

Iberdrola USA, Inc.
Consolidated Financial Statements
For the Years Ended December 31, 2010 and 2009

Iberdrola USA, Inc.

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Management's Report on Internal Control Over Financial Reporting

Iberdrola USA, Inc.'s (the company) internal control over financial reporting is a process affected by those charged with governance, management, and other personnel, designed to provide reasonable assurance regarding the preparation of reliable financial statements in accordance with accounting principles generally accepted in the United States of America. An entity's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the entity; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the entity are being made only in accordance with authorizations of management and those charged with governance; and (3) provide reasonable assurance regarding prevention, or timely detection and correction of unauthorized acquisition, use, or disposition of the entity's assets that could have a material effect on the financial statements.

Management is responsible for establishing and maintaining effective internal control over financial reporting. Management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2010, based on the framework set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control—Integrated Framework*. Based on that assessment, management concluded that, as of December 31, 2010, the company's internal control over financial reporting is effective based on the criteria established in *Internal Control—Integrated Framework*. The effectiveness of the company's internal control over financial reporting as of December 31, 2010, has been audited by PricewaterhouseCoopers LLP, an independent public accounting firm, as stated in their report which appears herein.

Iberdrola USA, Inc.
February 17, 2011



Report of Independent Auditors

To the Stockholder and Board of Directors of Iberdrola USA, Inc.

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of comprehensive income, of cash flows and of changes in equity present fairly, in all material respects, the financial position of Iberdrola USA, Inc. and its subsidiaries (collectively, the "Company") at December 31, 2010 and 2009, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assertion of the effectiveness of internal control over financial reporting, included in *Management's Report on Internal Control Over Financial Reporting* dated February 17, 2011, listed in the accompanying Index to the Iberdrola USA, Inc. Consolidated Financial Statements for the Years Ended December 31, 2010 and 2009. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits of the financial statements in accordance with auditing standards generally accepted in the United States of America and our audit of internal control over financial reporting in accordance with attestation standards established by the American Institute of Certified Public Accountants. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 2 to the consolidated financial statements, the Company sold three of their natural gas holding company subsidiaries and their natural gas distribution utilities on November 16, 2010.

A company's internal control over financial reporting is a process effected by those charged with governance, management, and other personnel, designed to provide reasonable assurance regarding the preparation of reliable financial statements in accordance with accounting principles generally accepted in the United States of America. A company's internal control over financial reporting



includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and those charged with governance; and (iii) provide reasonable assurance regarding prevention, or timely detection and correction of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

PricewaterhouseCoopers LLP

February 17, 2011

Iberdrola USA, Inc.
Consolidated Statements of Operations

Year ended December 31, (Thousands)	2010	2009
Operating Revenues		
Utility	\$3,262,847	\$3,188,716
Other	400,080	424,554
Total Operating Revenues	3,662,927	3,613,270
Operating Expenses		
Electricity purchased and fuel used in generation		
Utility	958,277	983,495
Other	277,867	299,123
Natural gas purchased		
Utility	351,207	462,430
Other	56,664	64,308
Other operating expenses	726,561	821,770
Maintenance	285,355	198,981
Depreciation and amortization	239,160	236,424
Other taxes	235,715	215,714
Total Operating Expenses	3,130,806	3,282,245
Operating Income	532,121	331,025
Other (Income)	(31,579)	(28,194)
Other Deductions	196,058	4,576
Interest Charges, Net	259,813	273,264
Income From Continuing Operations Before Income Taxes	107,829	81,379
Income Taxes (Benefits)	(24,124)	(7,107)
Income From Continuing Operations	131,953	88,486
Discontinued Operations		
(Loss) income from discontinued operations (including loss on sale of natural gas companies of \$364,046 in 2010)	(296,716)	27,249
Income taxes (including taxes on sale of \$18,300 in 2010)	42,181	3,115
(Loss) Income From Discontinued Operations	(338,897)	24,134
Net (Loss) Income	(206,944)	112,620
Less:		
Preferred Stock Dividends of Subsidiaries, Noncontrolling Interests	785	1,068
Net Income Attributable to Other Noncontrolling Interests	1,615	1,624
Net (Loss) Income Attributable to Iberdrola USA	\$(209,344)	\$109,928

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

Iberdrola USA, Inc.
Consolidated Statements of Comprehensive Income

Year ended December 31, (Thousands)	2010	2009
Net (Loss) Income	\$(206,944)	\$112,620
Other Comprehensive Income, Net of Tax	11,522	43,624
Comprehensive (Loss) Income	(195,422)	156,244
Less:		
Preferred Stock Dividends of Subsidiaries, Noncontrolling Interests	785	1,068
Comprehensive Income Attributable to Other Noncontrolling Interests	1,615	1,624
Comprehensive (Loss) Income Attributable to Iberdrola USA	\$(197,822)	\$153,552

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

Iberdrola USA, Inc.
Consolidated Balance Sheets

December 31, (Thousands)	2010	2009
Assets		
Current Assets		
Cash and cash equivalents	\$75,688	\$113,504
Accounts receivable and unbilled revenues, net	641,779	775,274
Fuel and natural gas in storage, at average cost	80,515	226,768
Materials and supplies, at average cost	31,483	30,147
Deferred income taxes	62,081	37,500
Derivative assets	9,924	5,145
Prepaid income taxes	168,600	129,223
Broker margin accounts	22,076	15,383
Prepayments and other current assets	97,970	123,236
Total Current Assets	1,190,116	1,456,180
Utility Plant, at Original Cost		
Electric	6,419,555	6,201,951
Natural gas	1,423,381	2,782,685
Common	539,260	607,776
	8,382,196	9,592,412
Less accumulated depreciation	3,029,712	3,318,424
Net Utility Plant in Service	5,352,484	6,273,988
Construction work in progress	496,319	188,540
Total Utility Plant	5,848,803	6,462,528
Assets Held For Sale	32,730	33,455
Other Property and Investments		
Other property and investments	150,702	217,806
Tax equity investments	478,016	304,821
Total Other Property and Investments	628,718	522,627
Regulatory and Other Assets		
Regulatory assets		
Nuclear plant obligations	75,896	109,896
Unfunded future income taxes	453,145	481,525
Environmental remediation costs	237,026	269,230
Unamortized loss on debt reacquisitions	44,667	49,150
Nonutility generator termination agreements	35,286	45,355
Natural gas hedges	12,802	9,652
Pension and other postretirement benefits	886,224	1,031,962
Other	291,181	427,595
Total regulatory assets	2,036,227	2,424,365
Other assets		
Goodwill	983,646	1,526,580
Prepaid pension benefits	87,336	145,723
Derivative assets	418	442
Other	66,082	101,302
Total other assets	1,137,482	1,774,047
Total Regulatory and Other Assets	3,173,709	4,198,412
Total Assets	\$10,874,076	\$12,673,202

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

Iberdrola USA, Inc.
Consolidated Balance Sheets

December 31, (Thousands, except shares)	2010	2009
Liabilities		
Current Liabilities		
Current portion of long-term debt	\$89,055	\$233,502
Notes payable	142,400	118,950
Accounts payable and accrued liabilities	265,445	195,697
Accounts payable, electricity purchased	108,560	91,975
Accounts payable, natural gas purchased	99,341	90,672
Interest accrued	26,003	36,515
Interest accrued on debt to affiliates	7,503	19,116
Taxes accrued	195,244	74,095
Derivative liabilities	13,351	9,608
Environmental remediation costs	49,044	40,028
Other	225,066	246,944
Total Current Liabilities	1,221,012	1,157,102
Regulatory and Other Liabilities		
Regulatory liabilities		
Accrued removal obligations	728,407	931,964
Deferred income taxes	368,564	367,764
Gain on sale of generation assets	47,196	22,860
Pension benefits	22,845	71,141
Positive benefit adjustments	200,339	297,938
Other	167,599	198,236
Total regulatory liabilities	1,534,950	1,889,903
Other liabilities		
Deferred income taxes	1,218,120	1,153,694
Nuclear plant obligations	143,104	150,279
Pension and other postretirement benefits	457,711	603,309
Environmental remediation costs	158,717	177,322
Derivative liabilities	427	493
Other	185,587	215,563
Total other liabilities	2,163,666	2,300,660
Total Regulatory and Other Liabilities	3,698,616	4,190,563
Long-term Debt		
Other long-term debt	2,139,334	2,598,933
Long-term debt owed to affiliates	650,000	1,350,000
Total Long-term Debt	2,789,334	3,948,933
Total Liabilities	7,708,962	9,296,598
Commitments and Contingencies		
Preferred Stock of Subsidiaries		
Redeemable preferred stock, noncontrolling interests	12,464	24,545
Iberdrola USA Common Stock Equity		
Common stock (\$.01 par value, 100 shares authorized and outstanding at December 31, 2010 and 2009)	-	-
Capital in excess of par value	2,009,101	2,009,101
Retained earnings	1,215,017	1,424,361
Accumulated other comprehensive loss	(85,204)	(96,726)
Total Iberdrola USA Common Stock Equity	3,138,914	3,336,736
Other Noncontrolling Interests	13,736	15,323
Total Equity	3,152,650	3,352,059
Total Liabilities and Equity	\$10,874,076	\$12,673,202

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

Iberdrola USA, Inc.
Consolidated Statements of Cash Flows

Year Ended December 31, (Thousands)	2010	2009
Operating Activities		
Net (loss) income	\$(206,944)	\$112,620
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	283,962	281,562
Amortization of regulatory and other assets and liabilities	104,106	68,917
Loss on sale of natural gas companies	88,243	-
Deferred income taxes and investment tax credits, net	(9,649)	147,878
Bridgeport pipeline contract impairment	-	7,312
Goodwill Impairment	275,802	-
Pension income (expense)	67,857	(4,962)
Positive benefit adjustments including carrying costs	(97,599)	17,928
Changes in current operating assets and liabilities		
Accounts receivable and unbilled revenues, net	37,717	141,627
Broker margin accounts	(6,693)	70,398
Environmental remediation costs	9,757	(26,269)
Inventory	10,898	141,778
Prepayments and other current assets	(126,190)	(36,193)
Accounts payable and accrued liabilities	85,144	(119,097)
Interest accrued on debt to affiliates	(11,613)	19,116
Interest accrued	(5,026)	(19,831)
Taxes accrued	215,568	(240)
Other current liabilities	4,919	41,199
Pension and other postretirement benefits contributions	(33,430)	(12,615)
Changes in other assets	10,428	(143,182)
Changes in other liabilities	(1,556)	(4,051)
Net Cash Provided by Operating Activities	695,701	683,895
Investing Activities		
Utility plant additions	(592,842)	(324,022)
Grants received from governmental entities	24,768	-
Proceeds from sale of Capitol Area System	-	10,624
Proceeds from sale of natural gas companies	917,929	-
Other property additions	(559)	(1,012)
Other property sold	7,276	1,440
Notes receivable from affiliate	(550,000)	-
Repayment of notes receivable from affiliate	550,000	-
Tax equity investments	(236,000)	(304,821)
Investments available for sale	54,434	18,957
Net Cash Provided by (Used in) Investing Activities	175,006	(598,834)
Financing Activities		
Equity contribution from parent	-	250,000
Repayment of preferred stock of subsidiaries, including net premiums	(11,253)	(4)
Derivative activity	-	(23,631)
Long-term note issuances, debt owed to affiliates	-	1,350,000
Long-term note repayments, debt owed to affiliates	(700,000)	-
Long-term note issuances	-	354,800
Long-term note repayments	(222,991)	(1,467,633)
Notes payable three months or less, net	28,094	(505,038)
Dividends to other noncontrolling interests	(1,588)	(875)
Dividends paid on preferred stock of subsidiaries, noncontrolling interests	(785)	(1,068)
Net Cash Used in Financing Activities	(908,523)	(43,449)
Net (Decrease) Increase in Cash and Cash Equivalents	(37,816)	41,612
Cash and Cash Equivalents, Beginning of Year	113,504	71,892
Cash and Cash Equivalents, End of Year	\$75,688	\$113,504

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

Iberdrola USA, Inc.
Consolidated Statements of Changes in Equity

(Thousands, except per share amounts)	Iberdrola USA Shareholder							
	Common Stock		Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Other Noncontrolling Interests	Compre- hensive Income (Loss)*	Total
	Outstanding Shares	\$.01 Par Value Amount						
Balance, January 1, 2009	-	-	\$1,759,101	\$1,314,433	\$(140,350)	\$14,574	\$2,947,758	
Net income*				109,928		1,624	\$111,552	
Other comprehensive income, net of tax					43,624		43,624	
Comprehensive income*							\$155,176	
Equity contribution from parent			250,000				250,000	
Dividends to other noncontrolling interests						(875)	(875)	
Balance, December 31, 2009	-	-	2,009,101	1,424,361	(96,726)	15,323	3,352,059	
Net income (loss)*				(209,344)		1,615	\$(207,729)	
Other comprehensive income, net of tax					11,522		11,522	
Comprehensive income*							\$(196,207)	
Dividends to other noncontrolling interests						(3,202)	(3,202)	
Balance, December 31, 2010	-	-	\$2,009,101	\$1,215,017	\$(85,204)	\$13,736	\$3,152,650	

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

*Amounts do not include Preferred Stock Dividends of Subsidiaries, Noncontrolling Interests of \$1,068 for 2009 and \$785 for 2010.

