.27% to 6.40%	2016 to 2037	**180,000**	215,700
Chester: Promissory and Senior Notes	7.05% to 10.48%	2020	**8,091**	9,274
Total long-term debt			**957,591**	769,474
Obligations under capital leases			**8,444**	10,174
Unamortized discount on debt			**(81)**	(96)
			965,954	779,552
Less debt due within one year, included in current liabilities			**22,426**	38,570
Total			**$943,528**	$740,982

[1] The first mortgage bonds are secured by a first mortgage lien on substantially all of our properties.

In January 2012 CMP issued $100 million of Series C first mortgage bonds that bear a coupon of 5.68% and will mature in January 2042. In May 2012 CMP priced $125 million of Series D first mortgage bonds and $225 million of Series E first mortgage bonds. The series D bonds were issued in June 2012, bear a coupon of 3.07% and will mature in June 2022. The Series E bonds were issued in January 2013, bear a coupon of 4.45% and will mature in January 2043. The proceeds of these bonds were used to reduce short-term debt and to fund capital expenditures.

One of our subsidiaries has debt totaling $8 million secured by its assets. We have no intercompany collateralizations and have no guarantees to affiliates or subsidiaries. None of our debt obligations are guaranteed or secured by our parent or affiliates.

At December 31, 2013, long-term debt, including sinking fund obligations and capital lease payments (in thousands) that will become due during the next five years are:

2014	2015	2016	2017	2018
$22,426	$2,292	$41,836	$1,901	$1,973

We have no financial debt covenant requirements related to our long-term debt at December 31, 2013 and 2012.

Note 5. Bank Loans and Other Borrowings

CMP relies on bank provided revolving credit facilities and on inter-company revolving credit facilities with IUSA, the parent of Networks, to fund short-term liquidity needs. In July 2011, CMP jointly entered into a bank provided revolving credit facility (the "Joint Facility") that allows maximum borrowings of up to $600 million in aggregate and expires in 2017. Sublimits that total to the aggregate limit apply to each joint borrower and can be altered within the constraints imposed by maximum limits that apply to each joint borrower. CMP's maximum credit limit under the joint facility is $300 million. Each borrower pays a facility fee ranging from 20 to 25 basis points annually depending on the rating of its unsecured debt.

In February 2012 we established a commercial paper program with a limit of $350 million. The Joint Facility serves as the backstop to this program. We intend to use commercial paper as an alternative to the Joint Facility as a source of short-term credit.

We also have an intercompany credit facility under a demand note agreement with Iberdrola USA that provides financing of up to $500 million. Under the terms of that agreement, which expires in

2018, we pay the same rate as under Iberdrola USA's credit facility which is 22.5 to 25 basis points. At December 31, 2013 we had no amount outstanding under this agreement.

We are a party to an intercompany agreement along with NYSEG and RG&E, under which each party to the agreement may lend to, or borrow from, the other parties, when the respective party has either a temporary cash surplus or short-term borrowing need. The interest rates on these transactions are based on the borrowing entity's external short-term borrowing costs. The agreement allows the parties to optimize its aggregate liquidity position. At December 31, 2013, we had a loan receivable from NYSEG of $16 million, bearing an interest rate of 0.25%.

We had no short-term debt outstanding at December 31, 2013 and $205 million outstanding at December 31, 2012. The weighted-average interest rate on short-term debt was .38% at December 31, 2012. At March 14, 2014, we had 54 million of short-term debt. We believe we have sufficient liquidity available to meet our working capital and capital spending requirements. As of March 14, 2014, we have $300 million available under the Joint Facility, $396 million available under the intercompany facility.

In our Joint Facility we 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 consolidated indebtedness to total capitalization, the facility excludes from consolidated net worth the balance of Accumulated other comprehensive income (loss) as it appears on the consolidated balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness we may maintain. Continued unremedied 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. Our ratio of indebtness to total capitalization pursuant to the revolving credit facility was .40 to 1.00 at December 31, 2013. We are not in default as of December 31, 2013.

Note 6. Preferred Stock

On June 22, 2012, CMP redeemed all of its outstanding shares of the 4.60% series and 4.75% series at a price of $101.00 per share plus accrued dividends from April 1, 2012 to the date of redemption.

On September 26, 2012, CMP Group, Inc. made a tender offer to purchase all of the outstanding shares of CMP's 6% preferred stock at $110.00 per share plus an amount equal to any accrued but unpaid dividends up to but not including the settlement date. The tender offer expired on November 15, 2012.

At December 31, 2013 and 2012, our consolidated 6% noncallable preferred stock was $571 thousand.

At December 31, 2013 CMP had 2,300,000 shares of $100 par value preferred stock authorized but unissued.

CMP's 5,713 shares outstanding include 3,792 shares owned by CMP Group, which are eliminated in consolidation for Networks.

