nationalgrid

New England Power Company

Financial Statements

For the years ended March 31, 2011 and March 31, 2010

NEW ENGLAND POWER COMPANY

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Report of Independent Auditors

To the Stockholders and Board of Directors of
New England Power Company:

In our opinion, the accompanying balance sheets and related statements of income, of other comprehensive income, of retained earnings, of capitalization and of cash flows present fairly, in all material respects, the financial position of New England Power Company (the "Company") at March 31, 2011 and 2010, 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. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

New England Power Company engages in significant transactions with affiliates.

PricewaterhouseCoopers LLP

June 30, 2011

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NEW ENGLAND POWER COMPANY
BALANCE SHEETS

(in thousands of dollars)	March 31, **2011**	March 31, 2010
ASSETS		
Current assets		
Cash and cash equivalents	**$ 11,594**	$ 102
Restricted cash	**36**	36
Accounts receivable	**38,499**	37,846
Accounts receivable from affiliates, net	**-**	24,682
Intercompany moneypool	**107,038**	144,675
Materials and supplies, at average cost	**4,494**	4,278
Derivative contracts	**226**	508
Current regulatory assets	**45,390**	48,432
Prepaids	**21,746**	49,862
Current deferred income tax assets	**6,828**	-
Total current assets	**235,851**	310,421
Equity investments	**2,184**	2,570
Property, plant and equipment, net	**1,392,722**	1,249,697
Deferred charges and other assets		
Regulatory assets	**312,050**	385,933
Goodwill	**337,614**	337,614
Derivative contracts	**-**	604
Other deferred charges	**9,746**	10,475
Total deferred charges and other assets	**659,410**	734,626
Total assets	**$ 2,290,167**	$ 2,297,314

The accompanying notes are an integral part of these financial statements.

NEW ENGLAND POWER COMPANY
BALANCE SHEETS

(in thousands of dollars, except per share and number of shares data)	March 31, 2011	March 31, 2010
LIABILITIES AND CAPITALIZATION		
Current liabilities		
Accounts payable	**$ 35,830**	$ 26,337
Accounts payable to affiliates, net	**21,233**	-
Customer deposits	**667**	741
Interest accrued	**67**	162
Regulatory liabilities - derivatives	**226**	-
Current portion of accrued Yankee nuclear plant costs	**14,740**	14,939
Current portion of purchased power obligations	**2,521**	2,521
Current derivative contracts	**28,130**	31,480
Current portion of deferred income tax liabilities	**-**	2,497
Other current liabilities	**6,031**	6,680
Total current liabilities	**109,445**	85,357
Deferred credits and other liabilities		
Regulatory liabilities	**94,371**	135,924
Deferred income tax liabilities	**308,615**	244,106
Postretirement benefits and other reserves	**8,067**	24,392
Accrued Yankee nuclear plant costs	**72,655**	66,665
Purchased power obligations	**5,212**	7,312
Derivative contracts	**131,708**	161,142
Other deferred liabilities	**58,043**	57,172
Total deferred credits and other liabilities	**678,671**	696,713
Capitalization		
Common stock, par value $20 per share,	**72,398**	72,398
Authorized - 6,449,896 shares		
Issued and outstanding - 3,619,896 shares		
Cumulative preferred stock, par value $100 per share	**1,112**	1,112
Authorized - 80,140 shares		
Issued and outstanding - 11,117 shares		
Additional paid-in capital	**733,545**	733,545
Retained earnings	**284,332**	297,595
Accumulated other comprehensive income	**333**	265
Total stockholder's equity	**1,091,720**	1,104,915
Long-term debt	**410,331**	410,329
Total capitalization	**1,502,051**	1,515,244
Total liabilities and capitalization	**$ 2,290,167**	$ 2,297,314

The accompanying notes are an integral part of these financial statements.

NEW ENGLAND POWER COMPANY
STATEMENTS OF INCOME

(in thousands of dollars)	Years Ended March 31, **2011**	2010
Operating revenues	**$ 353,124**	$ 384,419
Operating expenses		
Electricity purchased	**60,056**	71,438
Contract termination and nuclear unit shutdown charges	**16,540**	20,001
Operations and maintenance	**96,385**	89,379
Depreciation	**33,480**	30,405
Amortization of regulatory assets and stranded costs	**870**	8,836
Other taxes	**27,008**	22,449
Total operating expenses	**234,339**	242,508
Operating income	**118,785**	141,911
Other income and (deductions)		
Interest on long-term debt	**(4,215)**	(5,704)
Other interest, including affiliate interest	**(2,144)**	3,360
Other income (deductions)	**1,986**	(1,583)
Total other deductions	**(4,373)**	(3,927)
Income taxes		
Current	**(10,814)**	(26,335)
Deferred	**53,422**	82,105
Total income taxes	**42,608**	55,770
Net income	**$ 71,804**	$ 82,214

The accompanying notes are an integral part of these financial statements.

NEW ENGLAND POWER COMPANY
STATEMENT OF CASH FLOWS

(in thousands of dollars)	Years Ended March 31, **2011**	2010
Operating activities:		
Net income	$ **71,804**	$ 82,214
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation	**33,480**	30,405
Amortization of regulatory assets and stranded costs	**870**	8,836
Provision for deferred income taxes	**53,422**	82,105
Income from equity investments	**(398)**	(1,046)
Other non-cash items	**69**	602
Net prepayments and other amortizations	**1,260**	1,574
Net pension and other postretirement expense	**(11,780)**	(17,059)
Net environmental charges	**(209)**	(822)
Changes in operating assets and liabilities:		
Accounts receivable, net	**(653)**	711
Materials and supplies	**(216)**	(423)
Accounts payable and accrued expenses	**6,474**	(12,328)
Prepaid taxes and accruals	**-**	(3,167)
Intercompany receivable/payable	**45,915**	(15,241)
Other, net	**26,535**	(29,408)
Net cash provided by operating activities	**226,573**	126,953
Investing activities:		
Capital expenditures	**(157,545)**	(135,829)
Other, including cost of removal	**(10,106)**	(214)
Increase in moneypool	**37,637**	133,950
Net cash used in investing activities	**(130,014)**	(2,094)
Financing activities:		
Dividends paid on common and preferred stock	**(85,067)**	(125,067)
Net cash used in financing activities	**(85,067)**	(125,067)
Net increase (decrease) in cash and cash equivalents	**11,492**	(208)
Cash and cash equivalents, beginning of year	**102**	310
Cash and cash equivalents, end of year	$ **11,594**	$ 102
Supplemental disclosures of cash flow information:		
Interest paid	$ **5,415**	$ 5,197
Taxes (refunded) paid	$ **(53,654)**	$ 2,369
Dividends received from equity investments	$ **335**	$ 859
Capital-related accruals in accounts payable	$ **(2,924)**	$ 7,280

The accompanying notes are an integral part of these financial statements.

NEW ENGLAND POWER COMPANY
STATEMENTS OF OTHER COMPREHENSIVE INCOME

(in thousands of dollars)	Years Ended March 31, 2011	2010
Net income	**$ 71,804**	$ 82,214
Other comprehensive income (loss), net of taxes:		
Unrealized gains on investments	**254**	719
Reclassification adjustment for loss included in net income	**(186)**	(117)
Total other comprehensive income	**68**	602
Comprehensive income	**$ 71,872**	$ 82,816
Related tax expense (benefit):		
Unrealized gains on investments	**$ 164**	$ 464
Reclassification adjustment for loss included in net income	**(120)**	(76)
Total tax expense	**$ 44**	$ 388

STATEMENTS OF RETAINED EARNINGS

(in thousands of dollars)	March 31, 2011	2010
Retained earnings, beginning of year	**$ 297,595**	$ 340,448
Net income	**71,804**	82,214
Dividends declared on common and preferred stock	**(85,067)**	(125,067)
Retained earnings, end of year	**$ 284,332**	$ 297,595

The accompanying notes are an integral part of these financial statements.

NEW ENGLAND POWER COMPANY
STATEMENTS OF CAPITALIZATION

(in thousands of dollars except per share and number of shares data)			March 31, **2011**	March 31, 2010		March 31, **2011**		March 31, 2010
Common stockholder's equity								
Common stock, par value $20 per share,					$	**72,398**	$	72,398
Authorized			**6,449,896**	6,449,896				
Issued and outstanding			**3,619,896**	3,619,896				
Cumulative preferred stock, par value $100 per share						**1,112**		1,112
Authorized			**80,140**	80,140				
Issued and outstanding			**11,117**	11,117				
Additional paid-in capital						**733,545**		733,545
Retained earnings						**284,332**		297,595
Accumulated other comprehensive income						**333**		265
Total stockholder's equity						**1,091,720**		1,104,915
Long-term debt								
Pollution control revenue bonds								
Series	Rate%	Maturity						
CDA (a)	Variable	October 15, 2015				**38,500**		38,500
MIFA 1 (b)	Variable	March 1, 2018				**79,250**		79,250
BFA 1 (c)	Variable	November 1, 2020				**135,850**		135,850
BFA 1 (c)	Variable	November 1, 2020				**50,600**		50,600
MIFA 2 (b)	Variable	October 1 2022				**106,150**		106,150
Unamortized discounts						**(19)**		(21)
Amount						**410,331**		410,329
Total capitalization					$	**1,502,051**	$	1,515,244

(a) CDA = Connecticut Development Authority
(b) MIFA = Massachusetts Industrial Finance Authority (now known as Massachusetts Development Finance Agency)
(c) BFA = Business Finance Authority of the State of New Hampshire

The accompanying notes are an integral part of these financial statements.

