Northeast Utilities nationalgrid UIL HOLDINGS

July 3, 2014

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

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

Dear Heather:

Northeast Utilities, National Grid and United Illuminating are pleased to provide the attached response to the New England States Committee on Electricity Request for Expression of Interest to Act as a Counterparty issued on June 11, 2014. The response builds upon the framework presented by the Companies in the April 22, 2014 letter to NESCOE.

Sincerely,

James G. Daly
VP, Energy Supply
Northeast Utilities

Anthony Marone
Sr. VP, Customer & Business Services
UIL

James Holodak, Jr.
VP, Regulatory Strategy & Integrated Analytics
National Grid

Attachment:

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

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

Northeast Utilities, National Grid & UIL Holdings

July 3, 2014

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Northeast Utilities, National Grid, and UIL Holdings are pleased to provide this non-binding statement of interest on behalf of their subsidiary electric distribution companies ("the EDCs" more fully described in Section II below) to the New England States Committee on Electricity (NESCOE) in response to the Request for Expressions of Interest (REI) to Act as a Counterparty issued on June 11, 2014. As presented in the April 22, 2014 letter to NESCOE (a copy of which is included as Appendix C), the EDCs support the approach outlined by NESCOE, which contemplates the development of gas pipeline capacity infrastructure funded through a FERC – approved tariff. The EDCs confirm that they are interested in serving as counterparties under long – term pipeline capacity service contracts, to facilitate the development of additional gas transportation capacity needed to maintain reliable and cost – effective electric service in New England. This proposal is conditioned on the EDCs being appropriately compensated for making the required long-term contract commitments, and for lending financial stability in the form of their balance sheet and credit-rating qualifications. The EDC compensation is anticipated to be in the form of direct equity participation in the capacity expansion projects, and/or in a form of equity equivalent.

The EDCs are affiliates of the largest providers of electricity and natural gas service to New England customers. Collectively, the parent companies of the EDCs, through their operating companies, serve 5.1 million electricity customers and 1.8 million gas customers across 4 New England states. Our core business is the management of electricity and natural gas delivery and supply to our customers. As large combination electric and gas utilities, we have a wide range of expertise and strengths necessary to deliver on the New England Governors' initiatives being implemented by NESCOE.

In addition to possessing the operational capability to serve as the Contract Entity, the EDCs are attractive and viable counterparties for interstate natural gas pipelines or liquefied natural gas providers who are likely to be the service providers (Counterparties) to the Contract Entity. All three parent companies and their subsidiaries have solid investment grade credit ratings. In addition, the companies presently manage large portfolios of electric and gas supply contracts and possess the expertise to negotiate and manage the contracts required to deliver the infrastructure necessary to implement the Governors' Initiative to increase the reliability of gas supply to power generation in New England.

The EDCs would, in coordination with NESCOE, ISO-NE and the Counterparties, prepare and submit requests for all required State and Federal approvals of long-term gas transmission contracts and tariffs. The EDCs ability to enter into long-term gas transportation agreements is subject to the receipt of acceptable approvals from their respective state and federal regulators, as well as any required legislative changes.

NESCOE also requested information on the Capacity Manager Selection and Controls. The EDCs, through their affiliated Local Distribution Companies (LDCs), have extensive experience contracting and managing Capacity Managers. This includes the implementation of comprehensive FERC regulations pertaining to how capacity is managed and released to the market. Although the EDCs possess the ability to manage the capacity themselves, in order to avoid any potential conflict of interests and subject to NESCOE agreement, the EDCs propose to contract with an independent third party Capacity Manager that will be bound by a contract between the EDC and the Capacity manager as well as the terms of a new FERC approved Customized Rate Schedule pertaining to the release of the capacity. Further details on this approach are provided under confidentiality in Appendix A.

I. Background

On June 11, 2014 The New England States Committee on Electricity (NESCOE) issued a Request for Expression of Interest (REI) to further inform the New England states' understanding of (i) the entities that have an interest in serving as creditworthy counterparties to precedent agreements with natural gas pipeline companies (Pipeline Companies), (ii) the qualifications of those entities, and (iii) the conditions under which entities would serve in that role.

It is widely acknowledged that the market conditions experienced in the winter of 2013/14 underscore the need to take immediate action to relieve pipeline capacity constraints, particularly with the increasing regional reliance on gas-fired electric generation. This REI is the latest step in a process to identify an approach to facilitate the development of incremental natural gas infrastructure in New England. In December 2013, the New England Governors issued a joint statement (the *New England Governors' Commitment to Regional Cooperation on Energy Infrastructure Issues*) regarding energy infrastructure diversification. Since that time, the EDCs have actively worked with NESCOE and engaged other stakeholders in the region to propose a structure that would support the goal of increasing natural gas infrastructure and increase reliability and value for electric customers.

On April 22nd, 2014, the EDCs presented an approach to NESCOE whereby electric distribution companies would, subject to the necessary cost recovery assurances and remuneration acceptable to them, enter into long term contracts with interstate pipeline companies for new firm gas transportation capacity. This response to the REI is consistent with, and builds upon, the framework presented to NESCOE on April, 22nd 2014, a copy of which is attached to this proposal as Appendix C.

II. Description of Entities

The EDCs are affiliates of the largest providers of electric and natural gas delivery services to New England customers. Collectively, the parent companies of the EDCs, through their operating companies, serve 5.1 million electric and 1.8 million natural gas customers in New England across 4 states.

Northeast Utilities, a Massachusetts Voluntary Association, operates New England's largest energy delivery system. Through its subsidiaries, NU provided $7.1 billion in energy delivery and related services in 2013. NU maintains dual headquarters in Boston, MA and Hartford, CT, and is the parent company of 4 New England EDCs which may serve as a Contract Entity:

- *The Connecticut Light & Power Company*, a Connecticut corporation, serves 1.2 million customers throughout Connecticut
- *NSTAR Electric Company*, a Massachusetts corporation, serves 1.1 million customers in the Boston metropolitan area and Eastern Massachusetts.
- *Western Massachusetts Electric Company, a* Massachusetts corporation, serves more than 200,000 customers in Western Massachusetts.
- *Public Service Company of New Hampshire,* a New Hampshire corporation, serves 500,000 customers throughout New Hampshire.

National Grid plc, incorporated in England and Wales, is the parent holding company of National Grid USA. National Grid plc is engaged primarily in utility operations in the United Kingdom and the northeastern United States, and, to a lesser extent, in Europe and other countries. National Grid plc is headquartered in London and its shares are listed on the London Stock Exchange. Through its subsidiaries, National Grid USA is engaged in electric transmission and distribution, and in the sale and distribution of natural gas to residential, commercial and industrial customers in New England and New York. Together, National Grid USA subsidiaries provide safe, and reliable energy to approximately 7 million U.S. customers. National Grid USA is parent to two New England EDCs which may serve as Contract Entities:

- Massachusetts Electric Company, a Massachusetts corporation, delivers electric energy to 1.3 million retail customers in Massachusetts. Massachusetts Electric's service territory includes the commercial and industrial cities of Worcester, Lowell and Quincy, the Interstate 495 high technology belt, numerous suburban communities and many rural towns.

- The Narragansett Electric Company, a Rhode Island company, is engaged in the delivery of electric and gas energy in Rhode Island. Narragansett's electric service territory covers approximately 99% of Rhode Island serving 492,000 electric customers, and includes the cities of Providence, East Providence, Cranston and Warwick. Narragansett's gas business serves residential, commercial and industrial customers throughout the state.

UIL Holdings is a diversified energy delivery company serving approximately 700,000 electric and natural gas utility customers in 66 communities across two states, with combined total assets of over $5 billion. UIL Holdings is the parent company of The United Illuminating Company (UI). A proposed Contract Entity, UI provides for the transmission and delivery of electricity and other energy related services for over 317,000 customers in Connecticut's Greater New Haven and Bridgeport areas.

Financial information, organization charts, and contact information for each of the Companies is provided in Appendix B.

III. Qualifications

Construction of pipeline capacity to achieve the goal advocated by NESCOE (an overall increase of at least 1,000 MMcf/day of capacity for the region over 2013 capacity levels) will require an extraordinary level of investment by a variety of parties. The pipeline companies who have traditionally constructed these projects require long-term contract commitments with highly creditworthy counterparties to support construction. Provided that their cost recovery and appropriate remuneration is assured, the EDCs are willing to provide the creditworthiness necessary for these long-term contract commitments.

For the EDCs proposed Incremental Gas for Electric Reliability (IGER) concept to succeed, the Contract Entity must be sufficiently creditworthy and be able to manage the extensive regulatory requirements that will be associated with the project. The EDCs possess both the necessary creditworthiness and regulatory expertise to meet these objectives. The EDCs believe that their experience, expertise and financial integrity would contribute toward the success of the FERC approval process contemplated under the approach developed by NESCOE.

Collectively, the parent companies of the EDCs operate 7 electric distribution companies and 7 natural gas local distribution companies subject to the regulation of 4 New England states. The companies also own and manage an extensive network of interstate electric transmission facilities under the regulatory authority of FERC. These affiliate businesses provide the EDCs with significant regulatory experience and resources that, as the Contract Entity, will be leveraged to obtain the potentially extensive and somewhat unique requirements and approvals associated with this project.

A number of New England utilities affiliated with the EDCs have participated in the AIM and CT Expansion projects, and so have very recently evaluated such projects, negotiated such contracts and obtained necessary regulatory approvals. Gas utilities affiliated with the EDCs already contract for and manage large and diverse portfolios of capacity and supply for their customer demand and are highly experienced at managing variable demands of customers. A number of gas utilities provide gas supply service to electric generators both on and off-system, sometimes in conjunction with a third party. The EDCs believe that this experience contributes toward the ability of the EDCs to obtain the approvals of their respective state regulatory authorities needed to undertake these long-term commitments.

The pipeline companies who have traditionally constructed these projects require long-term contract commitments with highly creditworthy counterparties to support construction. The EDCs all possess solid investment grade credit ratings (Exhibit 1) and, through their existing businesses, have extensive experience managing the financial and regulatory reporting requirements of electric and gas contracts. The EDCs are not aware of any fact or circumstance whereby their acting as the Contract Entity would preclude the ability of any other party to also act as a contracting party.

Exhibit 1: Company Long-Term Credit Ratings

	Moody's	S&P	Fitch
Northeast Utilities	Baa1	A-	BBB+
CL&P	Baa1	A-	BBB+
NSTAR	A2	A-	A
WMECO	A3	A-	BBB+
PSNH	Baa1	A-	BBB+
National Grid PLC	Baa1	A-	BBB
Massachusetts Electric	A3	A-	-
Narragansett Electric	A3	A-	-
UIL Holdings Corp	Baa2	BBB	-
United Illuminating	Baa1	BBB	-

Source: Moody's, Standard & Poor's and Fitch as of June 19, 2014

The EDCs' financial capability and credit quality make them highly suitable Contract Entities that will enhance the viability of the project.

IV. Capacity Manager Selection and Controls

Given the magnitude of the capacity involved it would make sense to have a capacity-management function in place to optimize the value of the released capacity rather than having the EDCs manage the capacity release on their own. Some of our LDCs already use portfolio-management services to manage pipeline-capacity releases for natural gas customers, so we have experience with this model. The EDCs view the Capacity Manager role as administrative rather than a trading function. The manager could handle a range of capacity transactions (including capacity releases) and would allocate capacity to generators and the market to the degree generators do not need the capacity during certain times of the year. The Capacity Manager will not be "choosing winners and losers" in allocating the capacity. Generators would bid for the capacity with the highest bidder(s) securing capacity. There are a number of considerations that need to be addressed with this approach under FERC regulations. Therefore, we would propose to address these through the new FERC-approved tariff or other means as appropriate. There are other administrative and regulatory requirements that would be imposed on the Capacity Manager which are more fully described in the attached Appendix A (Confidential).

The gas utility affiliates of the EDCs have extensive experience contracting for and managing firm pipeline capacity and many other pipeline services in order to serve our customers with a reliable supply at a reasonable cost. Collectively such entities:

1) Contract and manage 2.2 bcf/d of pipeline capacity which represents about two-thirds of the interstate gas capacity in New England.
2) Represent the anchor shippers and major contract holders on the Algonquin AIM projects scheduled to go into service in late 2016.
3) Represent 100% of the shippers on the only recent Tennessee Gas Pipeline expansion into New England, the Connecticut project scheduled to go into service in late 2016.
4) Are familiar and skilled at developing natural gas and capacity portfolios to serve customers and have extensive experience dealing with suppliers and partners such as asset managers.
5) Have a long history of providing reliable and cost effective service to gas customers including contracting for, operating and managing capacity since pipelines were built into New England in the 1950's.
6) Are familiar through off-system sales program, pipeline capacity release programs and serving generators on system with the needs of electric generation plants.

The EDCs clearly understand the objective is to remedy an electric reliability concern which should also result in lower costs for gas generation thereby resulting in lower electric wholesale market costs. The Capacity Manager role will be designed to achieve the intent, obtain necessary FERC approvals, and reduce or negate influences such as third party arbitrage that are threats to the program's goals.

With respect to the proposed selection process for the Capacity Manager, the EDCs, as counter-parties or base shippers for pipeline capacity, would issue an RFP for entities that may be able to perform a specific pre-defined role envisioned for the Capacity

Manager. Central to the success of this process is the need to have a high level of confidence up front in a detailed, holistic, and well thought out plan. Please refer to *CONFIDENTIAL Appendix A: <u>EDC/LDC Proposal to NESCOE on Allocation of Gas Capacity to Generators and Implementation Thereof Through a FERC Approved Pipeline Rate Schedule</u>* for the proposed specific role of the Capacity Manager which includes:

- Ensuring the firm pipeline capacity is targeted for and used by ISO-NE electric generators through priority access at market prices.
- Determining the timing, duration, minimum prices and structure of the capacity releases.
- Ensuring the capacity is used in the intended manner, releasing into the general market any unneeded for generation capacity; and,
- Managing the related operational and administrative tasks and submitting information and performance reports to the EDCs.

The proposed EDC role is contingent upon the authority to select a Capacity Manager, in conjunction with NESCOE and the states, and as described in the response above. The EDCs have a long term business interest in customer satisfaction and regional prosperity. Increased reliability and reduced volatility and electric wholesale energy prices contribute to both. Defining the Capacity Manager role and participating in oversight of the Capacity Manager, in conjunction with NESCOE and the New England states, is of critical importance to the success of the envisioned gas capacity program. The EDCs bring extensive expertise and experience, coupled with a long term view and interest. The EDCs envision a public-private partnership with NESCOE and the states, working together with the Capacity Manager to accomplish the objectives. As counter-parties to the pipeline capacity contracts, the EDCs have a vested interest in ensuring the entire process works as intended and it would be their capacity rights that are being managed by the Capacity Manager.

The Capacity Manager’s existing business arrangements and/or affiliate relationships may present an actual or apparent conflict of interest. The Capacity Manager can have no conflict of interest that may distract or conflict its important market and compliance responsibilities. At the present time the EDCs envision a preferred model that would involve a single purpose entity with no conflict of interest, which performs the intended services with very specific roles and responsibilities. That entity’s responsibilities would include reporting on results, reporting to a management committee of the shipper EDCs and performing such services at a modest fixed fee per dth of capacity managed. The LDCs are familiar with such a model and currently utilize a similar structure for a portion of their portfolios.

Specific controls, policies and procedures would be developed to ensure appropriate management controls are in place for the Capacity Manager. The EDCs are highly experienced in developing and operating under such controls, policies and procedures.

With respect to the ongoing review and oversight of the Capacity Manager, the EDCs propose the establishment of a management committee comprised of representatives from each of the participating EDCs. The management committee would meet on a quarterly basis, or more frequently if required, reviewing reports of the Capacity Manager related to its activities and results, centered upon compliance with associated tariffs, reliability, utilization of capacity, wholesale energy market cost information from ISO-NE, value obtained and other pertinent information. The management committee would operate pursuant to a charter setting forth its goals and decision making methodology.

The EDCs would also establish a Stakeholder Liaison Committee to provide a forum for the transparent exchange of information and discussion of matters relevant to the conduct of the initiative. It is anticipated that representatives of States, NESCOE, ISO New England as well as other interested parties would participate in this committee.

The EDCs believe the approach more fully outlined in Appendix A (Confidential) to manage the associated firm pipeline capacity under contract is well suited to the achievement of the program's objectives:

V. Costs and Other Business Terms

The EDCs participation as Contract Entities is contingent upon appropriate compensation for the financial commitments to be made and the management services to be provided. The responsibilities of the Contract Entity will require resources to support acquisition of regulatory approvals, and manage ongoing regulatory and reporting requirements. The EDCs are uniquely qualified to provide these resources, but require recovery of the associated costs.

The EDCs are proposing to assume significant administrative and financial obligations by serving as the Contract Entity. The proposed project will be made feasible as a result of the Companies committing their financial resources to support contracts required to implement the IGER Proposal. The EDCs will need to be appropriately compensated for making these long-term contract commitments, and for lending financial stability in the form of their balance sheet and credit-rating qualifications. This compensation could be in the form of direct equity participation in the capacity expansion projects, and/or in a form of equity equivalent or fee-for-service compensation, depending on the size of the contract commitments and the investment opportunity. At this time, it is too early to specify the appropriate value of such compensation as the size and specific nature of contract commitments and investment opportunities are not known. When specific projects are identified to implement the IGER Proposal, the EDCs will evaluate these commitments and opportunities. The EDCs note that the process being contemplated involves negotiation of project – specific terms with the Counterparties and/or NESCOE, all within the context of FERC-approved pipeline tariff service, with the associated service agreements being approved by the applicable state authorities and costs to be ultimately recovered from retail electric customers, who are the primary beneficiaries of this proposal.

VI. FERC Review

FERC approval of an ISO administered tariff will be necessary to support funding of the projects and to allocate the costs (net of capacity release revenue) to electric loads. The allocation of gas transportation costs to electric load is appropriate as electric customers will be the beneficiaries. Such allocation is subject to FERC approval and will involve some justification. The EDCs, however, believe that a compelling case can be made as the underlying service is for reliability of supply to electric customers.

In addition to FERC approval of the ISO Administered Tariff, the projects will need FERC approval for Tariff and customized rate schedules to provide the services contemplated under the IGER Proposal. More details are provided on this approach and discussed under confidentiality in Appendix A.

The EDCs fully support the NESCOE and New England states' effort to address a long standing reliance on gas without the associated gas infrastructure and keenly understand the negative ramifications that have resulted from this, and the EDCs desire to be part of the solution-thus our participation and this proposal. The EDCs and their gas utility affiliates are highly experienced at FERC policy matters and regularly contribute views and analysis through informal conferences, testimony and filings that help shape regulatory policy. The EDCs have a long term business interest in customer satisfaction and regional prosperity, and we see our role as contributing to that by ensuring a more reliable and lower cost wholesale electric market. The EDCs believe they have the expertise, resources and coordination experience to contribute to the development of a FERC strategy to achieve approval for the program. One example of that expertise is the idea of the use of a pipeline rate schedule rather than through a FERC request for a general waiver of the gas capacity release regulations. To the extent the EDCs are selected to work with NESCOE and the states, we will assist in the development of a FERC strategy and work on the necessary filings.

In terms of pipeline capacity, the EDCs through their LDC affiliates add substantial expertise and value to the envisioned program as the LDCs have negotiated contractual agreements similar in nature to those envisioned here and understand the entire process from start to finish, including the importance of obtaining FERC and other approvals related to supporting the need for the pipeline and its installation. Recent examples include the Algonquin AIM project and the Tennessee Connecticut expansions, and upcoming proposed expansions Spectra Atlantic Bridge and the Tennessee Northeast Direct projects.

VII. State Review

In addition to the FERC filings and approvals referenced above, the EDCs would require approval by their respective state regulatory authorities for these contract commitments, and for recovery of associated costs in retail rates. We acknowledge that additional effort will be required to identify all necessary legislation, regulatory filings and approvals, and to develop appropriate strategies for obtaining FERC approvals. We appreciate the potentially extensive and somewhat unique nature of the approvals required for this project, and that some states may not be prepared to immediately participate in this activity. It should be noted that the proposed solution outlined in this letter is scalable, to enable EDC participation beyond the undersigned parties. We note that the Maine utilities, Central Maine Power Company (CMP) and Emera Maine, have expressed support in a letter to NESCOE for the original EDC proposal and indicated their desire to participate under similar terms as outlined by the EDCs. The addition of these two Maine EDCs would broaden participation to EDCs within 5 of the six New England States, including all of the states with deregulated retail markets, and include EDCs that collectively serve approximately 85% of the New England load.

VIII. Prerequisites or Impediments to Participation

The EDCs would require both state and federal approvals for their participation as Contract Entity. All applicable internal approvals must be received by the EDCs including, but not limited to, those pertaining to risk and credit, and any required board and management approvals. Furthermore, the EDCs would require approval by their respective state regulatory authorities for these contract commitments, and for recovery of associated costs in retail rates. To the extent regulatory agencies need legislation to provide that authority, the EDCs would work with the necessary stakeholders to advance that legislation.

IX. Conflicts of Interest

The EDCs recognize potential conflicts of interest exist due their relationships and affiliations with multiple electric and natural gas market participants. The EDCs and their parent companies are experienced in managing such potential conflicts through appropriate internal and regulatory controls. In addition, the EDCs believe that their proposal for an independent third party Capacity Manager to manage the allocation of capacity under the IGER proposal would be an effective means to avoid conflicts of interest or self-dealing (or the appearance of the same) related to the management, release and use of gas transportation capacity.

X. Timeline

The EDCs encourage NESCOE to pursue an aggressive schedule to achieve the goal articulated by the New England Governors for new gas transportation capacity to be available by the winter of 2017/2018. The urgency to increase natural gas supply for power generation was highlighted this winter when gas fired generation produced significantly less than its capacity, (e.g. on January 28 when gas fired units had a peak capacity supply obligation of 11,000 MW but only produced 3,000 MW[1]). With the retirement of more coal and nuclear base load generation announced, reliability is further eroded for the coming winters until new gas capacity is provided. The EDCs are prepared to commit the necessary time and resources to move from a non-binding statement of interest to a definitive agreement, accomplishing the necessary activities within an aggressive schedule, recognizing that EDC support is contingent upon all requisite approvals.