Note 7. Commitments and Contingencies

***CMP customer charge-offs*:** Under Maine electric restructuring law, Maine electric delivery utilities are required to bill customers for delivery and supply service. This includes managing delivery and supply accounts receivable and uncollectibles. In October 2010 the MPUC initiated a proceeding to investigate CMP's credit and collection practices, and, in particular, whether CMP complies with the MPUC's new credit and collection rules, including the treatment of unpaid customer balances for delivery charges and supply charges.

In August 2012 the Hearing Examiner issued a report and recommended decision in the case, recommending that the MPUC order CMP to retroactively reallocate $2.6 million of customer deposits, previously applied to CMP's delivery service receivables during the period 2008 through 2010 as a credit to Standard Offer Service receivables. The Examiner's Report also recommended that the MPUC find CMP's collections practices during the period 2005 through 2010 were imprudent, resulting in an additional recommended disallowance of $3.7 million. In total, the Examiner's Report recommended that the MPUC order CMP to credit the Standard Offer Service retainage account by $6.3 million at CMP's expense. In September 2012 CMP filed its exceptions to the Examiner's Report, arguing that the Examiner's recommendations constitute illegal, retroactive, single-issue ratemaking and that the Examiner has failed to meet the burden of proof necessary to support a finding of imprudent utility behavior. In October 2012 the MPUC deliberated the matter and agreed with the Hearing Examiner's recommendation to require CMP to retroactively reallocate $2.6 million of customer deposits. The MPUC also agreed with the Hearing Examiner's finding of imprudent behavior with respect to appropriately pursuing customer collections during the period of 2008 through 2010. The MPUC determined that this imprudent behavior resulted in additional harm of $1.5 million and CMP should therefore credit a total of $4.1 million to Standard Offer Service receivables. On January 25, 2013, the MPUC issued its written Order confirming the $4.1 million credit to the standard offer retainage account. In December 2012 CMP reallocated $5.1 million in customer receivables with an associated charge to operating expense.

On February 14, 2013, CMP filed a motion requesting that the MPUC reconsider its January 25 order with respect to the allocation of customer deposits. On May 14, 2013, the MPUC issued an order denying CMP's motion. On June 4, 2013, CMP filed an appeal of the MPUC's January 25 and May 14 orders with the Maine Supreme Judicial Court. On August 22, 2013, CMP submitted its initial brief to the Court, disputing the MPUC's order with regard to the retroactive reallocation of customer deposits, but not seeking review of the MPUC's finding of imprudence. Following submission of the MPUC's brief and CMP's reply brief in October 2013, the Court will likely issue a final decision in early 2014. We cannot predict the outcome of this matter at this time.

***New England Transmission Owners Allowed Rate of Return*:** CMP's transmission rates are determined by a tariff regulated by the FERC and administered by ISO-NE. Transmission rates are set annually pursuant to a FERC authorized formula that allows for recovery of direct and allocated transmission operating and maintenance expenses, as well as return of and on investment in transmission assets. The FERC provides base return on equity (ROE) and additional incentive adders applicable to assets based upon vintage, voltage and other factors.

Pursuant to a FERC incentive rate order, CMP is provided a 12.89% ROE and allowed to include the CWIP related to the MPRP in rates, subject to an annual reconciliation.

In September 2011 the Massachusetts Attorney general and other state officials filed a complaint with the FERC that the ISO-NE base ROE for transmission owners in New England is too high and should be lowered. CMP is a member of the New England Transmission Owners (NE-TOs). The current base ROE is 11.14% excluding incentive adders. The complaint requested that the FERC reduce the NE-TO's allowed base ROE by 1.94% to a value of 9.2%.

A FERC Administrative Law Judge (ALJ) issued a recommended decision (RD) on August 6, 2013. The ALJ recommended that the ROE for the refund period be reduced from 11.14% to 10.6%. The refund period, limited by law to 15 months, is the 15 months from October 2011 to

December 2012. The ALJ also recommended that for the prospective period, which would begin with the date of the final decision, expected in early 2014, the ROE would be set at 9.7%. The ROE should, according to FERC precedent and not disputed by the other parties, be subject to adjustments for changes in 10-year treasury bond rates. As a result of the RD, CMP has recorded a regulatory liability of $6.2 million plus accrued interest of $0.4 million, which reflects the refunds that will ultimately be made to customers for the refund period. CMP has not recorded any entries for the prospective period because there will be no effect on periods before the final order. We cannot predict the outcome of this proceeding.

While the RD only covers the 15-month refund period and the prospective period, a coalition of customers has filed a second complaint against the NE-TOs seeking to lower the ROE to 8.7% for the period from January 2013 through April 2014. To date the FERC has not acted on the second complaint. We have not recorded a reserve for the 2013 period since we do not believe a refund for this period is probable.

***Power purchase contracts including nonutility generator*:** We expensed approximately $56 million for NUG power in 2013 and $55 million in 2012. We estimate that our power purchases will total $61 million in 2014 and 2015, $62 million in 2016; and $6 million in 2017 and 2018.

