Thomas R. Teehan
Senior Counsel

October 24, 2008

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 3931 - Least Cost Procurement Plan
Amended System Reliability Plan

Dear Ms. Massaro:

Enclosed please find ten (10) copies of an amended System Reliability Plan ("Plan") that reflects National Grid's[1] response to recommendations from the Energy Efficiency Resource Management Council ("the Council").

The Plan was originally filed with the Commission on September 3 prior to the Council's review and approval of the Plan.

The Plan was initially approved by the Council on October 16, with final edits being approved on October 23. The only significant changes made to the original filed Plan appear in the first three pages of the document. Also included is the projected System Reliability Procurement Plan costs, which is found after page 21. Any other changes that were made to the document are editorial in nature.

Thank you for your attention to this filing. If you have any questions, please feel free to contact me at (401) 784-7667.

Very truly yours,

Thomas R. Teehan

Enclosures

cc: Docket 3931 Service List

[1] The Narragansett Electric Company d/b/a National Grid.

System Reliability Plan

I. Purpose and Introduction

It is clear from Rhode Island Law that Least Cost Procurement includes *both* energy efficiency and conservation procurement (which is also sometimes referred to as "least cost procurement") *and* System Reliability procurement, and that National Grid has been instructed to provide a three year plan for both:

> ***§ 39-1-27.7 System reliability and least-cost procurement. –*** *Least-cost procurement shall comprise system reliability and energy efficiency and conservation procurement as provided for in this section and supply procurement as provided for in § 39-1-27.8, as complementary but distinct activities that have as common purpose meeting electrical energy needs in Rhode Island, in a manner that is optimally cost-effective, reliable, prudent and environmentally responsible.*

The overall intent of this System Reliability Procurement Plan is to identify customer-side opportunities beyond energy efficiency that are cost effective and provide the path to lower supply and delivery costs to ratepayers in RI. The ability to defer distribution system investments as discussed in Section III should provide savings over time for customers, while securing sources of energy supply and capacity from in-state should lower the volatility and costs versus the larger energy and capacity markets in NE. As an example, investments that reduce the peak load needed to be procured through the forward capacity market will lower capacity costs that all ratepayers pay through the supply portion of the electric bill.

The law states that "system reliability" resources are intended to include:

> *(i) Procurement of energy supply from diverse sources, including, but not limited to, renewable energy resources as defined in chapter 26 of this title;*
>
> *(ii) Distributed generation, including, but not limited to, renewable energy resources and thermally leading combined heat and power systems, which is reliable and is cost-effective, with measurable, net system benefits;*
>
> *(iii) Demand response, including, but not limited to, distributed generation, back-up generation and on-demand usage reduction, which shall be designed to facilitate electric customer participation in regional demand response programs, including those administered by the independent service operator of New England ("ISO-NE") and/or are designed to provide local system reliability benefits through load control or using on-site generating capability;*

Benefits of System Reliability:

- The law anticipates the contribution of system reliability resources to transmission and distribution reliability for National Grid. Other benefits on the generation, or supply, side will be addressed in the supply procurement filing in §39-1-27.7 due March 1, 2009. Specific analyses of various Alternate Resource Technologies (ARTs) will feed into future supply procurements as they are determined to provide some of the following: The ability to provide diversification of supply resources, through the inclusion of renewable energy and combined heat and power (CHP)
- The potential to control prices to a certain extent for some portion of supply through the acquisition of energy sources not tied to the price volatility of fossil fuel.
- The possible ability to manage the peak load in Rhode Island, both for New England system reliability purposes and for reliability on sub-components of the system. Demand response (DR) may also be used to manage the price effects of peaks in a market-based generation system. With the new Forward Capacity Market mechanism in place in NE, peak load reduction will need to increase year by year to provide on-going savings to RI customers. We need to be aware that proceeds from the FCM will not be available until at least 2013, if DR resources can be bid into the next forward capacity auction based on the mechanics of the FCM.

Similarities to and Differences from Efficiency and Conservation Procurement:

There is a long history of energy efficiency program investment. Systems for designing, implementing, funding, and evaluating programs and rewarding utilities for implementing programs effectively are in place. Preliminary thoughts are to model the delivery of ARTs to follow the energy efficiency model.