---

[1] ISO New England – Cold Weather Operations, FERC Technical Conference on Winter 2013-14 Operations and Market Performance, April 1, 2014.
http://www.ferc.gov/CalendarFiles/20140401083935-Brandien,%20ISO-New%20England..pdf

APPENDIX A

EDC/LDC Proposal to NESCOE on Allocation of Gas Capacity to Generators and Implementation Thereof Through a FERC Approved Pipeline Rate Schedule

CONFIDENTIAL

APPENDIX B

Additional Company Information

Northeast Utilities

Company Representative:

James G. Daly
Vice President, Energy Supply
1 NSTAR Way, NE220
Westwood, MA 02090
James.daly@nu.com
Ph: 781-441-8258

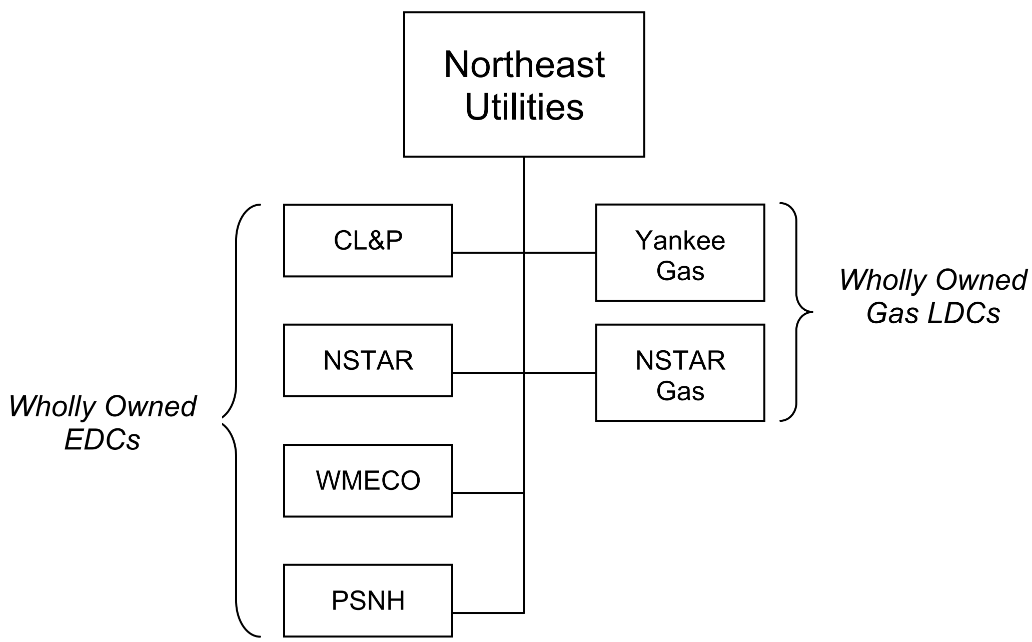
Principal Business Addresses:

NSTAR Electric Company
800 Boylston St.
Boston, MA 02199

The Connecticut Light and Power Company
107 Selden St
Berlin, CT 06037-1616

Public Service of New Hampshire
Energy Park
780 North Commercial St
Manchester, NH 03101-1134

Applicable Organizational Structure:



Financial Information:

Please refer to the Company annual financial reports at:

http://www.nu.com/investors/reports/Financial_Reports.asp

National Grid

Company Representative:

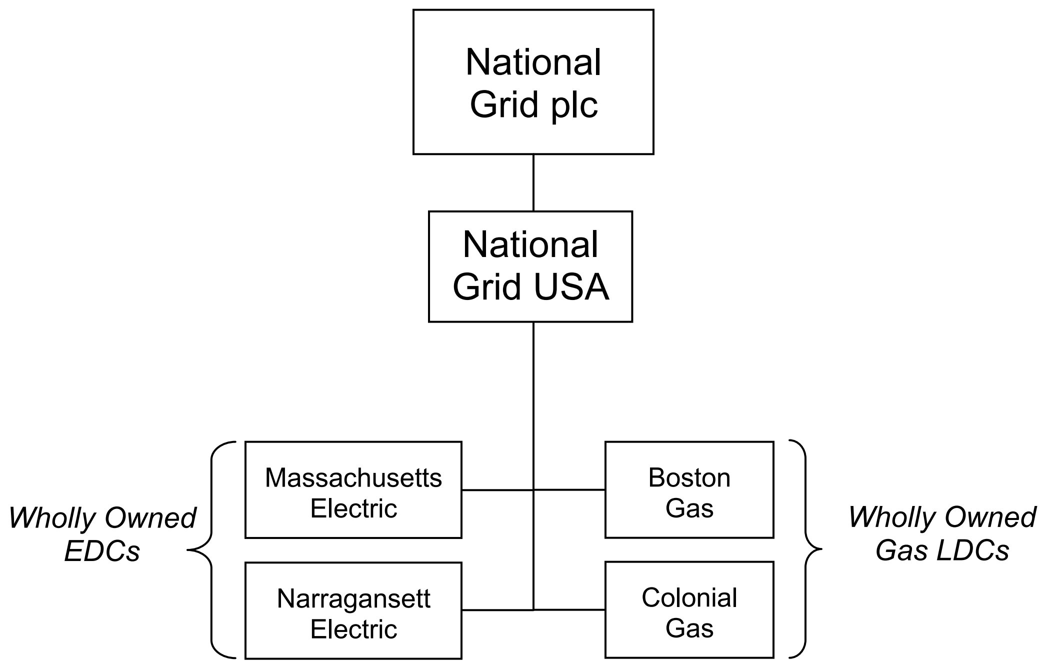
James Holodak, Jr.
Vice President, Regulatory Strategy & Integrated Analytics
One Metro Tech Center
Brooklyn
New York 11201
james.holodakJr@nationalgrid.com
Ph: 929 324 4599

Principal Business Addresses:

Massachusetts Electric Company
40 Sylvan Rd
Waltham, MA 02451

Narragansett Electric Company
280 Melrose St
Providence, RI 02907

Applicable Organizational Structure:



Financial Information:

Please refer to the attached Company annual financial reports

United Illuminating Holdings

Company Representative:

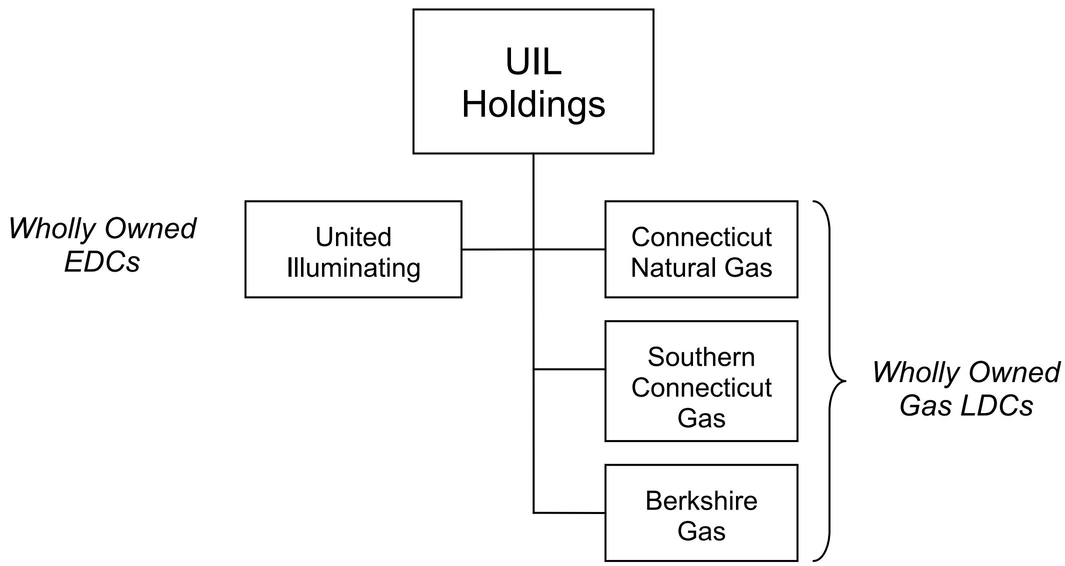
Anthony Marone
Sr. Vice President, Customer & Business Services
Anthony.Marone@uinet.com
(203) 499-2032

Principal Business Addresses:

UIL Holdings
157 Church Street
New Haven, Ct 06510-2100

The United Illuminating Company
180 Marsh Hill Road
Orange, Ct 06477

Applicable Organizational Structure:



Financial Information:

Please refer to the Company annual financial reports at:

https://www.uil.com/wps/portal/uil/home

APPENDIX C

EDC Letter to NESCOE dated April 22, 2014

Northeast Utilities nationalgrid UIL HOLDINGS

April 22, 2014

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

Re: Gas Capacity Infrastructure Expansion in New England

Dear Heather:

As you know, in December, 2013 the New England Governors issued a joint statement (the *New England Governors' Commitment to Regional Cooperation on Energy Infrastructure Issues*) regarding energy infrastructure diversification. Consistent with this directive, NESCOE has identified an approach to facilitate the development of gas pipeline capacity infrastructure to be funded by a FERC approved tariff. NESCOE has called upon interested parties including the gas and electric utilities in New England to participate in a collaborative process to assist in the development of strategies and projects that would contribute to the expansion of gas pipeline capacity to serve New England. It is widely acknowledged that the market conditions experienced in the winter of 2013/14 underscore the need to take immediate action to relieve pipeline capacity constraints, particularly with the increasing regional reliance on gas-fired electric generation.

In response to this initiative, Northeast Utilities, National Grid and United Illuminating have been in discussions with Ms. Katie Scharf Dykes, Deputy Commissioner Energy, Connecticut Department of Energy and Environmental Protection, and some of your colleagues regarding an approach whereby electric distribution companies would, subject to the necessary cost recovery assurances and remuneration acceptable to them, consider entering into long term contracts with interstate pipeline companies for new firm gas transportation capacity. The capacity associated with these contracts would enable the delivery of adequate gas supplies necessary to fuel the gas-fired electric generation units in the region. We believe that this proposed approach may be both feasible in the near term and fair, to the extent that the result would be that the costs of developing this additional infrastructure will be borne by those who derive the long term benefits from this investment.

The following elaborates on a number of the attributes of this proposed approach, in an effort to assist you and your colleagues at NESCOE to evaluate the desire of the New England States to pursue and facilitate this option.

Need for the Investment

ISO-NE has concluded that both short term and long term actions will be required to ensure the stability and reliability of the New England electric grid. The pipeline capacity restrictions for non-firm natural gas this past winter led to near outage conditions. In fact, ISO-NE has stated that outages were avoided only by the implementation of a winter-reliability program, which mandated that plants capable of firing on oil have specific quantities of oil in inventory at the start of the winter. Due to the cold weather and the limited availability (and resulting price volatility) of non-firm natural gas capacity, a heavy reliance on these plants resulted in these oil supplies being essentially depleted. Clearly, reliance on such stop-gap measures, while essential to maintaining the integrity of the electric grid in the short term, does not contribute to (and may in fact detract from) the necessary long-term infrastructure solution. The imminent retirement of several significant non- gas fueled generating plants in the region will further stress the existing gas pipeline system and emphasizes the need for resource diversification, including the integration of additional renewable energy sources.

Bearing the Cost and Reaping the Benefits of the Investment

The increased reliance on gas-fired generation has brought some significant economic and environmental benefits to New England, but this generation is relying on gas transmission infrastructure that was historically designed to serve the gas-heating needs of New England. This infrastructure is largely dedicated to the customers of the gas utilities under long term contracts, and not for electric generator demand. Clearly, gas service customers should not be responsible for the cost of developing the necessary infrastructure necessary to provide fuel to power plants. Rather, if electric customers receive the primary benefits in the form of increased reliability and stability of the electric grid then it is appropriate for them to be responsible for that cost.

Facilitating the Infrastructure Development

Construction of pipeline capacity to achieve the goal advocated by NESCOE (an overall increase of at least 1,000 MMcf/day of capacity for the region over 2013 capacity levels) will require an extraordinary level of investment by a variety of parties. The pipeline companies who have traditionally constructed these projects require long-term contract commitments with highly creditworthy counterparties to support construction. Provided that their cost recovery is assured, electric distribution companies could play a significant role in providing the creditworthiness necessary for these long-term contract commitments. Additionally, as noted below, some utilities may be in a position to make an equity investment to assist in supporting these projects. A number of New England utilities have participated in the AIM and CT Expansion projects, so have very recently evaluated such projects and negotiated such contracts. Gas utilities contract for and manage large and diverse portfolios of capacity and supply for their customer demand and are highly experienced at managing variable demands of customers. A number of gas utilities provide service to non-firm gas supply service to electric generators both on and off-system, sometimes in conjunction with a third party.

Electric Distribution Company (EDC) Model

As depicted in the attached diagram, the transactions facilitated by the proposed business model involve the EDCs, again, subject to the necessary cost recovery assurances and remuneration acceptable to them, entering into long-term contracts with the interstate pipelines for the gas capacity necessary to serve the electric generators. The EDCs would also arrange for the management of such capacity by a capacity manager(s), who would manage the capacity and allocate the capacity among the electric generators through pre-determined means, (alternative strategies are currently being reviewed and discussed with the states), designed to achieve the intent of the added infrastructure. The EDCs would pay the pipeline charges associated with the capacity and would be credited actual capacity related revenue, net of compensation to the capacity manager. The EDCs would recover the net actual contract costs through an ISO-NE tariff rate approved by the FERC and administered by ISO-NE. Costs would be allocated to New England electric load as agreed to by the New England states and approved by FERC. On an ongoing basis the program's effectiveness and actual results compared to goals will be reviewed in conjunction with the states, specifics to be determined and any appropriate adjustments made, however the EDC's will be assured of collection of the capacity costs by customers.

Capacity Management

At several of our discussions, it was noted that given the magnitude of the capacity involved it would make sense to have a capacity-management function in place to optimize the value of the released capacity rather than having the EDCs manage the capacity release on their own. Some gas utilities already use portfolio-management services to manage pipeline-capacity releases for natural gas customers, so we have experience with this model. The manager could handle a range of capacity transactions (including capacity releases) and would allocate capacity to generators and the market to the degree generators do not need the capacity during certain times of the year. There are a number of considerations that need to be addressed with this approach under FERC regulations. Therefore, we would propose to address these through the FERC-approved tariff or other means as appropriate.

Regulatory Action

In addition to the FERC filings and approvals referenced above, the EDCs would require approval by their respective state regulatory authorities for these contract commitments, and for recovery of associated costs in retail rates. We acknowledge that additional effort will be required to identify all necessary regulatory filings and approvals, and to develop appropriate strategies for obtaining FERC approvals. We appreciate the potentially extensive and somewhat unique nature of the approvals required for this project, and that some states may not be prepared to immediately participate in this activity. It should be noted that the proposed solution outlined in this letter is scalable, to enable EDC participation beyond the undersigned parties, should a state agency desire participation at a later date.

Rate Recovery

As noted above, the EDCs would recover the FERC-approved tariff rate on a non-bypassable basis from electric retail customers in New England. The EDCs would need to be appropriately compensated for entering into these long-term contract commitments and for lending financial stability in the form of balance sheet and credit-rating qualifications. This compensation could be in the form of equity participation in the capacity expansion project and/or other compensation for lending credit quality, depending on the size of the contract commitments and the equity participation opportunity.

Additional Considerations

We acknowledge that, in addition to the construction of new pipeline capacity, solutions that include increased availability of LNG supplies (independently or coupled with additional pipeline capacity), gas storage and no-notice pipeline services should be explored. Through an open and competitive process, we are confident that a variety of solutions will be offered and deserve to be explored.

Timeline

In order to accommodate the goal articulated by the Governors and NESCOE (for new capacity to be available by the winter of 2017/2018), we have developed the attached schedule. Please note that this schedule calls for a request for proposals for infrastructure solutions to be issued in June 2014, with preliminary agreements to be signed by October 2014. This aggressive schedule requires a decision by NESCOE and the participating state agencies to pursue the option described in this letter by May 1, 2014, and the issuance by the state agencies to the EDCs of the corresponding directive to proceed by that date, so that we may develop the RFP materials and engage the market. Although we understand this schedule is aggressive, we are committed to devoting the necessary time and resources to accomplishing the necessary activities.

Given the complexity and scope of a project like this, we are in the early stages of our due diligence processes, including legal and regulatory review. As such, any commitments would of course be subject to each utility's or their parents' board approvals and would be contingent on regulatory and legislative approvals on the state or federal level as required. However, based on the preliminary work we have conducted, we believe this may be a workable and preferred option for delivering increased gas capacity and supply to generation in New England.

We look forward to further discussions with you at the earliest convenient date.

Sincerely,

James G. Daly
VP, Energy Supply
Northeast Utilities

James Holodak Jr
VP Regulatory Strategy
National Grid USA

~~James Stanzione~~
Director, Gas
NationalGrid

Anthony Marone
Sr. VP, Customer & Business Services
UIL

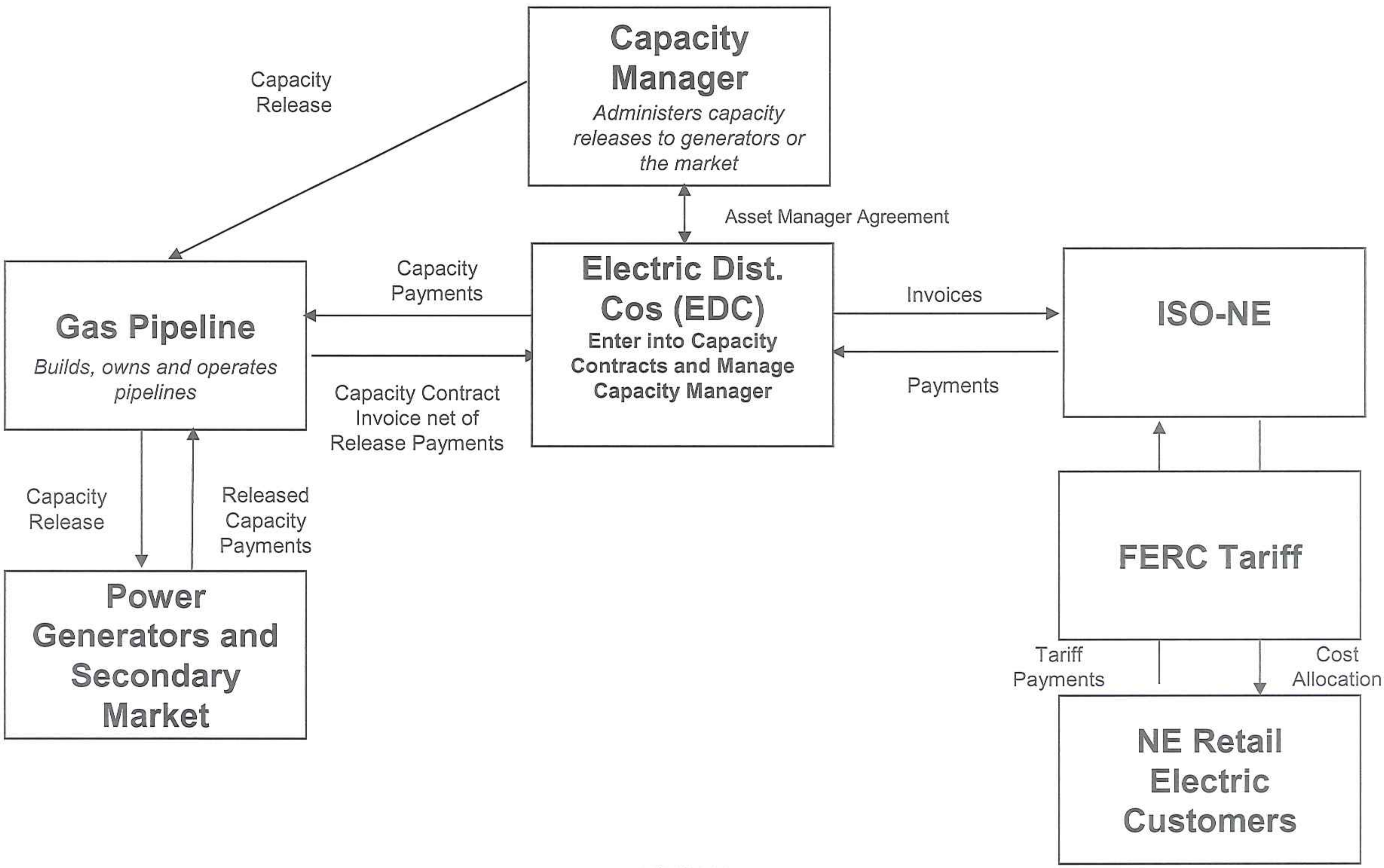
Attachments:

Business Model Flow Diagram
Proposed Timeline

CC:

Katie Scharf Dykes
Deputy Commissioner – Energy
Connecticut Department of Energy
and Environmental Protection
79 Elm Street
Hartford, CT 06106-5127

EDC Model



Capacity Manager
Administers capacity releases to generators or the market
Capacity Release
Asset Manager Agreement
Gas Pipeline
Builds, owns and operates pipelines
Capacity Payments
Electric Dist. Cos (EDC)
Enter into Capacity Contracts and Manage Capacity Manager
Capacity Contract Invoice net of Release Payments
Invoices
Payments
ISO-NE
Capacity Release
Released Capacity Payments
Power Generators and Secondary Market
FERC Tariff
Tariff Payments
Cost Allocation
NE Retail Electric Customers

Timeline Proposed to NESCOE

NESCOE Gas Pipeline Timeline		ISO Tariff Schedule Timeline	NESCOE Clean Power Supply/Transmission RFP Timeline	
Determine Parties Contracting (EDC/LDC/Other)	April 2014	**Stake Holder Process**	Determine Parties Contracting	April – May 2014
			RFP and Contract Development	
Determine Target Pipeline Capacity MDQ's	May 2014			
Release RFP and/or participate in Open Season Begin Negotiations with Pipelines Precedent Agreements Rate Issues Terms and Conditions Services Regulatory Out	June – September 2014	**Tariff Development**	RFP Release Date	June 2014
Evaluate Receipt and Delivery Points/Quantities	June/July 2014		Bidders Conference	June 2014
Determine Receipt and Delivery Points/Quantities	July/August 2014	**NEPOOL Vote**	Bid Proposals Due	July 2014
		Tariff Filing at FERC		
			Short List	August 2014
Sign Precedent Agreements	**October 2014**		**Contracts Signed**	**October 2014**
File for State Regulatory Approvals as Required	October 2014			
			State Filings	November 2014
Regulatory Approval/Out	December 2014	**FERC Approval**		
FERC Pre-File FERC 7C Application	December 2014 December 2015		State Approvals	April 2015
Receive Certificate	December 2016			
Projects In-Service	November 1, 2017/18/19		Projects In-Service	2017/18/19

Attachment 1

Financial Statements of
Massachusetts Electric Company and
Narragansett Electric Company

Massachusetts Electric Company

Financial Statements

For the years ended March 31, 2013 and March 31, 2012

MASSACHUSETTS ELECTRIC COMPANY

TABLE OF CONTENTS

pwc

Independent Auditor's Report

To the Shareholder and Board of Directors of Massachusetts Electric Company:

We have audited the accompanying financial statements of Massachusetts Electric Company (the "Company"), which comprise the balance sheets as of March 31, 2013 and March 31, 2012, and the related statements of income, comprehensive income, cash flows, capitalization and changes in shareholders' equity for the years then ended.