NOTES TO FINANCIAL STATEMENTS

Note 1. Summary of Significant Accounting Policies

A. Nature of Operations

New England Power Company's (the "Company", "we", "us" and "our") business is the transmission of electricity in wholesale quantities to other electric utilities. Approximately 80% of the Company's local transmission service is provided to the following wholly-owned subsidiaries of National Grid USA ("NGUSA"): Granite State Electric Company, Massachusetts Electric Company, Nantucket Electric Company and The Narragansett Electric Company. The Company owns non-controlling interests in three companies which own nuclear generating facilities that are permanently retired and are conducting decommissioning operations.

The Company is a wholly-owned subsidiary of NGUSA, a utility holding company with regulated subsidiaries engaged in the generation of electricity and the transmission, distribution and sale of both natural gas and electricity. NGUSA is an indirectly-owned subsidiary of National Grid plc, a public limited company incorporated under the laws of England and Wales.

B. Basis of Presentation

The Company's accounting policies conform to accounting principles generally accepted in the United States of America ("GAAP"), including the accounting principles for rate-regulated entities.

The Company applies the provisions of the Financial Accounting Standards Board ("FASB") guidance related to the accounting for the effects of certain types of regulation, which requires regulated entities, in appropriate circumstances, to establish regulatory assets or liabilities, and thereby defer the statement of income impact of certain charges or revenues because they are expected to be collected or refunded through future customer billings.

The accounts of the Company are maintained in accordance with the Uniform System of Accounts prescribed by the regulatory bodies having jurisdiction.

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates.

C. Accounting for the Effects of Rate Regulation

The Federal Energy Regulatory Commission ("FERC") and the Massachusetts Department of Public Utilities ("DPU") provide the final determination of the rates we charge our customers. In certain cases, the actions of the FERC or the DPU would result in an accounting treatment different from that used by non-regulated companies to determine the rates we charge our customers. In this case, the Company is required to defer the recognition of costs (a regulatory asset) or the recognition of obligations (a regulatory liability) if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in future rates.

In the event the Company determines that its net regulatory assets are not probable of recovery, the Company would be required to record an after-tax, non-cash charge against income for any remaining regulatory assets and liabilities. The resulting charge could be material to the Company's reported financial condition and results of operations.

D. Revenue Recognition

The Company has two primary sources of revenue: transmission and stranded cost recovery. Much of the Company's revenues are derived from affiliated companies. Transmission revenues are based on a formula rate that recovers the Company's actual costs plus a return on investment. Stranded cost recovery revenues are collected through a contract termination charge ("CTC"), which is billed to former wholesale customers of the Company in connection with the Company's divestiture of its electricity generation investments.

E. Property, Plant and Equipment

Property, plant, and equipment are stated at original cost. The cost of additions to property, plant and equipment and replacements of retirement units of property are capitalized. Costs include direct material, labor, overhead and allowance for funds used during construction ("AFUDC"). Replacement of minor items of property, plant and equipment and the cost of current repairs and maintenance are charged to expense. Whenever property, plant and equipment is retired, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation.

F. Goodwill and Other Intangible Assets

Goodwill
Goodwill represents the excess of purchase price of a business combination over the fair value of the tangible and intangible assets acquired, net of the fair value of liabilities assumed and the fair value of any non-controlling interest in the acquisition. The Company tests goodwill for impairment on an annual basis and on an interim basis when certain events or circumstances exist.

The goodwill impairment analysis is comprised of two steps. In the first step, the Company compares the fair value of each reporting unit to its carrying value. The Company can consider both an income-based approach using projected discounted cash flows and a market-based approach using valuation multiples of comparable companies to determine fair value. The Company's estimate of fair value of each reporting unit is based on a number of subjective factors including: (i) the appropriate weighting of valuation approaches (income-based approach and market-based approach), (ii) estimates of the future revenue and cash flows, (iii) discount rate for estimated cash flows, (iv) selection of peer group companies for the market-based approach, (v) required levels of working capital, (vi) assumed terminal value, (vii) the time horizon of cash flow forecasts and (viii) control premium.

If the fair value of the reporting unit exceeds the carrying value of the net assets assigned to that unit, goodwill is not considered impaired and no further analysis is required to be performed. If the carrying value of the net assets assigned to the reporting unit exceeds the fair value, then a second step is performed to determine the implied fair value of the reporting unit's goodwill. If the carrying value of a reporting unit's goodwill exceeds its implied fair value, then an impairment charge equal to the difference is recorded.

The Company utilizes a discounted cash flow approach incorporating its most recent business plan forecasts together with a projected terminal year calculation in the performance of the annual goodwill impairment test. Critical assumptions used in the Company's analysis include a discount rate of 5.9% and a terminal year growth rate of 2.4% based upon expected long-term average growth rates. Within its calculation of forecasted returns, the Company made certain assumptions with respect to the amount of pension and environmental costs to be recovered in future periods. Should the Company not continue to receive the same level of recovery in these areas, the result could be a reduction in fair value of the Company, which in turn could give rise to an impairment of goodwill. Our forecasts assume long-term recovery and rate of returns that are in line with historical levels within the utility industry. The resulting fair value of the annual analysis determined that no adjustment of the goodwill carrying value was required.

G. Cash and Cash Equivalents
Company classifies short-term investments that are highly liquid and have maturities of three months or less at the date of purchase as cash equivalents. These short-term investments are carried at cost which approximates fair value.

H. Restricted Cash

Restricted cash consists of special deposits the Company is required to have available as security on its insurance policies for property and dental coverage. Deposits are also recorded for its worker's compensation premium and health care claims policies.

I. Income Taxes

Federal and state income taxes are recorded under the current accounting provisions for the accounting and reporting of income taxes. Income taxes have been computed utilizing the asset and liability approach that requires the recognition of deferred tax assets and liabilities for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities.

Deferred income taxes reflect the tax effect of net operating losses, capital losses and general business credit carryforwards and the net tax effects of temporary differences between the carrying amount of assets and liabilities for financial statement and income tax purposes, as determined under enacted tax laws and rates. The financial effect of changes in tax laws or rates is accounted for in the period of enactment. Deferred investment tax credits are amortized over the useful life of the underlying property. Additionally, the Company follows the current accounting guidance relating to uncertainty in income taxes which applies to all income tax positions reflected on the Company's balance sheets that have been included in previous tax returns or are expected to be included in future tax returns.

J. Comprehensive Income/(Loss)

Comprehensive income/(loss) is the change in the equity of a company, not including those changes that result from shareholder transactions. While the primary component of comprehensive income/(loss) is reported net income (loss), the other primary component of comprehensive income/(loss) relates to changes in unrealized gains and losses associated with certain investments held as available for sale.

K. Derivatives

The Company accounts for derivative financial instruments under the FASB guidance relating to the accounting for derivatives and hedging activities. The provisions of this guidance dictate that all derivatives, except those qualifying for the normal purchase/normal sale exception, are to be recognized on the Balance Sheet at their fair value. Fair value is determined using current quoted market prices, when available. When current quoted market prices are not available, fair value is determined using valuation models which require the use of estimates and assumptions. Since the Company's rate agreement provides for the pass through of derivative gains and losses, the Company applies the requirements of the FASB guidance on derivatives and hedging activities and records an offsetting regulatory asset or regulatory liability associated with the fair value of its derivative instruments.

L. Employee Benefits

NGUSA follows certain accounting guidance that requires employers to fully recognize all postretirement plans' funded status on the Balance Sheets as a net liability or asset and requires an offsetting adjustment to accumulated other comprehensive income in shareholders' equity upon implementation. Consistent with past practice and as required by the current accounting guidance, the Company values its pension and postretirement benefits other than pension ("PBOP") assets using the year-end market value of those assets. Benefit obligations are also measured at year-end.

M. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The following is the fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

Level 1 — quoted prices (unadjusted) in active markets for identical assets or liabilities that a company has the ability to access as of the reporting date.

Level 2 — inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data.

Level 3 — unobservable inputs, such as internally-developed forward curves and pricing models for the asset or liability due to little or no market activity for the asset or liability with low correlation to observable market inputs.