As part of this, National Grid will over the next three years:

- Characterize more fully the ARTs to be included in system reliability acquisition including clear identification of their costs, performance and benefits;
- Integrate measures and strategies, where appropriate, into existing least cost procurement programs;
- Identify additional ARTs to secure and deploy system reliability resources and;
- Identify sources of funding to support these ARTs.

There are several settings in which these activities will happen. A list of those settings is presented below, and is discussed further as each type of ART is discussed in more detail later in this Plan. Each of these areas of activity represents an area of focus for National Grid in meeting its customer needs as it moves to a least cost procurement approach under the guidance of the 2006 act.

Assessment of Potential: The EERMC in consultation with National Grid, will continue to assess the opportunity for securing various ARTs (i.e. CHP, DR, renewable energy resources, etc.) in RI.. The Opportunity Report was submitted to the Council on July 15, 2008 was a first step in this process. The EERMC and National Grid have already committed to conducting a second phase of this resource characterization process. In 2009, that second phase will be a key part of defining in greater detail what the potential for ARTs (as well as energy efficiency resources) is.
Integration of Gas and Electric least cost offerings: As outlined in National Grid's Energy Efficiency Procurement Plan, the Company has identified the integration of gas and electric efficiency offerings as a very high priority. In this context, the treatment of CHP, for instance, and solar hot water, could be integrated in large part, into existing efficiency programs.

Incorporation of the effects of energy efficiency and system reliability resources into Transmission and Distribution System Planning: The potential for energy efficiency and ARTs to provide T&D system benefits will require identification of growth areas where load reduction and load management might be a strategy to defer or avoid significant growth-related expenditures.

Integration with Market Actors: There are a number of active market players securing Demand Response contracts from businesses throughout New England, and in Rhode Island. These Curtailment Service Providers (CSPs) focus on securing DR capability with regard to participating in the ISO-NE's Forward Capacity Market. As the provider of last resort for the current ISO-NE demand response programs, National Grid has been working with various working groups to define what role, if any, legacy demand response programs will play when the FCM is fully in place on 06/01/10. If these programs are supplanted entirely by the FCM, the Company will determine how or if specific RI-centric programs should be developed. This will require constructive working relationships between National Grid and those CSPs as it develops its own DR approach and programs.

Funding: There is currently no budget proposed for system reliability procurement as a separate item. As we learn more about the attributes of the ARTs, some future system reliability costs could legitimately be included in the proposed efficiency program budget; some could be included in natural gas efficiency program expenditures, some could be included in the cost of service. It may well be that other costs are covered by sources outside National Grid, including market vendors in DR (funded in part by Forward Capacity Market payments), or other Rhode Island programs focused on renewable energy. National Grid identified costs related to system reliability procurement, and the proposed funding source is described at the end of this document.

The next section describes the Plan elements in each of the three primary technology areas as well as a targeted distributed resources initiative that will combine elements of all three. This is followed by a section on funding. An appendix describes National Grid's prior history with demand response.

II System Reliability Plan Components

1. CHP

In reviewing NESCAUM's CHP opportunity report, the Company sees that there is economic potential of over 300 MWs of CHP in the state. The report clearly states that without the proposed phase 2 study, this number is a preliminary estimate that may change. The Company is committed to working with the EERMC to undertake phase 2 at its direction to further understand how best to promote the use of this technology to its customers. As part of the Energy Efficiency Program Plan (EEPP), combination audits will be conducted for interested customers to identify gas and electric energy efficiency, demand response, renewable energy and CHP opportunities as we assist customers with their long-term plans to reduce their costs and their carbon footprint with a variety of measures.

The Company has begun offering a gas energy efficiency incentive for CHP. An evaluation will be conducted to determine the overall cost/benefit of CHP. This cost/benefit analysis would determine actual annualized efficiencies of projects receiving incentives. The annualized efficiency is critical to determine how the CHP compares to the emissions and efficiency characteristics of the standard alternative of grid power and use of an on-site boiler. This evaluation would be used to provide guidance as to the parameters required for CHP.

The Company also has promoted the installation of some micro-CHP to residential and small commercial customers and will be conducting detailed evaluations of these installations.

Under the current regulatory and rate making environment in the state, standby rates for CHP are currently in place. In the future as rate making theory is modified, these rates will be addressed.