Decision in Yankee Litigation vs. DOE: CMP has an ownership interest in three nuclear generating companies (the Yankee companies) that have been decommissioned and currently store spent nuclear fuel (SNF) on their sites. In May 2012 the U.S. Court of Appeals issued a favorable decision in the Yankee companies' Phase I litigation over the U.S. Department of Energy (DOE)'s failure to remove SNF from the three New England single-unit decommissioned nuclear reactor sites as required by contract and the Nuclear Waste Policy Act beginning in 1998. Damages awarded to the three companies totaled nearly $160 million. CMP's share of the award is approximately $37 million.

The Yankee companies received the proceeds in early 2013. The proceeds will be used to offset future costs of spent fuel storage which are borne by the owners, with any excess being credited to the owners. Each of the Yankee companies have established a schedule to refund any excess to its owners, including CMP. Any refund ultimately distributed to CMP will ultimately be passed on to customers through lower rates. During 2013 CMP recorded a receivable of $30.6 million with an offsetting regulatory liability. CMP is obligated, as required by a Maine law enacted in 2013, to transfer to Efficiency Maine approximately $13.1 million, of its Phase I proceeds from Maine Yankee Atomic Power Company which will reduce the amount ultimately credited to customers. As a result, CMP established a liability to Efficiency Maine with an offsetting decrease in the regulatory liability.

On November 14, 2013, the Court of Federal Claims in Washington, D.C. issued a ruling in favor of the Yankee companies in Phase II of their litigation with the DOE, awarding a total of about $235 million in damages. CMP's share of the award is approximately $28 million. There was a 60-day appeal period that ended on January 14, 2014, and the U.S. Department of Justice, representing the DOE, did not appeal the decision. As a result, the decision is final and non-appealable. Once the funds are received by the Yankee companies, they will establish the amount and timing of future refunds. At December 31, 2013 CMP has not recorded a receivable for the Phase II proceeds, or an offsetting liability to Efficiency Maine as the amounts are not realized or realizable.

Note 8. 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.

The United States Environmental Protection Agency and various state environmental agencies, as appropriate, have notified us that we are among the potentially responsible parties that may be liable for costs incurred to remediate certain hazardous substances at 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 $1.1 million related to the six sites at December 31, 2013.

We have recorded an estimated liability of $1.9 million at December 31, 2013, 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. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to us.

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

Our estimate for all costs related to investigation and remediation of the two sites range from a minimum of $170 thousand to $240 thousand at December 31, 2013. 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 $170 thousand at December 31, 2013, and $360 thousand at December 31, 2012. 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 9. 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.

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 $(217) thousand as of December 31, 2013, and $(293) thousand as of December 31, 2012, 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)			
2013			
Interest rate contracts	**-**	Interest expense	**$(2,195)**
Commodity contracts:			
Other	**$(176)**	Other operating expenses	**(252)**
Total	**$(176)**		**$(2,447)**
2012			
Interest rate contracts	-	Interest expense	$(2,175)
Commodity contracts:			
Other	$(213)	Other operating expenses	(142)
Total	$(213)		$(2,317)

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 $14.6 million for 2013 and a net loss of $16.8 million for 2012. For the year ended December 31, 2013, we reported $2.2 million in net derivative losses related to discontinued cash flow hedges. We will amortize approximately $2.2 million of discontinued cash flow hedges in 2014.

At December 31, 2013, $(217) thousand 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.

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

The carrying amounts and estimated fair values of our financial instruments are shown in the following table. Carrying amounts include related debt discounts.

December 31,	2013		2012	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
(Thousands)				
First mortgage bonds	**$750,000**	**$800,003**	$525,000	$640,696
Pollution control notes, fixed	**$19,500**	**$19,773**	$19,500	$20,488
Various long-term debt	**$188,010**	**$210,886**	$224,878	$272,376

The carrying amounts for cash and cash equivalents, accounts receivable, notes receivable, notes payable and interest accrued approximate their estimated fair values.

We value all fixed rate long-term debt, whether unsecured or secured by a first mortgage lien, taxable or tax exempt, by assigning a market-based yield for each security and then deriving the price from the yield. Market-based yields are determined by observing secondary market trading levels for debt of similar maturity, rating, tax and structural characteristics.

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)				
2013				
Assets				
Noncurrent investments available for sale	**$330**	**$330**	**-**	**-**
Total	**$330**	**$330**	**-**	**-**
Liabilities				
Derivatives	**$217**	**-**	**-**	**$217**
Total	**$217**	**-**	**-**	**$217**
2012				
Assets				
Noncurrent investments available for sale	$337	$337	-	-
Total	$337	$337	-	-
Liabilities				
Derivatives	$293	-	-	$293
Total	$293	-	-	$293

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2013 and 2012. 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.