Notes to Consolidated Financial Statements

Note 1. Significant Accounting Policies

Background: Iberdrola USA, Inc. (Iberdrola USA, the company, we, our, us) is a public utility holding company operating under the Public Utility Holding Company Act of 2005. Iberdrola USA is a wholly-owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain. On December 1, 2009, we changed our legal and operating name to Iberdrola USA, Inc., from Energy East Corporation. We are a super-regional energy services and delivery company with operations in New York, Maine, Connecticut and New Hampshire. Our wholly-owned subsidiaries, and their principal operating utilities, 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).

On November 16, 2010, after receiving all regulatory approvals, we sold three of our natural gas holding company subsidiaries and their natural gas distribution utilities to UIL Holdings Corporation (UIL). The three holding companies and their related natural gas distribution utilities are: CTG Resources, Inc. (CTG) and Connecticut Natural Gas Corporation (CNG); Connecticut Energy Corporation (CEC) and The Southern Connecticut Gas Company (SCG); and Berkshire Energy Resources (BER) and The Berkshire Gas Company (BGC). (See Note 2.)

We have evaluated events or transactions that occurred after December 31, 2010, for inclusion in these financial statements through February 17, 2011, which is the date these financial statements were available to be issued.

As part of an effort to reduce costs and increase efficiency, we undertook various measures to reduce workforce levels in 2010. We reduced workforce levels by 140 through an involuntary separation at a cost of approximately \$3 million, which we paid in cash and charged to other operating expenses. We also offered voluntary early retirement programs (VERPs) to qualifying nonunion and union employees. The 525 employees who accepted the VERPs will receive forms of enhanced pension benefits. In addition, we offered a voluntary severance program (VSP) to certain employees, resulting in a reduction of 36 employees. In 2010 we recorded costs totaling approximately \$38 million for the VERPs, which will be paid from our companies' pension plans, and approximately \$1 million for the VSP. As part of the New York rate order (see Note 15), we were allowed to recover and defer \$32 million of these costs in rates.

Accounts receivable: Accounts receivable at December 31 include unbilled revenues of \$167 million for 2010 and \$209 million for 2009, and are shown net of an allowance for doubtful accounts at December 31 of \$40 million for 2010 and \$42 million for 2009. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was \$37 million in 2010 and \$42 million in 2009.

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 for each service region and operating segment. Each month the operating companies review their allowance for doubtful accounts and past due accounts over 90 days and/or above a specified amount, and review all other balances on a pooled basis by age and type of receivable. When an operating company believes that a receivable will not be recovered, it charges off the account balance against the allowance. Changes in assumptions about input factors and customer receivables, which are inherently uncertain and susceptible to change from period to period, could significantly affect the

Notes to Consolidated Financial Statements

allowance for doubtful accounts estimates. During 2010 we recorded an increase in the allowance for doubtful accounts of \$7 million because we no longer consider customer security deposits when we determine the amount of our allowance for doubtful accounts.

Asset retirement obligations: We record the fair value of the liability for an asset retirement obligation (ARO) and/or 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. Our regulated utilities defer any timing differences between rate recovery and depreciation expense 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 and/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 \$34 million for 2010 and \$51 million for 2009. The ARO primarily consists of obligations related to removal or retirement of: asbestos, PCB-contaminated equipment, gas pipeline and cast iron gas mains. The long-lived assets associated with our AROs are generation property, gas storage property, distribution property and other property.

The following table reconciles the beginning and ending aggregate carrying amount of the ARO for the years ended December 31, 2010 and 2009.

Year ended December 31,	2010	2009
(Thousands)		
ARO, beginning of year	\$50,953	\$50,788
Liabilities settled during the year	(2,500)	(2,309)
Accretion expense	3,016	2,140
Revisions in estimated cash flows	(219)	334
Disposition of liabilities related to sale of natural gas companies	(17,572)	-
ARO, end of year	\$33,678	\$50,953

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

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

Notes to Consolidated Financial Statements

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	2010	2009
(Thousands)		
Cash paid (received) during the year ended December 31:		
Interest, net of amounts capitalized	\$257,798	\$255,014
Income taxes, net of cash paid	\$(68,103)	\$(150,374)

Interest capitalized was \$3 million in 2010 and \$1 million in 2009. We have decreased utility plant additions by \$87 million for amounts payable as of December 31, 2010.

Preliminary survey costs: Consolidated preliminary survey costs included in Other assets at December 31 totaled approximately \$11 million for 2010 and \$16 million for 2009. Preliminary survey costs represent expenditures incurred for the purpose of determining the feasibility of utility projects under contemplation. When construction begins on such projects, the amounts are moved to Construction work in progress, 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 an appropriate expense account, and included in future rates.

Depreciation and amortization: We determine depreciation expense substantially using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal, in service at each operating company. The weighted-average service lives of certain classifications of property are: transmission property - 56 years, distribution property - 54 years, generation property - 57 years, gas production property - 20 years, gas storage property - 23 years, and other property - 37 years. Our depreciation accruals were equivalent to 2.7% of average depreciable property for 2010 and 2.8% for 2009.

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.

Bridgeport pipeline contract impairment: CNE Energy Services Group, Inc. (CNE Energy), was formerly a subsidiary of CEC; however, after the sale of natural gas companies in November 2010, it is now a subsidiary of The Energy Network, Inc. CNE Energy provided the funds for the construction of an 11.5 mile long pipeline in Bridgeport, Connecticut, which was subject to a 20 year gas transmission agreement (Agreement) with an unrelated entity. SCG constructed the pipeline and has owned and operated it since its completion. In addition to funding the pipeline construction costs, CNE Energy paid all operating and maintenance costs related to the pipeline project. In February 1998 the Connecticut Department of Public Utility Control (DPUC) issued a decision concerning the allocation of revenues during the first 10 years of the Agreement, allocating a portion to SCG for the benefit of its ratepayers with the remaining portion retained by CNE Energy.

The original DPUC decision required SCG to petition the DPUC by July 1, 2008, for an adjustment to the allocation of revenues for the second 10 years of the Agreement. The DPUC issued a decision on April 1, 2009, reducing the annual revenue allocation to CNE Energy for the remaining term of the Agreement. Based on its estimate of undiscounted cash flows for the remaining years, CNE Energy determined that the combined \$7.1 million carrying amount of the contract interest and valuation adjustment was not recoverable, and impaired the entire net carrying amount. In addition, because substantially all of its economic activity is derived from the Bridgeport contract, CNE Energy also impaired \$0.2 million of net goodwill in 2009. The combined pretax impairments totaling approximately \$7.3 million are included in depreciation and

Notes to Consolidated Financial Statements

amortization on the income statement. The total after-tax effect of the impairments is approximately \$4.7 million.

Goodwill: We are required to perform an annual goodwill impairment test at the same time each year and, accordingly, we perform our annual impairment testing of goodwill during the third quarter of each year. We update the test between annual tests if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value. The analysis of a potential impairment of goodwill requires a two step process. 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.

In performing our annual goodwill impairment test, for purposes of the step one analysis, we base the determination of the fair value of our reporting units on the income approach, which estimates fair value based on discounted future cash flows. Based on the completion of step one of our annual impairment analysis, management determined that the fair value of each reporting unit was greater than its carrying value.

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.

As a result of our decision in May 2010 to sell the natural gas companies we updated our impairment test of the goodwill for SCG, CNG and BGC in accordance with the two step process described above. We determined that the carrying value of the combined companies exceeded the purchase price agreed to by UIL, resulting in a goodwill impairment of \$275.8 million. (See Note 3.)

Government grants: Authoritative accounting principles generally accepted in the United States of America do not address accounting for government grants. For that reason, we account for government grants related to depreciable assets in accordance with the prescribed Federal Energy Regulatory Commission (FERC) accounting 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 it becomes receivable. (See Note 9.)

Notes to Consolidated Financial Statements

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

Fair value measurements: The FASB has issued a number of new standards related to fair value measurements. In April 2009 the FASB issued two new standards related to fair value measurements, which we began applying effective April 1, 2009:

- One of the new standards provides guidance for determining fair value when the volume and level of activity for an asset or liability have significantly decreased and for identifying transactions that are not orderly. It provides additional guidance to entities for estimating fair value in accordance with existing requirements when the volume and level of activity for an asset or a liability has significantly decreased. Even in those circumstances, and without considering the valuation technique(s) used, the intention of fair value measurement does not change. The new standard also provides guidance for identifying circumstances that indicate a transaction is not orderly. In addition, it amends the disclosures in connection with fair value measurements to require disclosure in interim and annual periods about the inputs and valuation techniques used to measure fair value as well as a discussion of any changes in them during the period; and to require disclosures concerning debt and equity securities according to major security types.

As a result of the revised guidance and continued illiquidity in the auction rate securities market, we reassessed the fair value of our \$3.85 million investment in auction rate securities. We have held the investment for over two years as a result of several failed auctions. In 2009 we reduced the carrying value of our investment to \$2.7 million; the writedown of \$1.1 million is included in Other Deductions on the income statement.

- The other new standard provides amended guidance concerning the recognition and presentation of other-than-temporary impairments. It amends the guidance in U.S. generally accepted accounting principles for other-than-temporary impairment of debt securities (but not equity securities) to make it more operational and to improve the financial statement presentation and disclosure of other-than-temporary impairments on debt and equity securities.

In August 2009 the FASB issued an accounting standards update to provide amended guidance concerning the fair value measurement of liabilities. The key provisions of the amendments include clarification about valuation techniques that are to be used in circumstances in which a quoted price in an active market for the identical liability is not available and that a reporting entity is not to include a separate input or adjustments to other inputs to reflect the existence of a restriction that prevents the transfer of a liability. The amended guidance is effective for an entity's first reporting period (including interim periods) beginning after issuance of the update. We initially began applying the guidance effective October 1, 2009.

In January 2010 the FASB issued amendments to improve disclosures about fair value measurements. New disclosures that are or will be required include: 1) details of transfers in and out of Level 1 and Level 2 of the fair value measurement hierarchy, and 2) gross presentation of roll forward activity within Level 3 – separate presentation of information about purchases, sales, issuances and settlements. Entities will also have to provide fair value measurement disclosures for each class of assets and liabilities, as well as disclosures about inputs and valuation techniques for both recurring and nonrecurring Level 2 and Level 3 fair value measurements. The amendments are effective for interim and annual reporting periods beginning after December 15, 2009, except that the disclosures about Level 3 roll forward activity are effective for fiscal years beginning after December 15, 2010, and interim periods within those fiscal years.

Notes to Consolidated Financial Statements

Except for the reduction in the carrying value of our investment in auction rate securities in 2009, our adoption of the new standards related to fair value measurements had no effect on our financial position, results of operation or cash flows. Our adoption of the amendments concerning Level 3 roll forward activity effective for fiscal years beginning on or after January 1, 2011, and interim periods within those fiscal years, will not affect our results of operation, financial position or cash flows.

Variable interest entities: In June 2009 the FASB issued amendments to its revised interpretation concerning consolidation of variable interest entities (VIEs). The amendments clarify, but do not significantly change, the criteria for determining whether an entity meets the definition of a VIE, and change existing consolidation guidance so that qualifying special purpose entities are no longer exempt from consolidation. The amendments require an enterprise to perform ongoing assessments as to whether an entity is a VIE and whether the enterprise is the primary beneficiary of a VIE. Previously such assessments were required only when specified events occurred. The amended standard will alter how an enterprise determines when an entity that is not sufficiently capitalized or not controlled through voting should be consolidated. An enterprise will also be required to perform a qualitative analysis to determine whether it should provide consolidated reporting of an entity based upon the entity's purpose and design and the enterprise's ability to direct the entity's actions. The amended standard also requires enhanced disclosures to provide more transparent information about an enterprise's involvement in a VIE, and any significant changes in its risk exposure due to that involvement. The amendments are effective at the start of a company's first fiscal year beginning after November 15, 2009, including interim periods. Our adoption of the amendments effective January 1, 2010, did not affect our results of operation, financial position or cash flows.

Other (Income) and Other Deductions:

Year Ended December 31,	2010	2009
(Thousands)		
Interest and dividend income	\$(1,648)	\$(2,298)
Allowance for funds used during construction	(4,705)	(1,152)
Earnings from equity investments	(4,344)	(4,403)
Carrying costs on regulatory assets	(19,385)	(20,193)
Miscellaneous	(1,497)	(148)
Total other (income)	\$(31,579)	\$(28,194)
Early retirement of debt	\$128,128	-
Losses on energy risk contracts	-	\$443
Civic donations	1,268	1,175
Impairment of auction rate security investment	-	1,115
Losses from tax equity investments	62,805	579
Miscellaneous	3,857	1,264
Total other deductions	\$196,058	\$4,576

Early retirement of debt: Iberdrola USA paid premiums in connection with the early retirement of long-term debt owed to an affiliate, Scottish Power, Limited as follows: premium of \$82 million for the repayment of \$400 million in November 2010 and premium of \$46 million for the repayment of \$300 million in December 2010.

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

Notes to Consolidated Financial Statements

Reclassifications: Certain amounts have been reclassified in our consolidated financial statements to conform to the 2010 presentation. The reclassifications primarily affect the income statement in connection with the presentation of discontinued operations, and the presentation of certain notes that contain income statement information.