Management's Responsibility for the Financial Statements

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

Auditor's Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Massachusetts Electric Company at March 31, 2013 and March 31, 2012, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

PricewaterhouseCoopers LLP

October 18, 2013

MASSACHUSETTS ELECTRIC COMPANY
BALANCE SHEETS
(in thousands of dollars)

	March 31, 2013	March 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 2,024**	$ 2,906
Restricted cash	**68,500**	68,500
Accounts receivable	**299,159**	272,525
Allowance for doubtful accounts	**(31,786)**	(35,912)
Accounts receivable from affiliates	**4,550**	6,135
Unbilled revenues	**87,222**	85,789
Materials and supplies	**20,037**	17,765
Current portion of deferred income tax assets	**-**	30,266
Regulatory assets	**155,403**	80,211
Prepaid taxes	**42,164**	3,430
Other current assets	**21,292**	3,449
Total current assets	**668,565**	535,064
Property, plant, and equipment, net	**2,408,734**	2,314,747
Deferred charges and other assets:		
Regulatory assets	**623,629**	592,523
Goodwill	**1,008,244**	1,008,244
Financial investments	**6,075**	5,617
Other deferred charges	**7,645**	7,275
Total deferred charges and other assets	**1,645,593**	1,613,659
Total assets	**$ 4,722,892**	$ 4,463,470

The accompanying notes are an integral part of these financial statements

MASSACHUSETTS ELECTRIC COMPANY
BALANCE SHEETS
(in thousands of dollars)

	March 31,	
	2013	2012
LIABILITIES AND CAPITALIZATION		
Current liabilities:		
Accounts payable	**$ 226,462**	$ 154,219
Accounts payable to affiliates	**76,548**	21,468
Taxes accrued	**1,914**	-
Customer deposits	**12,004**	11,102
Interest accrued	**18,005**	18,006
Intercompany money pool	**162,302**	86,938
Regulatory liabilities	**33,802**	80,462
Current portion of deferred income tax liabilities	**7,520**	-
Energy efficiency certificate obligations	**83,025**	54,431
Other current liabilities	**19,429**	17,456
Total current liabilities	**641,011**	444,082
Deferred credits and other liabilities:		
Regulatory liabilities	**351,886**	333,096
Asset retirement obligations	**1,596**	1,633
Deferred income tax liabilities	**568,282**	511,734
Postretirement benefits	**170,392**	202,114
Environmental remediation costs	**96,230**	95,954
Other deferred liabilities	**40,086**	55,043
Total deferred credits and other liabilities	**1,228,472**	1,199,574
Capitalization:		
Shareholders' equity	**2,035,781**	2,002,275
Long-term debt	**817,628**	817,539
Total capitalization	**2,853,409**	2,819,814
Total liabilities and capitalization	**$ 4,722,892**	$ 4,463,470

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

MASSACHUSETTS ELECTRIC COMPANY
STATEMENTS OF INCOME
(in thousands of dollars)

	Yeas Ended March 31,	
	2013	2012
Operating revenues	**$ 2,032,180**	$ 2,042,851
Operating expenses:		
Purchased electricity	**747,735**	860,134
Contract termination charges from affiliates	**21,752**	5,657
Operations and maintenance	**971,195**	832,024
Depreciation	**112,678**	109,362
Other taxes	**60,491**	53,025
Total operating expenses	**1,913,851**	1,860,202
Operating income	**118,329**	182,649
Other income and (deductions):		
Interest on long-term debt	**(48,597)**	(48,707)
Other interest, including affiliate interest	**(2,025)**	3,697
Other deductions, net	**10,382**	(4,785)
Storm penalties	**(18,734)**	(1,200)
Total other deductions, net	**(58,974)**	(50,995)
Income before income taxes	**59,355**	131,654
Income tax expense (benefit)		
Current	**(69,279)**	(45,674)
Deferred	**96,965**	97,442
Total income tax expense	**27,686**	51,768
Net income	**$ 31,669**	$ 79,886

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

MASSACHUSETTS ELECTRIC COMPANY
STATEMENTS OF COMPREHENSIVE INCOME
(in thousands of dollars)

	Years Ended March 31,	
	2013	2012
Net income	**$ 31,669**	$ 79,886
Other comprehensive income:		
Unrealized gains on securities, net of $184 and $301 tax expense	**276**	451
Change in pension and other postretirement obligations, net of $20 and ($50) tax expense (benefit)	**31**	(74)
Reclassification of gains into net income, net of $91 and $175 tax benefit	**(137)**	(262)
Other comprehensive income	**170**	115
Comprehensive income	**$ 31,839**	$ 80,001

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

MASSACHUSETTS ELECTRIC COMPANY
STATEMENTS OF CASH FLOWS
(in thousands of dollars)

	Years Ended March 31, 2013	2012
Operating activities:		
Net income	**$ 31,669**	$ 79,886
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation	**112,678**	109,362
Bad debt expense	**23,495**	1,129
Provision for deferred income taxes	**96,965**	97,442
Net prepayments and other amortizations	**414**	479
Pension and other postretirement contributions	**(56,943)**	(24,642)
Pension and other postretirement expense	**32,381**	59,058
Net environmental remediation payments	**(6,462)**	(7,432)
Changes in operating assets and liabilities:		
Accounts receivable, net, and unbilled revenues	**(55,688)**	(49,521)
Materials and supplies	**(2,272)**	1,269
Accounts payable and accrued expenses	**68,119**	(36,071)
Regulatory assets and liabilities	**(160,444)**	(89,010)
Prepaid taxes and accruals	**(38,147)**	7,263
Accounts receivable from/payable to affiliates, net	**(5,398)**	(2,649)
Other liabilities	**14,419**	(20,528)
Standard offer recovery	**-**	1,557
Other, net	**(13,792)**	3,050
Net cash provided by operating activities	**40,994**	$ 130,642
Investing activities:		
Capital expenditures	**(172,395)**	(168,093)
Proceeds from sale of investments	**-**	2,075
Other, including cost of removal	**(8,575)**	(9,924)
Net cash used in investing activities	**(180,970)**	(175,942)
Financing activities:		
Dividends paid on preferred stock	**(100)**	(100)
Affiliated money pool borrowing and other	**137,427**	40,375
Share based compensation	**1,767**	390
Net cash provided by financing activities	**139,094**	40,665
Net increase in cash and cash equivalents	**(882)**	(4,635)
Cash and cash equivalents, beginning of period	**2,906**	7,541
Cash and cash equivalents, end of period	**$ 2,024**	$ 2,906
Supplemental disclosures:		
Interest paid	**$ 54,921**	$ 42,895
Income taxes refunded from Parent	**15,450**	8,948
Significant non-cash items:		
Capital-related accruals included in accounts payable	**9,104**	4,981

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

MASSACHUSETTS ELECTRIC COMPANY
STATEMENTS OF CAPITALIZATION
(in thousands of dollars)

			March 31,	
			2013	2012
Total shareholders' equity			**$ 2,035,781**	$ 2,002,275
Long-term debt:	Interest Rate	Maturity Date		
Notes payable - Unsecured senior notes	5.90%	November 15, 2039	**800,000**	800,000
State authority financing - Tax exempt pollution control revenue bonds	Variable	August 1, 2014	**20,000**	20,000
Unamortized discounts			**(2,372)**	(2,461)
Total long-term debt			**817,628**	817,539
Total capitalization			**$ 2,853,409**	$ 2,819,814

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

MASSACHUSETTS ELECTRIC COMPANY
STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(in thousands of dollars, except number of shares data)

	Common Stock, par value $25 per share		Preferred Stock, par value $100 per share				Accumulated Other Comprehensive Income			
	Issued and Outstanding Shares	Amount	Issued and Outstanding Shares	Amount	Additional Paid-in Capital	Retained Earnings	Unrealized Gain (Loss) on Available for Sale Securities	Pension and Postretirement Benefits	Total Accumulated Other Comprehensive Income	Total
Balance as of March 31, 2011	2,398,111	$ 59,953	22,585	$ 2,259	$ 1,558,161	$ 296,775	$ 371	$ 4,465	$ 4,836	$ 1,921,984
Net income	-	-	-	-	-	79,886	-	-	-	79,886
Comprehensive income:										
Unrealized gains on securities, net of $301 tax expense	-	-	-	-	-	-	451	-	451	451
Change in pension and other postretirement obligations, net of $50 tax benefit	-	-	-	-	-	-	-	(74)	(74)	(74)
Reclassification of gains into net income, net of $175 tax benefit	-	-	-	-	-	-	(262)	-	(262)	(262)
Share based compensation	-	-	-	-	390					390
Dividends on preferred stock	-	-	-	-	-	(100)	-	-	-	(100)
Balance as of March 31, 2012	2,398,111	$ 59,953	22,585	$ 2,259	$ 1,558,551	$ 376,561	$ 560	$ 4,391	$ 4,951	$ 2,002,275
Balance as of March 31, 2012	2,398,111	$ 59,953	22,585	$ 2,259	$ 1,558,551	$ 376,561	$ 560	$ 4,391	$ 4,951	$ 2,002,275
Net income	-	-	-	-	-	31,669	-	-	-	31,669
Comprehensive income:										
Unrealized gains on securities, net of $184 tax expense	-	-	-	-	-	-	276	-	276	276
Change in pension and other postretirement obligations, net of $20 tax expense	-	-	-	-	-	-	-	31	31	31
Reclassification of gains into net income, net of $91 benefit	-	-	-	-	-	-	(137)	-	(137)	(137)
Share based compensation	-	-	-	-	1,767	-	-	-	-	1,767
Dividends on preferred stock	-	-	-	-	-	(100)	-	-	-	(100)
Balance as of March 31, 2013	2,398,111	$ 59,953	22,585	$ 2,259	$ 1,560,318	$ 408,130	$ 699	$ 4,422	$ 5,121	$ 2,035,781

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

MASSACHUSETTS ELECTRIC COMPANY

NOTES TO THE FINANCIAL STATEMENTS

Note 1. Summary of Significant Accounting Policies

A. Nature of Operations

Massachusetts Electric Company ("the Company") is an electric retail distribution company providing electric service to approximately 1.3 million customers in 171 cities and towns in Massachusetts. The properties of the Company consist principally of substations and distribution lines interconnected with transmission and other facilities of New England Power Company ("NEP"), an affiliated entity.

The Company is a wholly-owned subsidiary of National Grid USA ("NGUSA"), a public 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.

The Company has evaluated subsequent events and transactions through October 18, 2013, the date of issuance of these financial statements, and concluded that there were no events or transactions that require adjustment to or disclosure in the financial statements as of and for the year ended March 31, 2013, except as disclosed in footnote 2, "Rates and Regulation".

B. Basis of Presentation

The financial statements for the years ended March 31, 2013 and March 31, 2012 are prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"), including the accounting principles for rate-regulated entities. The financial statements reflect the rate-making practices of the applicable regulatory authorities.

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.

Within the statements of cash flows, all amounts that are settled through the Regulated Money Pool (refer to Note 9, "Related Party Transactions") are treated as constructive cash receipts and payments, and therefore are presented as such.

C. Regulatory Accounting

The Federal Energy Regulatory Commission ("FERC") and the Massachusetts Department of Public Utilities ("DPU") provide the final determination of the rates that the Company charges its customers. In certain cases, the rate actions of the DPU can result in accounting that differs from non-regulated companies. In these cases, the Company defers costs (as regulatory assets) or recognizes obligations (as regulatory liabilities) if it is probable that such amounts will be recovered or refunded through the rate-making process, which would result in a corresponding increase or decrease in future rates.

D. Revenue Recognition

The Company bills its customers on a monthly cycle basis at approved tariffs based on energy delivered, a minimum customer service charge, and, in some instances, their demand. Revenues are determined based on these bills plus an estimate for unbilled energy delivered between the cycle meter read date and the end of the accounting period. These amounts are billed to customers in the next billing cycle following the month-end. Revenues are subject to a Decoupling Adjustment Factor which requires the Company to adjust annually its base rates to reflect the over or under recovery of the Company's targeted base distribution revenues from the prior season. Revenue decoupling is a rate-making mechanism that breaks the link between the Company's base revenue requirement and sales. This mechanism allows the Company to offer various energy efficiency measures to its customers without financial detriment to the Company resulting from reductions in electricity.

The Revenue Decoupling Mechanism ("RDM") requires the Company to adjust its base rates semi-annually to reflect the over or under recovery of the Company's targeted base distribution revenues from the prior season.

The Company's revenue from the sale and delivery of electricity for the years ended March 31, 2013 and March 31, 2012 is as follows:

	March 31,	
	2013	2012
Residential	**73%**	72%
Commercial	**24%**	25%
Industrial	**3%**	3%

E. Property, Plant and Equipment

Property, plant and equipment is stated at original cost. The cost of additions to property, plant and equipment and replacements of retired units of property are capitalized. Costs include direct material, labor, overhead and allowance for funds used during construction ("AFUDC"). The cost of renewals and betterments that extend the useful life of property, plant and equipment are also capitalized. The cost of repairs, replacements and major maintenance projects, which do not extend the useful life or increase the expected output of the asset, are expensed as incurred. Depreciation is generally computed over the estimated useful life of the assets using the composite straight-line method. Depreciation studies are conducted periodically to update the composite rates and are approved by the DPU. Whenever property, plant and equipment is retired, the original cost less salvage, is charged to accumulated depreciation, and the related cost of removal is removed from the associated regulatory liability.

The average composite rates and average service lives for the years ended March 31, 2013 and March 31, 2012 are as follows:

	March 31,	
	2013	2012
Composite rates - depreciation	**2.3%**	2.3%
Composite rates - cost of removal	**0.9%**	0.9%
Total composite rates	**3.2%**	3.2%
Average service life	**44 years**	44 years

The Company's depreciation expense includes estimated costs to remove property, plant and equipment, which is recovered through the rates charged to its customers. At March 31, 2013 and March 31, 2012, the Company had cumulative costs recovered in excess of costs incurred totaling $219.5 million and $196.6 million, respectively. These amounts are reflected as regulatory liabilities in the accompanying balance sheets.

In accordance with applicable regulatory accounting guidance, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds necessary to finance the construction of new regulated facilities. The equity component of AFUDC is a non-cash amount within the statements of income. AFUDC is capitalized as a component of the cost of property, plant and equipment, with an offsetting credit to other income deductions, net for the equity component and other interest expense for the debt component in the accompanying statements of income. After construction is completed, the Company is permitted to recover these costs through inclusion in its rate base and corresponding depreciation expense.

The components of AFUDC capitalized and composite AFUDC rates for the years ended March 31, 2013 and March 31, 2012 are as follows:

	March 31, 2013	March 31, 2012
	(in thousands of dollars)	
Debt	**$ 226**	$ 828
Equity	**167**	1,592
	$ 393	$ 2,420
Composite AFUDC rate	**0.9%**	4.8%

F. Goodwill

Goodwill represents the excess of the purchase price of a business 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 annually on January 31, and whenever events occur or circumstances change that would more likely than not reduce the fair value of the reporting unit below its carrying amount.

The goodwill impairment analysis is comprised of two steps. In the first step, the estimated fair value of the reporting unit is compared with its carrying value. If the fair value exceeds the carrying value, goodwill is not impaired and no further analysis is required. If the carrying value exceeds the fair value, then a second step is performed to determine the implied fair value of goodwill. If the carrying value of goodwill exceeds its implied fair value, then an impairment charge equal to the difference is recorded.

The Company calculated the fair value of the reporting unit in the performance of its annual goodwill impairment test for the fiscal year ended March 31, 2013 utilizing both income and market approaches, as described below. The Company ultimately determined the fair value of the business using 50% weighting for each valuation methodology, as it believes that each methodology provides equally valuable information.

- To estimate fair value utilizing the income approach, the Company used a discounted cash flow methodology incorporating its most recent business plan forecasts together with a projected terminal year calculation. Key assumptions used in the income approach were: (a) expected cash flows for the period from April 1, 2013 to March 31, 2018; (b) a discount rate of 5.5%, which was based on the Company's best estimate of its after-tax weighted-average cost of capital; and (c) a terminal growth rate of 2.25%, based on the Company's expected long-term average growth rate in line with estimated long term US economic inflation.

- To estimate fair value utilizing the market approach, the Company followed a market comparable methodology. Specifically, the Company applied a valuation multiple of earnings before interest, taxes, depreciation and amortization ("EBITDA"), derived from data of publicly-traded benchmark companies, to business operating data. Benchmark companies were selected based on comparability of the underlying business and economics. Key assumptions used in the market approach included the selection of appropriate benchmark companies and the selection of an EBITDA multiple of 10.0, which the Company believes is appropriate based on comparison of its business with the benchmark companies.

The results of the first step of the goodwill impairment test indicated that the fair value of the reporting unit was less than its carrying value, and therefore performance of the second step of the goodwill impairment test was required. In the second step of the goodwill impairment test, the implied fair value of goodwill was determined by allocating the fair value of the reporting unit to all of its assets and liabilities and then computing the excess of the reporting unit's fair value over the amounts assigned to the assets and liabilities. Inherent in the Company's measurement of the implied fair value of goodwill is the assumption that any difference between the book value and fair value of the Company's long-term debt would not be recovered from customers under the Company's rate agreement. The

Company determined that the implied fair value of goodwill exceeded the carrying value of goodwill, and thus, no impairment or adjustment of the goodwill carrying value was necessary.

G. Available-For-Sale Securities

The Company holds available-for-sale securities which primarily include equities, municipal bonds and corporate bonds. These investments are recorded at fair value and are included in financial investments in the accompanying balance sheets.

H. Cash and Cash Equivalents

The Company classifies short-term investments that are highly liquid and have original maturities of three months or less as cash equivalents. Cash and cash equivalents are carried at cost which approximates fair value.

I. Restricted Cash and Special Deposits

Restricted cash consists of deposits to the Independent System Operator ("ISO") of New England, Inc., which serve to support the Company's obligations to the ISO as collateral.

Special deposits primarily include health care claims deposits of \$3.2 million and \$2.7 million at March 31, 2013 and March 31, 2012, respectively, and are included in other current assets in the accompanying balance sheets.

J. Allowance for Doubtful Accounts

The Company recognizes an allowance for doubtful accounts to record accounts receivable at estimated net realizable value. The allowance is calculated by applying a reserve factor to outstanding receivables. The reserve factor is based upon historical write-off experience and assessment of customer collectability.

K. Materials and Supplies

Materials and supplies are stated at the lower of weighted average cost or market and are expensed or capitalized into specific capital additions as used. At March 31, 2013 and March 31, 2012, the balance of materials and supplies was \$20.0 million and \$17.8 million, respectively. The Company's policy is to write off obsolete inventory. There were no material write offs of obsolete inventory for the years ended March 31, 2013 or March 31, 2012.

L. Income and Other Taxes

Federal and state 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. National Grid North America Inc. ("NGNA,"formerly National Grid Holdings Inc.), an indirectly-owned subsidiary of National Grid plc and the intermediate holding company of NGUSA, files consolidated federal tax returns including all of the activities of its subsidiaries. Each subsidiary company is included in the consolidated group and determines its current and deferred taxes based on the separate return method. The Company settles its current tax liability or benefit each year with NGNA pursuant to a tax sharing arrangement between NGNA and its included subsidiaries. Benefits allocated by NGNA are treated as capital contributions.

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 in the accompanying balance sheets that have been included in previous tax returns or are expected to be included in future tax returns. The accounting guidance for uncertainty in income taxes provides that the financial effects of a tax position shall initially be recognized in the financial statements when it is more likely than not, based on the technical merits, that the position will be sustained upon examination, assuming the position will be audited and the taxing authority has full knowledge of all relevant information.

The Company collects from customers various taxes that are levied by state and local governments on the sale or distribution of electricity. The Company presents taxes that are imposed on customers (such as sales taxes) on a net basis (i.e., excluded from revenues) and presents excise taxes on a gross basis.

M. Employee Benefits

The Company follows the accounting guidance for defined benefit pension and postretirement benefit ("PBOP") plans for recording pension expenses and resulting plan asset and liability balances. The guidance requires employers to fully recognize all pension and postretirement plans' funded status on the balance sheets as a net liability or asset. In the case of regulated entities, the offset to such net liability or asset is recorded as a regulatory asset or liability when the balance will be recovered from or refunded to customers in future rates. The Company has determined that such amounts will be included in future rates and follows the regulatory format for recording the balances. The Company measures and records its pension and PBOP obligations at the year-end date. Pensions and PBOP assets are measured at fair value, using the year-end market value of those assets.

N. Fair Value Measurements

The Company measures available for sale securities at fair value. 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:

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; and

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.

The asset or liability's fair value measurement level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. The Company uses valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

O. New and Recent Accounting Guidance

<u>*Accounting Guidance Adopted in Fiscal Year 2013*</u>

Fair Value Measurements

In May 2011, the Financial Accounting Standards Board ("FASB") issued accounting guidance that amended existing fair value measurement guidance. The amendment was issued with a goal of achieving 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, requires new disclosures about fair value measurements, and changes specific applications of the fair value measurement guidance. 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 became effective for financial statements issued for annual periods (for non-public entities such as the Company) beginning after December 15, 2011. The Company adopted this guidance for the fiscal year ended March 31, 2013, which only impacted its fair value disclosures. There were no changes to the Company's approach to measuring fair value as a result of adopting this new guidance.

Goodwill Impairment

In September 2011, the FASB issued accounting guidance related to goodwill impairment testing, whereby an entity has the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If, after assessing the totality of events or circumstances, an entity determines it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the two-step impairment test is not required. Otherwise, the entity is required to perform the two-step impairment test. This guidance became effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. The Company adopted this guidance in its fiscal year ended March 31, 2013 and did not elect the option to perform a qualitative analysis.

Other Comprehensive Income

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 new guidance seeks to improve financial statement users' ability to understand the causes of an entity's change in financial position and results of operations. As a result of this guidance entities are required to either present the statement of income and statement of comprehensive income in a single continuous statement or in two separate, but consecutive statements of net income and other comprehensive income. This guidance does not change the items that are reported in other comprehensive income or any reclassification of items to net income. In addition, the new guidance does not change an entity's option to present components of other comprehensive income net of or before related tax effects. This guidance became effective for non-public companies for fiscal years ending after December 15, 2012, and for interim and annual periods thereafter, and it is to be applied retrospectively. The Company adopted this guidance for the fiscal year ended March 31, 2013, with no impact on its financial position, results of operations, or cash flows.

<u>*Accounting Guidance Not Yet Adopted*</u>

Offsetting Assets and Liabilities

In December 2011, the FASB issued accounting guidance requiring enhanced disclosure related to offsetting assets and liabilities. Under the new guidance, reporting entities will be required to disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting agreement, such as for derivatives. In January 2013, the FASB issued additional guidance to clarify that the specific instruments and activities that should be considered in these disclosures will be limited to recognized derivatives, repurchase and reverse repurchase agreements, and securities lending transactions. This guidance is effective for fiscal years, and interim periods within those years, beginning after January 1, 2013, and is to be applied retrospectively. The Company will begin including the new required disclosures in its fiscal year 2014 quarterly financial statements as applicable and does not expect any impact on its financial position, results of operations, or cash flows.