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,	**2013**	**2012**
(Thousands)		
Beginning balance	**$293**	$222
Total gain or loss for the period		
Included in earnings	**(252)**	(142)
Included in other comprehensive income	**176**	213
Ending balance	**$217**	$293

The amounts of realized and unrealized gain and loss included in earnings for the period (above), which are reported in Other operating expense are:

(Thousands)	
Total gain (loss) included in earnings for year ended December 31,	
2013	**$(252)**
2012	$(142)

Note 11. Accumulated Other Comprehensive (Loss) Income

	Balance January 1, 2012	2012 Change	Balance December 31, 2012	2013 Change	Balance December 31, 2013
(Thousands)					
Amortization of pension cost for nonqualified plans	-	**-**	-	**$(1,889)**	**$(1,889)**
Unrealized (loss) gain on derivatives qualified as hedges:					
Unrealized (loss) during period on derivatives qualified as hedges, net of income tax benefit of $162 for 2012 and $72 for 2013		**$(235)**		**(104)**	
Reclassification adjustment for loss included in net income, net of income tax (benefit) of $(133) for 2012 and $(103) for 2013		**193**		**149**	
Reclassification adjustment for loss on settled cash flow treasury hedges, net of income tax (benefit) of $(887) for 2012 and $(896) for 2013		**1,288**		**1,299**	
Net unrealized (loss) gain on derivatives qualified as hedges	(11,351)	**1,246**	**(10,105)**	**1,344**	**(8,761)**
Accumulated Other Comprehensive (Loss) Income	$(11,351)	**$1,246**	**$(10,105)**	**$(545)**	**$(10,650)**

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

Note 12. Retirement Benefits

We have funded noncontributory defined benefit pension plans that cover substantially all of our 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 there benefit accumulates based on a percentage of annual salary and credited interest. During 2013 the company announced that it would freeze the benefits for all non-union employees covered under the cash balance plans. Their earned balances would continue to accrue interest, but would no longer be increased by a percentage of earnings. In place of the pension benefit for 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.

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.

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Obligations and funded status:

	Pension Benefits		Postretirement Benefits	
	2013	**2012**	**2013**	**2012**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	**$406,642**	$356,353	**$104,361**	$120,320
Service cost	**8,110**	6,296	**837**	793
Interest cost	**16,329**	16,538	**4,103**	4,998
Plan participants' contributions	**-**	-	**609**	722
Plan amendments	**-**	-	**-**	(19,422)
Actuarial loss (gain)	**(49,166)**	42,408	**(9,115)**	6,395
Benefits paid	**(37,949)**	(14,953)	**(7,109)**	(9,859)
Federal subsidy on benefits paid	**-**	-	**130**	414
Benefit obligation at December 31	**$343,966**	$406,642	**$93,816**	$104,361
Change in plan assets				
Fair value of plan assets at January 1	**$253,892**	$217,121	**$40,085**	$30,597
Actual return on plan assets	**21,154**	27,796	**4,194**	7,068
Employer contributions	**8,052**	23,928	**-**	3,000
Withdrawal from VEBA	**-**	-	**(3,000)**	(580)
Employer and plan participants' contributions	**-**	-	**6,979**	9,445
Federal subsidy on benefits paid	**-**	-	**130**	414
Benefits paid	**(37,949)**	(14,953)	**(7,109)**	(9,859)
Fair value of plan assets at December 31	**$245,149**	$253,892	**$41,279**	$40,085
Funded status at December 31	**$(98,817)**	$(152,750)	**$(52,537)**	$(64,276)

Amounts recognized in the balance sheet	**Pension Benefits**		**Postretirement Benefits**	
December 31,	**2013**	**2012**	**2013**	**2012**
(Thousands)				
Noncurrent liabilities	**$(98,817)**	$(152,750)	**$(52,537)**	$(64,276)

Effective January 1, 2013, for current and future nonunion Medicare-eligible retirees (typically age 65 and above) and certain current union retirees and their dependents, we transitioned from company-sponsored group coverage to individual coverage available on the open market. We communicated the changes to retirees and employees in early August 2012. Due to the change, as of September 1, 2012, we remeasured both the plan assets and benefit obligations of our Other Postretirement Employee Benefit plans, using current values and updated assumptions. The remeasured Accumulated Pension Benefit Obligation and Net periodic benefit cost prospectively from the date of the event were based on a discount rate of 4.0%. The remeasurement reflected an updated discount rate, updated asset values and updated census information, as well as the effect of the change to the benefit plan, including a change in the participation rate.

Notes to Consolidated Financial Statements

During 2013 we offered terminated vested employees an option to receive their future pension benefit as a lump sum. Approximately $20.2 million of payments were made in 2013 as a result of employees exercising that option. The lump sums paid did not trigger any settlement accounting. Another $5.8 million will be paid out in 2014.

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:

	Pension Benefits		Postretirement Benefits	
December 31,	**2013**	**2012**	**2013**	**2012**
(Thousands)				
Net loss	**$141,411**	$208,220	**$27,708**	$40,733
Prior service cost (credit)	**$312**	$506	**$(18,638)**	$(26,230)

Our accumulated benefit obligation for all defined benefit pension plans at December 31 was $313 million for 2013 and $359 million for 2012.