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

Pursuant to the requirements concerning accounting for regulated operations our utilities capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric and natural gas rates. Substantially all regulatory assets for which funds have been expended are either included in rate base or are accruing carrying costs. As a result of the New York rate decision (see Note 15), the majority of regulatory assets and liabilities for NYSEG and RG&E are now included in rate base. As a result, carrying costs will decline significantly from 2010 levels. Our operating utilities also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs.

Unfunded future income taxes and deferred income taxes are amortized as the related temporary differences reverse. Unamortized loss on debt reacquisitions is amortized over the lives of the related debt issues. Nuclear plant obligations, demand side management program costs, gain on sale of generation assets, other regulatory assets and other regulatory liabilities are amortized over various periods in accordance with each operating utility's current rate plans. Amortization of total regulatory assets net of amortization of total regulatory liabilities was \$74 million in 2010 and \$51 million in 2009.

In 2009 we recorded reserves totaling \$48.2 million on existing regulatory assets to reflect management's assessment of risk and increased uncertainty about the ultimate recovery for certain issues that had not been resolved with our regulators. Those amounts included \$30 million for NYSEG and \$10 million for RG&E related to disputes about earnings sharing accruals (see Note 9) and \$5.5 million for CMP related to deferred storm costs. The resulting charge increased other operating expenses for the period.

Notes to Consolidated Financial Statements

Other regulatory assets and other regulatory liabilities consisted of:

December 31, (Thousands)	2010	2009
Other postretirement benefits	\$12,428	\$31,320
Customer Hardship Arrearage Forgiveness and related programs	434	47,550
Loss on sale of RG&E Oswego generating unit	16,335	22,467
Asset retirement obligation	28,455	25,986
Deferred storm costs	54,479	103,744
Deferred pension costs	47,913	44,600
Stranded cost reconciliation	520	8,501
Deferred natural gas costs	1,077	40,356
Nonbypassable wires charge	4,004	19,324
Incremental assessment	11,261	20,681
Cost to achieve efficiency initiatives	29,966	-
Other	84,309	63,066
Total other regulatory assets	\$291,181	\$427,595
Deferred natural gas costs	\$8,839	\$22,643
Asset retirement obligation	4,419	12,246
Nonfirm margin sharing	-	12,478
Economic development	35,951	21,657
Pension	13,435	27,237
Nuclear decommissioning	12,545	17,320
Tennessee gas pipeline settlement	2,285	10,408
Nonbypassable wires charge	20,033	-
Other	70,092	74,247
Total other regulatory liabilities	\$167,599	\$198,236

Related party transactions: We have a depository agreement with Scottish Power, Limited (Scottish Power) under which, in November 2010, we deposited \$550 million for investment on our behalf by Scottish Power. In December 2010 we redeemed those funds. We earned \$128 thousand on the investment. There was no amount outstanding under the depository agreement at December 31, 2010.

See Note 5 concerning amounts we owe to Scottish Power under a debt agreement. Interest expense on the debt for the year ended December 31 was \$90 million for 2010 and \$66 million for 2009.

See Note 8 concerning our related party transactions with respect to tax equity investments.

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

Pursuant to a Maine state law, CMP is prohibited from selling power to its retail customers. CMP does not enter into purchase or sales arrangements for power with ISO New England Inc., the New England Power Pool, or any other independent system operator or similar entity. CMP sells all of its power entitlements under its nonutility generator (NUG) and other purchase power contracts to unrelated third parties under bilateral contracts.

NYSEG and RG&E enter into power purchase and sales transactions with the New York Independent System Operator (NYISO). When NYSEG and RG&E sell electricity from owned generation to the NYISO, and subsequently repurchase electricity from the NYISO to serve their

Notes to Consolidated Financial Statements

customers, they record the transactions on a net basis in their statements of income. NYSEG and RG&E net their purchase and sale transactions with the NYISO on an hourly basis.

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

Taxes: We file a consolidated federal income tax return and allocate income taxes among Iberdrola USA and its subsidiaries in proportion to their contribution to consolidated taxable income. The determination and allocation of our income tax provision and its components are outlined and agreed to in the tax sharing agreements among Iberdrola USA and its subsidiaries.

Deferred income taxes reflect the effect of temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and the amount recognized for tax purposes. 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 and penalties related to uncertain tax positions as income tax expense.

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; and (8) earnings sharing mechanism (ESM), nonbypassable wires charges and environmental remediation liability. 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. Sale of Natural Gas Companies

On November 16, 2010, we sold three of our natural gas holding company subsidiaries and their natural gas distribution utilities to UIL at an after-tax loss of \$382 million, including impairments of goodwill totaling \$275.8 million. The three holding companies and related natural gas distribution utilities are: CTG and CNG, CEC and SCG, and BER and BGC. Pursuant to the purchase agreement we retained our nonutility subsidiaries CNE Energy Services Group, Inc. and TEN Companies, Inc. (TEN Cos.) at the time of the transaction.

The transaction was valued at \$1,296 million, including the assumption of approximately \$386 million of debt. We received approximately \$918 million in cash at closing, which reflects closing adjustments of \$8 million primarily for estimated cash balances and changes in net working capital. The agreement provides for an adjustment to the final purchase price in April 2011 for actual cash and working capital balances as of the date of the sale.

Notes to Consolidated Financial Statements

The following provides a summary of the discontinued operations presented in the consolidated statements of income for the periods indicated:

	Period January 1, to November 16, 2010	Year Ended December 31, 2009
(Thousands)		
Operating Revenues		
Sales and services	\$643,533	\$748,371
Operating Expenses		
Natural gas purchased	366,726	418,545
Depreciation and amortization	21,540	45,657
Goodwill impairment	275,802	-
Other operating expenses	165,786	223,440
Total Operating Expenses	829,854	687,642
Operating (Loss) Income	(186,321)	60,729
Other (Income) Deductions, net	(6,140)	(1,533)
Loss on Sale of Natural Gas Companies	88,243	-
Interest Charges, Net	28,292	35,013
(Loss) Income Before Income Taxes	(296,716)	27,249
Taxes on Sale of Natural Gas Companies	18,300	-
Income Taxes	23,881	3,115
(Loss) Income From Discontinued Operations	\$(338,897)	\$24,134

The above Depreciation and amortization expense excludes approximately \$21 million of depreciation and amortization for the period of time that we classified the assets as held for sale. The amount of Interest Charges, Net represents interest on the direct obligations of the natural gas companies sold. Transaction costs of \$2 million are included in the loss on sale.

The following table provides the carrying amounts of the major classes of assets and liabilities of the discontinued operations as of the dates indicated.

	Nov. 16, 2010	Dec. 31, 2009
(Thousands)		
Assets		
Current assets	\$307,090	\$339,472
Utility plant, net	961,961	956,390
Regulatory assets	390,831	405,751
Goodwill	267,132	542,934
Other assets	28,401	40,647
Total assets of discontinued operations	\$1,955,415	\$2,285,194
Liabilities		
Current liabilities	\$127,842	\$141,408
Regulatory liabilities	335,846	339,166
Long-term debt, including current portion	381,000	424,000
Other liabilities	377,754	377,288
Total liabilities of discontinued operations	\$1,222,442	\$1,281,862

Notes to Consolidated Financial Statements

Note 3. Goodwill

We do not amortize goodwill, but test it for impairment at least annually. Impairment testing includes various assumptions, primarily the discount rate, which is based on an estimate of our marginal, weighted-average cost of capital, and forecasted cash flows. We test the reasonableness of the conclusions of our impairment testing using a range of discount rates and a range of assumptions for long-term cash flows. Our decision in May 2010 to sell the natural gas companies helped meet a key strategic objective of our parent, Iberdrola S. A., as it allows us to focus on electric operations. The decision to sell represented a triggering event and we immediately performed an impairment test of the goodwill for SCG, CNG and BGC in accordance with the two step process described in Note 1. We determined that the carrying value of the combined companies exceeded the purchase price agreed to by UIL, resulting in a goodwill impairment of \$275.8 million. We had no impairment of goodwill in 2010 or 2009 as a result of our annual impairment testing, which we perform in the third quarter each year. No impairment was indicated within any of the ranges of assumptions analyzed for our New York, Maine or nonutility reporting units. There were no events or circumstances subsequent to our annual impairment testing that required us to update the test.

The carrying amount of goodwill as of December 31, 2010 and 2009, is shown in the following table. Goodwill has not been adjusted to reflect Iberdrola's purchase of Energy East.

	2010	2009
(Thousands)		
Balance as of January 1		
Goodwill	\$1,526,822	\$1,526,598
Accumulated impairment losses	(242)	-
	1,526,580	1,526,598
Preacquisition income tax adjustments	-	838
Goodwill related to sale of business units	(267,132)	(614)
Impairment for natural gas companies sold	(275,802)	-
Impairment for Bridgeport	-	(242)
Balance as of December 31		
Goodwill	983,888	1,526,822
Accumulated impairment losses	(242)	(242)
	\$983,646	\$1,526,580

In May 2008 TEN Cos. and the state of Connecticut (State) signed a memorandum of understanding (MOU) to allow interested parties to finalize an agreement for the State's purchase of certain heating and cooling equipment that serves certain state buildings (Capitol Area System) at a specified purchase price of \$10.6 million, along with other terms specified in the MOU. TEN Cos. entered into an Asset Purchase Agreement (Agreement) contemplated in the MOU with the State in November 2008. The State passed legislation authorizing the Agreement and the sale was completed on June 1, 2009. The sale resulted in a \$614 thousand decrease in goodwill.

Notes to Consolidated Financial Statements

Note 4. Income Taxes

Year Ended December 31,	2010	2009
(Thousands)		
Current		
Federal	\$(259,708)	\$(114,866)
State	(6,594)	3,676
Current taxes charged to expense	(266,302)	(111,190)
Deferred		
Federal	234,214	118,192
State	10,237	(11,814)
Deferred taxes charged to expense	244,451	106,378
Investment tax credit adjustments	(2,273)	(2,295)
Total for Continuing Operations	\$(24,124)	\$(7,107)

The significant decrease in current income tax expense in 2010, and corresponding increase in deferred income tax expense as compared to 2009 is driven primarily by the tax depreciation related to our Tax equity investment in Aeolus VI made on December 2010 as well as a full year's worth of tax depreciation related to our Tax equity investment in Aeolus V made in April of 2009. (See Note 8.)

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

Year Ended December 31,	2010	2009
(Thousands)		
Tax expense at statutory rate	\$37,740	\$28,483
Depreciation and amortization not normalized	11,669	9,521
Investment tax credit amortization	(2,273)	(2,295)
Removal costs	(7,847)	(5,942)
Medicare subsidy	2,708	(3,731)
Tax return and audit adjustments	(3,341)	(14,232)
Tax equity investment depreciation not normalized	(37,031)	-
Tax equity investment production tax credits	(24,245)	(14,543)
State taxes, net of federal benefit	2,368	(5,290)
Other, net	(3,872)	922
Total for Continuing Operations	\$(24,124)	\$(7,107)

Income taxes were \$61.8 million less in 2010 than they would have been at the federal statutory rate of 35% and \$35.6 million less in 2009. The 2010 effective tax rate was less than the statutory rate primarily due to the tax benefits, including production tax credits, generated from our Tax equity investments in two wind farm partnerships, offset by the increase in taxes related to the depreciation and amortization not normalized. The 2009 effective tax rate was less than the statutory rate primarily due to the recording of a deferred tax asset related to production tax credits generated as a result of our Tax equity investment in a wind farm partnership and the flow-through effect of the tax deduction related to previously capitalized repair costs taken for CMP on the 2008 return filed in 2009.

Notes to Consolidated Financial Statements

Our consolidated deferred tax assets and liabilities consisted of:

December 31, (Thousands)	2010	2009
Current Deferred Income Tax Assets	\$62,081	\$37,500
Noncurrent Deferred Income Tax Liabilities (Assets)		
Property related	\$1,379,484	\$1,377,569
Pension	249,182	243,737
Unfunded future income taxes	166,764	150,306
Deferred (gain) on sale of generation assets	26,008	38,248
Accumulated deferred investment tax credits	23,753	26,805
Federal and state net operating loss carryforwards	(50,985)	(80,382)
Other postretirement benefits	(102,163)	(101,966)
Positive benefits adjustments merger order	(79,365)	(118,028)
Other	(25,994)	(14,831)
Total Noncurrent Deferred Income Tax Liabilities	1,586,684	1,521,458
Less amounts classified as regulatory liabilities		
Deferred income taxes	368,564	367,764
Noncurrent Deferred Income Tax Liabilities	\$1,218,120	\$1,153,694
Deferred tax assets	\$320,588	\$352,707
Deferred tax liabilities	1,845,191	1,836,665
Net Accumulated Deferred Income Tax Liabilities	\$1,524,603	\$1,483,958

Iberdrola USA and its subsidiaries have the following loss carry-forward amounts: state of New York - \$682 million, Maine - \$503 million, and various other unitary states of \$1 million which expire between 2027 and 2030. We have not recorded a valuation allowance because we believe we will be able to fully utilize the loss carryforwards.

Reconciliation of Gross Income Tax Reserves (Thousands)	2010	2009
Balance as of January 1	\$39,498	\$4,702
Increases for tax positions related to prior years	-	38,142
Reductions for tax positions related to prior years	-	(3,346)
Disposition of amounts related to sale of natural gas companies	(6,788)	-
Balance as of December 31	\$32,710	\$39,498

The total gross unrecognized tax benefits as of December 31, 2010, were \$35.3 million, including gross income tax reserves of \$32.7 million and interest of \$2.6 million. Including interest, \$8.3 million of the total gross unrecognized tax benefits would affect the effective tax rate, if recognized. Gross income tax reserves decreased \$6.8 million in 2010 primarily due to the sale of the natural gas companies.