Interconnection procedures were recently updated to reflect the federal "Small Generator Interconnection Procedures" developed by a consortium of developers and utilities due to a Notice of Proposed Rulemaking by the Federal Energy Regulatory Commission (FERC). The procedures are centered around the latest IEEE 1547 requirements. The Company feels these procedures are working well for customers and are similar to those used in Massachusetts and Connecticut as well as at the ISO-NE.

2. Renewables

In reviewing URI's portion of the opportunity report on small scale renewables, it appears that offering a credit for photovoltaics (PV) of 150% of the retail price of electricity could provide enough incentive for customers to install more PV. Another option that could provide a similar benefit would be to offer a retail credit, but based on actual hourly commodity prices instead of the current flat standard service offering.

The Company is committed to working with the EERMC to undertake phase 2 of the opportunity report at its direction to further understand how best to promote the use of this technology to its customers. As part of the combined energy efficiency filings combination audits will be conducted for interested customers to identify gas and electric energy efficiency, demand response, renewable energy and CHP opportunities as we assist customers with their long-term plans to reduce their costs and their carbon footprint with a variety of measures.

Company Owned Renewables

With the recently passed legislation, the Company plans to install 15 MWs of solar energy or wind energy project in RI. Costs of this program are required to be proved to be in the ratepayers' best interests by the Commission prior to actually entering into construction of any projects. The Company has started meeting with customers who are constructing new facilities to prevent potential lost opportunity for a solar installation on the customer's roof. The customers will be required to have committed to extensive energy efficiency improvements prior to the Company discussing installing rate-based PV on or near their facility.

Net-Metering

With the new net-metering law allowing for up to 1.65 MWs of wind or solar, and the ability for cities and towns to transfer credits earned at one account to one or more other accounts (virtual net-metering), the Company is committed to streamlining this process and assisting interested communities in this effort.

Renewable Energy Standard

From page 6 of http://www2.sec.state.ri.us/dar/regdocs/released/pdf/PUC/4694.pdf:

1) Starting in Compliance Year 2007, all Obligated Entities shall obtain, from Eligible Renewable Energy Resources, a target percentage of at least three percent (3%) of electricity sold by an Obligated Entity at retail to Rhode Island End-use Customers, inclusive of losses. For the purposes of this section, electricity sold by an Obligated Entity at retail to Rhode Island End-use Customers shall equal the sum of the Real Time Load Obligations for each Load Asset in the New England Markets that represents the electricity sold by an Obligated Entity at retail to Rhode Island End-use Customers. In each subsequent Compliance Year through Compliance Year 2019, *the target percentage shall increase according to the table in Section 4.2 below, except as provided in Section 4.4.*

2) For each Obligated Entity and in each Compliance Year, the amount of retail electricity sales used to meet this obligation that is derived from Existing Renewable Energy Resources shall not exceed two percent (2%) of total retail electricity sales.

Compliance Year	Total Target Percentage	Percentage from New Renewable Energy Resources	Percentage from *either* New *or* Existing Renewable Energy Resources
2007	3.0%	1.0%	2.0%
2008	3.5%	1.5%	2.0%
2009	4.0%	2.0%	2.0%
2010	4.5%	2.5%	2.0%
2011[1]	5.5%	3.5%	2.0%
2012[1]	6.5%	4.5%	2.0%
2013[1]	7.5%	5.5%	2.0%
2014[1]	8.5%	6.5%	2.0%
2015[1]	10.0%	8.0%	2.0%
2016[1]	11.5%	9.5%	2.0%
2017[1]	13.0%	11.0%	2.0%
2018[1]	14.5%	12.5%	2.0%
2019[1]	16.0%	14.0%	2.0%
2020 and thereafter[2]	16.0%	14.0%	2.0%

The Company does not currently have an approved plan for procuring its RPS obligation after 2009. It is likely that the procurement and future plans will be in the energy supply filing due on April 1, 2009.

<u>Other Renewable Efforts</u>

The Company offers an incentive for customers to convert gas water heating to solar thermal installations through its gas efficiency program, and will look to expand this to customers with electric water heating.

For those areas where the Company will not be installing company-owned renewable energy equipment, the Company proposes to work with OER to determine how best to promote renewables. Some ideas not listed above: fund additional wind studies; providing a $/watt PV incentive; and providing on-the-bill financing for renewable projects.