Our postretirement benefits were partially funded at December 31, 2013 and 2012.

The projected benefit obligation and accumulated benefit obligation exceeded the fair value of pension plan assets for our plans as of December 31, 2013 and 2012. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets for the relevant periods.

December 31,	**2013**	**2012**
(Thousands)		
Projected benefit obligation	**$343,966**	$406,641
Accumulated benefit obligation	**$312,633**	$358,660
Fair value of plan assets	**$245,149**	$253,892

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

	Pension Benefits		Postretirement Benefits	
Years ended December 31,	**2013**	**2012**	**2013**	**2012**
(Thousands)				
Net periodic benefit cost				
Service cost	**$8,110**	$6,296	**$837**	$793
Interest cost	**16,330**	16,538	**4,103**	4,998
Expected return on plan assets	**(19,441)**	(19,023)	**(2,778)**	(2,353)
Amortization of prior service cost (benefit)	**194**	203	**(7,593)**	(6,551)
Amortization of net loss	**15,931**	12,148	**2,494**	2,275
Net periodic benefit cost	**$21,124**	$16,162	**$(2,937)**	$(838)
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net loss	**$(50,879)**	$33,634	**$(10,532)**	$1,679
Amortization of net (loss)	**(15,931)**	(12,148)	**(2,494)**	(2,275)
Current year prior service credit	**-**	-	**-**	(19,422)
Amortization of prior service (cost) credit	**(194)**	(203)	**7,593**	6,551
Total recognized in regulatory assets and regulatory liabilities	**(67,004)**	21,283	**(5,433)**	(13,467)
Total recognized in net periodic benefit				

cost and regulatory assets and regulatory liabilities	**$(45,880)**	$37,445	**$(8,370)**	$(14,305)

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, 2014	**Pension Benefits**	**Postretirement Benefits**
(Thousands)		
Estimated net loss	**$10,492**	$1,502
Estimated prior service cost (credit)	**$179**	$(3,875)

We expect that no pension benefit or postretirement benefit plan assets will be returned to us during the fiscal year ended December 31, 2014.

Weighted-average assumptions used to determine benefit obligations at December 31,	**Pension Benefits 2013**	**2012**	**Postretirement Benefits 2013**	**2012**
Discount rate	**4.90%**	4.10%	**4.90%**	4.10%
Rate of compensation increase	**4.30%**	4.00%	**NA**	NA

As of December 31, 2013, we increased our discount rate from 4.1% to 4.9%. 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 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 2013**	**2012**	**Postretirement Benefits 2013**	**2012**
Discount rate	**4.10%**	4.75%	**4.10%**	4.75%
Expected long-term return on plan assets	**7.50%**	7.75%	**-**	-
Expected long-term return on plan assets - nontaxable trust	**-**	-	**7.50%**	7.75%
Expected long-term return on plan assets - taxable trust	**-**	-	**5.00%**	5.00%
Rate of compensation increase	**4.00%**	4.00%	**4.00%**	4.00%

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. 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,	**2013**	**2012**
Health care cost trend rate (pre 65/post 65)	**8.0%/7.5%**	7.6%/7.5%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	**4.5%**	4.5%
Year that the rate reaches the ultimate trend rate	**2027**	2028

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	**$187**	**$(157)**
Effect on postretirement benefit obligation	**$3,892**	**$(3,274)**

Cash Flows

***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 $14 million to our pension benefit plans in 2014.

***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)			
2014	$17,504	$7,698	$127
2015	$17,992	$7,411	$146
2016	$18,472	$7,250	$167
2017	$18,985	$7,127	$188
2018	$19,512	$7,005	$212
2019 - 2023	$107,160	$33,586	$1,432

***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.

Our 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 of 45% equity securities, 35% fixed income and 20% for all other types of investments. The target allocations within allowable ranges are further diversified into 16% large cap domestic equities, 5% medium and small cap domestic equities, 7% global equity, 5% emerging markets, and 12% international equity securities. Fixed income investment targets and ranges are segregated into long dated corporate securities 10%, annuity contracts 8%, long-term treasury STRIPS 5%, treasury inflation protection securities 5% and opportunistic fixed income 7%. All fixed income investments are in domestic securities. Other, alternative investment targets are 5% for real estate, and 15% for absolute return and strategic markets. Systematic rebalancing within the target ranges, should any asset categories drift outside their specified ranges, increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk.

The fair values of Networks' pension benefits plan assets at December 31, 2013 and 2012, by asset category are shown in the following table. CMP's share of the total consolidated assets is approximately 11% for 2013 and 12% for 2012.