N. Materials and Supplies

Materials and supplies are stated primarily at the lower of cost or market value under the average cost method. The Company's policy is to write off obsolete materials and supplies.

O. Equity Investments

The Company owns as part of its principal assets, investments (including goodwill), representing ownership interests of 50% or less in energy-related businesses that are accounted for under the equity method. None of these current investments are publicly traded.

P. Recent Accounting Pronouncements

Prospective Accounting Pronouncements

In the preceding twelve months, the FASB has issued numerous updates to GAAP. The Company has evaluated various guidelines and has deemed them as not applicable based on its nature of operations. A discussion of the more significant and relevant updates is as follows:

In June 2011, the FASB issued accounting guidance that eliminated the option to present the components of other comprehensive income as part of the statement of changes in stockholders' equity. This update seeks to improve financial statement users' ability to understand the causes of an entity's change in financial position and results of operations. The Company is now required to consecutively present the statement of income and statement of comprehensive income and also present reclassification adjustments from other comprehensive income to net income on the face of the financial statements. This update does not change the items that are reported in other comprehensive income or any reclassification of items to net income. Additionally, the update does not change an entity's option to present components of other comprehensive income net of or before related tax effects. This guidance is effective for public companies for fiscal years, and interim periods within that year, beginning after December 15, 2011, and it is to be applied retrospectively. Early adoption is permitted. The Company does not expect adoption of this guidance to have an impact on the Company's financial position, results of operations or cash flows.

In April 2011, the FASB issued accounting guidance that substantially amended existing guidance with respect to the fair value measurement topic ("the Topic"). The guidance seeks to amend the Topic in order to achieve common fair value measurement and disclosure requirements in GAAP and International Financial Reporting Standards. Consequently, the guidance changes the wording used to describe many of the requirements in GAAP for measuring fair value and for disclosing information about fair value measurements as well as changing specific applications of the Topic. Some of the amendments clarify the FASB's intent about the application of existing fair value measurement requirements. Other amendments change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements including, but not limited to, fair value measurement of a portfolio of financial instruments, fair value measurement of premiums and discounts and additional disclosures about fair value measurements. This guidance is effective for financial statements issued for interim and annual periods beginning after December 15, 2011. The early adoption of this guidance is not permitted and can only be applied prospectively. The Company is currently determining the potential impact of the guidance on its financial position, results of operations and cash flows.

In March 2011, the FASB issued updated guidance over the agreements between two entities to transfer financial assets. Prior to this update, an entity could recognize this transfer when it was deemed that the transferee had effective control over the transferred asset, specifically whether the entity has the ability to repurchase substantially the same asset based on the transferor's collateral. This accounting update evaluates the effectiveness of the entity's control by focusing on the transferor's contractual rights and obligations as opposed to the entity's ability to perform on those rights and obligations. This update also eliminates the requirement to demonstrate that the transferor possesses adequate collateral to fund substantially all the cost of purchasing replacement financial assets. This guidance is treated prospectively and effective for annual or interim reporting periods beginning on or after December 15, 2011. The Company does not expect adoption of this guidance to have an impact on the Company's financial position, results of operations or cash flows.

In December 2010, the FASB issued an accounting update to address inconsistencies in the application of accounting guidance related to reporting pro forma revenue and earnings of business combinations. This update is effective for entities who entered into an acquisition and whose acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. This disclosure requires revenue and earnings of the combined entity to be disclosed as though the combination had occurred at the beginning of the prior reporting period. The supplemental disclosure related to this activity now is required to provide a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination. The Company does not expect the adoption of this guidance to have an impact on the Company's financial position, results of operations or cash flows.

In December 2010, the FASB issued an accounting update that modified the goodwill impairment procedures necessary for entities with zero or negative carrying value. The FASB created this guidance to require entities to complete Step 2 of the impairment test, which requires the entity to assess whether or not it was likely that impairment existed throughout the period. To do this, an entity should consider whether there were adverse qualitative factors throughout the period that would contribute to impairment. This update is effective for fiscal years and interim periods beginning after December 15, 2011. The Company does not expect adoption of this guidance to have an impact on the Company's financial position, results of operations or cash flows.

Recently Adopted Accounting Pronouncements

In March 2010, the FASB issued updated guidance that provides for scope exceptions applicable to financial instrument contracts with embedded credit derivative features. This FASB guidance is effective for financial statements issued for interim periods beginning after June 15, 2010. On an ongoing basis, the Company evaluates new and existing transactions and agreements to determine whether they are derivatives, or have provisions that meet the characteristics of embedded derivatives. Those transactions designated for any of the elective accounting treatments for derivatives must meet specific, restrictive criteria, both at the time of designation and on an ongoing basis. None of the financial instrument contracts or credit agreements the Company has entered were identified and designated as meeting the criteria for derivative or embedded derivative treatment. The adoption of this guidance did not have an impact on the Company's financial position, results of operations or cash flows.

In February 2010, the FASB issued an amendment to certain recognition and disclosure requirements for events that occur after the balance sheet date but before the financial statements are issued or are available to be issued. The amendment applies to both issued financial statements and financial statements revised as a result of either a correction of an error or retrospective application of GAAP. The new provisions require non-public entities to disclose both the date that the financial statements were issued, or available to be issued, and the date the revised financial statements were issued or available to be issued. The amendment is effective for interim or annual periods ending after June 15, 2010. The adoption of this guidance did not have an impact on the Company's financial position, results of operations or cash flows.

In January 2010, the FASB issued an amendment to the accounting guidance for fair value measurements that will provide for additional disclosures about (a) the different classes of assets and liabilities measured at fair value, (b) the valuation techniques and inputs used, (c) the activity in Level 3 fair value measurements, and (d) the transfers between Levels 1, 2, and 3. This FASB guidance is effective for financial statements issued for interim and annual periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the roll forward of activity in Level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. The adoption of this guidance did not have an impact on the Company's financial position, results of operations or cash flows.

In June 2009, the FASB issued an amendment to the accounting and disclosure requirements for transfers and servicing of financial assets and extinguishment of liabilities. The objective of the amendment is to improve the relevance, representational faithfulness, and comparability of the information that a reporting entity provides in its financial statements about a transfer of financial assets; and effects of a transfer on its financial position, financial performance and cash flows; and transferor's continuing involvement, if any, in transferred financial assets. The new provisions must be applied as of the beginning of each reporting entity's first annual reporting period beginning after November 15, 2009 and are to be applied to transfers occurring on or after the date of adoption. The adoption of this guidance did not have an impact on the Company's financial position, results of operations or cash flows.

In June 2009, the FASB issued an amendment to the accounting and disclosure requirements for the consolidation of variable interest entities. The objective of the amendment is to improve financial reporting by enterprises involved with variable interest entities and to provide more relevant and reliable information to users of financial statements. The amendment requires an enterprise to perform an analysis to determine whether the enterprise's variable interest or interests give it a controlling financial interest in a variable interest entity. The new requirements shall be effective as of the beginning of each reporting entity's first annual reporting period that begins after November 15, 2009. The adoption of this guidance did not have an impact on the Company's financial position, results of operations or cash flows.

In May 2009, the FASB issued accounting guidance establishing the general standards of accounting for the disclosure of events that occur after the balance sheet date but before the financial statements are issued or are available to be issued. In particular, this FASB guidance requires enhanced disclosures about (a) events or transactions that may occur for potential recognition or disclosure in the financial statements in the period after the balance sheet date, (b) circumstances under which an entity should recognize such events, and (c) date through which an entity has evaluated subsequent events, including the basis for that date, and whether that date represents the date the financial statements were issued or available to be issued. The FASB guidance is effective for financial statements issued for interim and annual periods ending after June 15, 2009. The Company adopted this standard for the reporting period beginning April 1, 2010 and noted no impact on the Company's financial position, results of operations or cash flows due to the adoption of this standard.

Q. Reclassifications

Certain amounts from prior years have been reclassified in the accompanying financial statements to conform to the current year presentation. These reclassifications had no effect on the results of operations and operating cash flows.

Note 2. Rates and Regulatory

Regulatory assets and liabilities at March 31, 2011 and March 31, 2010 were comprised of the following items:

(in thousands of dollars)	March 31, 2011	2010
Regulatory assets – current		
Purchased power payment obligations	**$ 2,521**	$ 2,521
Derivative contracts	**28,130**	30,972
Accrued Yankee nuclear decommissioning costs	**14,739**	14,939
Total current regulatory assets	**45,390**	48,432
Regulatory assets – non-current		
Purchased power payment obligations	**5,213**	7,312
Derivative contracts	**131,708**	160,538
Accrued Yankee nuclear decommissioning costs	**72,655**	66,665
Pension and postretirement benefits	**64,543**	94,049
Regulatory tax asset	**15,458**	16,953
Other regulatory assets	**22,473**	40,416
Total non-current regulatory assets	**312,050**	385,933
Total regulatory assets	**357,440**	434,365
Regulatory liabilities – current		
Derivative contracts	**(226)**	-
Regulatory liabilities – non-current		
CTC related liabilities	**(47,850)**	(86,925)
Cost of removal	**(26,253)**	(24,764)
Revaluation – pensions and PBOPs	**(20,268)**	(24,235)
Total regulatory liabilities	**(94,597)**	(135,924)
Net regulatory assets	**$ 262,843**	$ 298,441

The regulatory items above are not included in the utility rate base.