3. Demand Response

This service supports participation of our customers in ISO-New England's forward capacity market (FCM) and demand response programs as well as in areas targeted by the Company for local load relief. Its goal is to help customers efficiently deploy existing and emerging efficiency technologies and strategies to manage their energy costs as well as reduce electrical load during peak hours (typically summer) throughout the Company's service territory. If this load relief can be targeted to a specific area, this reduction may defer capital investments in the distribution system, assist in stabilizing electricity costs and improve the reliability of the local electrical grid.

With the bulk of demand response in New England contracted from customers by third party demand response providers (i.e. Enernoc, ConsumerPowerline, Comverge, etc.), it is critically important that the Company have access to ISO-NE data as to what resources are available in certain areas on the Company's distribution system. This information could provide relatively low cost assets to respond to Company emergency conditions or Targeted Demand Response (TDR) project to better manage the system. The rationale is that the customers are already contracted to respond, and for minimal costs could be asked to respond to a Company request in addition.

The Company has run a number of TDR projects in RI over the past 5 years (see Appendix A for particulars). The intent of TDR projects is to contract with customers in a specific area that the Company had determined is in need of an infrastructure improvement, but the load growth in the area might exceed the ratings of the existing infrastructure prior to the improvement being completed. In a TDR project in MA, the Company has negotiated a 'handshake' agreement with a third party demand response provider to have their customer agree to shed load if the Company were to call an event. The Company has approached the ISO-NE to formalize this sort of arrangement, but the ISO-NE has specific rules about customer confidentiality. The Company continues to pursue this issue with the ISO-NE in anticipation of finding a solution that works for all parties.

Current Demand Response Program

Since 2002, the Company has offered qualifying customers the opportunity to participate in the ISO voluntary Real Time Price Response program as well as its Real Time Demand Response Program. Until 2007 the focus was on the voluntary price response, because there were not significant credits available from the demand response programs to enable customer participation until the transitional forward capacity market began in December 2006. The ISO-NE programs are designed to maintain reliability of the bulk power system; specifically, the administered transmission system and bulk generators interconnected to this system are currently funded through the transmission surcharge on customer's electric bills. When the FCM is fully functional, these payments would be funded through customer's Installed Capacity (Icap) charges from the electric commodity supplier.

A key component of a planned demand response program is providing customers with a demand response audit that results in an action plan customers can execute that enables them to better manage and automate their load. The Company has offered only a limited number of demand response audits in Rhode Island since 2004 because only limited funding was available through the overall energy efficiency program offerings. We propose to dedicate additional funding for demand response audits in Rhode Island for use by any customer participating in either a Company or ISO-NE demand response program and/or taking advantage of hourly pricing through a third party supplier. In 2008 the proposal is to identify various demand response actions that may be undertaken by customers depending on the level of need and potential credits as well as the actions that customers can take to maximize the benefits from hourly pricing as provided by third party energy suppliers. The audits would identify specific load management strategies that may help customers reduce demand charges, identify additional energy efficiency and load automation opportunities, increase load factors, and maximize demand response program participation.

Another key aspect to successful demand response is providing information – such as the results of a load shed event – to customers about their energy consumption patterns. Consequently, the Company proposes to fund installation of advanced near real time metering technology for customers who have received load shed audit services and elect to enroll in the Company's distribution demand response program. These meters would assist customers in determining the impact of their actions on their load and assist the Company in assessing the actual demand reduction that is achieved by the customer. Near real time metering information may also supplement other energy efficiency activities at customer sites such as energy consumption analyses and commissioning. The Company would also explore ways to develop customer responsiveness to load and price signals through these meters and other sensing technologies, as well as through enhancements to the internet based Energy Profiler Online service available to large customers.

In addition, the Company will propose to offer financial incentives to encourage the installation costs for devices that can be used to control, monitor, and automate loads. These rebates would be specifically for control of hard wired devices (i.e. controllers on chillers, lighting, etc.) that could be remotely monitored and controlled to shed load upon request, either due to one of the Company's targeted demand response projects, in response to an ISO-NE load shed event, or as part of managing an hourly pricing option from a third party energy supplier. The intent is to assess the benefits and costs of such a demand reduction oriented control installation, and to begin developing cost effective use cases for load automation. The costs of the rebates also would be a part of the program costs recovered from customers in rates.