We have been audited through 2005 for federal income taxes. The statute of limitations in all state jurisdictions has expired for all years through 2006. Our federal returns for 2006 through 2009 are currently under review. We anticipate that the reviews will be completed in 2011. We cannot predict the ultimate outcome of the reviews.

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 this accelerated tax depreciation. There is no earnings impact related to this election as the accelerated tax depreciation creates a temporary difference that requires the establishment of a deferred tax liability.

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Elimination of tax deduction related to Medicare Part D Subsidy: The Patient Protection and Affordable Care Act (PPACA) and the Health Care and Education Reconciliation Act of 2010 (H.R. 4872) were signed into U.S. law in late March 2010. We receive a federal subsidy because we sponsor retiree health benefit plans that provide a benefit that is at least actuarially equivalent to the benefits under Medicare Part D. The subsidy is known as the Retiree Drug Subsidy (RDS or the subsidy). The RDS payments we receive are not currently taxed. A provision in the PPACA changes the tax treatment of the RDS, requiring the amount of the subsidy received to be offset against the amount of retiree health care payments that would be eligible for a tax deduction. As a result, the subsidy received would reduce an employer's tax deduction for the costs of retiree health care. Our subsidy receipts will effectively become taxable in tax years that begin after December 31, 2012.

In accordance with U.S. GAAP concerning accounting for income taxes, a reporting entity is required to immediately recognize the effect of a change in tax law in continuing operations in the income statement in the period that includes the enactment date. We recorded the effect of the change related to the RDS in the quarter ended March 31, 2010, due to the fact that we accounted for the future tax benefit on an accrual basis. In accounting for the effect of the change for U.S. GAAP reporting, an employer that captured the tax benefit of future subsidies on an accrual basis would now be required to reduce the accumulated deferred tax asset on its balance sheet related to the accrued estimated deductible retiree health care payments to reflect the fact that the future deduction will now be reduced by the collection of the accrued subsidy.

Companies that meet the requirements concerning accounting for regulated operations offset that decrease with the establishment of a regulatory asset. As a result, we have recorded a regulatory asset for unfunded future income taxes of approximately \$26 million and reduced our deferred income tax asset related to the costs of retiree health care by approximately \$17 million for NYSEG and RG&E combined. In addition, because the recognition of the unfunded future income tax regulatory asset is considered a temporary difference, we have recognized an associated deferred income tax liability of approximately \$9 million. There is no immediate effect on the income statement under this accounting, only our balance sheet is affected. The amortization of the \$26 million regulatory asset and associated \$9 million deferred tax liability commenced on September 1, 2010 in accordance with the provisions of the NYSEG and RG&E rate settlements. The amortization period is 40 months.

CMP recorded a \$5.6 million income tax expense as a result of the tax law change and is seeking recovery of approximately \$3.5 million of that amount pursuant to the mandated cost provision of its current rate plan.

Notes to Consolidated Financial Statements

Note 5. Long-term Debt

At December 31, 2010 and 2009, our consolidated long-term debt was:

Company	Interest Rates	Maturity	Amount (Thousands)		
			2010	2009	
First mortgage bonds ⁽¹⁾					
RG&E	Series TT, WW, VV, XX & YY	5.90% - 8.00%	2011 - 2033	\$536,000	\$636,000
RG&E	PCN 2004 Series A	4.75%	2016	10,500	10,500
RG&E	PCN 2004 Series B	5.375%	2032	50,000	50,000
RG&E	PCN Series C	5.00%	2016	29,350	29,350
CMP	Series A	5.70%	2019	150,000	150,000
SCG	Medium Term Notes I, II, III & IV	5.772% - 7.95%	2010 - 2037	-	234,000
Berkshire Gas	Series P	10.06%	2019	-	10,000
Total first mortgage bonds				775,850	1,119,850
Unsecured pollution control notes (PCNs), fixed					
NYSEG	1985 Series A, B & D	4.00% - 4.10%	2015	132,000	132,000
NYSEG	1994 Series B & C	3.00%	2013	101,000	-
NYSEG	2004 Series B & C	3.245% - 5.35%	2028 - 2034	70,000	170,000
NYSEG	2006 Series A	3.00%	2013	12,000	-
RG&E	1998 Series A	5.95%	2033	25,500	25,500
CMP	Industrial Development Authority of the state of New Hampshire Notes	5.375%	2014	19,500	19,500
Total unsecured pollution control notes, fixed				360,000	347,000
Unsecured PCNs, variable					
NYSEG	2006 Series A	.27%	2024	-	12,000
NYSEG	2005 Series A	.25%	2026	25	1,550
NYSEG	2004 Series A	.25%	2027	175	175
NYSEG	2004 Series C	.70%	2034	100,000	-
NYSEG	1994 Series B, C, D1 & D2	.17% - .24%	2029	-	175,000
RG&E	1997 Series A & B	.60%	2032	68,000	68,000
Total unsecured pollution control notes, variable				168,200	256,725
Various long-term debt					
NYSEG	Unsecured Notes	5.50% - 6.15%	2012 - 2023	600,000	600,000
CMP	Series E & F Medium Term Notes	5.10% - 7.00%	2011 - 2037	293,200	293,200
CNG	Medium Term Notes Series A, B, C & D	5.63% - 9.10%	2012 - 2037	-	150,000
Berkshire Gas	Unsecured Notes	4.76% - 9.60%	2011 - 2021	-	30,000
Chester	Promissory and Senior Notes	7.05% - 10.48%	2020	11,640	12,823
Total various long-term debt				904,840	1,086,023
Obligations under capital leases				15,537	18,897
Unamortized premium (discount) on debt, net				3,962	3,940
				2,228,389	2,832,435
Less debt due within one year, included in current liabilities				89,055	233,502
Total Other long-term debt				2,139,334	2,598,933
Long-term debt owed to affiliates					
Iberdrola USA	Unsecured Notes	5.90%	2013	300,000	300,000
Iberdrola USA	Unsecured Notes	7.08%	2019	350,000	1,050,000
Total Long-term debt owed to affiliates				650,000	1,350,000
Total Long-term Debt				\$2,789,334	\$3,948,933

⁽¹⁾ The first mortgage bonds are secured by liens on substantially all of the respective utility's properties.

Notes to Consolidated Financial Statements

In April 2009 the obligor on our \$1.3 billion of outstanding unsecured debt was transferred to Iberdrola International, a subsidiary of Iberdrola S.A. In exchange we entered into a debt agreement with Scottish Power, Limited (Scottish Power), another subsidiary of Iberdrola S.A., for \$1.05 billion and received an equity infusion of \$250 million from Iberdrola S.A. In May 2009 we borrowed an additional \$300 million from Scottish Power. On November 17, 2010, we repaid \$400 million of the debt, at a premium of \$82 million, and on December 29, 2010, we repaid \$300 million of the debt at a premium of \$46 million.

In June 2010 NYSEG converted \$113 million of variable-rate pollution control notes (PCNs) (1994 Series B & C and 2006 Series A) to fixed rate mandatory tender bonds due in 2013. Concurrent with that transaction NYSEG redeemed and did not remarket an additional \$74 million of its variable-rate PCNs (1994 Series D1 & D2) and terminated a \$190 million credit facility that had served as backstop liquidity for the variable rate PCNs prior to their conversion or redemption.

On December 30, 2010, RG&E completed a make-whole redemption of \$100 million of 6.95% Series TT first mortgage bonds, due in April 2011, at a premium of \$1.6 million, using excess cash on hand.

There are federal and state regulatory restrictions on our ability to borrow funds from our utility subsidiaries. While we may be able to borrow funds from our utility subsidiaries by obtaining regulatory approvals and meeting certain conditions, we do not expect to seek such loans. Iberdrola USA has no secured indebtedness and none of its assets are mortgaged, pledged or otherwise subject to lien. None of Iberdrola USA's debt obligations are guaranteed or secured by its subsidiaries.

As of December 31, 2010, NYSEG and RG&E had outstanding \$598 million of tax-exempt PCNs, of which \$278 million have coupons fixed to maturity, \$113 million are notes with a mandatory redemption date in 2013, \$40 million are notes with a mandatory redemption date in 2016, \$100 million are 7-day auction rate notes and \$68 million are 35-day auction rate notes. The notes with mandatory redemption dates in 2013 and 2016 have maturity dates in 2024 through 2032 and may be remarketed as tax-exempt bonds in a different interest rate mode after the mandatory redemptions.

As of December 31, 2009, NYSEG and RG&E had outstanding \$674 million of tax-exempt PCNs, of which \$277 million had coupons fixed to maturity, \$40 million were notes with a mandatory redemption date in 2016, \$100 million were auction rate notes under a special rate period where the rate was fixed until January 2010, \$187 million were weekly VRDNs, \$2 million were 7-day auction rate notes and \$68 million were 35-day auction rate notes.

In August 2008 NYSEG and RG&E began to place orders for their own accounts in the auctions. NYSEG and RG&E bid at each auction for 100% of the outstanding securities at the greater of the one-month London Interbank Offer Rate (LIBOR) or the Securities Industry and Financial Markets index. In August 2009 RG&E remarketed, as mandatory tender bonds, the securities it held pursuant to this program. NYSEG continued to bid on \$99 million of its auction rate notes during 2010 and 2009. At December 31, 2010, NYSEG held a total of \$99 million of those securities, and \$97 million at December 31, 2009.

In August 2009 RG&E converted PCN 1997 Series C and PCN 2004 Series A from auction rate to mandatory tender bonds, with 2016 tender dates. Those two series had been subject to the program described above wherein RG&E was bidding for the securities at auction. At the time of the conversion, RG&E held \$33 million of PCN 1997 Series C bonds and \$11 million of PCN 2004 Series A bonds. Also at the time of conversion, RG&E retired \$4.6 million of PCN 1997 Series C bonds in connection with the closing of its Russell Station. After the conversion, there

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were \$29 million of PCN 1997 Series C bonds and \$11 million of PCN 2004 Series A bonds outstanding.

As of February 11, 2011, NYSEG and RG&E were:

- Paying rates averaging 0.67% on the remaining \$168 million of auction rate notes for which they are not placing orders at auction.
- Paying rates averaging 0.27% on the \$99 million of auction rates notes on which they are placing orders at auction, substantially all of which are being held on account and have been accounted for as a redemption of long-term debt.

In June 2009 RG&E issued \$150 million Series YY first mortgage bonds bearing a coupon of 5.9% and with a maturity date of July 15, 2019. The proceeds of the issuance funded the redemption at maturity of \$100 million of Series B Medium Term Notes in October 2009. The remainder of the funds were used to reduce short-term debt and for general corporate purposes. RG&E settled its October 2009 hedge in June 2009 at a loss of \$20.9 million in connection with the pricing of those Series YY Bonds.

In May 2009 CMP issued \$150 million Series A first mortgage bonds bearing a coupon of 5.7% and with a maturity date of June 1, 2019. The proceeds of the issuance were used to reduce short-term debt and for general corporate purposes. CMP had entered into two derivative transactions – forward starting swaps – to hedge that financing transaction. CMP settled the hedges in May 2009 at a loss of \$19.9 million.

The above hedge losses are included in other comprehensive income and are being amortized to interest expense over the term of the related new debt that was issued.

At December 31, 2010, long-term debt, including sinking fund obligations and capital lease payments (in thousands) that will become due during the next five years is:

2011	2012	2013	2014	2015
\$89,055	\$155,606	\$451,862	\$22,724	\$134,755

Cross-default provisions: Iberdrola USA has a provision in its revolving credit facility, which provides that its default with respect to any other debt in excess of \$50 million will be considered a default under its revolving credit facility.

We are in compliance with all debt covenants as of December 31, 2010 and 2009.

Note 6. Bank Loans and Other Borrowings

Iberdrola USA is the sole borrower in a revolving credit facility providing maximum borrowings of up to \$300 million. Our operating utilities are joint borrowers in a revolving credit facility providing maximum borrowings of up to \$475 million in aggregate. 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. Both facilities have expiration dates in 2012 and require fees on undrawn borrowing capacity. One of our operating utilities has uncommitted bilateral credit agreements for a total of \$5 million. The two revolving credit facilities and the one bilateral credit agreement provided for consolidated maximum borrowings of \$780 million at December 31, 2010, and \$785 million at December 31, 2009. Iberdrola USA pays a facility fee of 6 basis points annually on its \$300 million revolver and each joint borrower pays a facility fee on its revolver sublimit, ranging from 6 to 10 basis points annually depending on the rating of its unsecured debt.

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We use drawings on our credit facilities to finance working capital needs, to temporarily finance certain refundings and for other corporate purposes. Drawings on Iberdrola USA's revolving credit facility are used to provide financing to its nonregulated subsidiaries and can be used to provide additional financing to its operating utilities. There was \$142 million of such short-term debt outstanding at December 31, 2010, and \$119 million outstanding at December 31, 2009. The weighted-average interest rate on short-term debt was .5% at December 31, 2010, and 2009. At February 10, 2011, there was \$152 million of such debt outstanding.