Rate Matters

The Company has received authorization from the FERC to recover through CTCs, substantially all of the costs associated with its former generating business not recovered through their divestiture. Additionally, the FERC enables transmission companies to recover their specific costs of providing transmission service. Therefore, substantially all of the Company's business, including the recovery of its stranded costs, remains under cost-based rate regulation.

Under settlement agreements approved by state commissions and FERC, the Company is permitted to recover costs associated with its former generating investments (nuclear and nonnuclear) and related contractual commitments that were not recovered through the sale of those investments (stranded costs). Stranded costs are recovered from the Company's affiliated former wholesale customers with whom it has settlement agreements through a CTC. The Company's affiliated former wholesale customers in turn recover the stranded cost charges through delivery charges to their distribution customers. The Company earns a return on equity ("ROE") of approximately 11% on stranded cost recovery. Most stranded costs have been fully recovered through CTCs by the end of 2010 and the Company intends to recover remaining stranded costs through 2020.

The Company is a Participating Transmission Owner ("PTO") in the New England Regional Transmission Organization ("RTO") which commenced operations effective February 1, 2005. The Independent System Operator for New England ("ISO-NE") has been authorized by the FERC to exercise the operations and system planning functions required of RTOs and is the independent regional transmission provider under the ISO-NE Open Access Transmission Tariff ("ISO-NE OATT"). The ISO-NE OATT is designed to provide non-discriminatory open access transmission services over the transmission facilities of the PTOs and recover their revenue requirements. The FERC issued a series of orders in 2004 and 2005 that approved the establishment of the RTO and resolved certain issues concerning the New England Transmission Owners ("NETOs"). Other ROE issues were set for hearing in the 2004 order.

Effective on the RTO operations date of February 1, 2005, the Company's transmission rates began to reflect a proposed base ROE of 12.8%, subject to refund, plus an additional 0.5% incentive return on regional network service ("RNS") rates that the FERC approved in March 2004. An additional 1.0% incentive adder was also applicable to new RNS transmission investment, subject to refund. Approximately 70% of the Company's transmission costs are recovered through RNS rates.

The Company and other NETOs participated in FERC proceedings to resolve outstanding ROE issues, including base ROE and the proposed 1.0% ROE incentive for new transmission investment. On October 31, 2006, the FERC issued an order approving the proposed 1.0% ROE adder for all new transmission investment approved through the regional system planning process as an incentive to build new transmission infrastructure. The resulting ROE varied depending on whether costs are recovered through RNS rates or local network service ("LNS") rates, and whether the costs are for existing or new facilities. For the locked-in period (February 2005 to October 2006), the resulting ROEs were 10.7% (including a 0.5% RTO participation adder) for recovery of existing transmission through RNS rates; 11.7% (including 0.5% and 1.0% adders) for new transmission costs recovered through RNS; and 10.2% (base ROE only) for LNS. For the prospective period beginning November 1, 2006, those ROEs increased to 11.4%, 12.4% and 10.9%, respectively, as a result of a FERC adjustment to reflect updated bond data. Overall, the ROEs approved by the FERC increased the Company's last authorized ROE of 10.25%.

On rehearing, the FERC issued an order in March 2008 increasing the Company's base ROE for all classes of transmission plant by 24 basis points retroactive to February 1, 2005 and limiting the 1.0% ROE adder to new transmission plant placed in service on or before December 31, 2008. In December 2008, certain parties in the underlying FERC proceeding filed an appeal of the Commission's orders with the US Court of Appeals for the District of Columbia Circuit arguing that the Commission's approval of the 1.0% ROE adder was unjustified. The appeal was denied by the Court in January 2010.

In September 2008, the Company, The Narragansett Electric Company, and Northeast Utilities jointly filed an application with FERC to recover financial incentives for the New England East-West Solution ("NEEWS"), pursuant to the FERC's Transmission Pricing Policy Order, Order No. 679. NEEWS, estimated to cost a total of $2.1 billion, consists of a series of inter-related transmission upgrades identified in the New England Regional System Plan and is being undertaken to address a number of reliability problems in the tri-state area of Connecticut, Massachusetts, and Rhode Island. The Narragansett Electric Company's share is estimated to be approximately $0.6 billion and the Company's share is estimated to be approximately $0.2 billion. Effective November 2008, the FERC granted (1) an incentive ROE of 12.89% (125 basis points above the approved base ROE of 11.64%), (2) 100% construction work in progress in rate base and (3) recovery of plant abandoned for reasons beyond the companies' control. Parties opposing the NEEWS incentives have sought rehearing of the FERC order. The Company cannot predict the outcome of this attempt for a rehearing.

For the year ended March 31, 2011, the Company's NEEWS-related CWIP and in-service investment related to NEEWS totaled $31.2 and $15.9 million, respectively. In April 2011 the Company and Northeast Utilities jointly filed with the FERC to transfer the recovery of 100% of NEEWS-related CWIP from its Local Network Service Rate to the Regional Network Service ("RNS") Rate under section II of the ISO-NE OATT. The Massachusetts Attorney General has filed a Motion to Intervene, Partial Protest and Request for Relief. On May 27th 2011, the

Company received approval from FERC and expects to begin recovery of NEEWS CWIP through the RNS rate beginning in June 2011.

Under the terms of its FERC Electric Tariff No. 1, The Company operates its transmission facilities and those of its New England affiliates as a single integrated system and reimburses its affiliates for the cost of those facilities, including a return. The Company's costs under Tariff No. 1 are then allocated among transmission customers in New England in accordance with the terms of the ISO-NE OATT. On December 30, 2009, NEP filed with the FERC a proposed amendment to Tariff No.1 (1) to adjust depreciation rates and postretirement benefits other than pensions ("PBOPs") according to recent depreciation and actuarial studies updating such costs, and (2) to update rate formulas applicable to Massachusetts Electric Company. The result of the proposed rate change would be an overall rate decrease of $1.6 million. In March 2010, the FERC issued an order establishing hearing and settlement procedures for this filing and made the new rates effective January 1, 2010, subject to refund, pending the outcome of the proceeding. In March 2011, the Company filed an uncontested settlement agreement with the FERC resolving all issues raised by the Massachusetts Attorney General in this proceeding. At this time, the FERC has not acted on the proposed settlement.

Other Regulatory Matters

In November 2008, FERC commenced an audit of NGUSA, including its service companies and other affiliates in the National Grid holding company system. The audit evaluated our compliance with: 1) cross-subsidization restrictions on affiliate transactions; 2) accounting, recordkeeping and reporting requirements; 3) preservation of records requirements for holding companies and service companies; and 4) Uniform System of Accounts for centralized service companies. The final audit report from the FERC was received in February 2011. In April 2011, NGUSA replied to the FERC and outlined its plan to address the findings in the report, which we are currently in the process of implementing. None of the findings had a material impact on the financial statements of the Company.

Note 3. Employee Benefits

Summary

The Company participates with certain other NGUSA subsidiaries in a non-contributory defined benefit pension plan and a PBOP (the "Plans"). The Plans cover substantially all employees of the Company.

The pension plan is a non-contributory, tax-qualified defined benefit plan which provides union employees with a retirement benefit and non-union employees hired before January 1, 2011 with a retirement benefit.

Supplemental nonqualified, non-contributory executive retirement programs provide additional defined pension benefits for certain executives.

PBOPs provide health care and life insurance coverage to eligible retired employees. Eligibility is based on age and length of service requirements and, in most cases, retirees must contribute to the cost of their coverage.

Pension Benefits

The Company participates in the pension plans with certain other NGUSA subsidiaries. Pension plan assets are commingled and cannot be allocated to an individual company. Pension costs are allocated to the Company. The pension plans have a net underfunded obligation of $354.8 million and $420.6 million as of March 31, 2011 and March 31, 2010, respectively. The Company's net periodic pension cost for the years ended March 31, 2011 and March 31, 2010 was $3.8 million and $3.2 million, respectively.

Postretirement Benefits Other Than Pension

The Company participates in the PBOP plans with certain other NGUSA subsidiaries. PBOP costs are allocated to the Company. The PBOP plans have a net underfunded obligation of $401.6 million and $477.3 million as of March 31, 2011 and March 31, 2010, respectively. The Company's net periodic postretirement benefit cost for each of the years ended March 31, 2011 and March 31, 2010 was $1.7 million.