Reclassifications From Accumulated Other Comprehensive Income

In February 2013, the FASB issued accounting guidance that requires an entity to report information about significant reclassifications out of accumulated other comprehensive income. The new guidance requires presentation either in a single footnote or parenthetically on the financial statements, of the effect of significant amounts reclassified out of accumulated other comprehensive income based on the corresponding line items in the statement of net income. For amounts that are not required to be reclassified in their entirety to net income in the same reporting period, an entity would cross-reference other disclosures that provide additional detail about those amounts. The amendments do not change the current requirements for reporting net income or other comprehensive income in the financial statements. For non-public entities, the amendments are effective prospectively for reporting periods beginning after December 15, 2013. Early adoption is permitted. The Company is evaluating the impact, if any, on its financial position, results of operations, and cash flows.

Q. Financial Statement Revisions and Reclassifications

During 2013, management determined that the Company's previously issued financial statements for the year ended March 31, 2012 included errors related to the recording of certain accounting transactions. The Company corrected these errors by revising the prior period financial statements, the impacts of which are described below. Management has concluded that the errors did not have a material impact on any previously issued financial statements but would have been material if the corrections were recorded in the current year statement of income. Therefore, the previously reported amounts were revised within the financial statements for the year ended March 31, 2012.

The first error related to a correction of software depreciation charges allocated from NGUSA's service company. A cumulative adjustment of $0.4 million (net of income taxes) was recorded in the financial statements for the year ended March 31, 2012 as a reduction of net income to reflect the fiscal 2012 activity related to this error.

The second error related to a correction of deferred storm costs determined as a result of a full scope review of costs incurred over the prior 18 month period to be submitted for rate recovery. A cumulative adjustment of $2.4 million (net of income taxes) was recorded in the financial statements for the year ended March 31, 2012, of which $0.1 million was recorded as an adjustment to beginning retained earnings (as of March 31, 2011), and $2.3 million was recorded as a reduction of net income for the year ended March 31, 2012 to reflect the fiscal 2012 activity related to this error.

The third error related to incorrect recording of transactions related to distributed generation work performed by the Company, which should have been recorded as a contra-balance to utility plant, rather than as revenue. A cumulative adjustment of $1.2 million (net of income taxes) was recorded in the financial statements for the year ended March 31, 2012 as a reduction of net income to reflect the fiscal 2012 activity related to this error. In addition, this error resulted in reclassification of $2 million from cash flow from operating activities to cash flow from investing activities.

The fourth error related to insufficient property tax expenses being recorded relating to an updated assessment. A cumulative adjustment of $1.2 million (net of income taxes) was recorded in the financial statements for the year ended March 31, 2012 as a reduction of net income to reflect the fiscal 2012 activity related to this error.

The fifth error related to the incorrect accounting for share based awards. A cumulative adjustment of $1 million (net of income taxes) was recorded in the financial statements for the year ended March 31, 2012, of which $0.6 million was recorded as an adjustment to beginning retained earnings (as of March 31, 2011), and $0.4 million was recorded as an increase of net income for the year ended March 31, 2012 to reflect the fiscal 2012 activity related to this error.

In addition, certain misclassifications related to the presentation of current and deferred income taxes and uncertain tax positions have been reflected in the revisions below. The Company misclassified the current portion of deferred tax assets by $1.2 million and prepaid taxes by $29.9 million. These misclassifications in assets were offset by misclassifications in accrued taxes of $5.0 million, regulatory liabilities of $0.2 million, non-current deferred tax liabilities of $.9 million, and other deferred liabilities of $21.1 million. The adjustments for these balance sheet presentation errors in the prior fiscal year had an immaterial impact on the statement of income. In addition, amounts related to postemployment benefits of $12 million were reclassified from postretirement benefits and other reserves to other deferred liabilities. Further, amounts related to construction advances of $1.3 million were reclassified from cash flows from operating activities to cash flows from investing activities.

The following table shows the amounts previously reported as revised:

	As Previously Reported	Adjustments	As Revised
	March 2012	*(in thousands of dollars)*	March 2012
Balance Sheet			
Current assets			
Current portion of deferred income tax assets	$ 29,106	$ 1,160	$ 30,266
Prepaid taxes	32,023	(28,593)	3,430
Total Current assets	**562,497**	**(27,433)**	**535,064**
Property, plant, and equipment, net	2,316,747	(2,000)	2,314,747
Deferred charges and other assets			
Regulatory assets	607,375	(14,852)	592,523
Total Deferred charges and other assets	**1,628,511**	**(14,852)**	**1,613,659**
Current liabilities			
Accounts payable to affiliates	21,289	179	21,468
Taxes accrued	4,968	(4,968)	-
Total Current liabilities	**448,871**	**(4,789)**	**444,082**
Deferred credits and other liabilities			
Regulatory liabilities	343,872	(10,776)	333,096
Deferred income tax liabilities	511,970	(236)	511,734
Postretirement benefits	214,107	(11,993)	202,114
Other deferred liabilities	67,249	(12,206)	55,043
Total Deferred credits and other liabilities	**1,234,785**	**(35,211)**	**1,199,574**
Capitalization:			
Additional Paid-in Capital			
March 31, 2012	1,556,766	1,785	1,558,551
March 31, 2011	1,556,766	1,395	1,558,161
Retained Earnings			
March 31, 2012	382,631	(6,070)	376,561
March 31, 2011	298,282	(1,507)	296,775

	As Previously Reported	Adjustments	As Revised
		(in thousands of dollars)	
	March 2012		March 2012
Statement of Income			
Operating revenues	$ 2,044,851	$ (2,000)	$ 2,042,851
Operating expense:			
Operations and maintenance	828,415	3,609	832,024
Other taxes	51,125	1,900	53,025
Operating income	190,158	(7,509)	182,649
Income before income taxes	139,163	(7,509)	131,654
Income taxes			
Current	(45,567)	(107)	(45,674)
Deferred	100,281	(2,839)	97,442
Net income	84,449	(4,563)	79,886
Statement of Cash Flows			
Net income	$ 84,449	$ (4,563)	$ 79,886
Provision for deferred income taxes	100,281	(2,839)	97,442
Pension and other postretirement expense	62,140	(3,082)	59,058
Regulatory assets and liabilities	(92,601)	3,591	(89,010)
Prepaid taxes and accruals	(15,674)	22,937	7,263
Accounts receivable from/payable to affiliates	(4,325)	1,676	(2,649)
Other liabilities	888	(21,416)	(20,528)
Net cash provided by operating activities	134,338	(3,696)	130,642
Capital expenditures	(171,399)	3,306	(168,093)
Net cash used in investing activities	(179,248)	3,306	(175,942)
Share based compensation	-	390	390
Net cash used in financing activities	40,275	390	40,665

Note 2. Rates and Regulation

The following table presents the Company's regulatory assets and regulatory liabilities at March 31, 2013 and March 31, 2012:

	March 31,	
	2013	2012
Regulatory assets	*(in thousands of dollars)*	
Current:		
Renewable energy certificates	**65,404**	54,272
Rate adjustment mechanisms	**27,383**	25,642
Loss on reacquired debt	**587**	-
Storm costs	**41,884**	-
Transmission service	**15,710**	-
Other	**4,435**	297
Total	**155,403**	80,211
Non-current:		
Postretirement benefits	**319,231**	337,755
Loss on reacquired debt	**3,859**	5,293
Environmental response costs	**98,044**	96,580
Storm costs	**200,030**	143,937
Other	**2,465**	8,958
Total	**623,629**	592,523
Regulatory liabilities		
Current:		
Rate adjustment mechanisms	**30,125**	74,224
Transmission service	**-**	6,238
Other	**3,677**	-
Total	**33,802**	80,462
Non-current:		
Cost of removal	**219,514**	196,599
Environmental response fund	**70,001**	70,970
Postretirement benefits	**34,739**	39,522
Regulatory deferred tax liabilities	**23,702**	22,289
Other	**3,930**	3,716
Total	**351,886**	333,096
Net regulatory assets	**$ 393,344**	$ 259,176

Cost of removal: The Company's current and prior rate plans have collected through rates an implied cost of removal for its plant assets. This regulatory liability represents costs collected from customers for costs associated with removing and disposing of replaced or retired assets. For a vast majority of its electric distribution assets, the Company uses these funds to remove the asset so a new one can be installed in its place.

Environmental response costs: This regulatory asset represents deferred costs associated with the Company's share of the estimated costs to investigate and perform certain remediation activities at sites with which it may be associated. The Company believes future costs, beyond the expiration of current rate plans, will continue to be recovered through rates.

Environmental response fund: This amounts represents the amount of customer contributions and insurance proceeds recovered to pay for costs to investigate and perform certain remediation activities at sites with which it may be associated.

Postretirement benefits: The Company is allowed to recover non-capitalized pension and PBOP costs outside of base rates through a separate factor. As a result, the Company is authorized to recover all pension and PBOP expenses from its customers. The difference in the costs of the Company's pension and PBOP plans from the amounts billed through this separate factor as well as the non-cash accrual of net actuarial gains and losses is deferred to a regulatory asset or liability to be recovered or refunded over the following three years.

Rate adjustment mechanisms: The Company is subject to a number of rate adjustment mechanisms such as for commodity costs, whereby an asset or liability is recognized resulting from differences between actual revenues and the underlying cost being recovered, or differences between actual revenues and targeted amounts as approved by the DPU.

Renewable energy certificate costs: Massachusetts has implemented regulations to encourage the use of renewable energy which require load serving entities (LSEs) to purchase a minimum percentage of their electric supplies from qualified renewable energy sources. The Commonwealth of Massachusetts has given various incentives like renewable energy certificates (REC) to the producers of renewable energy. LSEs need to purchase RECs associated with renewable energy and not necessarily the energy itself to demonstrate compliance with the state regulations.

The Company does not self-generate any RECs but rather purchases them from various providers primarily via standalone contracts. Purchased RECs are recorded within prepaid and other current assets on the accompanying balance sheets. In addition, the Company records a compliance liability based on retail electricity sales, which are classified within other current liabilities or other deferred liabilities on the accompanying balance sheets based on the period of the compliance requirement. The costs associated with the RPS are recoverable from customers through rate adjustment mechanism. As a result, expenses associated with the compliance obligation are deferred as a regulatory asset and relieved through the rate adjustment mechanism. The Company does not expect to make any alternative compliance payment related to it calendar year 2012 requirement as it had sufficient RECs to meet its obligation.

Storm costs: This regulatory asset represents the incremental operation and maintenance costs to restore power to customers resulting from major storms. Additionally, the Company's rate order allows for the operation of a storm fund whereby the Company collects through rates an amount meant to offset incurred storm costs. The Company may use money in the fund for incremental storm costs that exceed a $1.25 million threshold per event, subject to the Department reviewing the costs and determining that they have been reasonably and prudently incurred. The regulatory asset recorded represents the excess of incremental operation and maintenance costs which have been incurred by the Company to restore power to customers resulting from major storms above the amount collected in the storm fund.

Transmission service: The Company arranges transmission service on behalf of its customers' and bills the costs of those services to customers pursuant to the Company's Transmission Service Cost Adjustment Provision. Any over or under recoveries of these costs are passed on to customers receiving transmission service through the Company over the subsequent twelve months.

Carrying Charges: The Company includes in rate base or records carrying charges on most regulatory balances related to renewable energy certificates, rate adjustment mechanisms, storm costs and environmental response costs for which cash expenditures have been made and are subject to recovery, or for which cash has been collected and is subject to refund. Carrying charges are not recorded on items for which expenditures have not yet been made. If recovery is not concurrent with the cash expenditures, the Company will record the appropriate level of carrying charges. Carrying charges are not earned on loss on reacquired debt and transmission service. Losses on reacquired debt have recovery periods ranging from five to thirty-four years.

The following table presents the carrying charges that were recognized in the accompanying statement of income during the years ended March 31, 2013 and March 31, 2012:

	March 31,	
	2013	2012
	(in thousands of dollars)	
Other interest (expense) income , including affiliate interest	**$ (1,358)**	$ 3,815
Other income, net	**12,591**	222
	$ 11,233	$ 4,037

Rate Matters

Rates for services rendered by the Company are subject to approval by the DPU. The DPU approved an RDM arising from the 2009 distribution rate case filed by the Company and its affiliate, Nantucket Electric Company ("Nantucket Electric"). In connection with the Company's first RDM filing made in November 2010 and supplemented in February 2011, the DPU opened a proceeding in March 2011, as requested by the Massachusetts Attorney General's Office ("Attorney General"), for an independent audit of the Company's 2009 capital investments which, in part, formed the basis for the Company's RDM rate adjustment. The selection of an auditor, following a competitive solicitation process that has been completed, is at the discretion of the DPU. The Company cannot currently predict the outcome of this proceeding.

As part of their last general rate case, the Company and Nantucket Electric received approval from the DPU to recover approximately $65.7 million of incremental costs associated with a December 2008 winter storm ("December 2008 Storm") subject to further DPU review, reconciliation and demonstration by the Company and Nantucket Electric that they reasonably and prudently incurred the costs. On April 1, 2011, the Company and Nantucket Electric filed an audit report of costs incurred to restore electric service following the December 2008 Storm. On December 7, 2011 the DPU issued an interlocutory order requiring the companies to file testimony in support of the reasonableness and prudency of the costs. On March 1, 2012 the companies filed testimony consistent with the requirements of the interlocutory order and reduced their request for recovery to $64.9 million. On July 3, 2012, the Attorney General issued rebuttal testimony challenging certain of the Company's costs. Hearings were held at the DPU in August 2012. Following the hearings, the Company and Nantucket Electric reduced their request for recovery to $64.8 million.

The Company and Nantucket Electric have deferred net costs of approximately $214 million as of March 31, 2013, net of customer contributions to the Company's Storm Contingency Fund, to restore power associated with several major weather events occurring since January 2010, pending ultimate approval by the DPU to charge its deferred costs to the Company's Storm Contingency Fund. This amount represents approximately $228 million of deferred storm costs, excluding net carrying costs of $16 million. On March 5, 2013, the Company and Nantucket Electric filed with the DPU a request for accelerated funding for the Company's Storm Contingency Fund of $40 million per year over a period of up to five years, or $200 million. On May 3, 2013, the DPU approved $40 million annually for up to three years, or $120 million. In its ruling, the DPU also directed the Company and Nantucket Electric to submit two filings of all documentation supporting its storm costs for DPU approval. The Company and Nantucket Electric submitted the first filing for $128 million of costs on May 31, 2013 for qualifying storms occurring during calendar years 2010 and 2011. The Company and Nantucket Electric must submit documentation of storm costs incurred during calendar year 2012 and January and February 2013 by December 31, 2013. The Company cannot currently predict the outcome of any proceedings related to storm recovery.

In addition to the rates and tariffs put into effect following its most recent rate case, the Company continues to be authorized to recover costs associated with the procurement of electricity for its customers, all transmission costs, and costs charged by the Company's affiliate NEP, for stranded costs associated with NEP's former electric generation investments.

The Company's affiliate, NEP, operates the transmission facilities of its New England affiliates as a single integrated system and reimburses the Company for the cost of limited transmission facilities owned by Massachusetts Electric, including a return on those facilities, under NEP's Tariff No. 1. In turn, these costs are allocated among transmission customers in New England in accordance with the ISO New England transmission tariff. Massachusetts Electric is compensated for its actual monthly transmission costs with its authorized ROE ranging from 11.14% to 12.64% based on the prevailing ROE approved by the FERC for transmission rates in New England. Under this agreement, the Company received payments from NEP in the amount of $10.3 million and $8.5 million for the years ended March 31, 2013 and 2012, respectively.

On September 30, 2011, several state and municipal parties in New England, including the Attorney General, the Connecticut Public Utilities Regulatory Authority and the DPU ("Complainants"), filed with the FERC a complaint under Section 206 of the Federal Power Act against certain New England Transmission Owners, including NEP ("NETOs"), to lower the base ROE for transmission rates in New England from the FERC approved rate of 11.14%, to 9.2%. On May 3, 2012, the FERC set the matter for hearing and settlement procedures. A hearing on the initial complaint commenced on May 6, 2013 and concluded on May 10, 2013.

On August 6, 2013, a FERC Administrative Law Judge ("ALJ") issued an Initial Decision in the complaint proceeding, finding that the just and reasonable base ROE for the refund period is 10.6% and the just and reasonable base ROE for the prospective period is 9.7%, prior to any adjustments that would be applied by the FERC in a final order based on the change in 10-year US Treasury Bond rates from the date hearings closed to the date of the FERC's order. The refund period is the 15-month period from October 1, 2011 through December 31, 2012. The prospective period begins when the FERC issues its order on the Initial Decision. An ALJ's Initial Decision does not itself affect the ROE rate or create an obligation to issue refunds to customers. Instead, the FERC will act on the Initial Decision and adopt or modify the ALJ's recommendations in an order that is expected no sooner than early 2014. Although the ALJ's Initial Decision is non-binding upon the FERC, based on an evaluation of facts and circumstances, and consideration of the accounting guidance for contingencies, the Company has recorded a reduction of regulatory asset of $4.2 million for the portion that would be refunded to the customers through existing rate agreements.

On December 27, 2012, a new ROE complaint was filed against the NETOs by a coalition of consumers seeking to lower the base ROE for New England transmission rates to 8.7% effective as of December 27, 2012. The FERC has not yet acted on this complaint.

Other Regulatory Matters

In the general rate case involving the Company's Massachusetts gas distribution affiliates, the DPU opened an investigation to address the allocation and assignment of costs to the gas affiliates by the National Grid service companies. In June 2011, the Attorney General's Office requested that the DPU expand the scope of the audit to address the allocation and assignment of costs to the Company by the NGUSA service companies and to review NGUSA's cost allocation practices. NGUSA agreed to expand the scope of the audit to its Massachusetts electric distribution companies. On March 12, 2012 the DPU issued an order confirming that the scope of the audit would include the Massachusetts electric distribution companies. The Company issued the Request for Proposal ("RFP") in April 2012 and on May 21, 2012 informed the DPU that no bids were received. The Company revised the RFP and it is now pending before the DPU for approval. The Company cannot currently predict the outcome of this proceeding.

In January 2011, the DPU opened an investigation into the Company and Nantucket Electric's preparation and response to a December 2010 winter storm. The DPU has the authority to issue fines not to exceed approximately $0.3 million for each violation for each day that the violation persists. On September 22, 2011, the DPU approved a settlement between the Company and the Attorney General that included a $1.2 million refund to customers. The DPU also investigated the Company and Nantucket Electric's response to Tropical Storm Irene and the October 2011 winter storm in a consolidated proceeding. On December 11, 2012, the DPU issued an order in which it assessed the Company and Nantucket Electric a penalty of $18.7 million associated with the Company and Nantucket Electric's performance in responding to these two weather events, consisting of $8.1 million for Tropical Storm Irene and $10.6 million for the October 2011 winter storm. This amount is included in other deductions, net in the accompanying statements of income. The Company and Nantucket Electric have appealed this ruling, however credited customers during March 2013 subject to recoupment of the amount of penalty, if any, vacated by the court pursuant to the Company's appeal. In addition, in its order, the DPU ordered a management audit of the Company and Nantucket Electric's emergency planning, outage management, and restoration. The Company cannot predict the outcome of the appeal or of the management audit.

Energy Efficiency and Renewables

Pursuant to the 2008 Green Communities Act, the Massachusetts Legislature mandated large scale and innovative ideas for implementing renewable and alternative energy sources, as well as increased energy efficiency spending. On January 28, 2013, the DPU approved the Company's second three-year energy efficiency plan which covers calendar years 2013 through 2015 and which significantly expands energy efficiency spending. The Company's approved electric energy efficiency budget for calendar years 2013 through 2015 is approximately $680 million. In addition to cost recovery, the Company has the opportunity to earn performance incentives over the 3-year period of the plan.

In October 2009 the DPU approved the Company and Nantucket Electric's proposal to construct, own, and operate approximately 5 MW of solar generation on five separate properties owned by the Company and/or its affiliates in Dorchester, Everett, Haverhill, Revere, and a location on the Sutton/Northbridge border. The actual capital cost of the projects amounted to $29 million. As each unit went into service, the Company and Nantucket Electric requested and received approval to recover the costs of each site with a return equal to the weighted average cost of capital approved by the DPU in the Company's most recent rate proceeding. The Company and Nantucket Electric requested rate adjustments under this mechanism for the Sutton/Northbridge facility in August 2010 for recovery of approximately $1.0 million, and for the Revere, Everett and Haverhill facilities in February 2011 for recovery of approximately $2.5 million. In February 2012, the Company and Nantucket Electric filed for recovery of approximately $1.4 million associated with the Dorchester facility. In each instance, the DPU issued an order approving recovery subject to its ongoing review and further investigation and reconciliation of the Company's costs for the sites. The DPU has issued final orders approving recovery for each of the sites.

In May 2010, the Company and Nantucket Electric announced that they entered into a 15-year power purchase agreement ("PPA") with Cape Wind Associates, LLC to purchase half of the energy, capacity and renewable energy credits generated by a proposed offshore wind project with capacity of up to 468 MW. The base price is specified at 18.7 cents per kilowatt hour beginning in 2014 and is subject to escalation by 3.5% in each annual period thereafter. The base price can be adjusted based on several factors, including eligibility for tax credits, the size of the facility, financing and construction costs, and performance. In November 2010, the DPU approved the PPA including the Company's proposed cost recovery mechanism with 4% remuneration on the contract cost, as provided for by the Green Communities Act. The Supreme Judicial Court of Massachusetts affirmed the DPU Order approving the PPA on December 28, 2011.Cape Wind expects the project to achieve initial commercial operation in May 2016. Construction of the project has not yet begun.

Note 3. Employee Benefits

The Company participates with other NGUSA subsidiaries in a qualified and non-qualified non-contributory defined benefit plan (the "Pension Plan") and PBOP plan (together with the Pension Plan (the "Plan")), covering substantially all employees. The Pension Plan is a defined benefit plan which provides union employees, as well as 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. The Company participates in the following plans: The Final Average Pay Pension Plan (FAPP), National Grid USA Companies' Executive SERP (Version I-FAPP) (ESRP), National Grid Deferred Compensation Plan, National Grid Executive Life Insurance Plan, Eastern Utilities Associates (EUA) Retirement Plans, Eastern Utilities Associates (EUA) Retirement Plans, National Grid Retirees Health and Life Plan I (Nonunion) and National Grid Retirees Health and Life Plan II (Union).

During the years ended March 31, 2013 and March 31, 2012, the Company made contributions of approximately $59.4 million and $24.6 million, respectively, to the Plan.

The PBOP Plan provides 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.