Table 1. Proposed DR budget for 2009-2011

	Year		
Program	2009	2010	2011
Number of proposed demand response audits	50	75	100
Estimated cost per audit	$4,000	$4,250	$4,500
Estimated annual audit costs	$200,000	$318,750	$450,000
Number of proposed demand response projects	20	40	60
Estimated rebate per project	$10,000	$15,000	$20,000
Estimated annual rebate costs	$200,000	$600,000	$1,200,000
Total proposed costs	**$400,000**	**$918,750**	**$1,650,000**

<u>Target Market and Marketing Approach</u>

Market segments that will be targeted with demand response services include:

- large customers on highly loaded distribution system components;
- small and medium sized customers with potential for direct load control located where past and anticipated load growth has the potential to outpace infrastructure improvements;
- customers who have enrolled in ISO-New England's demand response programs or who either are currently receiving hourly price signals or have an hourly pricing contract.

The primary population for audit services are customers who participate in ISO-NE Real time Demand Response Programs and the FCM they are transitioning to. Typical customer profiles include customers with newer buildings (office buildings, retail establishments, schools, institutional customers etc.), which currently have building management systems (BMS) to monitor life safety conditions (smoke, fire alarms), security, and HVAC systems. Buildings with modern building management systems are typically less than 25 years old. Using and/or modifying these systems to automate the control should have the potential to garner significant electrical savings, while also providing load control during peak hours of the year. Industrial process customers with potentially controllable or variable production loads are also possible candidates.

The Company's demand response program manager, in consultation with the Company's Account Executives, would market this initiative to customers on a one-to-one basis. Customers would be informed of the potential benefits to their companies, to the utility, and to the regional electricity market. The individual participating customers would not incur any cost for the basic load shed audit up to a cap to be established by the Company.

Target End Uses, Recommended Technologies, and Financial Incentives

The list of measures recommended for consideration by a customer may include some or all of the following:

- implementation of efficiency measures that offer options to cost-effectively reduce demand
    - lighting retrofits, including multi level or dimmable electronic ballasts for lighting;
    - cooling system upgrades, including chiller efficiency improvements and CO_2 sensors to regulate air distribution;
    - compressed air system modifications

- automating load shedding measures
    - building management system control changes, including temperature setbacks for HVAC systems;
    - integration of existing building management systems with emerging demand response dispatching systems;
    - lighting controls, either manually or through an EMS;
    - operation of emergency generation under extreme reliability emergencies;
    - integration of services provided through the Retro-Commissioning Initiative with demand response services
- load shift measures
    - scheduling of industrial processes, such as rearranging shift operations

Energy consumption and load can be controlled by building management systems through various strategies employing equipment such as dimmable electronic ballasts for lighting, temperature setbacks for HVAC systems and CO_2 sensors to regulate air distribution. Utilizing existing technology within the buildings to automate systems should provide ways for customers to shed load, and potentially allow the Company to control these loads. Open protocol systems are now becoming commonplace and can be integrated into existing systems to provide a much higher level of control.

Demand-reducing measures that also save energy may be run through the Custom Measure approach under Energy Initiative and Design 2000*plus* to determine cost-effectiveness and rebate eligibility under standard energy efficiency protocols. If a measure is not cost-effective, it would not be funded through the energy efficiency programs.

Combined measures that result in energy savings as well as creating ability for customers to reduce short-term demand may be evaluated based on retail bill savings as well as anticipated demand response payments with costs allocated in proportion.

Providing customers access to the payment streams from the ISO-NE demand response programs and the FCM through additional energy efficiency funding, and more importantly, the tools to allow participation, would provide added incentives for customers. An internet enabled gateway also has potential to provide real-time demand data allowing customers to experiment within their facility to modify their load curves and further reduce the overall electric bill. As more experience is gained, the benefit-cost analyses of demand response strategies would be further refined.

Delivery Mechanisms

Following the initial recruitment of customers by the program manager and Account Executives, several technical assistance (TA) contractors would be used to identify demand response options, prepare analyses and reports, and coordinate their implementation. Economies may be achieved if these demand-oriented studies are performed simultaneously with broader energy efficiency TA studies. As mentioned previously, there may be an opportunity to couple demand response audits with retro-commissioning studies.