		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)				
2013				
Cash and cash equivalents	**$43,170**	**$1,665**	**$41,505**	**-**
U.S. government securities	**187,556**	**187,556**	**-**	**-**
Common stocks	**607,549**	**426,311**	**181,238**	**-**
Registered investment companies	**115,008**	**115,008**	**-**	**-**
Corporate bonds	**224,709**	**-**	**224,709**	**-**
Preferred stocks	**2,383**	**2,383**	**-**	**-**
Common/collective trusts	**513,293**	**-**	**54,980**	**$458,313**
Partnership/joint venture interests	**56,880**	**-**	**-**	**56,880**
Real estate investments	**67,266**	**-**	**-**	**67,266**
Other investments, principally annuity and fixed income	**359,690**	**21,625**	**1,470**	**336,595**
Total	**$2,177,504**	**$754,548**	**$503,902**	**$919,054**
2012				
Cash and cash equivalents	$78,161	$460	$77,701	-
U.S. government securities	224,377	224,377	-	-
Common stocks	690,621	523,352	167,269	-
Registered investment companies	180,961	180,961	-	-
Corporate bonds	258,170	-	258,170	-
Preferred stocks	3,702	3,702	-	-
Common/collective trusts	306,704	-	57,154	$249,550
Partnership/joint venture interests	50,040	-	-	50,040
Real estate investments	59,119	-	-	59,119
Other investments, principally annuity and fixed income	344,718	22,739	2,942	319,037
Total	$2,196,573	$955,591	$563,236	$677,746

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.

	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, 2011	$264,013	$50,928	$52,298	$175,517	$542,756
Actual return on plan assets:					
Relating to assets still held at the reporting date	35,499	(1,830)	-	17	33,686
Relating to assets sold during the year	5,833	4,347	1,876	4,363	16,419
Purchases, sales and settlements	(55,795)	(3,405)	4,945	139,140	84,885
Transfers into and/or out of Level 3	-	-	-	-	-
Balance, December 31, 2012	249,550	50,040	59,119	319,037	677,746
Actual return on plan assets:					
Relating to assets still held at the reporting date	**357**	**-**	**-**	**(1,899)**	**(1,542)**
Relating to assets sold during the year	**49,424**	**6,840**	**4,819**	**(7,409)**	**53,674**
Purchases, sales and settlements	**158,982**	**-**	**3,328**	**26,866**	**189,176**
Transfers into and/or out of Level 3	**-**	**-**	**-**	**-**	**-**
Balance, December 31, 2013	**$458,313**	**$56,880**	**$67,266**	**$336,595**	**$919,054**

Our postretirement benefits plan assets are held with a trustee in multiple voluntary employees' beneficiary association (VEBA) and 401(h) arrangements and are invested among and within various asset classes in order 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 25% of the postretirement benefits plan assets are invested in VEBA and 401(h) arrangements that are not subject to income taxes. The remainder is invested in arrangements subject to income taxes.

We have established a target asset allocation policy within allowable ranges for our postretirement benefits plan assets of 47% equity securities, 38% fixed income and 15% for all other types of investments. The target allocations within allowable ranges are further diversified into 20% large cap domestic equities, 12% medium and small cap domestic equities, 10% international developed market and 5% emerging market equity securities. Fixed income investment targets and ranges are segregated into core fixed income at 31%, global high yield fixed income 4% and international developed market debt 3%. Other, alternative investment targets are 5% for real estate, 5% absolute return and 5% tangible assets. Systematic rebalancing within target ranges, should any asset categories drift outside their specified ranges, increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk.

The fair values of Networks' other postretirement benefits plan assets at December 31, 2013 and 2012, by asset category are shown in the following table. CMP's share of the total consolidated assets is approximately 32% for 2013 and 34% for 2012.

		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)				
2013				
Money market funds	**$6,495**	**$6,495**	**-**	**-**
Mutual funds, fixed	**19,672**	**19,672**	**-**	**-**
Government & corporate bonds	**18,049**	**8,819**	**$9,230**	**-**
Mutual funds, equity	**41,522**	**41,522**	**-**	**-**
Common stocks	**36,960**	**36,960**	**-**	**-**
Mutual funds, other	**5,333**	**5,333**	**-**	**-**
Total assets measured at fair value	**$128,031**	**$118,801**	**$9,230**	**-**
2012				
Money market funds	$4,586	$4,586	-	-
Mutual funds, fixed	46,443	46,443	-	-
Mutual funds, equity	61,617	61,617	-	-
Mutual funds, other	5,803	5,803	-	-
Total assets measured at fair value	$118,449	$118,449	-	-

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 bond, 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.

Diversified equity securities did not include any Iberdrola common stock at December 31, 2013.

Note 13. CMP Rate Setting Process

CMP's rates are segregated into three primary components: transmission, distribution and stranded costs, each governed by a distinct regulatory process. The transmission rates are determined by a tariff regulated by the FERC and administered by ISO New England, Inc. Transmission rates are set annually pursuant to a FERC authorized formula that allows for recovery of direct and allocated transmission operating and maintenance expenses, as well as return of and on investment in transmission assets. The base ROE is currently set at 11.14% with various additional return adders applicable to assets based upon vintage, voltage, and other factors. The formula also includes provisions to reflect forecasted plant additions in rates, subject to reconciliation in the following year. Pursuant to a FERC incentive rate order, CMP is also allowed to include the CWIP related to the MPRP in rates, subject to the same reconciliation mechanism.