Plan's assets are commingled and cannot be allocated to an individual company. The Plan's costs are first directly charged to the Company based on the Company's employees that participate in the Plan. Costs associated with affiliated service companies' employees are then allocated as part of the labor burden for work performed on the Company's behalf. The Company applies deferral accounting for pension and PBOP expenses associated with its regulated electric operations. Any differences between actual pension costs and amounts used to establish rates are deferred and collected from or refunded to customers in subsequent periods. Pension and PBOP expense is included in operations and maintenance expenses in the accompanying statements of income.

NGUSA companies' pension and PBOP plans that the Company participates in have unfunded obligations at March 31, 2013 and March 31, 2012 are as follows:

	March 31,	
	2013	2012
	(in thousands of dollars)	
Pension Plan	**$ 471,000**	$ 493,600
PBOP	**368,100**	384,800
	$ 839,100	$ 878,400

The Company's net pension and PBOP expenses directly charged and allocated from affiliated service companies, net of capital, for the years ended March 31, 2013 and March 31, 2012 are as follows:

	Years Ended March 31,	
	2013	2012
	(in thousands of dollars)	
Pension Plan	**$ 27,454**	$ 21,655
PBOP	**14,732**	18,812
	$ 42,186	$ 40,467

Defined Contribution Plan

The Company has a defined contribution pension plan that covers substantially all employees. For each of the years ended March 31, 2013 and March 31, 2012, the Company recognized an expense of approximately $3.2 million in the accompanying statements of income for matching contributions.

Other Benefits

The Company accrued $5.7 million and $1.9 million at March 31, 2013 and March 31, 2012, respectively, regarding workers compensation, auto and general insurance claims which have been incurred but not yet reported.

Note 4. Property, Plant and Equipment

At March 31, 2013 and March 31, 2012, property, plant and equipment at cost along with accumulated depreciation and amortization are as follows:

	March 31, 2013	March 31, 2012
	(in thousands of dollars)	
Plant and machinery	**$ 3,438,586**	$ 3,330,305
Land and buildings	**169,739**	161,772
Assets held for future use	**562**	562
Assets in construction	**84,400**	66,130
Total	**3,693,287**	3,558,769
Accumulated depreciation	**(1,284,553)**	(1,244,022)
Property, plant and equipment, net	**$ 2,408,734**	$ 2,314,747

Note 5. Fair Value Measurements

Available for Sale Securities

The Company measures available for sale securities at fair value. Available for sale securities primarily included equities, preferred securities and cash equivalents based on quoted market prices in active markets (Level 1), and municipal and corporate bonds based on quoted prices of similar traded assets in open markets (Level 2).

The following table presents available for sale securities measured and recorded at fair value in the accompanying balance sheets on a recurring basis and their level within the fair value hierarchy as of March 31, 2013 and March 31, 2012:

	March 31, 2013			
	Level 1	**Level 2**	**Level 3**	**Total**
	(in thousands of dollars)			
Assets:				
Available for sale securities	**$ 2,584**	**$ 3,491**	**$ -**	**$ 6,075**

	March 31, 2012			
	Level 1	**Level 2**	**Level 3**	**Total**
	(in thousands of dollars)			
Assets:				
Available for sale securities	$ 2,451	$ 3,166	$ -	$ 5,617

A transfer into Level 3 represents existing assets or liabilities that were previously categorized at a higher level for which the inputs became unobservable. A transfer out of Level 3 represents assets and liabilities that were previously classified as Level 3 for which the inputs became observable based on the criteria discussed previously for classification in Level 2. These transfers, which are recognized at the end of each period, result from changes in the observability of forward curves from the beginning to the end of each reporting period. There were no transfers between Level 1 and Level 2, and no transfers into and out from Level 3 during the years ended March 31, 2013 and March 31, 2012, respectively.

Other Fair Value Measurements

The Company's balance sheets reflect the long-term debt at amortized cost. The fair market value of the Company's long-term debt was estimated based on the quoted market prices for similar issues or on the current rates offered to the Company for similar debt. The fair value of long-term debt at March 31, 2013 and March 31, 2012 was $1 billion and $964.5 million, respectively.

All other financial instruments on the balance sheets such as money pool and intercompany balances, accounts receivable and accounts payable are stated at cost, which approximates fair value.

Note 6. Income Taxes

The components of federal and state income tax expense (benefit) are as follows:

	Years Ended March 31,	
	2013	2012
	(in thousands of dollars)	
Current tax expense (benefit):		
Federal	**$ (65,277)**	$ (47,293)
State	**(4,002)**	1,619
Total	**(69,279)**	(45,674)
Deferred tax expense:		
Federal	**82,002**	89,061
State	**15,848**	9,608
Total	**97,850**	98,669
Amortized investment tax credits [1]	**(885)**	(1,227)
Total deferred tax expense	**96,965**	97,442
Total income tax expense	**$ 27,686**	$ 51,768

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

A reconciliation between the 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, 2013 and March 31, 2012 is as follows:

	Years Ended March 31,	
	2013	2012
	(in thousands of dollars)	
Computed tax	**$ 20,774**	$ 46,079
Change in computed taxes resulting from:		
State income tax, net of federal benefit	**7,700**	7,298
Investment tax credit	**(885)**	(1,227)
Other items - net	**97**	(382)
Total	**6,912**	5,689
Federal and state income taxes	**$ 27,686**	$ 51,768

Significant components of the Company's net deferred tax assets and liabilities at March 31, 2013 and March 31, 2012 are as follows:

	March 31,	
	2013	2012
	(in thousands of dollars)	
Deferred tax assets:		
Pensions, OPEB and other employee benefits	**$ 80,288**	$ 92,127
Reserve - environmental	**42,140**	41,578
Future federal benefit on state taxes	**30,109**	24,325
Regulatory liabilities - other	**17,475**	9,738
Allowance for uncollectible accounts	**13,192**	15,036
Net operating losses	**27,313**	-
Other items	**3,388**	4,466
Total deferred tax assets [(1)]	**213,905**	187,270
Deferred tax liabilities:		
Property related differences	**540,719**	469,876
Regulatory assets - pension and OPEB	**112,377**	114,800
Regulatory assets - storm costs	**97,624**	61,348
Other items	**29,947**	15,576
Total deferred tax liabilities	**780,667**	661,600
Net deferred income tax liabilities	**566,762**	474,330
Deferred investment tax credits	**9,040**	7,138
Net deferred income tax liabilities and investment tax credits	**575,802**	481,468
Current portion of net deferred income tax (liability) asset	**(7,520)**	30,266
Non-current deferred income tax liability and investment tax credits	**$ 568,282**	$ 511,734

(1) There were no valuation allowances for deferred tax assets at March 31, 2013 or March 31, 2012.

The following table presents the amounts and expiration dates of net operating losses as of March 31, 2013:

Expiration of net operating losses:	Federal
	(in thousands of dollars)
03/31/2024	$ 78,036

The Company is included in the NGNA and subsidiaries' consolidated federal income tax return. The Company has joint and several liability for any potential assessments against the consolidated group.

Unrecognized Tax Benefits

As of March 31, 2013 and March 31, 2012, the Company's unrecognized tax benefits totaled $37.9 million and $50.1 million, respectively, of which none would affect the effective tax rate, if recognized. The unrecognized tax benefits are included in other deferred liabilities in the accompanying balance sheets.

The following table reconciles the changes to the Company's unrecognized tax benefits for the years ended March 31, 2013 and March 31, 2012:

	Years Ended March 31,	
	2013	2012
	(in thousands of dollars)	
Balance at the beginning of the year	**$ 50,108**	$ 72,160
Gross decreases related to prior period	**(12,100)**	(28,970)
Gross decreases related to current period	**(1,601)**	(66)
Gross increases related to prior period	**359**	-
Gross increases related to current period	**1,111**	6,984
Balance at the end of the year	**$ 37,877**	$ 50,108

As of March 31, 2013 and March 31, 2012, the Company has accrued for interest related to unrecognized tax benefits of $1.3 million and $1.8 million, respectively. During the years ended March 31, 2013 and March 31, 2012, the Company recorded interest income of $0.5 million and interest expense of $0.3 million, respectively. The net interest income recorded in fiscal 2013 is attributable to a remeasurement based on an oral agreement with the IRS related to certain disputed issues. The Company recognizes accrued interest related to unrecognized tax benefits in other interest expense and related penalties, if applicable, in non-operating expenses. No tax penalties were recognized during the years ended March 31, 2013 and March 31, 2012.

In fiscal year 2013, as a result of recent experience by NGNA's consolidated group subsidiaries, the Company has remeasured its tax reserves for certain matters that are similar to matters agreed with the IRS by affiliate group members. Therefore, the Company believes that such matters will be concluded on similar terms and has concluded that in its assessment the potential exposure has declined and has reclassified a portion of its reserve for uncertain tax positions, in the amount of $11,520, to deferred tax liability.

In fiscal year 2012, the Company adopted Revenue Procedure 2011-43, which provides a safe harbor method of accounting that taxpayers may use to determine whether expenditures to maintain, replace, or improve electric transmission and distribution property must be capitalized under Section 263(a) of the Internal Revenue Code and therefore has reversed $26 million of tax reserves related to unrecognized tax benefits recorded in prior years, with a corresponding offset in deferred tax liability.

It is reasonably possible that other events will occur during the next 12 months that would cause the total amount of unrecognized tax benefits to increase or decrease. However, the Company does not believe any such increases or decreases would be material to their results of operations, financial position, or liquidity.

In fiscal year 2012, the IRS commenced an audit of NGNA and subsidiaries for the fiscal years ending March 31, 2008 and March 31, 2009. Fiscal years ended March 31, 2010 through March 31, 2013 remain subject to examination by the IRS.

The Company is a member of the National Grid USA Service Company Massachusetts unitary group since December 2010. The tax returns for the fiscal years ended March 31, 2010 through March 31, 2013 remain subject to examination by the State of Massachusetts.

The following table indicates the earliest tax year subject to examination:

Jurisdiction	Tax Year
Federal	March 31, 2005*
Massachusetts	March 31, 2010

*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 filing 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.

Note 7. Debt

Short-term Debt

The Company has regulatory approval from the FERC to issue up to $750 million of short-term debt. The Company had no short-term debt outstanding to third-parties as of March 31, 2013 or March 31, 2012.

Long-term Debt

Senior Note

In November 2009, the Company issued $800 million of unsecured long-term debt at 5.9% with a maturity date of November 15, 2039. In conjunction with this debt issuance, the Company incurred debt issuance cost of $6.8 million which is being amortized over the life of the debt.

Pollution Control Revenue Bonds

In 2004, the Company issued $20 million of pollution control revenue bonds maturing on August 1, 2014 with variable interest rates ranging from 0.35% to 0.90% for the year ended March 31, 2013 and rates ranging from 0.90% to 0.92% for the year ended March 31, 2012.

Bond Purchase Agreement

On March 31, 2012, the Company had a Standby Bond Purchase Agreement (“SBPA”) of $20.7 million, which expired in November 2012. The Company amended the SBPA to have a limit of $20 million and to expire on November 20, 2015. This agreement was available to provide liquidity support for $20 million of the Company’s long-term bonds in tax-exempt commercial paper mode. The Company has classified this debt as long-term due to its intent and ability to refinance the debt on a long-term basis if it is not able to remarket them. In addition, NGUSA has provided a letter of support which, in the event the SBPA is not in place, provides a sufficient means of funding on a long-term basis. At March 31, 2013 and March 31, 2012, there were no bond purchases made by the banks participating in this agreement.

The aggregate maturities of long-term debt subsequent to March 31, 2013 are as follows:

(in thousands of dollars)	
Year Ended March 31,	
2014	$ -
2015	20,000
2016	-
2017	-
2018	-
Thereafter	800,000
Total	$ 820,000

The Company is obligated to meet certain financial and non-financial covenants. During the years ended March 31, 2013 and March 31, 2012, respectively, the Company was in compliance with all such covenants.

Note 8. Commitments and Contingencies

Electricity Purchase and Capital Commitments

The Company has several types of long-term contracts for the purchase of electric power. The Company is liable for these payments regardless of the level of service required from third parties. The Company purchases any additional energy needed to meet its load requirements and can purchase the electricity through the ISO New England at market prices. In addition, the Company has various capital commitments related to the construction of plant, property and equipment.

The Company's commitments under these long-term contracts for years subsequent to March 31, 2013, are summarized in the table below:

(in thousands of dollars) Years Ending March 31,	**Energy Purchases**	**Capital Expenditures**
2014	$ 542,317	$ 116,243
2015	21,624	1,393
2016	-	11,856
2017	-	-
2018	-	-
Thereafter	-	-
Total	$ 563,941	$ 129,492

Asset Retirement Obligations

The Company has various asset retirement obligations associated with its distribution facilities. The following table represents the changes in the asset retirement obligations for the years ended March 31, 2013 and March 31, 2012:

	March 31,	
	2013	2012
	(in thousands of dollars)	
Balance as of beginning of year	**$ 1,633**	$ 1,822
Accretion expense	**77**	99
Liabilities settled	**(114)**	(388)
Liabilities incurred in the current year	**-**	100
Balance as of end of year	**$ 1,596**	$ 1,633

Guarantees

The Company unconditionally guarantees the full and prompt payment of the principal, premium, if any, and interest on certain tax exempt bonds issued by the Massachusetts Development Finance Agency in connection with Nantucket Electric's financing of its first and second underground and submarine cable projects. The Company would be required to make any principal, interest or premium payments if Nantucket Electric failed to pay. The carrying value of the debt guaranteed is approximately $52.3 million at March 31, 2013 and has maturities extending through 2042. This guarantee is absolute and unconditional.

Legal Matters

The Company is subject to various legal proceedings, primarily injury claims, arising out of the ordinary course of its business. The Company does not consider any of such proceedings to be material, individually or in the aggregate, 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. Under federal and state Superfund laws, potential liability for the historic contamination of property may be imposed on responsible parties jointly and severally, without regard to fault, even if the activities were lawful when they occurred.

The United States Environmental Protection Agency ("EPA") and the Massachusetts Department of Environmental Protection ("DEP"), as well as private entities, have alleged that the Company is a potentially responsible party ("PRP") under state or federal law for a number of sites at which hazardous waste is alleged to have been disposed. The Company's most significant liabilities relate to former manufactured gas plant ("MGP") facilities. The Company is currently investigating and remediating, as necessary, those MGP sites and certain other properties under agreements with the EPA and DEP. Expenditures incurred for the years ended March 31, 2013 and March 31, 2012 were $6.8 million and $7.4 million, respectively.

At March 31, 2013 and March 31, 2012, the Company had total reserves for environmental remediation costs of $96.2 million and $96.0 million, respectively, which include reserves established in connection with the Company's hazardous waste fund referred to below. These costs are expected to be incurred over the next 34 years. However, remediation costs for each site may be materially higher than estimated, depending upon changing technologies and regulatory standards, selected end use for each site, and actual environmental conditions encountered. The Company has recovered amounts from certain insurers, and, where appropriate, the Company may seek recovery from other insurers and from other PRPs, but it is uncertain whether, and to what extent, such efforts will be successful.

The DPU has approved a settlement agreement that provides for rate recovery of remediation costs of former MGP sites and certain other hazardous waste sites located in Massachusetts. Under that agreement, qualified costs related to these sites are paid out of a special fund established as a regulatory liability in the accompanying balance sheets. Rate-recoverable contributions of approximately $4 million are made along with interest, lease payments, and any recoveries from insurance carriers and other third parties. Accordingly, as of March 31, 2013 and March 31, 2012, the Company has recorded environmental regulatory assets of $98.0 million and $96.6 million, respectively, and environmental regulatory liabilities of $70.0 million and $71.0 million, respectively.

The Company believes that its ongoing operations, and its approach to addressing conditions at historic sites, are in substantial compliance with all applicable environmental laws, and that the obligations imposed on it because of the environmental laws will not have a material impact on its results of operations or financial position since, as noted above, environmental expenditures incurred by the Company are recoverable from customers.

Note 9. Related Party Transactions

Accounts Receivable from Affiliates and Accounts Payable to Affiliates

NGUSA and its affiliates provide various services to the Company, including executive and administrative, customer services, financial (including accounting, auditing, risk management, tax and treasury/finance), human resources, information technology, legal and strategic planning that are charged between the companies and charged to each company.

The Company records short-term payables to and receivables from certain of its affiliates in the ordinary course of business. The amounts payable to and receivable from its affiliates do not bear interest and are settled through the money pool. At March 31, 2013 and March 31, 2012, the Company had net outstanding accounts receivable from affiliates and accounts payable to affiliates balances as follows:

	Accounts Receivable from Affiliates		Accounts Payable to Affiliates	
	March 31, 2013	March 31, 2012	**March 31, 2013**	March 31, 2012
	(in thousands of dollars)		*(in thousands of dollars)*	
NGUSA	**$ 107**	$ 1,674	**$ -**	**$ -**
New England Power Co.	**-**	-	**23,565**	9,534
NGUSA Service Company	**-**	-	**45,883**	7,884
KeySpan Corp Services	**-**	-	**55**	2,900
Nantucket Electric	**-**	-	**2,180**	1,067
Niagara Mohawk Power Co.	**-**	874	**4,077**	-
The Narragansett Electric Co.	**159**	828	-	-
Metrowest Realty	**1,451**	1,423	-	-
Boston Gas Co.	**1,812**	817	-	-
Colonial Gas Co.	**388**	81	-	-
Other	**633**	438	**788**	83
	$ 4,550	$ 6,135	**$ 76,548**	$ 21,468

Money Pool

The settlement of the Company's various transactions with NGUSA and certain affiliates generally occurs via the money pool. As of November 1, 2012, NGUSA and its affiliates established a new Regulated Money Pool and an Unregulated Money Pool. Financing for the Company's working capital is obtained through participation in the Regulated Money Pool. The Company, as a participant in the Regulated Money Pool, can both borrow and lend funds. Borrowings from the Regulated and Unregulated Money Pools bear interest in accordance with the terms of the applicable money pool agreement. Since November 1, 2012, and because the Company now fully participates in the Regulated Money Pool rather than settling intercompany charges with cash, all changes in the intercompany moneypool balances and affiliate receivables and affiliate payables are reflected as investing or financing activities in the statement of cash flows.

The Regulated Money Pools is funded by operating funds from participants. Collectively, NGUSA and its subsidiary, KeySpan, have the ability to borrow up to $3 billion from National Grid plc for working capital needs including funding of the Money Pool, if necessary. The Company had short-term money pool borrowings of $162.3 million and $86.9 million at March 31, 2013 and March 31, 2012, respectively. The average interest rate for the money pool was approximately 0.6% and 0.2% for the years ended March 31, 2013 and March 31, 2012, respectively.

Related Party Reimbursement

In accordance with the Credit and Operating Support Agreement dated March 26, 1996, the Company will reimburse Nantucket Electric an amount equal to the difference between Nantucket Electric's actual net income for the year and the net income necessary for Nantucket Electric to earn an ROE equivalent to Nantucket Electric's DPU approved ROE for the fiscal year, currently 10.35%. This reimbursement shall constitute additional revenue to Nantucket Electric and an expense to the Company. To the extent Nantucket Electric's actual ROE for the year exceeds its allowed ROE, there will be no reimbursement. For the years ended March 31, 2013 and March 31, 2012, the Company reimbursed Nantucket Electric $3.8 million and $3.2 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 benefited 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 number of employees, number of customers/meters, capital expenditures, value of property owned, total transmission and distribution expenditures, etc. Lastly, all other costs are allocated based on a general allocator.

Charges from the service companies of NGUSA to the Company for the years ended March 31, 2013 and March 31, 2012 were $391.1 million and $348.4 million, 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 the Company, the estimated effect on net income would be approximately $5.3 million before taxes, and $3.4 million after taxes, for each of the years ended March 31, 2013 and March 31, 2012.

Note 10. Cumulative Preferred Stock

The Company has non-participating cumulative preferred stock outstanding which can be redeemed at the option of the Company. A summary of cumulative preferred stock at March 31, 2013 and March 31, 2012 is as follows:

	Shares Outstanding		Amount		
	March 31,		**March 31,**		Call
Series	**2013**	2012	**2013**	2012	Price
	(in thousands of dollars, except per share and number of shares data)				
4.44% Series	**22,585**	22,585	**$ 2,259**	$ 2,259	104.068

The Company did not redeem any preferred stock during the years ended March 31, 2013 and March 31, 2012.

Note 11. Dividend Restrictions

Pursuant to the preferred stock arrangement, as long as any preferred stock is outstanding, certain restrictions on payment of common stock dividends would come into effect if the common stock equity was, or by reason of payment of such dividends became, less than 25% of total capitalization. Common stock equity at March 31, 2013 and March 31, 2012 was approximately 71.3% and 71.0%, respectively, of total capitalization. Accordingly, the Company was not restricted as to the payment of common stock dividends under the foregoing provisions at March 31, 2013 or March 31, 2012.

The Narragansett Electric Company

Financial Statements

For the years ended March 31, 2013 and March 31, 2012

THE NARRAGANSETT ELECTRIC COMPANY

TABLE OF CONTENTS

pwc

Independent Auditor's Report

To the Shareholder and Board of Directors of The Narragansett Electric Company:

We have audited the accompanying financial statements of The Narragansett Electric Company, which comprise the balance sheets as of March 31, 2013 and March 31, 2012, and the related statements of income, comprehensive income, cash flows, capitalization and changes in shareholders' equity for the years then ended.