In our revolving credit facility we covenant not to permit, without the consent of the lender, our ratio of consolidated indebtedness to consolidated total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of consolidated indebtedness to consolidated 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 Iberdrola USA may maintain. Continued unremedied failure to comply with those covenants for 15 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 consolidated indebtedness to consolidated total capitalization pursuant to the revolving credit facility was 0.48 to 1.00 at December 31, 2010. We are not in default as of December 31, 2010.

In the revolving credit facility in which our operating utilities are joint borrowers, each joint borrower covenants not to permit, without the consent of the lender, its ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of consolidated indebtedness to total capitalization, the facility excludes from consolidated net worth the balance of 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 each borrower 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 for the party in default. We are not in default as of December 31, 2010.

Note 7. Redeemable Preferred Stock of Subsidiaries, Noncontrolling Interests

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

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At December 31, 2010 and 2009, our consolidated redeemable preferred stock, noncontrolling interests was:

Subsidiary and Series	Par Value per Share	Redemption Price per Share	Shares Authorized and Outstanding ⁽¹⁾	Amount (Thousands)	
				2010	2009
CMP, 6% Noncallable	\$100	-	2,347	\$235	\$518
CMP, 4.60%	100	101.00	11,664	1,167	3,000
CMP, 4.75%	100	101.00	9,028	903	5,000
CMP, 5.25%	100	102.00	-	-	5,000
NYSEG, 3.75%	100	104.00	78,379	7,838	7,838
NYSEG, 4.50% (1949)	100	103.75	11,800	1,180	1,180
NYSEG, 4.40%	100	102.00	7,093	709	709
NYSEG, 4.15% (1954)	100	102.00	4,317	432	432
NYSEG, Limited Voting Junior	1	-	1	-	-
RG&E, Limited Voting Junior	1	-	1	-	-
Berkshire Gas, 4.80%	100	100.00	-	-	118
CNG, 6.00%	100	110.00	-	-	410
CNG, 8.00% Noncallable	3.125	-	-	-	340
Total				\$12,464	\$24,545

⁽¹⁾ At December 31, 2010, Iberdrola USA and its subsidiaries had 6,632,519 shares of \$100 par value preferred stock, 16,800,000 shares of \$25 par value preferred stock, 1,000,000 shares of \$100 par value preference stock and 5,000,000 shares of \$1 par value preference stock authorized but unissued.

During 2010 we redeemed through tender offer \$11.2 million of various series of CMP's outstanding preferred stock.

Note 8. Tax Equity Investments

In April 2009 Iberdrola USA, through its subsidiary CNE Energy, acquired an interest in Aeolus Wind Power V LLC (Aeolus V) in exchange for \$305.4 million in cash. CNE Energy purchased its membership interest in Aeolus V from PPM Wind Energy LLC (PPM), an affiliate, which contributed its 100% ownership of various wind farms to Aeolus V.

The main characteristics of our investment in Aeolus V are as follows:

- PPM retains day-to-day management of the wind farms. Defined major decisions require consent from CNE Energy.
- As a minority shareholder, CNE Energy has the right to a substantial portion of the profits and tax credits generated by the wind farms up to the return level established at the beginning of the investment contract.
- CNE Energy initially holds a 50% interest in Aeolus V until it achieves a stipulated 7.5% return, after which it is entitled to maintain a 5% ownership interest.
- PPM has the option to purchase, at fair market value, CNE Energy's remaining residual equity interest, which is exercisable after CNE Energy achieves its agreed upon return.
- Whether or not CNE Energy obtains the agreed upon return depends on the economic performance of the wind farms. While PPM is bound to operate and maintain the facilities in an efficient manner and maintain appropriate insurance, it is not obligated to deliver cash to CNE Energy over and above the aforementioned profits and tax credits.

On December 17, 2010, we acquired, also through CNE Energy, an interest in Aeolus Wind Power VI LLC (Aeolus VI) in exchange for \$236.0 million in cash. CNE Energy purchased its membership interest in Aeolus VI from PPM, which contributed its 100% ownership of four wind farms to Aeolus VI. The partnership terms for Aeolus VI are similar to the terms described above for Aeolus V.

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CNE Energy uses an equity method referred to as Hypothetical Liquidation at Book Value (HLBV) to account for its investments in Aeolus V and in Aeolus VI. The application of that method results in CNE Energy recording a gain or loss on its investment based on the cash implications of a liquidation at book value, with a corresponding adjustment to the investment account. In addition, the HLBV method requires the tax effects related to Production Tax Credits (PTCs) (applies to Aeolus V only) and taxable income (loss) to be recorded in income taxes on the income statement. The primary difference in accounting for the Aeolus VI investment is that the Aeolus VI wind farms received cash grants from the federal government and consequently are not eligible for PTCs. Finally, the HLBV method requires a credit to accumulated deferred income taxes on the balance sheet and a debit to income taxes on the income statement for an amount representing the statutory rate applied to the difference between the tax basis and the book basis of the investment.

The following table shows the effects of our investments on our consolidated income statements and balance sheets:

Income statement for the year ended December 31, (Thousands)	2010	2009
Other (deductions), losses from tax equity investments	\$(62,805)	\$(579)
Income tax (benefit)	(83,258)	(14,746)
Total income statement benefit	\$20,453	\$14,167

Balance sheet at December 31, (Thousands)	2010	2009
Tax equity investment	\$478,016	\$304,821
Deferred tax liabilities, noncurrent	\$(151,149)	\$(32,964)
Prepaid income taxes	-	\$47,709

The following table provides summary financial information for Aeolus V and Aeolus VI:

Income statement for the year ended December 31, (Thousands)	2010	2009
Revenues*	\$84,958	\$51,070
Operating income	\$26,757	\$13,564
Net Income (Loss)	\$2,097	\$(1,048)

*Including PTCs for Aeolus V only.

Balance sheet at December 31, (Thousands)	2010	2009
Total Assets	\$2,050,155	\$686,386
Total Equity	\$1,700,201	\$674,948

Note 9. Commitments and Contingencies

Capital spending: We have commitments in connection with our capital spending program. We plan to invest approximately \$3.8 billion in our energy delivery infrastructure during the next five years, including amounts dedicated to electric reliability. We expect that about three-fourths of our capital spending will be paid for with internally generated funds and the remainder through the issuance of debt securities. The program is subject to periodic review and revision. Our capital spending will be primarily for the extension of energy delivery service, increased transmission capacity, necessary improvements to existing facilities and compliance with environmental requirements and governmental mandates.

On June 10, 2010, the Maine Public Utilities Commission granted approval for CMP's Maine Power Reliability Program (MPRP). The MPRP, expected to be completed in 2015, is a \$1.4

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billion project that will support the development of new renewable energy resources and help ensure long-term reliability for customers by increasing the capacity and efficiency of the New England transmission grid. The MPRP includes the construction of five new 345-kilovolt substations and related facilities linked by approximately 450 miles of new or rebuilt transmission lines. The project is the first upgrade of CMP's electricity grid in 40 years.

CMP's Advanced Metering Infrastructure (AMI) project, expected to be completed by the end of 2012, will provide its approximately 620,000 residential, commercial and industrial customers with information on electrical usage, allowing them to better manage energy use and cost. The new meters will also help CMP reduce costs, enhance system planning and pinpoint problems more quickly during outages. Reduced costs will result from operational efficiencies related to billing, account openings and closings, and credit and collections as well as instantaneous meter reading. The total estimated cost of the AMI project is \$166 million, and is being funded in part by a \$96 million grant from the U.S. Department of Energy (DOE), which was approved on April 26, 2010.

A Smart Grid Investment Grant (SGIG) was awarded to and is administered through the NYISO to the New York transmission owners, which include NYSEG and RG&E. The DOE awarded the grant to the NYISO, which concluded a sub-recipient agreement with NYSEG and RG&E on May 5, 2010. According to the grant the DOE will reimburse NYSEG and RG&E, through the NYISO, a total of approximately \$7.3 million for two projects at each company. NYSEG and RG&E will each spend a matching amount on the projects to bring the total value of the SGIG project to approximately \$14.6 million. The SGIG for each company consists of a project to add switched capacitors to its electric grid and another project to install phasor measurement units to the grid. The new equipment will improve the voltage stability of the New York electric grid and enhance the efficiency of power flows across New York, thereby reducing the cost and increasing the reliability of electric power for New York consumers. The companies expect to complete the projects by the end of July 2013.

On November 30, 2010, NYSEG executed a \$29.6 million cooperative funding agreement with the DOE as part of the agency's Smart Grid Demonstration Program. As a result, NYSEG launched a comprehensive feasibility study of a compressed air energy storage (CAES) facility. Compressed air would be pumped into a depleted underground salt cavern when low-cost, off-peak electricity is available to power the compressors. The compressed air could then be released to spin a turbine and generate electricity as needed, particularly during times of high customer demand. The feasibility study, to be completed in late 2011, will evaluate the technical and economic viability of CAES technology as an integral part of promoting stable electricity transmission system operation and the continued development of renewable energy. If the study confirms that CAES is feasible and economical, NYSEG would seek approval from state and federal agencies to proceed with construction of the plant with a target in-service date of late 2014.

Merger order: The Iberdrola merger order contained a capital expenditure condition for NYSEG and RG&E of an aggregate \$540 million during 2009 and 2010. In September 2009 we requested a limited waiver of the capital expenditure merger condition to allow us to spend our capital investment by 2011. The New York State Public Service Commission (NYPSC) denied the request in its order issued in April 2010. If NYSEG and RG&E were to spend less than the amount targeted in the merger order, they were obligated to provide a calculation of the revenue requirement effect resulting from the actual level of capital spending compared to the targeted amount, which could be returned to customers if ordered by the NYPSC.

NYSEG and RG&E were also afforded the opportunity to provide an assessment of other considerations, including the effects on customers associated with a lower level of capital spending, and to provide reasons why the total revenue requirement effect, as calculated, should

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not be returned to customers. NYSEG and RG&E made their required filing on January 31, 2011. In that filing they informed the NYPSC that their capital expenditures for 2009 and 2010 totaled \$546.7 million, or \$6.7 million more than the \$540 million merger condition, in the aggregate. NYSEG's electric and natural gas businesses and RG&E's natural gas business invested more than their required expenditure levels, but RG&E's electric business invested less than its required expenditure level. In their filing, the companies also demonstrate that a deferral of any revenue requirement effect (in the form of a customer credit/regulatory liability) is unnecessary because: 1) in aggregate NYSEG and RG&E met the capital expenditure condition, 2) they continue to provide safe and reliable service and 3) RG&E's lower electric capital expenditures resulted in a customer benefit due to lower revenue requirements.

Staff allegations concerning earnings sharing calculations: The New York Department of Public Service Staff (Staff) in its testimony and briefs in the merger proceeding alleged that NYSEG did not properly compute the amount due to customers under the electric ESM in NYSEG's electric rate plan that was in effect from 2002 through 2006. The Staff claimed that its preliminary analysis showed an additional \$67 million, including interest, that should have been allocated to customers. The Staff also raised issues with regard to the ESM under the RG&E electric rate plan currently in effect, but had not completed its analysis.

In its testimony on January 22, 2010, the NYPSC provided a detailed analysis of the issue. The Staff proposed a one-time charge of \$107 million relating to the companies' annual compliance filings including the calculation of the ESM and accounting for certain software costs. The companies vigorously dispute Staff's claims, but could not predict at that time how the matters would be resolved. As of December 31, 2009, the companies reduced their regulatory assets by \$40 million with an offsetting charge to other operating expense due to the uncertainty related to this proceeding. The recent rate case settlement, which the NYPSC approved on September 16, 2010, includes a resolution of those issues as part of the overall settlement. The amount the companies recognized in 2009 is approximately the same as the amount included in the settlement. (See Note 15.)

Homer City: In June 2008 NYSEG received a letter from subsidiaries of Edison Mission Energy regarding a notice of violation (NOV) from the U. S. Environmental Protection Agency (EPA) claiming that certain modifications to the Homer City Electric Generation Station (Homer City) during the time it was owned by NYSEG and Pennsylvania Electric Company (Penelec) were done in violation of EPA's new source review (NSR) regulations. Homer City was sold in 1999 to Edison Mission Energy by NYSEG and Penelec. Edison Mission Energy asserts that it is entitled to indemnification for certain fines, penalties and costs arising out of the violations alleged in the NOV under the terms of the Asset Purchase Agreement for Homer City. That appears to be the same claim Edison Mission Energy made to NYSEG in October 2000. NYSEG continues to believe that the costs sought by Edison Mission Energy are not liabilities of NYSEG and therefore did not retain liability for those material claims.

In September 2008 NYSEG, Penelec and Edison Mission Energy met with the EPA for a required NOV conference. EPA indicated at the meeting that it seeks a system-wide NSR settlement covering Edison Mission Energy's entire generation fleet, including a number of plants in Illinois, and would require installation of scrubbers on Homer City Units 1 and 2 as part of the settlement. In April 2009 EPA sent Edison Mission Energy a settlement proposal that included those controls, along with specified emissions caps, operational controls, improvement projects and fines. To our knowledge, Edison Mission Energy has not yet formally responded to EPA's proposal. While the EPA's settlement proposal substantially increases the potential value of the claim, NYSEG believes it has sound contractual defenses under the Asset Purchase Agreement. NYSEG estimates that its most likely cost exposure over the next several years will be primarily for legal

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defense costs and, potentially, a proportionate share of fines EPA may assess against Edison Mission Energy.