Pursuant to CMP's FERC authorized transmission rate formula, annual rate updates include an annual true-up (ATU) adjustment. The ATU is a reconciliation adjustment designed to recognize the rate impact of differences between the forecast levels of transmission plant additions and CWIP assumed for inclusion in rates, and the actual values for those rate components realized during the rate effective period. During 2012 CMP submitted to the FERC a change in CMP's rate formula that clarifies the implementation of FERC's authorized CWIP incentive for CMP's MPRP and, specifically, the timing of CMP's CWIP related recovery. Primarily as a result of the CWIP formula change, accepted by the FERC in May 2012, an ATU adjustment of $40.5 million was incorporated in CMP's rate update as a reduction in rates effective June 1, 2012. CMP recognized the full $40.5 million ATU refund obligation as a regulatory liability in June 2012 and amortized the liability over the subsequent 12 months of the effective rate year as the revenue reduction is realized. In June 2013, CMP recognized a regulatory liability of $10.7 million which will be amortized over the subsequent 12 month period. In November 2013 CMP recorded a regulatory liability of $3 million as the 2013 portion of the estimated 2014 refund.

CMP's distribution service rates are established pursuant to its Alternative Rate Plan 2008 (ARP 2008) approved by the MPUC with a five-year term that commenced on January 1, 2009. Under ARP 2008, our distribution service prices are adjusted on July 1 each year through 2013 based on an inflation index minus a 1% productivity factor. The rate plan also includes annual price change provisions for the recovery of significant unanticipated costs, including costs arising from changes in law, capital gains or losses, environmental remediation and major storms. CMP's operational performance is measured annually under the plan by seven service quality indicators and it is subject to penalties of up to $5 million for failure to achieve targeted levels of performance.

CMP submitted its fifth annual price change on March 14, 2013, seeking to increase distribution rates by approximately $18.8 million, or 8.24%. The requested increase reflects an inflation index value of 1.77%, less a one percent productivity factor, the recovery of approximately $5.4 million relating to 2012 storm restoration costs, the continued amortization of 2010 and 2011 storm restoration costs and numerous other minor adjustments. The requested amount also included approximately $15.2 million reflecting CMP's calculated revenue requirement impacts associated with CMP's Advanced Metering Infrastructure (AMI) deployment. On June 25, 2013, the MPUC approved a stipulation resolving all matters relating to the July 1, 2013, annual distribution price change. The stipulation incorporates numerous minor adjustments to the initial price change formula inputs and reduces the estimated AMI revenue requirement impacts to $11.5 million, resulting in a net distribution price increase of $14.9 million, or 6.5%. Pursuant to separate orders issued by the MPUC on June 17 and June 24, 2013, the amounts incorporated in CMP's distribution rates for AMI are subject to further adjustment in a subsequent rate proceeding, pending the results of an independent audit of CMP's management of the AMI project.

Also, pursuant to the stipulation in the ARP 2008 proceeding, the term of ARP 2008 ends on December 31, 2013. Under that stipulation and otherwise applicable law, CMP must file revenue requirement information and the MPUC must conduct a revenue requirement and earnings review prior to the adoption of a new or replacement alternative rate plan.

On May 1, 2013, CMP submitted a filing to the MPUC including the required revenue requirement information and requesting a new Alternative Rate Plan (ARP 2014) for distribution services during a five-year term commencing in 2014. ARP 2014 would replace CMP's current distribution rate plan, ARP 2008, which expired on December 31, 2013. The proposed ARP 2014 would continue many of the design characteristics of the current rate plan, including a price index formula that adjusts distribution prices annually based upon an inflation index less a productivity factor, as well as for exogenous costs due to extraordinary storms or unanticipated legislative or regulatory changes and an annual excess earnings sharing mechanism. The proposed plan also continues to include specific service quality measures with penalties of up to $6 million for failure to achieve defined performance targets. Proposed changes from ARP 2008 included a revenue decoupling mechanism, an annual adjustment to equity returns based upon a treasury bond yield index, and a series of pre-established annual price increases to fund committed capital investments during the rate plan term. The capital investment funding mechanism would be subject to a downward-only net plant reconciliation adjustment, as well as an incentive mechanism that would allow the Respondent to retain a percentage of savings achieved through efficient capital investment delivery. CMP's filing included revenue requirement calculations supporting a requested distribution rate increase of $18 million, effective July 1, 2014.