Management's Responsibility for the Financial Statements

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

Auditor's Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of The Narragansett Electric Company at March 31, 2013 and March 31, 2012, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

PricewaterhouseCoopers LLP

July 25, 2013

PricewaterhouseCoopers LLP, 300 Madison Avenue, New York, NY 10017
T: (646) 471 3000, F: (646) 471 8320, www.pwc.com/us

THE NARRAGANSETT ELECTRIC COMPANY
BALANCE SHEETS
(in thousands of dollars)

	March 31,	
	2013	2012
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 10,905**	$ 3,301
Restricted cash	**20,084**	20,057
Special deposits	**4,442**	36,767
Accounts receivable	**201,702**	176,349
Allowance for doubtful accounts	**(27,115)**	(31,961)
Accounts receivable from affiliates	**65,802**	10,480
Unbilled revenues	**60,273**	50,572
Materials, supplies, and gas in storage	**24,106**	27,256
Derivative contracts	**4,527**	448
Regulatory assets	**37,565**	61,759
Current portion of deferred income tax assets	**6,521**	11,631
Prepaid taxes	**75,134**	51,611
Prepaid and other current assets	**5,117**	1,661
Total current assets	**489,063**	419,931
Property, plant, and equipment, net	**1,986,075**	1,844,486
Deferred charges and other assets:		
Regulatory assets	**485,018**	293,136
Goodwill	**724,810**	724,810
Derivative contracts	**1,885**	44
Financial investments	**6,741**	6,663
Other deferred charges	**3,487**	883
Total deferred charges and other assets	**1,221,941**	1,025,536
Total assets	**$ 3,697,079**	$ 3,289,953

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

THE NARRAGANSETT ELECTRIC COMPANY
BALANCE SHEETS
(in thousands of dollars)

	March 31,	
	2013	2012
LIABILITIES AND CAPITALIZATION		
Current liabilities:		
Accounts payable	**$ 132,985**	$ 118,867
Accounts payable to affiliates	**30,970**	6,394
Current portion of long-term debt	**1,375**	1,375
Taxes accrued	**11,053**	5,932
Customer deposits	**8,364**	8,101
Interest accrued	**6,310**	3,436
Intercompany money pool	**56,880**	197,350
Regulatory liabilities	**56,381**	50,622
Derivative contracts	**3,459**	35,462
Other current liabilities	**21,434**	23,415
Total current liabilities	**329,211**	450,954
Deferred credits and other liabilities:		
Regulatory liabilities	**197,433**	191,291
Deferred income tax liabilities	**411,105**	275,081
Derivative contracts	**12**	10,382
Postretirement benefits	**146,541**	168,227
Environmental remediation costs	**136,714**	129,511
Other deferred liabilities	**59,330**	56,229
Total deferred credits and other liabilities	**951,135**	830,721
Capitalization:		
Shareholders' equity	**1,568,343**	1,408,758
Long-term debt	**848,390**	599,520
Total capitalization	**2,416,733**	2,008,278
Total liabilities and capitalization	**$ 3,697,079**	$ 3,289,953

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

THE NARRAGANSETT ELECTRIC COMPANY
STATEMENTS OF INCOME
(in thousands of dollars)

	Years Ended March 31,	
	2013	2012
Revenues:		
Electric services	**$ 813,925**	$ 803,329
Gas distribution	**398,656**	392,875
Total operating revenues	**1,212,581**	1,196,204
Operating expenses:		
Purchased electricity	**341,181**	368,839
Purchased gas	**203,012**	222,147
Operations and maintenance	**350,869**	324,832
Contract termination charges from affiliates	**7,383**	954
Depreciation and amortization	**79,377**	72,633
Amortization of rate plan deferrals	**5,737**	2,679
Other taxes	**89,914**	89,368
Total operating expenses	**1,077,473**	1,081,452
Operating income	**135,108**	114,752
Other income and (deductions):		
Interest on long-term debt	**(36,138)**	(34,230)
Other interest, including affiliate interest	**(2,940)**	(2,936)
Other income (deduction), net	**(2,166)**	(127)
Total other deductions, net	**(41,244)**	(37,293)
Income before income taxes	**93,864**	77,459
Income taxes:		
Current	**(48,770)**	(34,502)
Deferred	**81,938**	61,358
Income tax expense	**33,168**	26,856
Net income	**$ 60,696**	$ 50,603

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

THE NARRAGANSETT ELECTRIC COMPANY
STATEMENTS OF COMPREHENSIVE INCOME
(in thousands of dollars)

	Years Ended March 31,	
	2013	2012
Net income	**$ 60,696**	$ 50,603
Other comprehensive income (loss):		
Unrealized gains on securities, net of $111 and $144 tax expense	**207**	268
Changes in pension and other postretirement obligations, net of $2,731 and ($5,076) tax expense (benefit)	**7,850**	(9,426)
Adjustment for pension tracker, net of $54,481 tax expense	**90,588**	-
Reclassification of gains into net income, net of $191 and $200 tax expense	**354**	372
Other comprehensive income (loss)	**98,999**	(8,786)
Comprehensive income	**$ 159,695**	$ 41,817

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

THE NARRAGANSETT ELECTRIC COMPANY
STATEMENTS OF CASH FLOWS
(in thousands of dollars)

	Years Ended March 31, 2013	2012
Operating activities:		
Net income	**$ 60,696**	$ 50,603
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**79,377**	72,633
Amortization of rate plan deferrals	**5,737**	2,679
Provision for deferred income taxes	**81,938**	61,358
Amortization of debt discount	**224**	224
Bad debt expense	**16,648**	20,720
Pension and other postretirement expenses	**33,935**	26,564
Pension and other postretirement contributions	**(45,329)**	(33,748)
Net environmental remediation payments	**(1,930)**	(2,021)
Changes in operating assets and liabilities:		
Accounts receivable, net and unbilled revenues	**(56,548)**	17,873
Materials, supplies, and gas in storage	**3,150**	(5,214)
Accounts payable and accrued expenses	**50,281**	(23,985)
Prepaid and accrued taxes	**(18,403)**	4,626
Accounts receivable from/payable to affiliates, net	**(241)**	(27,553)
Derivative contracts	**460**	(251)
Other liabilities	**919**	(5,253)
Regulatory assets and liabilities, net	**(60,929)**	(59,313)
Other, net	**1,773**	(2,052)
Net cash provided by operating activities	**151,758**	97,890
Investing activities:		
Capital expenditures	**(235,100)**	(254,120)
Changes in restricted cash and special deposits	**32,298**	(9,716)
Cost of removal	**(17,360)**	(15,221)
Other	**343**	742
Net cash used in investing activities	**(219,819)**	(278,315)
Financing activities:		
Dividends paid on preferred stock	**(110)**	(110)
Proceeds from long-term debt	**250,000**	-
Payments on long-term debt obligation	**(1,375)**	(1,375)
Payment of debt issuance costs	**(1,875)**	-
Affiliated money pool borrowing and other	**(170,975)**	173,350
Net cash provided by financing activities	**75,665**	171,865
Net increase (decrease) in cash and cash equivalents	**7,604**	(8,560)
Cash and cash equivalents, beginning of year	**3,301**	11,861
Cash and cash equivalents, end of year	**$ 10,905**	$ 3,301
Supplemental disclosures:		
Interest paid	**$ (35,968)**	$ (33,844)
Income taxes refunded from Parent	**26,091**	24,651
Significant non-cash items:		
Capital-related accruals included in accounts payable	**8,515**	41,804

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

THE NARRAGANSETT ELECTRIC COMPANY
STATEMENTS OF CAPITALIZATION
(in thousands of dollars)

			March 31,	
			2013	2012
Total shareholders' equity			**$ 1,568,343**	$ 1,408,758
Long-term debt:	Interest Rate	Maturity Date		
Unsecured notes:				
Senior Note	4.534%	March 15, 2020	**250,000**	250,000
Senior Note	5.638%	March 15, 2040	**300,000**	300,000
Senior Note	4.170%	December 10, 2042	**250,000**	-
First Mortgage Bonds ("FMB"):				
FMB Series S	6.820%	April 1, 2018	**14,464**	14,464
FMB Series N	9.630%	May 30, 2020	**10,000**	10,000
FMB Series O	8.460%	September 30, 2022	**12,500**	12,500
FMB Series P	8.090%	September 30, 2022	**6,250**	6,875
FMB Series R	7.500%	December 15, 2025	**9,750**	10,500
Unamortized discounts			**(3,199)**	(3,444)
Total long-term debt			**849,765**	600,895
Long-term debt due within one year			**1,375**	1,375
Total long-term debt, excluding current portion			**848,390**	599,520
Total capitalization			**$ 2,416,733**	$ 2,008,278

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

THE NARRAGANSETT ELECTRIC COMPANY
STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(in thousands of dollars, except per share data)

	Common Stock, par value $50 per share		Cumulative Preferred Stock, par value $50 per share			Accumulated Other Comprehensive Income (Loss)					
	Authorized, Issued and Outstanding Shares	Amount	Authorized, Issued and Outstanding Shares	Amount	Additional Paid-in Capital	Unrealized Gain (Loss) on Available for Sale Securities	Hedging Activities	Pension and Postretirement Benefits	Total Accumulated Other Comprehensive Loss	Retained Earnings	Total
Balance at March 31, 2011	1,132,487	$ 56,624	49,089	$ 2,454	$ 1,353,559	$ 438	$ (6,102)	$ (89,003)	$ (94,667)	$ 49,081	$ 1,367,051
Net income	-	-	-	-	-	-	-	-	-	50,603	50,603
Comprehensive income:											
Unrealized gains on securities, net of $144 tax expense	-	-	-	-	-	268	-	-	268	-	268
Changes in pension and other postretirement obligations, net of ($5,076) tax benefit	-	-	-	-	-	-	-	(9,426)	(9,426)	-	(9,426)
Reclassification of (gains) lossess into net income, net of $200 tax expense	-	-	-	-	-	(122)	494	-	372	-	372
Dividends on preferred stock	-	-	-	-	-	-	-	-	-	(110)	(110)
Balance at March 31, 2012	1,132,487	56,624	49,089	2,454	1,353,559	584	(5,608)	(98,429)	(103,453)	99,574	1,408,758
Net income	-	-	-	-	-	-	-	-		60,696	60,696
Comprehensive income:											
Unrealized gains on securities, net of $111 tax expense	-	-	-	-	-	207	-	-	207	-	207
Changes in pension and other postretirement obligations, net of $2,731 tax expense	-	-	-	-	-	-	-	7,850	7,850	-	7,850
Adjustment for pension tracker, net of $54,481 tax expense	-	-	-	-	-	-	-	90,588	90,588	-	90,588
Reclassification of (gains) losses into net income, net of $191 tax expense	-	-	-	-	-	(107)	461	-	354	-	354
Dividends on preferred stock	-	-	-	-	-	-	-	-	-	(110)	(110)
Balance at March 31, 2013	1,132,487	$ 56,624	49,089	$ 2,454	$ 1,353,559	$ 684	$ (5,147)	$ 9	$ (4,454)	$ 160,160	$ 1,568,343

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

NOTES TO THE FINANCIAL STATEMENTS

Note 1. Summary of Significant Accounting Policies

A. Nature of Operations

The Narragansett Electric Company (the "Company," "we," and "our") is a retail distribution company providing electric service to approximately 492,000 customers and gas service to approximately 257,000 customers in 38 cities and towns in Rhode Island. The Company's service area covers substantially all of Rhode Island.

The Company is a wholly-owned subsidiary of National Grid USA ("NGUSA"), a public 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.

The Company has evaluated subsequent events and transactions through July 25, 2013, the date of issuance of these financial statements, and concluded that there were no events or transactions that require adjustment to or disclosure in the financial statements as of and for the year ended March 31, 2013.

B. Basis of Presentation

The financial statements for the years ended March 31, 2013 and March 31, 2012 are prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") including the accounting principles for rate-regulated entities. The financial statements reflect the rate-making practices of the applicable regulatory authorities.

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.

Within the statements of cash flows, all amounts that are settled through the Regulated Money Pool (refer to Note 11, "Related Party Transactions") are treated as constructive cash receipts and payments, and therefore are recorded as such.

C. Regulatory Accounting

The Federal Energy Regulatory Commission ("FERC"), the Rhode Island Public Utilities Commission ("RIPUC") and the Rhode Island Division of Public Utilities and Carriers ("Division") provide the final determination of the rates the Company charges its customers. In certain cases, the rate actions of the RIPUC can result in accounting that differs from non-regulated companies. In these cases, the Company defers costs (as regulatory assets) or recognizes obligations (as regulatory liabilities) if it is probable that such amounts will be recovered or refunded through the rate-making process, which would result in a corresponding increase or decrease in future rates.

D. Revenue Recognition

The Company bills its customers on a monthly cycle basis at approved tariffs based on energy delivered, a minimum customer service charge, and, in some instances, their demand. Revenues are determined based on these bills plus an estimate for unbilled energy delivered between the cycle meter read date and the end of the accounting period. These amounts are billed to customers in the next billing cycle following the month-end. Revenues are subject to a Decoupling Adjustment Factor which requires the Company to adjust semi-annually its base rates to reflect the over or under recovery of the Company's targeted base distribution revenues from the prior season. Revenue decoupling is a rate-making mechanism that breaks the link between the Company's base revenue requirement and sales. This mechanism allows the Company to offer various energy efficiency measures to its customers without financial detriment to the Company resulting from reductions in electricity and gas usage.

As approved by the RIPUC, the Company is allowed to pass through commodity-related costs to customers.

The Company's revenue from the sale and delivery of electricity and gas for the years ended March 31, 2013 and March 31, 2012 is as follows:

	Electric		Gas	
	March 31,		March 31,	
	2013	2012	**2013**	2012
Residential	**55%**	59%	**69%**	68%
Commercial and industrial	**45%**	41%	**31%**	32%

E. Property, Plant and Equipment

Property, plant and equipment is stated at original cost. The cost of additions to property, plant and equipment and replacements of retired units of property are capitalized. Costs include direct material, labor, overhead, and allowance for funds used during construction ("AFUDC"). The cost of renewals and betterments that extend the useful life of property, plant and equipment are also capitalized. The cost of repairs, replacements, and major maintenance projects, which do not extend the useful life or increase the expected output of the asset, are expensed as incurred. Depreciation is generally computed over the estimated useful life of the assets using the composite straight-line method. Depreciation studies are conducted periodically to update the composite rates and are approved by the RIPUC. Whenever property, plant and equipment is retired, the original cost, less salvage, is charged to accumulated depreciation, and the related cost of removal is removed from the associated regulatory liability.

The average composite rates and average service lives for the years ended March 31, 2013 and March 31, 2012 are as follows:

	Electric		Gas	
	March 31,		March 31,	
	2013	2012	**2013**	2012
Composite rates	**3.1%**	3.1%	**3.2%**	3.4%
Average service lives	**44 years**	44 years	**43 years**	43 years

The Company's depreciation expense includes estimated costs to remove property, plant and equipment, which is recovered through the rates charged to our customers. At March 31, 2013 and March 31, 2012, the Company had cumulative costs recovered in excess of costs incurred totaling \$160.1 million and \$155.8 million, respectively. These amounts are reflected as regulatory liabilities in the accompanying balance sheets.

In accordance with applicable regulatory accounting guidance, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds necessary to finance the construction of new regulated facilities. The equity component of AFUDC is a non-cash amount within the statements of income. AFUDC is capitalized as a component of the cost of property, plant and equipment, with an offsetting credit to other income (deductions), net for the equity component and other interest expense for the debt component in the accompanying statements of income. After construction is completed, the Company is permitted to recover these costs through inclusion in its rate base and corresponding depreciation expense.

The components of AFUDC capitalized and composite AFUDC rates for the years ended March 31, 2013 and March 31, 2012 are as follows:

	March 31,	
	2013	2012
	(in thousands of dollars)	
Debt	**$ 465**	$ 521
Equity	**488**	1,943
	$ 953	$ 2,464
Composite AFUDC	2.6%	6.8%

F. Goodwill

Goodwill represents the excess of the purchase price of a business 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 annually on January 31, and whenever events occur or circumstances change that would more likely than not reduce the fair value of the reporting unit below its carrying amount.

The goodwill impairment analysis is comprised of two steps. In the first step, the estimated fair value of the reporting unit is compared with its carrying value. If the fair value exceeds the carrying value, goodwill is not impaired and no further analysis is required. If the carrying value exceeds the fair value, then a second step is performed to determine the implied fair value of goodwill. If the carrying value of goodwill exceeds its implied fair value, then an impairment charge equal to the difference is recorded.

The Company calculated the fair value of the reporting unit in the performance of its annual goodwill impairment test for the fiscal year ended March 31, 2013 utilizing both income and market approaches.

- To estimate fair value utilizing the income approach, the Company used a discounted cash flow methodology incorporating its most recent business plan forecasts together with a projected terminal year calculation. Key assumptions used in the income approach were: (a) expected cash flows for the period from April 1, 2013 to March 31, 2018; (b) a discount rate of 5.5%, which was based on the Company's best estimate of its after-tax weighted-average cost of capital; and (c) a terminal growth rate of 2.25%, based on the Company's expected long-term average growth rate in line with estimated long term US economic inflation.

- To estimate fair value utilizing the market approach, the Company followed a market comparable methodology. Specifically, the Company applied a valuation multiple of earnings before interest, taxes, depreciation and amortization ("EBITDA"), derived from data of publicly-traded benchmark companies, to business operating data. Benchmark companies were selected based on comparability of the underlying business and economics. Key assumptions used in the market approach included the selection of appropriate benchmark companies and the selection of an EBITDA multiple of 10.0, which we believe is appropriate based on comparison of our business with the benchmark companies.

The Company ultimately determined the fair value of the business using 50% weighting for each valuation methodology, as we believe that each methodology provides equally valuable information. The resulting fair value of the annual analyses determined that no adjustment of the goodwill carrying value was required at March 31, 2013 or March 31, 2012.

G. Available-For-Sale Securities

The Company holds available-for-sale securities which primarily include equities, municipal bonds and corporate bonds. These investments are recorded at fair value and are included in financial instruments in the accompanying balance sheets.

H. Cash and Cash Equivalents

The Company classifies short-term investments that are highly liquid and have original maturities of three months or less as cash equivalents. Cash and cash equivalents are carried at cost which approximates fair value.

I. Restricted Cash and Special Deposits

Restricted cash primarily consists of deposits held by ISO New England, Inc. ("ISO-NE"). Special deposits primarily include collateral paid to the Company's counterparties for outstanding derivative contracts, health insurance and worker's compensation.

J. Allowance for Doubtful Accounts

The Company recognizes an allowance for doubtful accounts to record accounts receivable at estimated net realizable value. The allowance is calculated by applying a reserve factor to outstanding receivables. The reserve factor is based upon historical write-off experience and assessment of customer collectability.

K. Materials, Supplies and Gas in Storage

Materials and supplies are stated at the lower of weighted average cost or market and are expensed or capitalized into specific capital additions as used. At March 31, 2013 and March 31, 2012, material and supplies was $9.5 million and $9.3 million, respectively. The Company's policy is to write-off obsolete inventory. There were no material write-offs of obsolete inventory for the years ended March 31, 2013 or March 31, 2012.

Gas in storage is stated at weighted average cost, and is expensed when delivered to customers. Existing rate orders allow the Company to pass through the cost of gas purchased directly to customers along with any applicable authorized delivery surcharge adjustments. Accordingly, the value of gas in storage does not fall below the cost to the Company. Gas costs passed through to customers are subject to periodic regulatory approvals and are reported periodically to the RIPUC. At March 31, 2013 and March 31, 2012, gas in storage was $14.6 million and $17.9 million, respectively.

L. Income and Other Taxes

Federal 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. National Grid North America Inc. ("NGNA"), (formerly National Grid Holdings Inc.), an indirectly-owned subsidiary of National Grid plc and the intermediate holding company of NGUSA, files consolidated federal tax returns including all of the activities of its subsidiaries. Each subsidiary company is treated as a member of the consolidated group and determines its current and deferred taxes based on the separate return method. As a member, the Company settles its current tax liability or benefit each year with NGNA pursuant to a tax sharing arrangement between NGNA and its members. Benefits allocated by NGNA are treated as capital contributions. The Company has joint and several liability for any potential assessments against the consolidated group.

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 in the accompanying balance sheets that have been included in previous tax returns or are expected to be included in future tax returns. The accounting guidance for uncertainty in income taxes provides that the financial effects of a tax position shall initially be recognized in the financial statements when it is more likely than not, based on the technical merits, that the position will be sustained upon examination, assuming the position will be audited and the taxing authority has full knowledge of all relevant information.

The Company collects certain taxes from customers such as sales taxes, along with other taxes, surcharges, and fees that are levied by state or local governments on the sale or distribution of gas and electricity. The Company accounts for taxes that are imposed on customers (such as sales taxes), on a net basis (excluded from revenues).

M. Employee Benefits

The Company follows the accounting guidance related to the accounting for defined benefit pension and postretirement benefit ("PBOP") plans for recording pension expenses and resulting plan asset and liability balances. The guidance requires employers to fully recognize all pension and 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. In the case of regulated entities, this offsetting entry is recorded as a regulatory asset or liability when the balance will be recovered from or refunded to customers in future rates. The Company has determined that such amounts will be included in future rates and follows the regulatory format for recording the balances. The Company measures and records its pension and PBOP assets at the year-end date. Pension and PBOP assets are measured at fair value, using the year-end market value of those assets.

N. Derivatives

Derivatives are financial instruments that derive their value from the price of an underlying item such as interest rates, foreign exchange, credit spreads, commodities, equity or other indices. Derivatives enable their users to manage their exposure to these markets or credit risks. The Company uses derivative instruments to manage our operational market risks from commodities and economically hedge a portion of the Company's exposure to commodity price risk. When economic hedge positions are in effect, the Company is exposed to credit risks in the event of non-performance by counterparties to derivative contracts (hedging transactions), as well as non-performance by the counterparties of the underlying transactions.

Commodity Derivative Instruments – Regulated Accounting

The Company utilizes derivative financial instruments to reduce the cash flow variability associated with the purchase price for a portion of future natural gas purchases. The Company's strategy is to minimize fluctuations in firm gas sales costs to the Company's customers. The accounting for these derivative instruments is subject to the current accounting guidance for rate-regulated enterprises. Therefore the fair value of these derivatives is recorded as current or deferred assets or liabilities, with offsetting positions recorded as regulatory assets and regulatory liabilities in the accompanying balance sheets. Gains or losses on the settlement of these contracts are initially deferred and then refunded to or collected from the Company's customers consistent with regulatory requirements.

Certain non-trading contracts for the physical purchase of natural gas qualify for the normal purchase normal sales exception and are accounted for upon settlement. If the Company were to determine that a contract which it elected the normal purchase normal sale exception, no longer qualifies, the Company would recognize the fair value of the contract in accordance with the regulatory accounting described above.

Commodity Derivative Instruments – Non-Regulated Accounting

The Company also uses derivative instruments related to storage optimization, such as gas purchase contracts and swaps, to reduce the cash flow variability associated with forecasted purchases and sales of various energy-related commodities which do not receive regulatory recovery. All such derivative instruments are accounted for at fair value in the accompanying balance sheets with all changes in fair value reported in the statements of income.

Balance Sheet Offsetting

Accounting guidance relating to derivatives permits the offsetting of fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) arising from derivative instrument(s) recognized at fair value executed with the same counterparty under a master netting arrangement. The Company's accounting policy is to not offset fair value amounts recognized for derivative instruments and related cash collateral receivable or payable with the same counterparty under a master netting agreement, and to record and present the fair value of the derivative instrument on a gross basis, with related cash collateral recorded as special deposits in the accompanying balance sheets.

O. Fair Value Measurements

The Company measures commodity derivatives and available-for-sale securities at fair value. 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:

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; and

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.

The asset or liability's fair value measurement level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. The Company uses valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

P. New and Recent Accounting Guidance

<u>Accounting Guidance Adopted in Fiscal Year 2013</u>

Fair Value Measurements

In May 2011, the Financial Accounting Standards Board ("FASB") issued accounting guidance that amended existing fair value measurement guidance. The amendment was issued with a goal of achieving 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, requires new disclosures about fair value measurements, and changes specific applications of the fair value measurement guidance. 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 became effective for financial statements issued for annual periods (for non-public entities such as the Company) beginning after December 15, 2011. The Company adopted this guidance for the fiscal year ended March 31, 2013, which only impacted its fair value disclosures. There were no changes to our approach to measuring fair value as a result of adopting the new guidance.