In connection with this matter, on January 6, 2011, the U. S. Justice Department filed a lawsuit on behalf of the EPA in the U.S. District Court for the Western District of Pennsylvania against current and former owners and operators of Homer City. NYSEG and Penelec are named in the suit, along with EME Homer City Generation, the current operator, and eight limited liability companies who own the plant by virtue of a sale and leaseback refinancing that occurred in 2001. NYSEG believes it has a number of sound defenses to the claims included in the lawsuit, including that the statute of limitations and equitable principles prohibit EPA from forcing NYSEG to pay for costly improvements at a plant it has not owned or operated in over 10 years. NYSEG cannot predict the nature or amounts of any potential fines or penalties.

Nonutility generator power purchase contracts: We expensed approximately \$71 million for NUG power in 2010 and \$218 million in 2009. We estimate that our NUG power purchases will total \$72 million in 2011, \$65 million in 2012, \$63 million in 2013, \$63 million in 2014 and \$64 million in 2015.

Nuclear entitlement power purchase contracts: In connection with our sales of nuclear generating assets in 2001 and 2004, we entered into four entitlement contracts under which we purchase electricity at a fixed contract price. We expensed approximately \$292 million for nuclear entitlement power in 2010 and \$290 million in 2009. We estimate that our nuclear entitlement power purchases will be \$281 million in 2011, \$191 million in 2012, \$203 million in 2013, \$87 million in 2014 and \$3 million in 2015.

Note 10. Environmental Liability

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

The EPA and various state environmental agencies, as appropriate, have notified us that we are among the potentially responsible parties that may be liable for costs incurred to remediate certain hazardous substances at 24 waste sites. The 24 sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the 24 sites, 15 sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites, four are included in Maine's Uncontrolled Sites Program, one is included on the Massachusetts Non-Priority Confirmed Disposal Site list and four 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 million related to 12 of the 24 sites. We have paid remediation costs related to the remaining 13 sites, and do not expect to incur any additional liability. We have recorded an estimated liability of \$3.6 million related to another 12 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. 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 52 sites where gas was manufactured in the past. Eight sites are included in the New York State Registry, eight sites are included in the New York Voluntary Cleanup Program, three sites are part of Maine's Voluntary Response Action Program and those two sites are part of Maine's Uncontrolled Sites

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Program. We have entered into consent orders with various environmental agencies to investigate and, where necessary, remediate 44 of the 52 sites.

Our estimate for all costs related to investigation and remediation of the 52 sites ranges from \$204 million to \$406 million at December 31, 2010. Our estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial action, changes in technology relating to remedial alternatives and changes to current laws and regulations.

The liability to investigate and perform remediation, as necessary, at the known inactive gas manufacturing sites was \$204 million at December 31, 2010, and \$213 million at December 31, 2009. 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 unless payments are fixed and determinable. Nearly all of our environmental liability accruals, which are expected to be paid through the year 2030, have been established on an undiscounted basis. Some of our operating utility subsidiaries have received insurance settlements during the last two years, which they accounted for as reductions to their related regulatory assets.

Note 11. Accounting for Derivative Instruments and Hedging Activities

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

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

Commodity price risk: Commodity price risk, due to volatility experienced in the wholesale energy markets, is a significant issue for the electric and natural gas utility industries. We manage this risk through a combination of regulatory mechanisms, such as the pass-through of the market price of electricity and natural gas to customers, and through comprehensive risk management processes. Those measures mitigate our commodity price exposure, but do not completely eliminate it. Owned electric generation and long-term supply contracts reduce our exposure to market fluctuations.

We have electricity commodity purchases and sales contracts for both capacity and energy (physical contracts) that have been designated and qualify for the normal purchases and normal sales exception in accordance with the accounting requirements concerning derivative instruments and hedging activities.

Effective beginning January 1, 2010, NYSEG and RG&E no longer offer fixed price service to their customers. They currently have a nonbypassable wires charge adjustment that allows them to pass through rates any changes in the market price of electricity. They use electricity contracts, both physical and financial, to manage fluctuations in electricity commodity prices in order to provide price stability to customers. We include the cost or benefit of those contracts in the amount expensed for electricity purchased when the related electricity is sold. We record changes in the fair value of electric hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations. At December 31, 2010, the gain recognized in regulatory liabilities was \$1.1 million for electricity derivatives. For the year ended December 31, the gain

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(loss) reclassified from regulatory assets into income, which is included in electricity purchased, was \$5.6 million for 2010 and \$(6.9) million for 2009.

All of our natural gas utilities have purchased gas adjustment clauses that allow them to recover through rates any changes in the market price of purchased natural gas, substantially eliminating their exposure to natural gas price risk. NYSEG and RG&E use natural gas futures and forwards to manage fluctuations in natural gas commodity prices in order to provide price stability to customers. We include the cost or benefit of natural gas futures and forwards in the commodity cost that is passed on to customers when the related sales commitments are fulfilled. We record changes in the fair value of natural gas hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations. At December 31, 2010, the loss recognized in regulatory assets was \$12.8 million for natural gas hedges. For the year ended December 31, the gain (loss) reclassified from regulatory assets into income, which is included in natural gas purchased, was \$(21.8) million for 2010 and \$50.1 million for 2009.

Energetix, Inc. and NYSEG Solutions, Inc. offer retail electric and natural gas service to customers in New York State and actively hedge the load required to serve customers that have chosen them as their commodity supplier. As of January 5, 2011, the energy marketing subsidiaries' expected fixed price loads were fully hedged for 2011. A fluctuation of \$1.00 per Megawatt-hour in the average price of electricity would change earnings less than \$100,000 in 2011. The percentage of hedged load for the energy marketing subsidiaries is based on load forecasts, which include certain assumptions such as historical weather patterns. Actual results could differ as a result of changes in the load compared to the load forecast.

Those two companies designate financial electricity contracts 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. We record the ineffective portion of any change in fair value of cash flow hedges to the income statement as either Other (Income) or Other Deductions, as appropriate.

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

	Electricity Contracts	Natural Gas Contracts	Other Fuel Contracts
Year to settle	Financial Mwhts	Financial Dths	Financial Gals
As of December 31, 2010			
2011	4,652,994	16,983,245	1,569,200
2012	1,146,240	1,532,202	-
2013	-	10,164	-
As of December 31, 2009			
2010	3,158,334	17,249,762	3,743,000
2011	192,469	1,648,254	-

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The location and amounts of derivative fair values in the balance sheet are:

As of December 31, (Thousands)	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments				
2010				
Commodity contracts:				
Electricity derivatives:				
Current	Current assets	\$9,829	Current liabilities	\$(234)
Long-term	Other assets	400	Other liabilities	(370)
Natural gas derivatives:				
Current	Current assets	-	Current liabilities	(13,117)
Long-term	Other assets	18	Other liabilities	(57)
Other contracts:	Current assets	95	Current liabilities	-
Total		\$10,342		\$(13,778)
2009				
Commodity contracts:				
Electricity derivatives:				
Current	Current assets	\$4,383	Current liabilities	\$(321)
Long-term	Other assets	431	Other liabilities	(184)
Natural gas derivatives:				
Current	Current assets	129	Current liabilities	(9,271)
Long-term	Other assets	11	Other liabilities	(309)
Other contracts:	Current assets	633	Current liabilities	(16)
Total		\$5,587		\$(10,101)

Notes to Consolidated Financial Statements

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 Accumulated OCI into Income	Gain (Loss) Reclassified from Accumulated OCI into Income	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives
Derivatives in Cash Flow Hedging Relationships (Thousands)	Effective Portion ⁽¹⁾	Effective Portion ⁽¹⁾		Ineffective Portion and Amount Excluded from Effectiveness Testing ⁽²⁾	
2010					
Interest rate contracts	-	Interest expense	\$(9,035)	Interest expense	-
Commodity contracts:					
Electricity derivatives	\$7,921	Electricity purchased	(11,304)	Other (Income)/ Other Deductions	\$(136)
Natural gas	3,390	Natural gas purchased	(3,549)		-
Other	206	Other direct costs	59		-
Total	\$11,517		\$(23,829)		\$(136)
2009					
Interest rate contracts	\$(86,359)	Interest expense	\$(6,149)	Interest expense	-
Commodity contracts:					
Electricity derivatives	16,946	Electricity purchased	(56,497)	Other (Income)/ Other Deductions	\$104
Other	(1,748)	Other direct costs	(3,974)		-
Total	\$(71,161)		\$(66,620)		\$104

⁽¹⁾ Changes in OCI are reported in after-tax dollars.

⁽²⁾ Ineffective portion of long-term power supply contracts that are designated as cash flow hedges.

The amount in OCI related to previously settled forward starting swaps, after tax and accumulated amortization, as of December 31, 2010, is a net loss of \$131.8 million as compared to a net loss of \$140.9 million for 2009.

As of December 31, 2010, we reported \$20.3 million in net derivative losses related to discontinued cash flow hedges. At December 31, 2010, \$8.2 million in gains are reported in OCI because the forecasted transaction is considered to be probable. We expect that \$8.0 million of gains in OCI will be reclassified into earnings within the next 12 months.

As of December 31, 2010, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted energy transactions was 22 months – through October 2012.

NYSEG, RG&E and our unregulated energy marketing subsidiaries Energetix, Inc. and NYSEG Solutions, Inc., face risks related to counterparty performance on hedging contracts due to counterparty credit default. We have developed a matrix of unsecured credit thresholds that are dependent on a counterparty's or the counterparty guarantor's applicable credit rating (normally

Notes to Consolidated Financial Statements

Moody's or S&P). When our exposure to risk for a counterparty exceeds the unsecured credit threshold, the counterparty is required to post additional collateral or we will no longer transact with the counterparty until the exposure drops below the unsecured credit threshold.

We have various master netting arrangements in the form of multiple contracts with various single counterparties that are subject to contractual agreements that provide for the net settlement of all contracts through a single payment. Those arrangements reduce our exposure to a counterparty in the event of default on or termination of any one contract. For financial statement presentation, we do not offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement. Under the master netting arrangements our obligation to return cash collateral was \$1.5 million at December 31, 2010, and \$1.7 million at December 31, 2009.

Certain of our derivative instruments contain provisions that require us to maintain on our debt an investment grade credit rating from each of the major credit rating agencies. If our debt were to fall below investment grade, it would be in violation of those provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position on December 31, 2010, is \$13.8 million for which we have posted collateral of \$22.1 million in the normal course of business. If the credit-risk-related contingent features underlying those agreements were triggered on December 31, 2010, we would receive a refund of \$8.3 million of collateral with our counterparties.

Note 12. 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 premiums and discounts.

December 31,	2010		2009	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
(Thousands)				
First mortgage bonds	\$774,952	\$836,830	\$1,121,921	\$1,180,627
Pollution control notes, fixed	\$367,443	\$363,084	\$351,811	\$350,573
Pollution control notes, variable	\$168,200	\$146,931	\$256,725	\$247,903
Various long-term debt	\$902,258	\$914,731	\$1,083,081	\$1,083,945
Long-term debt owed to affiliates	\$650,000	\$725,834	\$1,350,000	\$1,481,946

The carrying amounts for cash and cash equivalents, accounts 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. We value all variable rate debt at par as it approximates fair value, except for the auction rate securities issued by RG&E, which do not have an active market.

Notes to Consolidated Financial Statements

Assets and liabilities measured at fair value on a recurring basis

Description (Thousands)	Total	Fair Value Measurements at December 31, Using		
		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
2010				
Assets				
Noncurrent investments available for sale, auction rate securities	\$2,700	-	-	\$2,700
Noncurrent investments available for sale, other	44,520	\$44,520	-	-
Derivatives				
Commodity contracts				
Electricity	10,230	1,431	-	8,799
Natural gas	18	18	-	-
Other	94	-	-	94
Total	\$57,562	\$45,969	-	\$11,593
Liabilities				
Derivatives				
Commodity contracts:				
Electricity	\$604	\$370	-	\$234
Natural gas	13,174	13,174	-	-
Total	\$13,778	\$13,544	-	\$234
2009				
Assets				
Noncurrent investments available for sale, auction rate securities	\$2,735	-	-	\$2,735
Noncurrent investments available for sale, other	114,706	\$114,706	-	-
Derivatives				
Commodity contracts:				
Electricity	4,814	-	-	4,813
Natural gas	140	140	-	-
Other	633	-	-	633
Total	\$123,028	\$114,846	-	\$8,181
Liabilities				
Derivatives				
Commodity contracts:				
Electricity	\$505	-	-	\$505
Natural gas	9,580	\$9,580	-	-
Other	16	-	-	16
Total	\$10,101	\$9,580	-	\$521

We had no significant transfers to or from Level 1 and 2 during the year ended December 31, 2010. 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.

Notes to Consolidated Financial Statements

Valuation techniques: We measure the fair value of our noncurrent investments available for sale, auction rate securities based on the estimated probabilities of when the auction rate markets would return to historic interest rate levels and include the measurements in Level 3. During 2009 we reassessed the valuation of our investment in accordance with guidance related to decreased market activity. (See Note 1.)

We measure the fair value of our noncurrent investments available for sale, other 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, but also include some fixed income and equity investments.