Evaluation Overview

Depending on the amount of customer participation with these programs, a process evaluation of the Demand Response program would be completed late in 2009 to determine the amount of automated load shed and the resulting costs to achieve the load shed.

III. Targeted application in constrained areas.

As a part of the larger Least Cost Procurement (LCP) plan, this System Reliability Procurement Plan (SRP), if approved, would provide the first of a number of potential pilots to use Alternate Resource Technologies (ARTs) as an alternative or an enhancement to proposed distribution and/or transmission upgrades. These sources include; targeted energy efficiency, demand response including direct load control (DLC), renewable energy generation, and combined heat and power (CHP). For all the ARTs above, analyses would be conducted to determine the cost/benefit of these sources. The costs for this plan would be recovered from RI customers through the necessary filings reviewed and approved by the Public Utilities Commission.

Distributed/Targeted Resources in Relation to T&D investments

The Company has a continuous process of infrastructure improvement in place. Improvements are needed to replace aging equipment, to improve reliability of the distribution system, and to meet anticipated load growth in a specific area. For the 12 month period ending in March of 2008, the Company spent 6%, or $3.38 million of its capital budget for load relief projects. This does not include the costs for the equipment to connect a new customer (service drop, on-site transformer, and the meter). The remainder is equipment replacement, reliability improvement projects, meters, etc. Depending on the extent of growth in an area, the customer mix, and the timeframe available, the Company will run a TDR project to provide sufficient time for the engineering, permitting, and construction of the new infrastructure needed to occur. The process for selecting an area for a TDR project is detailed in Appendix A. The Company proposes a pilot to use various ARTs in conjunction with a TDR project for the Aquidneck Island area in RI. In addition, the Company plans to utilize other utilities' experiences with similar efforts for the pilot.

A recent electric distribution level study discussed a wide variety of loading issues on the sub-transmission and distribution systems serving the islands of southeastern Rhode Island. This includes Newport, Middletown, Portsmouth, Jamestown and Prudence Island. The recommended solution of adding a substation and three 13.8 KV feeders is currently on hold pending determination of a suitable location for the new substation. An alternate plan of rebuilding the 23KV loop in the Newport area may be the most viable solution for the near term (next decade).

We propose a pilot program to determine cost/benefit of ARTs that would need to focus on the summer peaks which contribute to the electric system loading, as well as winter peaks which contribute to gas pressure problems at peak.

<u>Description of current issues with electric distribution and transmission</u>

A study titled "Newport, RI Supply and Distribution Study" was published in May 2007 by the Company's Distribution System Planning group. The study examines all the loads served by the L14 and M13 lines that terminate at Dexter #36 substation in Portsmouth. The customers served are in the communities of Newport, Middletown, Portsmouth, Jamestown and Prudence Island.

A wide variety of loading issues currently exist and are expected to worsen during the study's 10-year span due to anticipated annual load growth rate of 1.6%. The issues involve thermal loading on substation transformers, sub-transmission systems and distribution feeders; ground fault circuit breaker duties; loading above ties; and load above risk. Several options for relief of most of these concerns were considered. Three options were rejected and one of two remaining options, involving installation of a new substation and three 13.8KV feeders, was selected. The search for a suitable site for the new substation has not yet borne fruit. If National Grid is unable to secure a suitable site for the new substation, the only real option left is to reinforce the existing 23KV sub-transmission system. The area has a peak load of 146 MWs. The work has been split into 2 phases described below.

Phase 1 is designed to meet the immediate needs for the summer of 2009. The Company plans to expand the 13 kV distribution system by converting some of the load currently served on the 4 kV system, build a new 4 kV feeder, and better balance the 4 kV loads served from the 23 kV supply circuits in the area. This work is expected to alleviate the most critical loading concerns on the 23kV supply and 4kV distribution system until the new substation is constructed. However, if one of the two 23 kV circuits at peak loading conditions feeding the W. Howard and Harrison substations in Newport, and the Eldred and Clark St substations on Jamestown Island, were to go out, this would result in un-served load until repairs are completed.