Goodwill Impairment

In September 2011, the FASB issued accounting guidance related to goodwill impairment testing, whereby an entity has the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If, after assessing the totality of events or circumstances, an entity determines it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the two-step impairment test is not required. Otherwise, the entity is required to perform the two-step impairment test. This guidance became effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. The Company adopted this guidance in its fiscal year ended March 31, 2013 and did not elect the option to perform a qualitative analysis.

Other Comprehensive Income

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 new guidance seeks to improve financial statement users' ability to understand the causes of an entity's change in financial position and results of operations. As a result of this guidance entities are required to either present the statement of income and statement of comprehensive income in a single continuous statement or in two separate, but consecutive statements of net income and other comprehensive income. This guidance does not change the items that are reported in other comprehensive income or any reclassification of items to net income. In addition, the new guidance does not change an entity's option to present components of other comprehensive income net of or before related tax effects. This guidance became effective for non-public companies for fiscal years ending after December 15, 2012, and for interim and annual periods thereafter, and it is to be applied retrospectively. The Company adopted this guidance for the fiscal year ended March 31, 2013, with no impact on its financial position, results of operations, or cash flows.

Accounting Guidance Not Yet Adopted

Offsetting Assets and Liabilities

In December 2011, the FASB issued accounting guidance requiring enhanced disclosure related to offsetting assets and liabilities. Under the new guidance, reporting entities will be required to disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting agreement, such as for derivatives. In January 2013, the FASB issued additional guidance to clarify that the specific instruments and activities that should be considered in these disclosures will be limited to recognized derivatives, repurchase and reverse repurchase agreements, and securities lending transactions. This guidance is effective for fiscal years, and interim periods within those years, beginning after January 1, 2013, and is to be applied retrospectively. The Company will begin including the new required disclosures in its fiscal year 2014 interim financial statements as applicable and does not expect any impact on its financial position, results of operations, or cash flows.

Reclassifications From Accumulated Other Comprehensive Income

In February 2013, the FASB issued accounting guidance that requires an entity to report information about significant reclassifications out of accumulated other comprehensive income. The new guidance requires presentation either in a single footnote or parenthetically on the financial statements, of the effect of significant amounts reclassified out of accumulated other comprehensive income based on the corresponding line items in the statement of net income. For amounts that are not required to be reclassified in their entirety to net income in the same reporting period, an entity would cross-reference other disclosures that provide additional detail about those amounts. The amendments do not change the current requirements for reporting net income or other comprehensive income in the financial statements. For non-public entities, the amendments are effective prospectively for reporting periods beginning after December 15, 2013. Early adoption is permitted. The Company is evaluating the impact, if any, on its financial position, results of operations, and cash flows.

Q. Reclassifications

Certain reclassifications have been made to the financial statements to conform prior year's data to the current year's presentation. These reclassifications had no effect on the Company's results of operations and cash flows.

Note 2. Rates and Regulation

The following table presents the Company's regulatory assets and regulatory liabilities at March 31, 2013 and March 31, 2012:

	March 31, 2013	March 31, 2012
	(in thousands of dollars)	
Regulatory assets		
Current:		
Rate adjustment mechanisms	**$ 6,626**	$ 4,637
Revenue decoupling	**5,565**	12,575
Storm costs	**4,800**	-
Derivative contracts	**3,113**	35,459
2003 voluntary early retirement offer deferral	**1,883**	-
Losses on reacquired debt	**460**	-
Renewable energy certificates	**12,698**	9,088
Other	**2,420**	-
Total	**37,565**	61,759
Non-current:		
Postretirement benefits	**236,752**	90,164
Environmental response costs	**140,923**	133,964
Storm costs	**78,470**	11,833
Regulatory deferred tax assets	**14,137**	12,455
Losses on reacquired debt	**3,594**	4,600
Gas futures - gas supply	**2,440**	8,694
Derivative contracts	**12**	10,382
Cost to achieve	**-**	6,298
2003 voluntary early retirement offer deferral	**-**	4,395
Other	**8,690**	10,351
Total	**485,018**	293,136
Regulatory liabilities		
Current:		
Rate adjustment mechanisms	**22,770**	6,894
Energy efficiency	**28,555**	30,920
Derivative contracts	**4,511**	314
Gas costs	**545**	12,494
Total	**56,381**	50,622
Non-current:		
Cost of removal	**160,128**	155,768
Revaluation - pension and PBOP	**20,540**	23,783
Refund of customer credit	**8,364**	8,155
Environmental response fund	**1,872**	579
Derivative contracts	**1,885**	44
Other	**4,644**	2,962
Total	**197,433**	191,291
Net regulatory assets	**$ 268,769**	$ 112,982

Postretirement benefits: This amount primarily represents the excess costs of the Company's pension and postretirement benefits plans over amounts received in rates that are deferred to a regulatory asset to be recovered in future periods and the non-cash accrual of net actuarial gains and losses.

Environmental response costs: This regulatory asset represents deferred costs associated with the Company's share of the estimated costs to investigate and perform certain remediation activities at sites with which it may be associated. The Company's rate plans provide for specific rate allowances for these costs at a level of $4.4 million per year, with variances deferred for future recovery or return to customers. The Company believes future costs, beyond the expiration of current rate plans, will continue to be recovered through rates.

Storm costs: This regulatory asset represents the incremental costs to restore power to customers resulting from major storms. The Company's most recent settlement with RIPUC included reinstatement of base rate recovery of storm fund contributions at a level of $4.8 million per year, and then to $7.3 million per year effective January 1, 2014. The increase in storm costs is primarily attributable to the costs associated with restoring power to customers for Tropical Storm Sandy in October 2012, winter storm Nemo in February 2013, and other smaller storm events.

Rate adjustment mechanisms: The Company is subject to a number of rate adjustment mechanisms such as for commodity costs, whereby an asset or liability is recognized resulting from differences between actual revenues and the underlying cost being recovered, or differences between actual revenues and targeted amounts as approved by the RIPUC.

Cost of removal: The Company's current and prior rate plans have collected through rates an implied cost of removal for its plant assets. This regulatory liability represents costs collected from customers for costs associated with removing and disposing of replaced or retired assets. For a vast majority of its electric and gas distribution assets, the Company uses these funds to remove the asset so a new one can be installed in its place.

Carrying Charges: The Company includes in rate base or records carrying charges on most regulatory balances related to rate adjustment mechanisms, storm costs, postretirement benefits, and environmental costs for which cash expenditures have been made and are subject to recovery, or for which cash has been collected and is subject to refund. Carrying charges are not recorded on items for which expenditures have not yet been made. If recovery is not concurrent with the cash expenditures, the Company will record the appropriate level of carrying charges. Carrying charges are not earned on regulatory deferred tax assets or losses on reacquired debt. Losses on reacquired debt have a recovery period averaging ten years.

The following table presents the carrying charges that were recognized in the accompanying statements of income during the years ended March 31, 2013 and March 31, 2012:

	March 31,	
	2013	2012
	(in thousands of dollars)	
Other interest, including affiliate interest	**$ 1,051**	$ 2,179
Other income, net	**(342)**	(222)
	$ 709	$ 1,957

Rate Matters

On April 27, 2012, the Company filed an application with the RIPUC for an increase in electric base distribution revenue of approximately $31.4 million and gas base distribution revenue of approximately $20 million based upon a 10.75% ROE and a 49.60% common equity ratio. On December 20, 2012, the Commission approved a settlement agreement amongst the Division, the Department of the Navy, and the Company which provided for an increase in electric base distribution revenue of $21.5 million and an increase in gas base distribution revenue of $11.3 million based on a 9.5% allowed ROE and a common equity ratio of approximately 49.1%, effective February 1, 2013. The settlement also included reinstatement of base rate recovery of storm fund contributions at a level of $4.8 million per year, implementation of a pension adjustment mechanism for pension and PBOP expenses for the electric business identical to the mechanism in place for the gas business; and implementation of a property tax adjustment mechanism. New rates resulting from the approved settlement went into effect for both the electric and gas business on February 1, 2013.

In May 2010, Rhode Island enacted a decoupling law that provides for the annual reconciliation of the revenue requirement allowed in the Company's base distribution rate case to actual revenue billed by the electric and gas business. The new law also provides for submission and approval of an annual infrastructure spending plan spanning the fiscal year April 1 through March 31 without having to file a full general rate case. In the fiscal year 2013 plans, the Company requested a revenue requirement increase of approximately $4.1 million for the electric business and $5.4 million for the gas business, which the RIPUC approved for rates effective April 1, 2012. Because the Company's 2012 rate case rate base included forecasted capital investment through January 31, 2014, the Company's fiscal year 2014 infrastructure spending plans represented only two months of fiscal year 2014 to reflect investment not included in the Company's gas and electric distribution rates. In the plans, the Company requested a revenue requirement of $0.7 million for gas and $12.1 million for electric, which the RIPUC approved on March 21, 2013 and March 22, 2013, respectively.

The Company's affiliate, New England Power ("NEP") operates the transmission facilities of its New England affiliates as a single integrated system and reimburses the Company for the cost of its transmission facilities in Rhode Island, including a return on those facilities, under NEP's Tariff No. 1. In turn, these costs are allocated among transmission customers in New England in accordance with the ISO New England transmission tariff. Effective June 1, 2007, the FERC approved amendments to Tariff No. 1 whereby the Company is compensated for its actual monthly transmission costs with its authorized ROE ranging from 11.14% to 12.64%. The amounts reimbursed to the Company by NEP for the years ended March 31, 2013 and March 31, 2012 were $84.1 million and $66.2 million, respectively, which are included within operations and maintenance expense in the accompanying statements of income.

In September 2008, the Company, NEP, and Northeast Utilities jointly filed an application with the 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 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 Company's share of the NEEWS-related transmission investment is approximately $575 million and NEP's share is approximately $200 million. The Company is fully reimbursed for its transmission revenue requirements on a monthly basis by NEP through NEP's Tariff No. 1. Effective as of November 18, 2008, the FERC granted for NEEWS (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 sought rehearing of the FERC order. On June 28, 2011, the FERC denied all requests for rehearing.

As a condition of the FERC's approval, the FERC directed the Company to provide footnote disclosures in the notes to its financial statements which (1) fully explain the impact of construction work in progress ("CWIP") in rate base; (2) include details of AFUDC not capitalized because of CWIP in rate base for the current year, the previous two years, and the sum of all years; and (3) include partial balance sheets consisting of the assets and other debits section of the balance sheets to include the amounts of AFUDC not capitalized because of the inclusion of CWIP in rate base. As of March 31, 2013, the Company had total net electric utility plant assets excluding goodwill on its balance sheets of $1.3 billion including $122.4 million of CWIP. As of March 31, 2013 and March 31, 2012, the Companies' NEEWS-related CWIP and in-service investment totaled $405.5 million and $291.1 million, respectively.

On September 30, 2011, several state and municipal parties in New England, including the Massachusetts Attorney General's Office, the Connecticut Public Utilities Regulatory Authority and the Massachusetts Department of Public Utilities, filed with the FERC a complaint under Section 206 of the Federal Power Act against certain New England Transmission Owners, including NEP (the "NETOs"), to lower the base ROE for transmission rates in New England from the FERC approved rate of 11.14% to 9.2%, which may result in a reduction to the rates for NEP's support of the Company's transmission facilities. The FERC has conducted hearings on the matter and an initial decision by an Administrative Law Judge is expected by September 10, 2013. A final FERC order is expected no sooner than early 2014. Similarly, on December 27, 2012, a new ROE complaint was filed against the NETOs by a coalition of consumers seeking to lower the base ROE for New England transmission rates to 8.7% effective as of December 27, 2012. The FERC has not yet acted on this complaint.

In August 2012, the Company made its annual distribution adjustment charge ("DAC") filing for its gas business. The DAC was established to provide for the recovery and reconciliation of the costs of identifiable special programs, as well as to facilitate the timely revenue recognition of incentive provisions. The prior DAC rate recovered approximately $3.2 million from customers. On October 31, 2012, the RIPUC approved a DAC rate that will result in recovery of approximately $13.3 million from customers for the period November 2012 through October 2013.

The Company is allowed recovery of all of its electric and gas commodity costs through a fully reconciling rate recovery mechanism. In addition, the Company is allowed to recover from its electric customers all of its electric transmission costs and costs charged by the Company's affiliate NEP for stranded costs associated with NEP's former electric generation investments.

Long-Term Contracts for Renewable Energy

In 2009, Rhode Island passed a law promoting the development of renewable energy resources through long-term contracts for the purchase of capacity, energy, and attributes. The law also required the Company to negotiate a contract for an electric generating project fueled by landfill gas from the Rhode Island Central Landfill. The project, referred to as the Town of Johnston Project, is a combined cycle power plant with an average output of 32 megawatts ("MW") for which the Company entered into a contract with Rhode Island LFG Genco, LLC in June 2010. The facility reached commercial operation on May 28, 2013.

The 2009 law also required the Company to solicit proposals for a small scale renewable energy generation project of up to eight wind turbines with an aggregate nameplate capacity of up to 30 MW to benefit the Town of New Shoreham that also included a transmission cable to be constructed between Block Island and the mainland of Rhode Island. On June 30, 2010, the Company entered into a 20 year Amended Power Purchase Agreement ("PPA") with Deepwater Wind Block Island LLC ("Deepwater"), which was approved by the RIPUC in August 2010. The Company is currently negotiating with Deepwater to purchase the permits, engineering, real estate and other site development work for construction of the undersea transmission cable. The Company intends to file an unexecuted copy of the purchase agreement with the Division for review and consent in late summer 2013, following which the Company will make a filing with the FERC to recover the costs associated with the cable in transmission rates.

On July 28, 2011, the RIPUC unanimously approved a 15-year PPA with Orbit Energy Rhode Island, LLC for a 3.2 MW anaerobic digester biogas project. This is the first PPA that the Company submitted to the RIPUC for review as a result of the Company's annual solicitation process that was approved by the RIPUC on March 1, 2010. Following the Company's second annual solicitation, the Company executed a 15-year PPA with Black Bear Development Holdings, LLC on February 17, 2012, for a 3.9 MW run-of-river hydroelectric plant located in Orono, Maine. The Company submitted the PPA to the RIPUC on March 19, 2012. The RIPUC approved the PPA on May 11, 2012.

In June 2011, Rhode Island established a 10% carve out to the 90 MW of long-term contracting requirement for renewable energy to be used for long-term contracts for smaller DG projects over a four year period from 2011 through 2014. From 2011 through April 2013, the Company conducted four DG enrollments and awarded contracts for a total of approximately 18.4 MW of project nameplate capacity. In early July 2013, the Rhode Island legislature passed an amendment to state law that extended the deadline for meeting 100% of the long-term contract capacity from December 30, 2013 to December 30, 2014.

Energy Efficiency

On December 21, 2011, the RIPUC approved the annual Energy Efficiency ("EE") plan for the calendar year 2012, which includes a portfolio of electric and gas energy efficiency programs along with the associated budgets and electric and gas EE program charges for effect January 1, 2012. The calendar year 2012 electric and gas EE programs contain spending budgets of approximately $61.4 million and $13.7 million, respectively, which are to be collected through the approved EE program charges. On November 2, 2012, the Company filed its EE plan for the calendar year 2013 with proposed electric and gas spending budgets of $77.5 million and $19.5 million, respectively. This year's annual plan also contains a newly proposed combined heat and power ("CHP") program pursuant to a newly enacted amendment to the Rhode Island least cost procurement statute to support the development of CHP projects through energy efficiency. The plan consists of enhanced incentives and a proposed tariff amendment to assure that customers who receive incentives under the CHP program will continue to pay a fair share of the costs of the distribution system when the CHP unit is offline. The plan was approved by the RIPUC and reflected in rates effective January 1, 2013. On March 5, 2013, the Company filed a Petition with the RIPUC for approval of a $15.9 million incentive package to Toray Plastics (America), Inc. to install a 12.5 MW CHP system at their manufacturing facilities in North Kingstown, Rhode Island. This is the first incentive package offered pursuant to the 2013 EE Plan and the new law. The RIPUC approved the incentive package on June 20, 2013.

Note 3. Employee Benefits

The Company participates with other NGUSA subsidiaries in a qualified and non-qualified non-contributory defined benefit plan (the "Pension Plan") and PBOP (together with the Pension Plan (the "Plan")), covering substantially all employees. The Pension Plan 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. The Company participates in the following plans: The Final Average Pay Pension Plan, National Grid USA Companies' Executive SERP, National Grid Deferred Compensation Plan, Eastern Utilities Associates Retirement Plans, and National Grid Retirees Health and Life Plan I and II.

During the years ended March 31, 2013 and March 31, 2012, the Company made contributions of approximately $45.3 million and $33.7 million, respectively, to the Plan.

The PBOP Plan provides 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.

Plan assets are commingled and cannot be allocated to an individual company. The Plan's costs are first directly charged to the Company based on the Company's employees that participate in the Plan. Costs associated with affiliated service companies' employees are then allocated as part of the labor burden for work performed on the Company's behalf. The Company applies deferral accounting for pension and PBOP expenses associated with its regulated gas and electric operations. Any differences between actual pension costs and amounts used to establish rates are deferred and collected from or refunded to customers in subsequent periods. Pension and PBOP expense is included in operations and maintenance expenses in the accompanying statements of income.

NGUSA companies' pension and PBOP plans that the Company participates in have unfunded obligations at March 31, 2013 and March 31, 2012 as follows:

	March 31,	
	2013	2012
	(in thousands of dollars)	
Pension	**$ 471,000**	$ 493,600
PBOP	**368,100**	384,800
	$ 839,100	$ 878,400

The Company's net pension and PBOP expenses directly charged and allocated from affiliated service companies, net of capital, for the years ended March 31, 2013 and March 31, 2012 are as follows:

	Years Ended March 31,	
	2013	2012
	(in thousands of dollars)	
Pension	**$ 23,135**	$ 15,191
PBOP	**11,423**	13,308
	$ 34,558	$ 28,499

Pension Adjustment Mechanism ("PAM")

In February 2013, the RIPUC approved implementation of a PAM for the Company's electric operations. The PAM reconciles annual pension and PBOP expense with a base amount established in distribution rates through a base-rate proceeding and allows for recovery of the difference between the rate base amount and an annual expense. As a result of the implementation of a rate tracker, the Company reclassified $145.1 million, pre-tax, of accumulated other comprehensive income to regulatory assets. This reclassification is presented as an adjustment to accumulated other comprehensive income in the accompanying statements of comprehensive income.

In implementing the PAM, the Company will pay a carrying charge to customers at the weighted average cost of capital, which will be applied to any cumulative shortfall between the minimum funding obligation and amounts contributed to the pension and PBOP plans by the Company and/or its affiliated service company. The minimum funding obligation is equal to the amount of pension and PBOP costs recovered from customers, plus amounts capitalized on the Company's balance sheet. This carrying charge is asymmetrical, meaning that it is not applied to any excess Company contributions based on the same criteria.

Defined Contribution Plan

The Company has a defined contribution pension plan that covers substantially all employees. For the years ended March 31, 2013 and March 31, 2012, we recognized $2.0 million and $2.3 million of expense, respectively, in the accompanying statements of income for matching contributions.

Note 4. Property, Plant and Equipment

At March 31, 2013 and March 31, 2012, property, plant and equipment at cost along with accumulated depreciation and amortization are as follows:

	March 31,	
	2013	2012
	(in thousands of dollars)	
Plant and machinery	**$ 2,482,843**	$ 2,168,325
Land and buildings	**106,694**	111,774
Assets in construction	**180,879**	313,192
Software	**30,058**	29,758
Property held for future use	**15,016**	15,013
Total	**2,815,490**	2,638,062
Accumulated depreciation and amortization	**(829,415)**	(793,576)
Property, plant and equipment, net	**$ 1,986,075**	$ 1,844,486

Note 5. Renewable Energy Credits

Legislation in Rhode Island has established requirements to foster the development of new renewable energy sources through implementation of a Renewable Portfolio Standard ("RPS"). As a Retail Electricity Supplier ("RES"), the Company is required to source a minimum portion of its resources each calendar year from certain renewable or alternative energy resources, such as wind, solar, municipal waste combustion, coal gasification, cogeneration, and flywheel energy storage. To demonstrate compliance with the program, an RES can (1) obtain and deliver renewable energy credits ("RECs"); (2) contract for the output from a renewable or alternative energy resource; or (3) make an alternative compliance payment for each MWh of obligation not met under alternatives (1) or (2).

The Company does not self-generate any RECs but rather purchases them from various providers primarily via standalone contracts. Purchased RECs are recorded within prepaid and other current assets on the accompanying balance sheets. In addition, the Company records a compliance liability based on retail electricity sales, which are classified within other current liabilities or other deferred liabilities on the accompanying balance sheets based on the period of the compliance requirement. Our costs associated with the RPS are recoverable from customers through our rate adjustment mechanism. As a result, expenses associated with the compliance obligation are deferred as a regulatory asset and relieved through the rate adjustment mechanism. We recorded a regulatory asset of $12.7 million and $9.1 million as of March 31, 2013 and March 31, 2012, respectively. The Company does not expect to make any alternative compliance payment related to it calendar year 2012 requirement as it had sufficient RECs to meet its obligation.

Note 6. Derivatives

In the normal course of business, the Company enters into commodity derivative instruments, such as futures, swaps, and physical contracts that are principally used to manage commodity prices associated with natural gas distribution operations. These financial exposures are monitored and managed as an integral part of the Company's overall financial risk management policy. The Company generally engages in activities at risk only to the extent that those activities fall within commodities and financial markets to which it has a physical market exposure in terms and volumes consistent with its core business.

The Company utilizes derivative financial instruments to reduce the cash flow variability associated with the purchase price for a portion of future natural gas purchases. The Company's strategy is to minimize fluctuations in firm gas sales prices to the Company's customers. The Company also employs a small number of derivative instruments related to storage optimization and a limited number of natural gas swaps to hedge the risk associated with fixed price natural gas sales contracts for certain large gas sales customers.

The following are commodity volumes in dekatherms ("dths") associated with derivative contracts as of March 31, 2013 and March 31, 2012:

		March 31,	
		2013	2012
		(in thousands)	
Physical Contracts:	Gas purchase	**786**	983
Financial Contracts:	Gas swap	**14,343**	14,063
	Gas future	**16,830**	20,870
Total		**31,959**	35,916

The following table presents the Company's derivative assets and liabilities at March 31, 2013 and March 31, 2012 that are included in the accompanying balance sheets for the above contracts:

	Asset Derivatives March 31, 2013	Asset Derivatives March 31, 2012		Liability Derivatives March 31, 2013	Liability Derivatives March 31, 2012
	(in thousands of dollars)			*(in thousands of dollars)*	
Current assets:			Current liabilities:		
Rate recoverable contracts:			Rate recoverable contracts:		
Gas future contracts	**$ 1,300**	$ 314	Gas future contracts	**$ 1,797**	$ 21,848
Gas swap contracts	**3,211**	-	Gas swap contracts	**1,316**	13,611
Contracts not subject to rate recovery:			Contracts not subject to rate recovery:		
Gas purchase contracts	**-**	4	Gas purchase contracts	**37**	1
Gas swap contracts	**16**	130	Gas swap contracts	**309**	2
	4,527	448		**3,459**	35,462
Deferred charges and other assets:			Deferred credits and other liabilities:		
Rate recoverable contracts:			Rate recoverable contracts:		
Gas future contracts	**1,611**	39	Gas future contracts	**5**	6,427
Gas swap contracts	**274**	5	Gas swap contracts	**7**	3,955
	1,885	44		**12**	10,382
Total	**$ 6,412**	$ 492	Total	**$ 3,471**	$ 45,844

The changes in fair value of our rate recoverable contracts are offset by changes in regulatory assets and liabilities. As a result, the changes in fair value of those contracts had no impact on the accompanying statements of income. The changes in fair value of our contracts not subject to rate recovery are recorded within purchased gas in the accompanying statements of income.