Health Care Reform Act

In March 2010, the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 became law. These laws included provisions that resulted in the repeal, with effect from 2012, of the deduction for federal income tax purposes of the portion of the cost of an employer's retiree prescription drug coverage for which the employer received a benefit under the Medicare Prescription Drug Improvement and Modernization Act of 2003. The consequential reduction in the deferred tax asset balance resulted in a net charge to the income statement of approximately $0.9 million for the year ended March 31, 2010. As this change will be reflected in the rates charged by the Company to its customers, the net impact in the statement of income after reflecting accrued revenues and the associated taxes was zero.

Workforce Reduction Program

In connection with National Grid plc's acquisition of KeySpan, National Grid plc and KeySpan offered 673 non-union employees a voluntary early retirement offer ("VERO") in an effort to reduce the workforce. Eligible employees must have been working in a targeted area as of April 13, 2007 and be at least 52 years of age with seven or more years of service as of September 30, 2007. For eligible employees who have elected to accept the VERO offer, National Grid plc and KeySpan have the right to retain that employee for up to three years before VERO payments are made. An employee who accepts the VERO offer but elects to terminate employment with National Grid plc or KeySpan prior to the three year period, without consent of National Grid plc or KeySpan, forfeits all rights to VERO payments. The VERO is completed and the Company has accrued $5.6 million.

Note 4. Debt

Short-term Debt

The Company has state regulatory approval to issue up to $375 million of short-term debt. The Company had no short-term debt outstanding to third-parties at March 31, 2011 and March 31, 2010.

At March 31, 2011 and March 31, 2010, the Company had lines of credit and standby bond purchase facilities with banks totaling $75 million and $375 million, respectively, which are available to provide liquidity support for $410 million of the Company's long-term bonds, at each of the years ended March 31, 2011 and March 31, 2010, in tax-exempt commercial paper mode, and for other corporate purposes. The standby bond purchase agreement providing $375 million of support to the Company expires on November 30, 2011. There were no borrowings under these agreements at March 31, 2011.

Long-term Debt

At March 31, 2011, the Company had outstanding $410 million of the Pollution Control Revenue Bonds in tax exempt commercial paper mode which were issued through the Business Finance Authority of the State of New Hampshire, the Massachusetts Industrial Finance Authority, and the Connecticut Development Authority. Interest rates ranged from 0.50% to 1.05% for the year ended March 31, 2011.

The aggregate maturities of long-term debt for the five years subsequent to March 31, 2011 are as follows:

(in thousands of dollars)	
Year ended March 31	**Amount**
2012	$ -
2013	-
2014	-
2015	-
2016	39,000
Thereafter	371,331
Total	$ 410,331

At March 31, 2011, interest rates on the Company's variable rate long-term bonds ranged from 0.80% to 0.86%. There are no payments or sinking fund requirements due in 2012 through 2016.

Note 5. Property, Plant and Equipment

At March 31, 2011 and March 31, 2010, property, plant and equipment and accumulated depreciation are as follows:

	March 31,	
(in thousands of dollars)	**2011**	2010
Plant and machinery	**$ 1,499,019**	$ 1,413,597
Land and buildings	**53,823**	43,072
Assets in construction	**153,352**	87,695
Software and othe intangibles	**2,282**	2,267
Total	**1,708,476**	1,546,631
Accumulated depreciation and amortization	**(315,754)**	(296,934)
Property, plant and equipment, net	**$ 1,392,722**	$ 1,249,697

AFUDC

The Company capitalizes AFUDC as part of construction costs. AFUDC represents an allowance for the cost of funds used to finance construction and includes a debt component and an equity component. AFUDC is capitalized in "property, plant and equipment" with offsetting credits to "other interest, including affiliate interest" for the debt component and to “other income” for the equity component. This method is in accordance with an established rate-making practice under which a utility is permitted to earn a return on, and the recovery of, prudently incurred capital costs through its ultimate inclusion in rate base and in the provision for depreciation. The composite AFUDC rates were 7.9% and 8.0% for the years ended March 31, 2011 and March 31, 2010, respectively.

The amounts of AFUDC credits were recorded as follows:

	Years ended March 31,	
(in thousands of dollars)	**2011**	**2010**
Other income	**$ 4,796**	$ 3,212
Interest	**$ 176**	$ 189

Depreciation

Depreciation expense is determined using the straight-line method. The depreciation rates are based on periodic studies of the estimated useful lives of the assets and the estimated cost to remove them, net of salvage value. The Company performs depreciation studies to determine service lives of classes of property and adjusts the depreciation rates when necessary.

The provisions for depreciation, as a percentage of weighted average depreciable property, and the weighted average service life, in years, for each asset category for the years ended March 31 are presented in the table below:

	2011		2010	
	Provision	**Average service life**	Provision	Average service life
Asset Category:				
Electric	**2.3%**	**43**	2.3%	43

Amortization

Amortization of purchased power contracts and regulatory assets covered by CTC is provided over the recovery period as allowed in the applicable regulatory agreement.

Note 6. Other Investments

Yankee Nuclear Power Companies

At March 31, 2011, the Company had non-controlling interests in the Yankees which own nuclear generating units that have been permanently retired and physical decommissioning of the units is complete. Spent nuclear fuel remains on each site, awaiting fulfillment by the U.S. Department of Energy ("DOE") of its statutory obligation to remove it. In addition, groundwater monitoring is ongoing at each site. The Company has power contracts with each of the Yankees that require the Company to pay an amount equal to its share of total fixed and operating costs of the plant plus a return on equity. The Company's share of the expenses of the Yankees is accounted for in "purchased electric energy" on the statements of income.

The following table summarizes financial information furnished by the Yankees:

	Years Ended March 31,	
(in thousands of dollars)	**2011**	2010
Operating revenue	**$ 61,424**	$ 57,788
Net income	**$ 412**	$ 706
Company's equity in net income	**$ 83**	$ 142
Net plant	**$ 1,625**	$ 1,625
Other assets	**$ 929,755**	$ 942,338
Liabilities and debt	**$ (925,581)**	$ (936,975)
Net assets	**$ 5,800**	$ 6,988
Company's equity in net assets	**$ 1,459**	$ 1,710

Note 7. Income Taxes

Following is a summary of the components of federal and state income tax expense (benefit):

	Years Ended March 31,	
(in thousands of dollars)	**2011**	2010
Components of federal and state income taxes:		
Current tax expense (benefit):		
Federal	**$ (14,640)**	$ (23,661)
State	**3,826**	(2,674)
Total current tax benefit	**(10,814)**	(26,335)
Deferred tax expense:		
Federal	**54,391**	72,459
State	**(573)**	10,050
Total deferred tax expense	**53,818**	82,509
Investment tax credits [1]	**(396)**	(404)
Total income tax expense	**$ 42,608**	$ 55,770

[1] Investment tax credits ("ITC") are being deferred and amortized over the depreciable life of the property giving rise to the credits.

Income tax expense for the years ended March 31, 2011 and March 31, 2010 varied from the amount computed by applying the statutory rate to income before income taxes. A reconciliation of expected federal income tax expense, using the federal statutory rate of 35%, to the Company's actual income tax expense for the years ended March 31, 2011 and March 31, 2010 is presented in the following table:

	Years Ended March 31,	
(in thousands of dollars)	**2011**	2010
Computed tax	**$ 40,044**	$ 48,295
Increase (reduction) including those attributable to flow-through of certain tax adjustments:		
State income tax, net of federal benefit	**2,115**	5,615
Rate recovery of deficiency in deferred tax reserves	**2,777**	3,642
Allowance for equity funds used during construction	**(1,679)**	(1,124)
Intercompany tax allocation	**578**	(2,115)
Investment tax credit	**(396)**	(404)
Provision to return adjustments	**82**	(159)
Medicare charge attributable to the Patient Protection and Affordable Care Act	**-**	616
Adjustments to federal and state prior year balances	**-**	1,195
Other items - net	**(913)**	209
Total	**2,564**	7,475
Federal and state income taxes	**$ 42,608**	$ 55,770

Significant components of the Company's net deferred tax assets and liabilities at March 31, 2011 and March 31, 2010 are presented in the following table:

(in thousands of dollars)	**As of March 31, 2011**	2010
Reserve - nuclear and decommisioning	**$ 31,361**	$ 29,379
Future federal benefit on state taxes	**13,634**	13,177
Pensions, other post-employment benefits ("OPEB"), and other employee benefits	**3,530**	10,384
Other items	**3,657**	3,901
Total deferred tax assets[(1)]	**52,182**	56,841
Property related differences	**(302,896)**	(249,633)
Regulatory assets - pension and OPEB	**(39,333)**	(45,627)
Other items	**(6,761)**	(2,809)
Total deferred tax liabilities	**(348,990)**	(298,069)
Net accumulated deferred income tax liability	**(296,808)**	(241,228)
Deferred investment tax credit	**(4,979)**	(5,375)
Net accumulated deferred income tax liability (non-current)	**(301,787)**	(246,603)
Current portion of net deferred tax asset (liability)	**6,828**	(2,497)
Non-current portion of net deferred tax liability and investment tax credit	**$ (308,615)**	$ (244,106)

[(1)]There were no valuation allowances for deferred tax assets at March 31, 2011 or March 31, 2010.