Phase 2 would be to construct a new substation in the City of Newport. Negotiations continue with the Navy on the use of some of their land for this substation. Additional conversion from 4 kV to 13 kV would be done as well, along with additional balancing of loads on the 23 kV supply circuits. This would depend on siting and building a new substation which would likely take 2-4 years.

Since phase 2 is some years away the use of ARTs in the greater Newport area to relieve peak loading conditions either to prevent the potential loss of one of two 23 kV circuits into the substations discussed above or to provide load relief in the event of the loss of a 23 kV circuit and to allow greater flexibility to restore load quicker, may prove beneficial for the period 2009-2011. The standard energy efficiency cost effectiveness tests already use an average T&D deferral value, determining an incremental benefit, if any, over this average value will be considered for the ARTs installed in this pilot.

Description of customer base

In order to determine the menu of ARTs to be used in the area, the types and loads of different customer segments is needed. Just under 35,000 electric accounts exist for the communities in question. Figure 1 shows the breakdown by broad customer rate class:

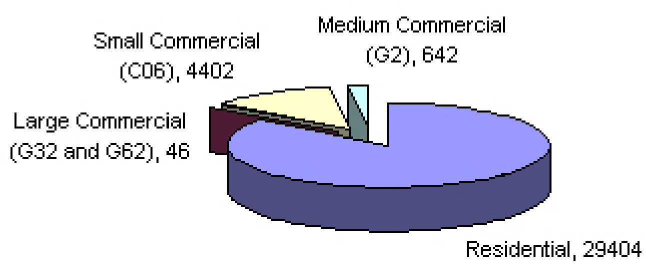

Figure 1 – Newport, Middleton, Portsmouth, Jamestown, Prudence Island customer base

The customer base is largely residential. There are two G62 customers and 44 G3 customers. The G62 customers are fed off of either 13.8 or 69 KV. A majority (32 of the G3 customers) are fed via 4KV and all 32 are located in Newport.

Load profiles

An examination of the Company's loading data for the four 4 kV substations that supply downtown Newport and Jamestown shows that peak loads occur during summer heat waves. By comparing the plot of loads for July-August with the annual load duration curve, one can see the correlation, at least in 2007, of peak loads with the summer heat wave. The daily curve during heat waves shows an extended peak, which may be difficult to reduce without a good mix of ARTs. The two substations shown below, West Howard (peaks at 11 MVA) and Harrison (peaks at 6.4 MVA), largely feed the tourist area and Fifth Ward areas around Lower Thames. The loading curves from both show the number of hours load relief is needed. Peak loads for West Howard Sub occurred from 5:00 – 6:00 PM on August 3, 2007. For Harrison Sub, the peak occurred from 4:00 – 5:00 PM on August 2, 2007.