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

- NYSEG, RG&E and our energy marketing subsidiaries enter into electric energy derivative contracts to hedge the forecasted purchases required to serve their electric load obligations. Those companies hedge their electric load obligations using derivative contracts that are settled based upon Locational Based Marginal Pricing published by the NYISO. In December 2009 NYSEG and RG&E began to hedge all of their electric load obligations in a NYISO location where an active market exists. The forward market prices used to value their open electric energy derivative contracts as of December 31, 2010, were readily available with no adjustment required and we include the fair value in Level 1. Our energy marketing subsidiaries, and NYSEG and RG&E for periods prior to December 31, 2009 enter into hedges for some NYISO locations where forward market price quotes are not actively traded and not readily available outright from market dealers. We derived forward market prices for these locations based on the historical relationship of prices in those locations to prices in locations where an active market exists. The resulting value represents the derived forward market price for each location, which we use to value the open derivative contracts. Because we adjust the quoted market prices for our own load characteristics, we include the fair values in Level 3.
- NYSEG, RG&E and our energy marketing subsidiaries enter into natural gas derivative contracts to hedge the forecasted purchases required to serve their natural gas load obligations. The forward market prices used to value our open natural gas derivative contracts are exchange-based prices for the identical derivative contracts traded actively on the New York Mercantile Exchange. Because we use prices quoted in an active market, we include those fair value measurements in Level 1.

Notes to Consolidated Financial Statements

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

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Auction Rate Securities	Derivatives, Net	Total
Balance, January 1, 2009	\$3,850	\$(130,742)	\$(126,892)
Total (losses) gains (realized/unrealized)			
Included in earnings	(1,115)	128,994	127,879
Included in other comprehensive income	-	(91,604)	(91,604)
Included in regulatory liabilities	-	57,089	57,089
Purchases, issuances and settlements	-	41,188	41,188
Transfers into Level 3	-	-	-
Balance, December 31, 2009	2,735	4,925	7,660
Total (losses) gains (realized/unrealized)			
Included in earnings	(35)	20,297	20,262
Included in other comprehensive income	-	(13,700)	(13,700)
Included in regulatory liabilities	-	-	-
Purchases, issuances and settlements	-	(2,863)	(2,863)
Transfers into of Level 3	-	-	-
Balance, December 31, 2010	\$2,700	\$8,659	\$11,359

Total gains for the period included in earnings attributable to the change in unrealized gains relating to assets still held at December 31,

2009	-	\$90	\$90
2010	-	-	-

The gains and losses included in earnings for the period (above), which are reported in the various categories indicated are:

(Thousands)	Electricity purchased	Other operating expense	Other Income	Other Deductions	Interest expense
Total gains (losses) included in earnings for year ended December 31,					
2009	\$103,088	\$19,667	\$90	\$(1,115)	\$6,149
2010	\$7,956	\$3,305	-	(35)	\$9,036

Notes to Consolidated Financial Statements

Note 13. Accumulated Other Comprehensive Income (Loss)

	Balance January 1, 2009	2009 Change	Balance December 31, 2009	2010 Change	Balance December 31, 2010
(Thousands)					
Net unrealized holding (losses) gains on investments, net of income tax (expense) of \$(749) for 2009 and \$(70) for 2010	\$(1,124)	\$1,124	-	\$(45)	\$(45)
Amortization of pension cost for nonqualified plans, net of income tax benefit (expense) of \$319 for 2009 and \$(769) for 2010	(9,428)	(567)	\$(9,995)	1,177	(8,818)
Unrealized gains (losses) on derivatives qualified as hedges:					
Unrealized gains during period on derivatives qualified as hedges, net of income tax (expense) of \$(28,529) for 2009 and \$(22,638) for 2010		42,631		41,345	
Reclassification adjustment for losses (gains) included in net income, net of income tax (benefit) expense of \$(23,969) for 2009 and \$24,007 for 2010		36,502		(36,558)	
Net unrecognized (losses) gains on settled cash flow treasury hedges, net of income tax benefit (expenses) of \$24,554 for 2009 and \$(3,726) for 2010		(36,066)		5,603	
Net unrealized (losses) gains on derivatives qualified as hedges	(129,798)	43,067	(86,731)	10,390	(76,341)
Accumulated Other Comprehensive (Loss) Income	\$(140,350)	\$43,624	\$(96,726)	\$11,522	\$(85,204)

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

Notes to Consolidated Financial Statements

Note 14. Retirement Benefits

We have funded noncontributory defined benefit pension plans that cover substantially all of our employees. The plans 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.

Obligations and funded status:

	Pension Benefits		Postretirement Benefits	
	2010	2009	2010	2009
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	\$2,333,547	\$2,240,741	\$529,945	\$497,995
Service cost	34,092	32,664	5,299	5,414
Interest cost	131,562	134,325	27,679	29,528
Plan participants' contributions	-	-	10,957	9,424
Curtailments	1,134	-	-	-
Plan amendments	10,886	125	(21,446)	-
Special termination benefits	37,351	-	-	-
Actuarial loss	166,733	66,046	22,442	29,084
Benefits paid	(158,769)	(140,354)	(49,482)	(44,534)
Federal subsidy on benefits paid	-	-	3,100	3,034
Disposition of obligations related to sale of natural gas companies	(350,116)	-	(57,082)	-
Benefit obligation at December 31	\$2,206,420	\$2,333,547	\$471,412	\$529,945
Change in plan assets				
Fair value of plan assets at January 1	\$2,253,753	\$1,995,905	\$146,309	\$112,433
Actual return on plan assets	262,786	396,287	18,123	27,094
Employer contributions	30,430	1,915	36,030	49,913
Plan participants' contributions	-	-	14,057	1,403
Benefits paid	(158,769)	(140,354)	(49,482)	(44,534)
Disposition of assets related to sale of natural gas companies	(237,001)	-	(17,039)	-
Fair value of plan assets at December 31	\$2,151,199	\$2,253,753	\$147,998	\$146,309
Funded status at December 31	\$(55,221)	\$(79,794)	\$(323,414)	\$(383,636)
Amounts recognized in the balance sheet				
December 31,	Pension Benefits		Postretirement Benefits	
	2010	2009	2010	2009
(Thousands)				
Noncurrent assets	\$87,336	\$145,723	-	-
Current liabilities	-	-	\$(6,545)	\$(6,391)
Noncurrent liabilities	(142,557)	(225,517)	(316,869)	(377,245)
	\$(55,221)	\$(79,794)	\$(323,414)	\$(383,636)

The change in benefit obligation and change in plan assets activity above reflect activity and the related decreases in the obligation and assets for the natural gas companies through November 16, 2010 (see Note 2). The amounts shown above for the disposition related to the sale of the natural gas companies were based on a roll forward of expenses, including amortization of gains and losses, for the period through November 16, 2010. Those plans were not remeasured as of the date of sale as the gas companies receive regulatory recovery of net periodic benefit costs through rates. Therefore, the sale of the gas companies did not result in gains or losses that should be recognized in our statement of operations.

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A Voluntary Early Retirement Program (VERP) was offered in the electric company plans during 2010, resulting in one-time charges for special termination benefits, and a one-time curtailment loss for CMP's Union Plan. NYSEG extended a retirement supplement, effective July 1, 2010, applicable to union employees who retire after age 59 between July 1, 2010, and June 30, 2015; the supplement was first effective July 1, 2005, and applied to retirements between July 1, 2005, and June 30, 2010. As a result of negotiations, CMP made changes to the retiree medical plan benefits for its union employees that include a cap on its contribution to the postretirement medical plans for employees who retire on or after July 1, 2013.

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

December 31, (Thousands)	Pension Benefits		Postretirement Benefits	
	2010	2009	2010	2009
Net loss	\$812,113	\$943,802	\$47,970	\$50,653
Prior service cost (credit)	\$29,630	\$26,044	\$(19,796)	\$(7,689)
Transition obligation	-	-	\$13,600	\$20,400

Our accumulated benefit obligation for all defined benefit pension plans was \$2.1 billion at December 31, 2010, and \$2.2 billion at December 31, 2009.

CMP's and NYSEG's postretirement benefits were partially funded at December 31, 2010. CMP's, CNG's, NYSEG's and SCG's postretirement benefits were partially funded at December 31, 2009.

The projected benefit obligation exceeded the fair value of pension plan assets for the CMP and RG&E plans as of December 31, 2010; and for the CMP, CNG, SCG, RG&E and Berkshire Gas plans as of December 31, 2009. The accumulated benefit obligation exceeded the fair value of pension plan assets for the CMP plan as of December 31, 2010; and for the CMP, CNG and SCG plans as of December 31, 2009. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets for those companies' plans for the relevant periods.

December 31, (Thousands)	Projected Benefit Obligation Exceeds Fair Value of Plan Assets		Accumulated Benefit Obligation Exceeds Fair Value of Plan Assets	
	2010	2009	2010	2009
Projected benefit obligation	\$785,851	\$1,049,408	\$331,295	\$594,083
Accumulated benefit obligation	\$725,962	\$971,240	\$300,039	\$544,709
Fair value of plan assets	\$643,294	\$823,891	\$210,564	\$387,141

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

Year ended December 31, (Thousands)	Pension Benefits		Postretirement Benefits	
	2010	2009	2010	2009
Net periodic benefit cost				
Service cost	\$34,092	\$32,664	\$5,299	\$5,415
Interest cost	131,562	134,325	27,679	29,528
Expected return on plan assets	(216,699)	(223,979)	(7,986)	(6,231)
Amortization of prior service cost (benefit)	3,507	4,001	(9,124)	(7,152)
Amortization of net loss	76,910	48,027	4,855	5,925
Special termination benefit charge	37,351	-	-	-
Curtailment charge	1,134	-	-	-
Amortization of transition obligation	-	-	6,800	6,800
Net periodic benefit cost (income)	\$67,857	\$(4,962)	\$27,523	\$34,285
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net (gain) loss	\$145,750	\$(106,262)	\$12,305	\$8,221
Prior service cost (benefit)	2,393	125	(21,446)	-
Amortization of net (loss)	(76,910)	(48,027)	(4,855)	(5,925)
Current year prior service cost	7,819	-	-	-
Amortization of prior service (cost) credit	(3,503)	(4,001)	9,124	7,152
Disposition of obligations related to sale of natural gas companies	(34,698)	-	(7,918)	-
Amortization of transition obligation	-	-	(6,800)	(6,800)
Total recognized in regulatory assets and regulatory liabilities	40,851	(158,165)	(19,590)	2,648
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	\$108,708	\$(163,127)	\$7,933	\$36,933

Net periodic benefit costs above include amounts related to the gas companies that were sold in 2010 (Thousands)	Pension Benefits	Postretirement Benefits
	January 1 through November 16, 2010	\$10,630
Year ended December 31, 2009	\$7,346	\$3,811

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. The amount of postretirement benefit cost deferred at December 31 was \$12 million for 2010 and \$31 million for 2009. We expect to recover any deferred postretirement costs by 2012. We are amortizing over 20 years the transition obligation for postretirement benefits that resulted from our adoption in 1992 of the accounting requirements concerning employers' accounting for postretirement benefits other than pensions.

Amounts expected to be amortized from regulatory assets or regulatory liabilities into net periodic benefit cost for the fiscal year ending December 31, 2011

(Thousands)	Pension Benefits	Postretirement Benefits
Estimated net loss	\$82,084	\$7,811
Estimated prior service cost	\$4,588	\$5,962
Estimated transition obligation	-	\$6,800

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We expect that no pension benefit or postretirement benefit plan assets will be returned to us during the fiscal year ended December 31, 2011.

Weighted-average assumptions used to determine benefit obligations at December 31,	Pension Benefits		Postretirement Benefits	
	2010	2009	2010	2009
Discount rate	5.00%	5.80%	5.00%	5.80%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%

As of December 31, 2010, we decreased our discount rate from 5.80% to 5.00%. The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rate by developing a yield curve derived from a portfolio of high grade noncallable bonds that closely matches the duration of the expected cash flows of our benefit obligations.

Weighted-average assumptions used to determine net periodic benefit cost for year ended December 31,	Pension Benefits		Postretirement Benefits	
	2010	2009	2010	2009
Discount rate	5.80%	6.10%	5.80%	6.10%
Expected long-term return on plan assets	8.75%	8.75%	-	-
Expected long-term return on plan assets - nontaxable trust	-	-	8.00%	8.00%
Expected long-term return on plan assets - taxable trust	-	-	4.80%	4.80%
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. The operating companies amortize unrecognized actuarial gains and losses either over 10 years from the time they are incurred or 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,

	2010	2009
Health care cost trend rate assumed for next year	7.8%	8.0%
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	2028	2028

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

	1% Increase	1% Decrease
(Thousands)		
Effect on total of service and interest cost	\$872	\$(756)
Effect on postretirement benefit obligation	\$11,895	\$(11,462)

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 benefits 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

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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 56% equity securities, 30% fixed income and 14% for all other types of investments. The target allocations within allowable ranges are further diversified into 28% large cap domestic equities, 7% medium and small cap domestic equities, 5% emerging markets, and 16% international equity securities. Fixed income investment targets and ranges are segregated into long dated corporate securities 17%, annuity contracts 5%, and 25 year zero coupon bonds 8%. All fixed income investments are in domestic securities. Other, alternative investment targets are 4% for real estate, and 10% 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 our pension benefits plan assets at December 31, 2010 and 2009, by asset category are:

Asset Category	Total	Fair Value Measurements at December 31, Using		
		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
2010				
Cash and cash equivalents	\$49,214	\$734	\$48,480	-
U.S. government securities	52,122	52,122	-	-
Common stocks	1,036,468	749,565	286,903	-
Registered investment companies	85,923	85,923	-	-
Corporate bonds	183,186	-	183,186	-
Preferred stocks	7,039	7,039	-	-
Common/collective trusts	351,408	-	76,476	\$274,932
Partnership/joint venture interests	96,624	-	-	96,624
Real estate investments	45,374	-	-	45,374
Other investments, principally annuity and fixed income	243,841	21,817	31,712	190,312
Total	\$2,151,199	\$917,200	\$626,757	\$607,242
2009				
Cash and cash equivalents	\$38,248	\$927	\$37,321	-
U.S. government securities	49,619	49,619	-	-
Common stocks	1,000,311	997,495	2,816	-
Registered investment companies	119,155	119,155	-	-
Corporate bonds	364,243	-	364,243	-
Preferred stocks	6,916	6,916	-	-
Common/collective trusts	358,201	-	62,557	\$295,644
Partnership/joint venture interests	93,269	-	-	93,269
Real estate investments	40,618	-	-	40,618
Other investments, principally annuity and fixed income	183,173	20,784	31,265	131,124
Total	\$2,253,753	\$1,194,896	\$498,202	\$560,655

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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.