The Company is a member of the National Grid Holdings Inc. ("NGHI") and subsidiaries consolidated federal income tax return. The Company has joint and several liability for any potential assessments against the consolidated group.

The Company adopted the provisions of the FASB guidance which clarifies the accounting and disclosures of uncertain tax positions in the financial statements. The guidance provides that the financial effects of a tax position shall initially be recognized when it is more likely than not, based on the technical merits, that the position will be sustained upon examination, assuming the position will be audited and the taxing authority has full knowledge of all relevant information.

As of March 31, 2011 and March 31, 2010, the Company's unrecognized tax benefits totaled \$37.9 million and \$27.1 million, respectively, of which none and \$0.1 million, respectively, would affect the effective tax rate, if recognized. The unrecognized tax benefits are included in "other deferred liabilities" on the balance sheets.

The following table reconciles the changes to the Company's unrecognized tax benefits for the years ended March 31, 2011 and March 31, 2010:

Reconciliation of Unrecognized Tax Benefits *(in thousands of dollars)*	**Years Ended March 31, 2011**	2010
Beginning balance	**$ 27,129**	$ 215
Gross increases related to prior period	**7,881**	-
Gross increases related to current period	**2,774**	27,249
Settlements with tax authorities	**154**	(335)
Reductions due to lapse of statute of limitations	**-**	-
Ending balance	**$ 37,938**	$ 27,129

As of March 31, 2011 and March 31, 2010, the Company has accrued interest related to unrecognized tax benefits of \$0.9 and \$0.6 million, respectively. During the years ended March 31, 2011 and March 31, 2010, the Company recorded interest expense of \$0.5 million and approximately \$0.1 million, respectively. The Company recognizes accrued interest related to unrecognized tax benefits in interest expense or interest income and related penalties, if applicable, in operating expenses. No penalties were recognized during the years ended March 31, 2011 and March 31, 2010.

Federal income tax returns have been examined and all issues have been agreed with the Internal Revenue Service ("IRS") and the NGHI consolidated filing group through March 31, 2004. During the year ended March 31, 2011, the NGHI consolidated group reached an agreement with the IRS that contained a settlement of the majority of the income tax issues related to the years ended March 31, 2005 through March 31, 2007 as well as an acknowledgment that certain discrete items remained disputed.

The Company is in the process of appealing certain disputed issues with the IRS Office of Appeals relating to its tax returns for March 31, 2005 through March 31, 2007. The Company does not anticipate a change in its unrecognized tax positions in the next twelve months as a result of the appeals. However, the Company's tax sharing agreement may result in a change to allocated tax as a result of current and future audits or appeals. The years ended March 31, 2008 through March 31, 2011 remain subject to examination by the IRS.

For the fiscal years ended March 31, 2011 and March 31, 2010, the Company is a member of the National Grid USA Service Company Massachusetts unitary group. The tax returns for these years remain subject to examination by the State of Massachusetts. Prior to filing as a member of this unitary group, the Company filed on a separate basis. The separate tax returns for the fiscal years ended March 31, 2008 and March 31, 2009 remain subject to examination by the State of Massachusetts.

The Company participates with certain other NGHI subsidiaries in filing a unitary New Hampshire business profits tax return. The New Hampshire unitary returns have been amended for all agreed IRS adjustments. There is currently no ongoing audit by the State of New Hampshire, although the tax returns for years ended March 31, 2008 through March 31, 2011 are open under the statute of limitations.

Note 8. Derivative Contracts

Physical Derivatives

As a result of the Bankruptcy Settlement, New England Power resumed the performance and payment obligations under power supply contracts that had been transferred to USGen when the Company divested its generating business. The fair value of these derivatives at March 31, 2011 and March 31, 2010 was a liability of $159.6 million and $191.5 million, respectively.

The Company continues to record this derivative liability which is the above-market portion of the power supply contracts with an equal offset to a corresponding regulatory asset. The performance and payment obligations will not affect the results of operations, as the Company will recover the above-market cost of the power supply contracts from customers through the CTC.

The following are commodity volumes associated with those derivative contracts as of March 31, 2011:

(in thousands)		
Physical	Electric (Mwhs)	3,222

The following table presents the Company's derivative contract assets and (liabilities) on the balance sheets:

Fair Values of Derivative Instruments - Balance Sheet

	Asset Derivatives			Liability Derivatives	
(in thousands of dollars)	**March 31, 2011**	March 31, 2010		**March 31, 2011**	March 31, 2010
Regulated contracts					
Electric contracts:					
Electric purchase contract - current asset	**$ 226**	$ 508	Electric purchase contract - current liability	**$ (28,130)**	$ (31,480)
Electric purchase contract - non-current asset	**-**	604	Electric purchase contract - non-current liability	**(131,708)**	(161,142)
Total	**$ 226**	$ 1,112		**$ (159,838)**	$ (192,622)

The following table presents the change in value and the asset and (liability) balances of the Company's derivative contracts. The Company had no derivative contracts eligible for non-rate-regulated accounting treatment as of March 31, 2011 and March 31, 2010. The change in fair value of the regulated contracts exactly corresponds to offsetting regulatory assets and liabilities. As a result, the changes in fair value of derivative contracts and their offsetting regulatory (assets) and liabilities had no statement of income impact.

Fair Values of Derivative Instruments

(in thousands of dollars)	Year to Date Movement	**March 31, 2011**	March 31, 2010
Regulated Contracts:			
Electric contracts:			
Electric purchase contracts - regulatory asset	$ 31,672	**$ (159,838)**	(191,510)
Electrict purchase contract - regulatory liability	226	**226**	-
Total	$ 31,898	$ **(159,612)**	(191,510)

Note 9. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The Company's Level 1 fair value derivative instruments primarily consist of natural gas and power futures and swaps traded on the New York Mercantile Exchange ("NYMEX"). There is no liquidity or credit reserve associated with such trades, and no discounting as well.

The Company's Level 2 fair value derivative instruments primarily consist of OTC electric swaps and forward physical electric deals where market data for pricing inputs is observable. Level 2 pricing inputs are obtained from the NYMEX and Intercontinental Exchange ("ICE"), except cases when ICE publishes seasonal averages or there were no transactions within the last seven days. During periods prior to March 31, 2011, Level 2 pricing inputs were obtained from the NYMEX and Platts M2M (industry standard, non-exchange-based editorial commodity forward curves) when it can be verified by available market data from ICE based on transactions within the last seven days. Level 2 derivative instruments may utilize discounting based on quoted interest rate curve as well as have liquidity reserve calculated based on bid/ask spread. Substantially all of these price curves are observable in the marketplace throughout at least 95% of the remaining contractual quantity, or they could be constructed from market observable curves with correlation coefficients of 0.95 or higher.

Level 3 fair value derivative instruments primarily consist of our physical electric transactions where pricing inputs are unobservable, as well as other complex and structured transactions. Complex or structured transactions can introduce the need for internally-developed models based on reasonable assumptions. Industry-standard valuation techniques, such as the Black-Scholes pricing model, Monte Carlo simulation, and Financial Engineering

Associates libraries are used for valuing such instruments. The value is categorized as Level 3. Level 3 is also applied in cases when forward curves are internally developed, extrapolated or derived from market observable curve with correlation coefficients less than 0.95, or optionality is present, or non-economical assumptions are made.

Available for sale securities are primarily in equities and are investments based on quoted market prices and municipal and corporate bonds based on quoted prices of similar traded assets in open markets.

The following table presents assets and liabilities measured and recorded at fair value on the Company's balance sheet on a recurring basis and their level within the fair value hierarchy as of March 31, 2011:

Fair Value Measurement Level Summary Table

(in thousands of dollars)	Level 1	Level 2	Level 3	Total
Assets				
Derivative contracts	$ -	$ -	$ 226	$ 226
Available for sale securities	2,851	3,763	-	6,614
Total assets	2,851	3,763	226	6,840
Liabilities				
Derivative contracts	-	-	(159,838)	(159,838)
Total liabilities	-	-	(159,838)	(159,838)
Net asset/(liability) balance	$ 2,851	$ 3,763	$ (159,612)	$ (152,998)

Year to Date Level 3 Movement Table

The following table presents the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the year ended March 31, 2011:

(in thousands of dollars)	
Balance at March 31, 2010	$ (191,510)
Total gains and losses:	
included in regulatory assets and liabilities	31,898
Balance at March 31, 2011	(159,612)
The amount of realized gains and (losses) included in net income attributed to the change in unrealized gains and (losses) related to derivative assets and liabilities at March 31, 2011	$ -

The Company transfers amounts from Level 2 to Level 3 as of the beginning of the period and amounts for Level 3 to Level 2 as of the end of each period.