On August 2, 2013, the MPUC issued an Order of Partial Dismissal, dismissing CMP's proposed capital investment funding mechanism and its associated reconciliation and incentive mechanisms. The Order found that the proposed mechanisms are inconsistent and incompatible with both cost-of-service and incentive ratemaking approaches and encouraged CMP to propose alternative mechanisms to fund its projected investment needs. In response to the Order of Partial Dismissal, CMP submitted an alternative distribution revenue adjustment proposal to the MPUC on September 20, 2013. The alternative proposal eliminates the dismissed capital investment funding mechanism and retains the general structure of prior distribution rate plans, whereby CMP's total distribution operating and capital investment requirements are funded through an annual price adjustment utilizing an inflation index and productivity, or "X" factor. In order to fund projected increasing capital investment needs with steady or declining distribution delivery volumes, the alternative structure proposes a negative X factor of -1.46%.

In December 2013, the MPUC Staff, the Maine Office of Public Advocate (OPA) and six other parties filed testimony in response to CMP's submittal. The MPUC Staff proposed a one-year cost of service rate change based on a 9.25% ROE and 47% equity ratio. The MPUC Staff requested the MPUC reject the proposed multi-year rate plan, reject CMP's proposed revenue decoupling and ROE adjustment mechanisms. The OPA accepted, but modifies, the proposed multi-year rate plan, including accepting and modifying the revenue decoupling and ROE adjustment mechanisms. The OPA recommends an ROE of 8.5% and equity ratio of 50%. Other parties comment on various aspects of CMP's rate filing, generally opposing certain rate design recommendations, including those related to standby service for on-site generation customers. CMP will respond to the positions of MPUC Staff, OPA and other parties in the first quarter of 2014. CMP expects an MPUC decision on its filing in the second quarter of 2014 with new rates effective July 1, 2014 and cannot predict the outcome of the proceeding at this time.

CMP recovers "stranded costs" pursuant to annual price adjustments that are also regulated by the MPUC. Those costs primarily include above-market costs of electric capacity and energy purchased under long-term power purchase agreements, as well as costs and refunds associated with CMP's interests in four decommissioned nuclear generation facilities. Stranded costs rates are periodically established based upon forecasts and are then fully reconciled to actual costs and recovery amounts on an annual basis.

Note 14. 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, $432 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.

The regulatory asset for pension and postretirement benefits represents the actuarial losses that will be reflected in customer rates when they are amortized and recognized in future expenses.

We are allowed in rates an estimate of the routine costs of service restoration. We 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. We deferred $24 million in 2013 for service restoration costs, primarily as a result of an ice storm in late December 2013. We have determined that the storm meets the criteria for deferral and future recovery. Our total deferral, including carrying costs was $31 million at December 31, 2013 and $25 million at December 31, 2012. Deferred costs related to major storms incurred prior to 2012 are being recovered through rates and we will seek to include the cost of the 2013 storm in customer rates in our annual ARP filing.

We amortize unfunded future income taxes and deferred income taxes as the amounts related to temporary differences that gave rise to deferrals are recovered in rates.

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 a specific regulatory asset or regulatory liability are subject to automatic annual adjustment.

Current and long-term regulatory assets at December 31, 2013 and 2012 consisted of:

December 31,	**2013**	**2012**
(Thousands)		
Current		
Storm costs	**$7,177**	$17,298
Nuclear plant obligations	**288**	2,365
Deferred meter replacement costs	**2,246**	118
Legacy meter retirement deferral	**2,861**	2,722
Merger related	**1,715**	1,715
Rate reconciliation mechanism	**2,345**	2,268
Deferred income taxes regulatory	**9,194**	-
Other	**1,158**	1,480
Total current regulatory assets	**$26,984**	$27,966
Other long-term		
Legacy meter retirement deferral	**$1,563**	$4,563
Deferred income taxes	**6,081**	-
Merger related	**4,382**	6,098
Storm costs	**24,201**	7,349
Nuclear plant obligations	**-**	2,836
Unamortized loss on debt reacquisitions	**1,518**	1,802
Other	**1,907**	3,138
Total other long-term regulatory assets	**39,652**	25,786
Pension and OPEB	**150,792**	223,229
Unfunded future income taxes	**274,161**	238,214
Advanced metering infrastructure	**39,225**	37,499
Total long-term regulatory assets	**$503,830**	$524,728

Current and long-term regulatory liabilities at December 31, 2013 and 2012 consisted of:

December 31,	**2013**	**2012**
(Thousands)		
Current		
Accrued removal obligations	**$2,251**	$2,251
Revenue reconciliation mechanism transmission revenue	**9,956**	18,634
Yankee DOE Phase I	**17,557**	-
Environmental	**-**	3,500
Stranded cost	**10,342**	3,337
Other	**215**	117
Total current regulatory liabilities	**$40,321**	$27,839
Other long-term		
Environmental	**$6,240**	$4,057
Pension and OPEB	**-**	6,655
Other	**-**	3
Total other long-term regulatory liabilities	**6,240**	10,715
Accrued removal obligations	**79,165**	82,431
Deferred income taxes	**165,274**	174,896
Total long-term regulatory liabilities	**$250,679**	$268,042