The following table presents the impact the change in the fair value of the Company's derivative contracts had on the accompanying balance sheets and statements of income for the years ended March 31, 2013 and March 31, 2012:

	March 31, 2013	March 31, 2012
	(in thousands of dollars)	
Regulated assets:		
Gas purchase contracts	$ -	$ (562)
Gas future contracts	**(26,473)**	17,155
Gas swap contracts	**(16,242)**	1,333
	(42,715)	17,926
Regulated liabilities:		
Gas future contracts	**2,558**	(955)
Gas swap contracts	**3,480**	(173)
	6,038	(1,128)
Total increase (decrease) in net regulatory assets	**$ (48,753)**	$ 19,054
Purchased gas:		
Gas purchase contracts	**$ (40)**	$ (27)
Gas swap contracts	**(420)**	(226)
	$ (460)	$ (253)

Credit and Collateral

Derivative contracts are primarily used to manage exposure to market risk arising from changes in commodity prices and interest rates. In the event of non-performance by counterparty to a derivative contract, the desired impact may not be achieved. The risk of counterparty non-performance is generally considered a credit risk and is actively minimized by assessing each counterparty credit profile and negotiating appropriate levels of collateral and credit support.

The credit policy for commodity transactions is owned and monitored by the Energy Procurement Risk Management Committee, and establishes controls and procedures to determine monitor and minimize the credit risk of counterparties. Counterparty credit exposure is monitored, and appropriate measures are taken to bring such exposures below the limits, including, without limitation, netting agreements, and limitations on the type and tenor of trades. The Company enters into enabling agreements that allow for payment netting with its counterparties, which reduces its exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. The Company's credit exposure for all derivative instruments, normal purchase normal sale contracts, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements is $0.9 million as of March 31, 2013.

The Company enters into commodity transactions on New York Mercantile Exchange ("NYMEX"). The NYMEX clearinghouses act as the counterparty to each trade. Transactions on the NYMEX must adhere to comprehensive collateral and margining requirements. As a result, transactions on NYMEX are significantly collateralized and have limited counterparty credit risk.

In instances where a counterparty's credit quality has declined, or credit exposure exceeds certain levels, we may limit our credit exposure by restricting new transactions with the counterparty, requiring additional collateral or credit support and negotiating the early termination of certain agreements. Similarly, the Company may be required to post collateral to its counterparties. The aggregate fair value of the Company's derivative instruments with credit-risk-related contingent features that are in a liability position on March 31, 2013 and March 31, 2012 was $1.0 million and $16.3 million, respectively. The Company had no collateral posted for these instruments at March 31, 2013 and March 31, 2012, respectively. If the Company's credit rating were to be downgraded by one or two levels, it would not be required to post any additional collateral. If the Company's credit rating were to be downgraded by three levels, it would be required to post $1.1 million additional collateral to its counterparties. The Company would have to be downgraded by four levels to receive a non-investment grade rating of BB+/Ba1.

Note 7. 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. Accounting guidance for fair value measurement emphasizes that fair value is a market based measurement, not an entity specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1— Quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity can access at the measurement date.

Level 2— Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly.

Level 3— Unobservable inputs for the asset or liability.

The following table presents assets and liabilities measured and recorded at fair value in the accompanying balance sheets on a recurring basis and their level within the fair value hierarchy as of March 31, 2013 and March 31, 2012:

	March 31, 2013			
	Level 1	Level 2	Level 3	Total
		(in thousands of dollars)		
Assets:				
Derivative contracts - gas				
Financial	$ 2,911	$ 3,501		$ 6,412
Available for sale securities	1,896	2,512	-	4,408
Total assets	4,807	6,013	-	10,820
Liabilities:				
Derivative contracts - gas				
Financial	1,802	1,632		3,434
Physical	-	37	-	37
Total liabilities	1,802	1,669	-	3,471
Net assets	$ 3,005	$ 4,344	$ -	$ 7,349

	March 31, 2012			
	Level 1	Level 2	Level 3	Total
		(in thousands of dollars)		
Assets:				
Derivative contracts - gas				
Financial	$ 353	$ 136		$ 489
Physical	-	3	-	3
Available for sale securities	1,751	2,263	-	4,014
Total assets	2,104	2,402	-	4,506
Liabilities:				
Derivative contracts - gas				
Financial	28,275	17,568	-	45,843
Physical	-	1	-	1
Total liabilities	28,275	17,569	-	45,844
Net liabilities	$ (26,171)	$ (15,167)	$ -	$ (41,338)

The following is a description of the inputs to and valuation techniques used to measure the fair values above:

Derivatives

The Company's Level 1 fair value derivative instruments consist of active exchange-based derivatives (e.g. natural gas futures traded on NYMEX) valued based on quoted prices (unadjusted) in active markets for identical assets or liabilities at the measurement date.

The Company's Level 2 fair value derivative instruments consist of over-the-counter ("OTC") gas swaps and forward physical gas deals pricing inputs obtained from the NYMEX and Intercontinental Exchange ("ICE"), except in cases in which ICE publishes seasonal averages or there were no transactions within last seven days. We may utilize discounting based on quoted interest rate curves that may include a liquidity reserve calculated based on the bid/ask spread for our Level 2 derivative instruments. 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 95% or higher.

Level 3 fair value derivative instruments consist of the Company's complex and structured OTC physical gas transactions valued based on internally-developed models. Industry-standard valuation techniques, such as Black-Scholes pricing model, Monte Carlo simulation, and Financial Engineering Associates libraries are used for valuing such instruments. A derivative instrument is designated Level 3 when it is valued based on a forward curve that is internally developed, extrapolated or derived from market observable curve with correlation coefficients less than 95%, optionality is present, or if non-economic assumptions are made. The internally developed forward curves have a high level of correlation with Platts Mark-to-Market curves.

Available for Sale Securities

Available for sale securities are included in financial investments in the accompanying balance sheets and primarily included equities and investments based on quoted market prices (Level 1), and municipal and corporate bonds based on quoted prices of similar traded assets in open markets (Level 2).

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 years ended March 31, 2013 and March 31, 2012:

	Years Ended March 31,	
	2013	**2012**
	(in thousands of dollars)	
Balance, at beginning of year	**$ -**	$ (586)
Purchases	**(347)**	57
Settlements:		
included in earnings	**85**	95
included in regulatory assets and liabilities	**262**	434
Balance, at end of year	**$ -**	$ -
The amount of total gains or losses for the period included in net income attributed to the change in unrealized gains or losses related to derivative non-regulatory assets and liabilities at year-end	**$ -**	**$ -**

A transfer into Level 3 represents existing assets or liabilities that were previously categorized at a higher level for which the inputs became unobservable. A transfer out of Level 3 represents assets and liabilities that were previously classified as Level 3 for which the inputs became observable based on the criteria discussed previously for classification in Level 2. These transfers, which are recognized at the end of each period, result from changes in the observability of forward curves from the beginning to the end of each reporting period. There were no transfers between Level 1 and Level 2, and no transfers into and out from Level 3 during the years ended March 31, 2013 and March 31, 2012, respectively.

Other Fair Value Measurements

The fair market value of the Company's long-term debt was estimated based on the quoted market prices for similar issues or on the current rates offered to the Company for debt of the same remaining maturity. The fair value of our long-term debt at March 31, 2013 and March 31, 2012 was $964.6 million and $675.1 million, respectively.

All other financial instruments on the balance sheets such as money pool and intercompany balances, accounts receivable and accounts payable are stated at cost, which approximates fair value.

Note 8. Income Taxes

The components of federal income tax expense (benefit) are as follows:

	Years Ended March 31,	
	2013	2012
	(in thousands of dollars)	
Current federal tax benefit	**$ (48,770)**	$ (34,502)
Deferred federal tax expense	**82,387**	61,844
Amortized investment tax credits, net (1)	**(449)**	(486)
Total deferred tax expense	**81,938**	61,358
Total income tax expense	**$ 33,168**	$ 26,856

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

A reconciliation between the 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, 2013 and March 31, 2012 is as follows:

	Years Ended March 31,	
	2013	2012
	(in thousands of dollars)	
Computed tax	**$ 32,854**	$ 27,111
Change in computed taxes resulting from:		
Investment tax credit	**(449)**	(486)
Other items, net	**763**	231
Total	**314**	(255)
Federal income taxes	**$ 33,168**	$ 26,856

Significant components of the Company's net deferred tax assets and liabilities at March 31, 2013 and March 31, 2012 are as follows:

	March 31,			
	2013		2012	
	(in thousands of dollars)			
Deferred tax assets:				
Pensions, PBOP and other employee benefits	$	**62,031**	$	76,266
Reserve - environmental		**47,211**		44,700
Net operating losses		**27,984**		-
Allowance for uncollectible accounts		**9,468**		11,164
Other items		**3,463**		15,142
Total deferred tax assets(1)		**150,157**		147,272
Deferred tax liabilities:				
Property related differences		**404,360**		309,185
Regulatory assets - pension and PBOP		**61,247**		32,633
Regulatory assets - environmental		**47,602**		45,045
Regulatory assets - storm cost		**29,145**		4,141
Other items		**11,574**		18,456
Total deferred tax liabilities		**553,928**		409,460
Net deferred income tax liability		**403,771**		262,188
Deferred investment tax credit		**813**		1,262
Net deferred income tax liability and investment tax credit		**404,584**		263,450
Current portion of net deferred income tax assets		**6,521**		11,631
Non-current deferred income tax liability	$	**411,105**	$	275,081

(1)There were no valuation allowances for deferred tax assets at March 31, 2013 or March 31, 2012.

The Company is a member of the NGNA and subsidiaries' consolidated federal income tax return.

Unrecognized Tax Benefits

As of March 31, 2013 and March 31, 2012, the Company's unrecognized tax benefits totaled $22.3 million and $19.8 million, respectively, none of which would affect the effective tax rate, if recognized. The unrecognized tax benefits are included in other deferred liabilities in the accompanying balance sheets.

The following table reconciles the changes to the Company's unrecognized tax benefits for the years ended March 31, 2013 and March 31, 2012:

	Years Ended March 31,			
	2013		2012	
	(in thousands of dollars)			
Balance at the beginning of the year	$	**19,811**	$	36,272
Gross increases related to prior period		**313**		831
Gross decreases related to prior period		**(536)**		(17,292)
Gross increases related to current period		**3,422**		-
Gross decreases related to current period		**(739)**		-
Balance at the end of the year	$	**22,271**	$	19,811

As of March 31, 2013 and March 31, 2012, the Company has accrued for interest related to unrecognized tax benefits of $0.5 million and $0.4 million, respectively. During the years ended March 31, 2013 and March 31, 2012, the Company recorded interest expense of $0.1 million and interest income of $0.02 million, respectively. The Company recognizes accrued interest related to unrecognized tax benefits in other interest expense and related penalties, if applicable, in other deductions in the accompanying statements of income. No penalties were recognized during the years ended March 31, 2013 and March 31, 2012.

In fiscal year 2012, the Company adopted Revenue Procedure 2011-43, which provides a safe harbor method of accounting that taxpayers may use to determine whether expenditures to maintain, replace, or improve electric transmission and distribution property must be capitalized under Section 263(a) of the Internal Revenue Code. As a result, the Company, during the year ended March 31, 2012 reversed $15.9 million of tax reserves related to unrecognized tax benefits recorded in prior years.

It is reasonably possible that other events will occur during the next twelve months that would cause the total amount of unrecognized tax benefits to increase or decrease. However, the Company does not believe any such increases or decreases would be material to its results of operations, financial position, or liquidity.

In fiscal year 2012, the Internal Revenue Service ("IRS") commenced an audit of NGNA and subsidiaries for the fiscal years ended March 31, 2008 and March 31, 2009. Fiscal years ended March 31, 2010 through March 31, 2013 remain subject to examination by the IRS.

March 31, 2005 is the earliest tax year subject to examination. 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 filing 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.

Note 9. Debt

Short-term Debt

The Company has regulatory approval from the FERC to issue up to $400 million of short-term debt. The Company had no short-term debt outstanding to third-parties as of March 31, 2013 or March 31, 2012.

Long-term Debt

Unsecured Notes

In December 2012, the Company issued $250 million of unsecured long-term debt at 4.17% with a maturity date of December 10, 2042.

On March 18, 2010, National Grid plc settled the derivative financial instruments that it had entered into in connection with $550 million of debt issued in March 2010, for the purpose of locking-in the risk-free interest rate element of the bond issues. The $5.6 million on the "treasury lock" settlement is being amortized over the life of the bonds to match the corresponding rate treatment. In the year ended March 31, 2013, $0.8 million pre-tax was reclassified out of accumulated other comprehensive income into the statement of income.

First Mortgage Bonds

At March 31, 2013, the Company had $53.0 million of First Mortgage Bonds ("FMB") outstanding. Substantially all of the assets used in the gas business of the Company are subject to the lien of the mortgage indentures under which these FMB have been issued. Interest rates on these FMB range from 6.82% to 9.63%. Maturities range on these FMB from April 2018 to December 2025. The FMB have annual sinking fund requirements totaling approximately $1.4 million.

The Company has a maximum 70% of debt-to-capitalization covenant. Furthermore, if at any time the Company's debt exceeds 60% of the total capitalization, each holder of bonds then outstanding shall receive effective as of the first date of such occurrence, a one time, and permanent 0.20% increase in the interest rate paid by the Company on its bonds. During the years ended March 31, 2013 and March 31, 2012, the Company was in compliance with this covenant. At March 31, 2013 and March 31, 2012 the Company's debt-to-capitalization ratio was 35% and 30%, respectively.

The aggregate maturities of long-term debt subsequent to March 31, 2013 are as follows:

(in thousands of dollars) Years Ended March 31,	
2014	$ 1,375
2015	1,375
2016	1,375
2017	1,375
2018	1,375
Thereafter	846,089
Total	$ 852,964

The Company is obligated to meet certain non-financial covenants. During the years ended March 31, 2013 and March 31, 2012, respectively, the Company was in compliance with all such covenants.

Note 10. Commitments and Contingencies

Purchase Commitments

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 has entered into various contracts for electricity and gas delivery storage and supply services. Certain of these contracts require payment of annual demand charges. The Company is liable for these payments regardless of the level of services required from third parties. Such charges are currently recovered from customers as gas and electricity costs. In addition, the Company has various capital commitments related to the construction of property, plant and equipment.

The Company's commitments under these long-term contracts for years subsequent to March 31, 2013, are summarized in the table below:

(in thousands of dollars) Years Ended March 31,	**Energy Purchases**	**Capital Expenditures**
2014	$ 249,356	$ 34,084
2015	83,890	-
2016	12,379	-
2017	11,173	-
2018	8,613	-
Thereafter	48,631	-
Total	$ 414,042	$ 34,084

The Company can purchase additional energy to meet load requirements from independent power producers, other utilities, energy merchants or the ISO-NE at market prices.

Asset Retirement Obligations

The Company has various asset retirement obligations associated with its distribution facilities. The following table represents the changes in the asset retirement obligations for the years ended March 31, 2013 and March 31, 2012:

	March 31,	
	2013	2012
	(in thousands of dollars)	
Balance as of beginning of year	**$ 3,660**	$ 3,799
Accretion expense	**204**	211
Liabilities settled	**(423)**	(350)
Balance as of end of year	**$ 3,441**	$ 3,660

Legal Matters

The Company is subject to various legal proceedings, primarily injury claims, arising out of the ordinary course of its business. The Company does not consider any of such proceedings to be material, individually or in the aggregate, 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. Under federal and state Superfund laws, potential liability for the historic contamination of property may be imposed on responsible parties jointly and severally, without regard to fault, even if the activities were lawful when they occurred.

The United States Environmental Protection Agency ("EPA"), the Massachusetts Department of Environmental Protection ("DEP"), and the Rhode Island Department of Environmental Management ("DEM") have alleged that the Company is a potentially responsible party under state or federal law for a number of sites at which hazardous waste is alleged to have been disposed. The Company's most significant liabilities relate to former manufactured gas plant ("MGP") facilities formerly owned by the Blackstone Valley Gas and Electric Company and the Rhode Island gas distribution assets of New England Gas. The Company is currently investigating and remediating, as necessary, those MGP sites and certain other properties under agreements with the EPA, DEM and DEP. Expenditures incurred for the years ended March 31, 2013 and March 31, 2012 were $1.9 million and $2.0 million, respectively.

The Company estimated the remaining costs of environmental remediation activities were $136.7 million and $129.5 million at March 31, 2013 and March 31, 2012, respectively. These costs are expected to be incurred over the next 38 years, and these undiscounted amounts have been recorded as reserves in the accompanying balance sheets. However, remediation costs for each site may be materially higher than estimated, depending upon changing technologies and regulatory standards, selected end use for each site, and actual environmental conditions encountered. The Company has recovered amounts from certain insurers, and, where appropriate, the Company may seek recovery from other insurers and from other potentially responsible parties, but it is uncertain whether, and to what extent, such efforts will be successful.

The RIPUC has approved a settlement agreement that provides for rate recovery of remediation costs of former MGP sites and certain other hazardous waste sites located in Rhode Island. Under that agreement, qualified costs related to these sites are paid out of a special fund established as a regulatory liability in the accompanying balance sheets. Rate-recoverable contributions of approximately $3 million are added annually to the fund along with interest and any recoveries from insurance carriers and other third parties. Accordingly, as of March 31, 2013 and March 31, 2012, the Company has recorded environmental regulatory assets of $140.9 million and $134.0 million, respectively, and environmental regulatory liabilities of $1.9 million and $0.6 million, respectively.

The Company believes that its ongoing operations, and its approach to addressing conditions at historic sites, are in substantial compliance with all applicable environmental laws, and that the obligations imposed on it because of the environmental laws will not have a material impact on its results of operations or financial position since, as noted above, environmental expenditures incurred by the Company are recoverable from customers.

Note 11. Related Party Transactions

Accounts Receivable from Affiliates and Accounts Payable to Affiliates

NGUSA and its affiliates provide various services to the Company, including executive and administrative, customer services, financial (including accounting, auditing, risk management, tax, and treasury/finance), human resources, information technology, legal and strategic planning that are charged between the companies and charged to each company.

The Company records short-term payables to and receivables from certain of its affiliates in the ordinary course of business. The amounts payable to and receivable from its affiliates do not bear interest and are settled through the money pool. At March 31, 2013 and March 31, 2012, the Company had net outstanding accounts receivable from affiliates/accounts payable to affiliates balances as follows:

	Accounts Receivable from Affiliates	Accounts Payable to Affiliates	Accounts Receivable from Affiliates	Accounts Payable to Affiliates
	March 31, 2013		March 31, 2012	
	(in thousands of dollars)		*(in thousands of dollars)*	
NGUSA	**$ 3**	**$ -**	$ 192	$ -
Boston Gas Company	**34,095**	**-**	-	-
Colonial Gas Company	**11,372**	**-**	-	-
New England Power Company	**19,269**	**-**	1,257	-
Massachusetts Electric Company	**-**	**158**	-	828
Niagara Mohawk Power Company	**466**	**-**	2,134	-
NGUSA Service Company	**-**	**27,942**	5,591	-
KeySpan Corporate Services	**-**	**-**	-	3,554
Other	**597**	**2,870**	1,306	2,012
Total	**$ 65,802**	**$ 30,970**	$ 10,480	$ 6,394

Money Pool

The settlement of the Company's various transactions with NGUSA and certain affiliates generally occurs via the money pool. As of November 1, 2012, NGUSA and its affiliates established a new Regulated Money Pool and an Unregulated Money Pool. Financing for the Company's working capital and gas inventory needs are obtained through participation in the Regulated Money Pool. The Company, as a participant in the Regulated Money Pool, can both borrow and lend funds. Borrowings from the Regulated and Unregulated Money Pools bear interest in accordance with the terms of the applicable money pool agreement.

The Regulated and Unregulated Money Pools are funded by operating funds from participants in the applicable Pool. Collectively, NGUSA and its subsidiary, KeySpan, have the ability to borrow up to $3 billion from National Grid plc for working capital needs including funding of the Money Pools, if necessary. The Company had short-term money pool borrowings of $56.9 million and $197.4 million at March 31, 2013 and March 31, 2012, respectively. The average interest rate for the money pool was approximately 0.6% and 0.2% for the years ended March 31, 2013 and March 31, 2012, 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 benefited 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 number of employees, number of customers/meters, capital expenditures, value of property owned, total transmission and distribution expenditures, etc. Lastly, all other costs are allocated based on a general allocator.

Charges from the service companies of NGUSA to the Company for the years ended March 31, 2013 and March 31, 2012 were $324.5 million and $310.8 million, 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 the Company, the estimated effect on net income would be approximately $3.5 million before taxes, and $2.3 million after taxes, for each of the years ended March 31, 2013 and March 31, 2012.

Note 12. Cumulative Preferred Stock

The Company has non-participating cumulative preferred stock outstanding which can be redeemed at the option of the Company. There are no mandatory redemption provisions on the Company's cumulative preferred stock. A summary of cumulative preferred stock at March 31, 2013 and March 31, 2012 is as follows:

	Shares Outstanding		Amount		
	March 31,		**March 31,**		Call
Series	**2013**	2012	**2013**	2012	Price
	(in thousands of dollars, except per share and number of shares data)				
$50 par value - 4.50% Series	**49,089**	49,089	**$ 2,454**	$ 2,454	55.000

The Company did not redeem any preferred stock during the years ended March 31, 2013 or March 31, 2012. The annual dividend requirement for cumulative preferred stock was approximately $0.1 million for the years ended March 31, 2013 and March 31, 2012.

Note 13. Dividend Restrictions

Pursuant to the preferred stock arrangement, as long as any preferred stock is outstanding, certain restrictions on payment of common stock dividends would come into effect if the common stock equity was, or by reason of payment of such dividends became, less than 25% of total capitalization. Common stock equity at March 31, 2013 and March 31, 2012 was approximately 65% and 70%, respectively, of total capitalization. Accordingly, the Company was not restricted as to the payment of common stock dividends under the foregoing provisions at March 31, 2013 or March 31, 2012.