Long-term debt is based on quoted market prices where available or calculated prices based on the remaining cash flows of the underlying bond discounted at the Company's incremental borrowing rate. The Company's balance sheets reflect the long-term debt at carrying value. The fair value of this debt at March 31, 2011 is $410.3 million.

Note 10. Accumulated Other Comprehensive Income/(Loss)

The following table presents the components of accumulated other comprehensive income on the Company's balance sheet:

(in thousands of dollars)		Unrealized Gains (Losses) On Available for Sale Securities
March 31, 2009 balance, net of tax	$	(338)
Unrealized gain on securities		991
Reclassification adjustment for gain included in net income		(388)
March 31, 2010 balance, net of tax		265
Unrealized gain on securities		112
Reclassification adjustment for gain included in net income		(44)
March 31, 2011 balance, net of tax	$	333

Note 11. Commitments and Contingencies

Long-term Contracts for the Purchase of Electric Power

The Company has several types of long-term contracts for the purchase of electric power. Substantially all of these contracts require power to be delivered before the Company is obligated to make payment. The Company's commitments under these long-term contracts, as of March 31, 2011, are summarized in the table below:

(in thousands of dollars)

Year		**Estimated Payments**
2012	$	72,718
2013		71,272
2014		69,891
2015		65,040
2016		53,837
Thereafter		53,201
Total	$	385,959

The Company purchases any additional energy needed to meet load requirements and can purchase the electricity from other independent power producers ("IPPs") other utilities, other energy merchants or the open market through the New York Independent System Operator ("NYISO") or the ISO-NE at market prices.

Legal Matters

The Company is subject to various legal proceedings arising out of the ordinary course of its business. The Company does not consider any of such proceedings to be material to its business or likely to result in a material adverse effect on its results of operations, financial condition, or cash flows.

Environmental Matters

The normal ongoing operations and historic activities of the Company are subject to various federal, state and local environmental laws and regulations. Like many other industrial companies, the Company generates hazardous wastes. Under federal and state Superfund laws, potential liability for the historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if activities were lawful when they occurred.

The Company is currently conducting a program to investigate and remediate, as necessary to meet current environmental standards, certain properties which the Company has learned may be contaminated with industrial waste sites as to which it may be determined that the Company has contributed. The Company has also been advised that various federal, state or local agencies believe certain properties require investigation and has prioritized the sites based on available information in order to enhance the management of investigation and remediation, if necessary.

The Company believes that obligations imposed on it because of environmental laws will not have a material impact on its results of operations or financial position.

Asset Retirement Obligations

The Company adheres to the current accounting guidance relating to asset retirement obligations associated with tangible long-lived assets. The Company does not have any material asset retirement obligations arising from legal obligations as defined under this guidance.

However, under the Company's current and prior rate plans, it has collected through rates an implied cost of removal for its plant assets. This cost of removal collected from customers differs from the FASB guidance definition of an asset retirement obligation in that these collections are for costs to remove an asset when it is no longer deemed usable (i.e. broken or obsolete) and not necessarily from a legal obligation. The Company estimates it has collected over time approximately $26.3 million and $24.8 million for cost of removal through March 31, 2011 and March 31, 2010, respectively, in excess of the costs incurred by the Company.

In March 2005, the FASB issued an interpretation of its earlier published guidance related to the accounting for asset retirement obligations which was adopted by the Company for the year ended March 31, 2006. This interpretation clarifies that the term "conditional asset retirement obligation" used in the earlier guidance refers to a 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 Company. The Company continues to monitor such contingencies, which do not have a material impact on the Company's results of operations or its financial position for the years ended March 31, 2011 and March 31, 2010.

Decommissioning Nuclear Units

The Yankees operated nuclear generating units that have been permanently retired. Physical decommissioning of the units is complete. Spent nuclear fuel remains on each site, awaiting fulfillment by the DOE of its statutory obligation to remove it. In addition, groundwater monitoring is ongoing at each site. Future estimated billings which are included in miscellaneous current/accrued liabilities and other deferred credits are as follows:

(in thousands of dollars)	The Company's Investment as of March 31, 2011			Future Estimated Billings to the Company
Unit	%	Amount	Date Retired	Amount
Yankee Atomic	34.5	$ 539	Feb 1992	$ 24,927
Connecticut Yankee	19.5	423	Dec 1996	43,527
Maine Yankee	24.0	497	Aug 1997	18,941

The Company recorded a liability and a regulatory asset reflecting the estimated future decommissioning billings from the Yankees. In a 1993 decision, the FERC allowed Yankee Atomic to recover its undepreciated investment in the plant, including a return on that investment, as well as unfunded nuclear decommissioning costs and other costs. Maine Yankee and Connecticut Yankee recover their prudently incurred costs, including a return, in accordance with settlement agreements approved by the FERC in May 1999 and July 2000, respectively. The

Yankees collect the approved costs from their purchasers, including the Company. The Company's share of the decommissioning costs is accounted for in "Purchased electric energy" on the Statements of Income. Under settlement agreements, the Company is permitted to recover prudently incurred decommissioning costs through CTCs.

The Yankees are periodically required to file rate cases for FERC approval, which present the Yankees' estimated future decommissioning costs. The Yankees are currently collecting decommissioning and other costs under FERC orders issued in their respective rate cases.

Future estimated billings from the Yankees are based on cost estimates. These estimates include the projected costs of groundwater monitoring, security, liability and property insurance and other costs. They also include costs for interim spent fuel storage facilities, which the Yankees have constructed during litigation they brought to enforce the DOE's obligation to remove the fuel as required by the Nuclear Waste Policy Act of 1982.

Following a trial at the U.S. Court of Federal Claims ("Claims Court") to determine the level of damages, on October 4, 2006, the Claims Court awarded the three companies an aggregate of $143 million for spent fuel storage costs that had been incurred through 2001 and 2002. The Yankees had requested $176.3 million. On December 4, 2006, the DOE filed a notice of appeal with the U. S. Court of Appeals for the Federal Circuit. The Court of Appeals rendered an opinion generally supporting the trial court's decision and has remanded the matter to the trial court for further proceedings. A Claims Court trial in the remanded cases was held in August, 2009. On September 7, 2010, the Court again awarded the three companies an aggregate of approximately $143 million. On November 8, 2010, the DOE again filed a notice of appeal with the same Court of Appeals. On November 19, 2010, the Yankees filed notices of cross-appeal. If the Yankees are successful in the litigation, the damages received by the Yankees, net of litigation expenses and taxes, will be applied to reduce the decommissioning and other costs collected from their purchasers including the Company. The Company cannot predict the outcome of the pending decisions for trial, appeal or the potential subsequent complaints. On December 14, 2007, the Yankees brought further litigation in the Claims Court to recover damages incurred subsequent to 2001 and 2002. Discovery in the further litigation is ongoing and a trial in the Claims Court is expected in October 2011. The DOE has severely curtailed budgetary support for the proposed long-term spent fuel storage facility at Yucca Mountain in Nevada and taken actions designed to prevent its construction and appointed a Blue Ribbon Commission charged with advising it regarding alternatives to disposal at Yucca Mountain. As a result, it is impossible to predict when the DOE will fulfill its obligation to take possession of the Yankees' spent fuel. The decommissioning costs that are actually incurred by the Yankees may exceed the estimated amounts, perhaps substantially.

Connecticut Yankee Rate Filing

On July 1, 2004, Connecticut Yankee asked the FERC for a rate increase to reflect increased costs for decommissioning, pensions and other employment benefits, increased security and insurance costs and other expenses. In aggregate, the increase requested amounted to approximately $396 million through 2011. The Company's share is included in the future estimated billings shown in the table above. On November 16, 2006, the FERC issued an Order approving a settlement reached by parties to the proceeding. Under the settlement, as a result of the operation of a budget incentive mechanism established in a prior rate settlement, the Company was not allowed to recover $1 million of its expenditures.

The settlement provides that Connecticut Yankee may resume payment of dividends to return equity to sponsors. After January 1, 2008, Connecticut Yankee will not earn a return on more than $10 million in equity.

On July 31, 2008, Connecticut Yankee submitted an application to the FERC to reduce its rates by $0.6 million annually. This reduction is the net effect of: (i) a reduction of $2.5 million annually in decommissioning charges, as a result of the reconciliation of actual and projected costs of completing decommissioning and (ii) an increase of $1.9 million annually in the recovery of costs for post-employment benefits other than pension. On September 10, 2008 the FERC issued an order accepting this rate filing and settlement.