(Thousands)	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)					Total
	Corporate Bonds	Common/Collective Trusts	Partnership/Joint Venture Interests	Real Estate Investments	Other Investments	
Balance, December 31, 2008	\$112	\$432,918	\$106,819	\$58,687	\$156,149	\$754,685
Actual return on plan assets:						
Relating to assets still held at the reporting date	-	2,557	2,565	-	-	5,122
Relating to assets sold during the year	-	112,364	3,869	(19,345)	-	96,888
Purchases, sales and settlements	(112)	(252,195)	(19,984)	1,276	(25,025)	(296,040)
Transfers into and/or out of Level 3	-	-	-	-	-	-
Balance, December 31, 2009	-	295,644	93,269	40,618	131,124	560,655
Actual return on plan assets:						
Relating to assets still held at the reporting date	-	4,678	-	-	110	4,788
Relating to assets sold during the year	-	41,218	3,207	4,163	510	49,098
Purchases, sales and settlements	-	(66,608)	148	593	58,568	(7,299)
Transfers into and/or out of Level 3	-	-	-	-	-	-
Balance, December 31, 2010	-	\$274,932	\$96,624	\$45,374	\$190,312	\$607,242

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Our postretirement benefits plan assets are held with two trustees 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 12% 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 56% equity securities, 37% fixed income and 7% for all other types of investments. The target allocations within allowable ranges are further diversified into 30% large cap domestic equities, 7% medium and small cap domestic equities, 13% international developed market and 6% emerging market equity securities. Fixed income investment targets and ranges are segregated into core fixed income at 30%, global high yield fixed income 4% and international developed market debt 3%. Other, alternative investment targets are 4% for real estate and 3% absolute return. 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 our other postretirement benefits plan assets at December 31, 2010 and 2009, by asset category are:

Asset Category (Thousands)	Total	Fair Value Measurements at December 31, Using		
		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
2010				
Money market funds	\$7,907	\$7,907	-	-
Mutual funds, fixed	49,100	49,100	-	-
Mutual funds, equity	90,964	90,964	-	-
Other investments	27	27	-	-
Total assets measured at fair value	\$147,998	\$147,998	-	-
2009				
Money market funds	\$4,214	\$4,214	-	-
Mutual funds, fixed	51,061	51,061	-	-
Mutual funds, equity	82,089	82,089	-	-
Other investments	3,109	1,865	\$774	\$470
Total assets measured at fair value	\$140,473	\$139,229	\$774	\$470
Whole life insurance contract	5,836			
Total postretirement benefits plan assets	\$146,309			

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

- Money market funds and Mutual funds, fixed and equity – based upon quoted market prices, which represent the NAV of the shares held.
- Other investments – these are primarily 401(h) investments that are an allocation of pension Master Trust investments.

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The whole life insurance contract is presented at the contract value at December 31, 2009, which is not a fair value measurement.

Diversified equity securities did not include any Iberdrola common stock at December 31, 2010.

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 \$38 million to our pension benefit plans and \$3 million to our other postretirement benefit plans in 2011.

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

(Thousands)	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
2011	\$145,440	\$39,538	\$3,069
2012	\$147,689	\$40,136	\$3,615
2013	\$151,763	\$40,672	\$3,933
2014	\$154,565	\$41,258	\$4,234
2015	\$156,662	\$41,552	\$4,512
2016 - 2020	\$795,935	\$206,194	\$26,406

Note 15. NYSEG and RG&E Rate Proceedings

In September 2009 NYSEG and RG&E filed rate cases with the NYPSC requesting approval to increase the rates the companies charge to deliver electricity and natural gas by a total of \$383 million. The rate filings requested an allowed rate of return on equity (ROE) of 11.43% applied to an equity ratio of 48%.

On September 16, 2010, the NYPSC approved a new rate plan for electric and natural gas service provided by the companies effective August 26, 2010, through December 31, 2013. Major provisions of the plan include:

- Approximate delivery rate increases as follows (in millions of dollars):

Rate year ending August 31,	NYSEG Electric	NYSEG Natural Gas	RG&E Electric	RG&E Natural Gas
2011	\$16.4 (2.5%)	\$9.9 (6.0%)	\$15.6 (4.1%)	\$10.9 (8.0%)
2012	\$27.8 (4.2%)	\$10.3 (5.8%)	\$10.2 (2.6%)	\$10.9 (7.3%)
2013	\$29.3 (4.3%)	\$10.5 (5.6%)	\$13.2 (3.2%)	\$11.0 (6.9%)

- The delivery rate increases were moderated and levelized through the use of \$311 million in positive benefits adjustments (PBAs), including \$36 million of carrying costs, that were required and set aside for the benefit of ratepayers when Iberdrola, S.A. acquired NYSEG and RG&E in 2008. The PBAs will be utilized as follows: in September 2010 a one-time write-off of \$82.5 million, which is offset by write-offs of deferred storm costs of \$76.4 million, \$6.1 million in property tax and amortizations during the rate years ended August 31 of: \$88.0 million in 2011, \$54.4 million in 2012 and \$26.9 million in 2013; and \$8.5 million in the four months ended December 31, 2013. The balance of \$50.2 million will be amortized at a later time.
- Rates were set to allow for the recovery, over the 40 months of the rate plan, of regulatory assets of \$126.0 million net of regulatory liabilities.

Notes to Consolidated Financial Statements

- The recovery includes \$32.4 million for the cost to achieve efficiency initiatives through workforce reductions (see Note 1). The rate increases were moderated with \$19.2 million in annual net savings from workforce reduction and related labor cost-cutting initiatives, as well as a one percent annual productivity adjustment.
- To resolve a number of disputed items related to the annual compliance filings, including the calculation of earnings sharing accruals, NYSEG reduced its environmental reserve by \$23 million and its deferred storm costs by \$4 million, and added \$6 million to the Asset Sale Gain Account (ASGA). RG&E absorbed \$20 million of prior loss from interest rate hedges and added \$6.5 million to the ASGA. In December 2009 NYSEG established a reserve of \$30 million and RG&E established a reserve of \$10 million for those contingencies, which were reversed as a result of the rate decision.
- The revenue requirements are based on a 10% allowed ROE applied to an equity ratio of 48 percent. Beginning in 2011, if earnings exceed the allowed return, a tiered earnings sharing mechanism (ESM) will capture a portion of the excess for the benefit of ratepayers. The ESM is subject to specified downward adjustments if the companies fail to meet certain reliability and customer service measures.
- Key components of the rate plan include electric reliability performance mechanisms, natural gas safety performance measures, customer service quality metrics and targets, and electric distribution vegetation management programs that establish threshold performance targets. There will be downward revenue adjustments if the companies fail to meet the targets.
- Low-income program budgets have been increased to approximately \$19.2 million. All home energy assistance program recipients will be eligible for the program.
- New revenue decoupling mechanisms (RDMs), intended to remove company disincentives to promote increased energy efficiency were established. Under the RDMs, electric revenues are based on revenue per customer class rather than billed revenue, while natural gas revenues are based on revenue per customer. Any shortfalls (excesses) between billed revenues and allowed revenues will be accrued for future recovery (refund).

Under the merger order prescribed by the NYPSC, NYSEG and RG&E customers were to receive \$275 million in PBAs. Those benefits were to be used, over time, to either reduce rates or moderate requested rate increases. Conditions were also established to ensure that ratepayers receive a portion of any added benefits associated with synergy savings and efficiency gains produced by the transaction. We recorded the PBAs in September 2008, in accordance with the merger order, as a regulatory liability with an offsetting charge to income, and accrued a carrying cost at the pretax rate allowed by the NYPSC until used for the benefit of customers. Carrying costs, which are included in interest expense, were \$13 million in 2010 and \$18 million in 2009.

Notes to Consolidated Financial Statements

As part of the new rate plan, the companies offset the PBAs and other regulatory liabilities against certain regulatory assets. In addition, the companies established a regulatory asset to allow recovery of the special termination benefits and severance costs associated with workforce reductions (see Note 1), and wrote off some undepreciated fixed assets and reversed a reserve established in December 2009. The effects on net income of the various adjustments to regulatory assets and regulatory liabilities are:

Description	Income Statement Line Item	Increase (Decrease) in Net Income
<i>(Millions)</i>		
Elimination of annual compliance filing reserve regulatory liability	Electric operating revenue	\$40.0
ASGA	Electric operating revenue	(6.5)
Interim period adjustment	Electric operating revenue	2.8
	Total Electric Operating Revenue	36.3
Elimination of PBA regulatory liability	Other operating expenses	82.4
Elimination of storm costs regulatory assets	Maintenance	(81.4)
Elimination of environmental reserve regulatory asset	Other operating expenses	(23.0)
Establishment of cost to achieve efficiency regulatory asset*	Other operating expenses	32.9
Elimination of property taxes	Other taxes	(5.1)
	Net effects of new rate case on operating and maintenance	5.8
Property, plant and equipment	Depreciation and amortization	(10.8)
	Total Operating Expenses	(5.0)
	Income Before Income Taxes	31.3
Income tax effect	Income Taxes	(12.4)
	Net Income	\$18.9

*Relates to the recovery of special termination benefit costs (see Note 1).

Beginning on August 26, 2010, NYSEG will amortize \$15.2 million per year of a theoretical excess depreciation reserve of \$303.9 million; and beginning on September 1, 2012, RG&E will amortize \$5.25 million per year of its theoretical excess depreciation reserve of \$105 million. Both amortization amounts reflect a 20-year amortization period. Theoretical excess depreciation is the difference between actual accumulated depreciation taken to date and a theoretical reserve. The actual accumulated depreciation is the result of depreciation rates allowed in prior rate orders based on estimates of useful lives and net salvage values as determined in those cases. The theoretical reserve is the amount that would have accumulated if the depreciation rates in the new rate plan had been in place for the entire useful lives of the affected assets. Differences between the actual reserve and the theoretical reserve are normal aspects of utility ratemaking. The usual treatment is to flow any excess or deficiency back as an adjustment to depreciation expense over the remaining life of the property. However, in accordance with the new rate plan, NYSEG and RG&E will moderate electric rates by recording the theoretical reserve amortization as a debit to accumulated depreciation and a credit to other revenues, and normalize the amortization from a tax perspective.

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Note 16. Sale of NYSEG's Seneca Lake Storage Facility

In January 2010 NYSEG entered into an agreement to sell its Seneca Lake Storage facility and related assets for \$65 million. The carrying amount of the facility assets is separately stated on the balance sheet and was approximately \$33 million at December 31, 2010, and December 31, 2009. The sale of the facility is contingent on receiving appropriate regulatory approvals from the NYPSC. The FERC issued an order on August 26, 2010, authorizing the parties to proceed with the transaction, subject to compliance requirements that the buyer must attend to but that should not delay the closing. NYSEG is unable to predict at this time when final approval for the transaction will be obtained, or when the closing will occur. Because current rates include recovery of depreciation on these assets, we are continuing to record depreciation expense even though we have classified the assets as held for sale. Depreciation expense for 2010 was \$1.5 million.

Note 17. Sale of Fossil Fuel Generation Assets

Iberdrola, in connection with receiving authorization from the NYPSC in September 2008 to acquire Energy East, agreed to sell certain fossil fuel generation assets owned by either RG&E or Cayuga Energy, Inc. (Cayuga). In its order authorizing the acquisition, the NYPSC directed Iberdrola and the other petitioners in the acquisition proceeding to develop, in collaboration with interested parties, a divestiture plan for the fossil fuel generation assets. Iberdrola and Energy East filed the divestiture plan with the NYPSC in November 2008. The NYPSC issued an order approving the divestiture plan as filed, effective November 17, 2009.

The divestiture plan required the generation assets to be sold at auction in a two-stage process, as well as extensive consultation with the NYPSC Staff concerning the auction process. The auction process would be suspended, but not terminated, if bids obtained were priced at less than the current net book value of the assets (approximately \$14 million at December 31, 2009). Iberdrola/RG&E would then petition the NYPSC for guidance on the next steps to be taken. On December 29, 2010, we filed a petition with the NYPSC for permission to terminate the auction process.

As a result of the unsuccessful auction process we performed an impairment test of all long-lived assets not included in regulated rates. We determined that no impairment of long-lived assets had occurred.

We have determined that the criteria are not met in order to classify the assets as held for sale. In addition, the net book value of the assets is immaterial to our balance sheet.