On April 6, 2010, Connecticut Yankee asked the FERC to waive a requirement of its wholesale rate schedule that otherwise would require an upward adjustment of the decommissioning charges to the Company and other customers effective, May 1, 2010. Connecticut Yankee stated that it would reflect the impact of the increase, together with other factors affecting decommissioning charges, in a revised schedule of such charges that it is required by the 2006 settlement to submit, before the end of 2010. On May 5, 2010, the FERC issued an order granting the requested waiver.

On October 13, 2010, Connecticut Yankee submitted to the FERC its decommissioning cost estimate and schedule of decommissioning charges, as it had committed to do in the 2006 settlement. Connecticut Yankee stated that the decommissioning cost estimate approved as part of the 2006 settlement, escalated to 2010 dollars, remains a reasonable projection of decommissioning costs and Connecticut Yankee did not propose an adjustment to decommissioning charges. The only change that Connecticut Yankee proposed to its rates was the removal of the automatic adjustment mechanism that was the subject of the FERC's May 5, 2010 waiver order. On December 20, 2010, the FERC issued an order accepting Connecticut Yankee's filing, including the elimination of the adjustment mechanism.

Yankee Atomic Rate Filing

On November 23, 2005, Yankee Atomic submitted a filing to the FERC to increase its rates. On May 1, 2006, the parties to the proceeding submitted a settlement, subsequently accepted by the FERC, based on an estimated cost of $212.7 million for the period 2005 through 2022. The settlement included a requirement to file an updated decommissioning cost estimate and schedule of decommissioning charges by December 31, 2010.

On October 13, 2010, Yankee Atomic submitted to the FERC its decommissioning cost estimate and schedule of decommissioning charges, Yankee Atomic stated that the decommissioning cost estimate approved as part of the 2006 settlement, escalated to 2010 dollars, remains a reasonable projection of decommissioning costs and Yankee Atomic did not propose an adjustment to decommissioning charges. The only change that Connecticut Yankee proposed to its rates was the removal of an automatic adjustment mechanism that had been added by the 2006 settlement. The Connecticut Department of Public Utility Control ("CDPUC") filed a notice of intervention and comments urging the FERC to accept Yankee Atomic's filing, but asking the FERC to confirm the CDPUC's interpretation of the scope of a provision of the 2006 settlement relating to the application of possible proceeds from Yankee's lawsuit against the DOE. On December 30, 2010, the FERC issued an order accepting Yankee Atomic's filing, including the elimination of the adjustment mechanism, and denying CDPUC's request for clarification.

Maine Yankee Rate Filing

Maine Yankee submitted a Section 205 rate filing to the FERC on August 1, 2008. The sole purpose of this filing was to modify the Maine Yankee tariff in order to replenish the Spent Fuel Disposal Trust ("SFDT") Fund as contemplated in the settlement agreement approved by the Commission in Maine Yankee's last rate case proceeding, on September 16, 2004. Maine Yankee is proposing a five-year recovery period and requests $6.4 million on an annualized basis to fund the SFDT. Because the effective date of this filing occurs on the month following the completion of decommissioning collections, Maine Yankee's annual decommissioning rates will reduce to zero and therefore, even with the recovery of the amounts to replenish the SFDT fund, its total rates will decrease by approximately $20 million annually.

In its initial FERC filing, Maine Yankee requested a 6.5% ROE. In its intervention and comments, the Maine Public Utility Commission ("PUC") indicated that they could not support the 6.5%. After negotiations, the parties agreed to a 5.5% ROE and the filing was amended to include this change. On October 30, 2008, the FERC accepted Maine Yankee's amended filing, effective as of November 1, 2008.

Hydro Quebec Interconnection

Three affiliates of NGUSA were created to construct and operate transmission facilities to transmit power from Hydro Quebec (a generation facility in Quebec, Canada) to New England. Under the financial and organizational agreements (the "Support Agreements") entered into at the time these facilities were constructed, the Company agreed to guarantee a portion of the project debt. At December 31, 2009, the Company had guaranteed approximately $8.1 million of project debt with terms through 2015. Costs associated with these Support Agreements are recoverable from the Company's customers through CTCs.

Note 12. Restrictions on Payment of Dividends

Pursuant to the provisions of the long-term note agreement, payment of dividends on common stock would not be permitted if, after giving effect to such payment of dividends, common equity becomes less than 30% of total capitalization. At March 31, 2011 and March 31, 2010 common equity was 72.6% of total capitalization. Under these provisions, none of the Company's retained earnings at March 31, 2011 and March 31, 2010 were restricted as to common dividends.

Note 13. Related Party Transactions

Moneypool

The Company participates with NGUSA and certain affiliates in a system moneypool. The moneypool is administered by the NGUSA service company as the agent for the participants. Short-term borrowing needs are met first by available funds of the moneypool participants. Borrowings from the moneypool bear interest at the higher of (i) the monthly average of the rate for high-grade, 30-day commercial paper sold through dealers by major corporations as published in the Wall Street Journal, or (ii) the monthly average of the rate then available to moneypool depositors from an eligible investment in readily marketable money market funds or the existing short-term investment accounts maintained by moneypool depositors or the NGUSA service company during the period in question. In the event neither rate is one that is permissible for a transaction because of constraints imposed by the state regulatory commission having jurisdiction over a utility participating in the transaction, the rate is adjusted to a permissible rate as determined under the requirements of the state regulatory commission. Companies that invest in the moneypool share the interest earned on a basis proportionate to their average monthly investment in the moneypool. Funds may be withdrawn from or repaid to the moneypool at any time without prior notice. The average interest rate for the moneypool was 0.27% for each of the years ended March 31, 2011 and March 31, 2010. The Company had a short-term moneypool investment of $107 million at March 31, 2011 and $144.7 million at March 31, 2010.

Advances to/from Affiliates

Additionally, the Company engages in various transactions with NGUSA and its affiliates. Certain activities and costs, such as executive and administrative, financial (including accounting, auditing, risk management, tax and treasury/finance) human resources, information technology, legal and strategic planning are shared between the companies and allocated to each company appropriately. In addition, the Company has a tax sharing agreement with NGHI, a NGUSA affiliate, in filing consolidated tax returns. The Company's share of the tax liability is allocated resulting in a payment to or refund from NGHI. At March 31, 2011 and March 31, 2010, the Company had a net accounts payable to affiliates of $21.2 million and a net accounts receivable from affiliates of $24.7 million, respectively.

Service Company Charges

The affiliated service companies of NGUSA provide certain services to the Company at their cost. The service company costs are generally allocated to associated companies through a tiered approach. First and foremost, costs are directly charged to the benefitted company whenever practicable. Secondly, in cases where direct charging cannot be readily determined, costs are typically allocated using cost/causation principles linked to the relationship of that type of service, such as meters, square footage, number of employees, etc. Lastly, other costs are allocated based on a general allocator. These costs include operating and capital expenditures of $62.1 million and $139.0 million for the year ended March 31, 2011 and $23.7 million and $53.1 million for the year ended March 31, 2010, respectively.

Holding Company Charges

NGUSA received charges from National Grid Commercial Holdings Limited (an affiliated company in the UK) for certain corporate and administrative services provided by the corporate functions of National Grid plc to its US subsidiaries. These charges, which are recorded on the books of NGUSA, have not been reflected on these financial statements. Were these amounts allocated to this subsidiary, the estimated effect on net income would be approximately $1.0 million and $0.7 million before taxes, and $0.7 million and $0.4 million after taxes, for the years ended March 31, 2011 and 2010, respectively.

Organizational Restructuring

On January 31, 2011, National Grid plc announced substantial changes to the organization, including new global, US and UK operating models, and changes to the leadership team. The announced structure seeks to create a leaner, more-efficient business backed by streamlined operations that will help meet, more efficiently, the needs of regulators, customers and shareholders. The implementation of the new U.S. business structure commences on April 4, 2011 and targets annualized savings of $200 million by March 2012 primarily through the reduction of up to 1,200 positions. As of March 31, 2011, NGUSA had recorded a $66.8 million reserve for one-time employment termination benefits related to severance, payroll taxes, healthcare continuation, outplacement services as well as consulting fees related to the restructuring program. These charges have been recorded by NGUSA and none have been allocated to the Company as at March 31, 2011. Subsequently in June 2011, we offered a voluntary severance plan to certain individuals which is expected to cost up to an additional $20 million across all entities affiliated with NGUSA.

Note 14. Subsequent Events

In accordance with current authoritative accounting guidance, the Company has evaluated for disclosure subsequent events that have occurred up through June 30, 2011, the date of issuance of these financial statements. As of June 30, 2011, there were no subsequent events which required recognition or disclosure.