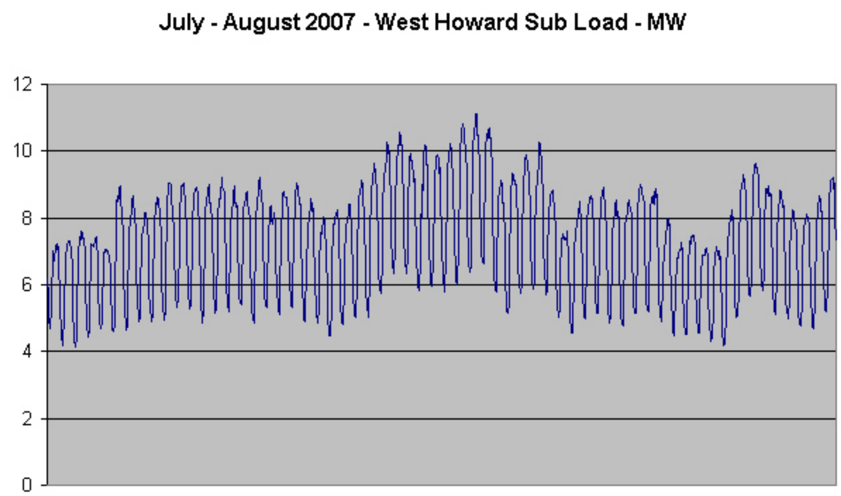

Figure 2 – W Howard loads 2007

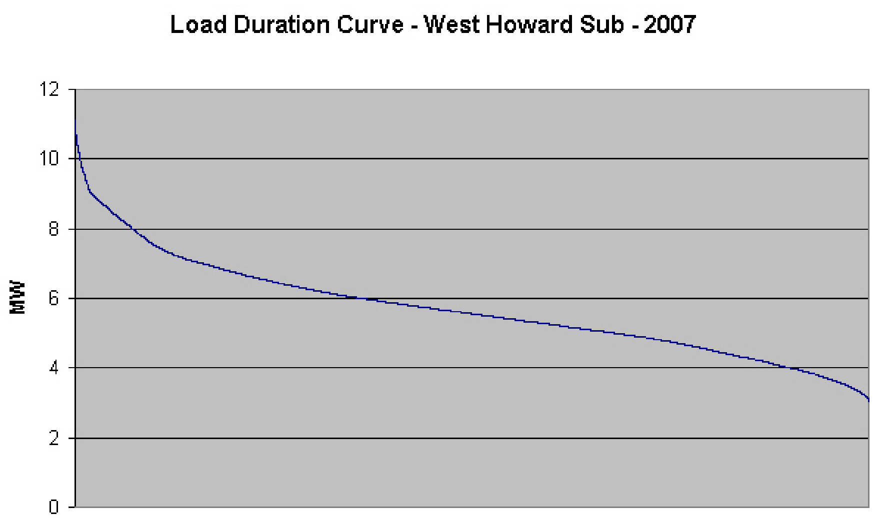

Figure 3 – W Howard load duration curve

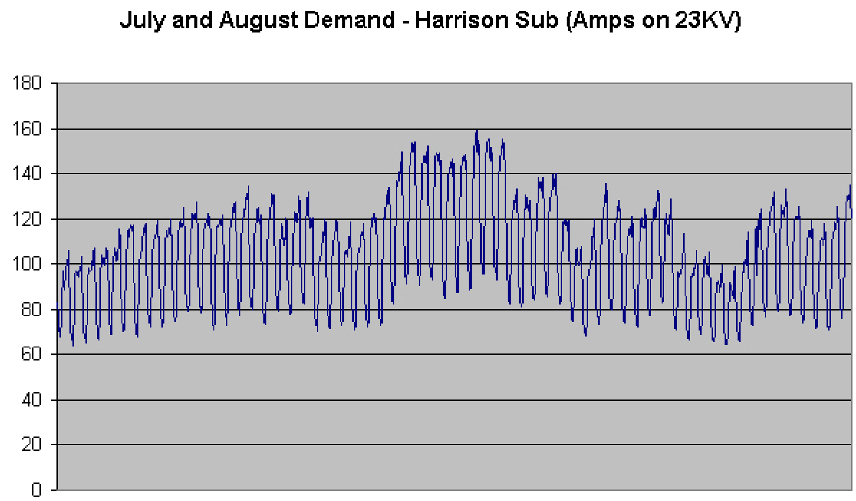

Figure 4 - Harrison substation loads 2007

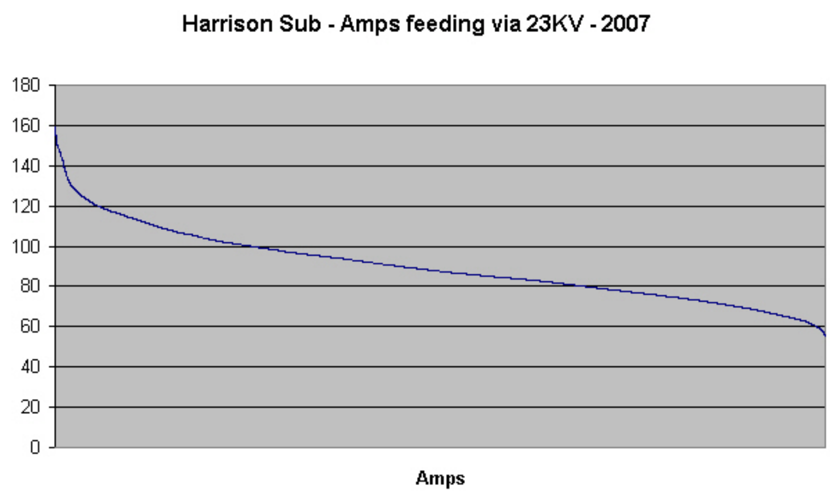

Figure 5 - Harrison Substation load duration curve

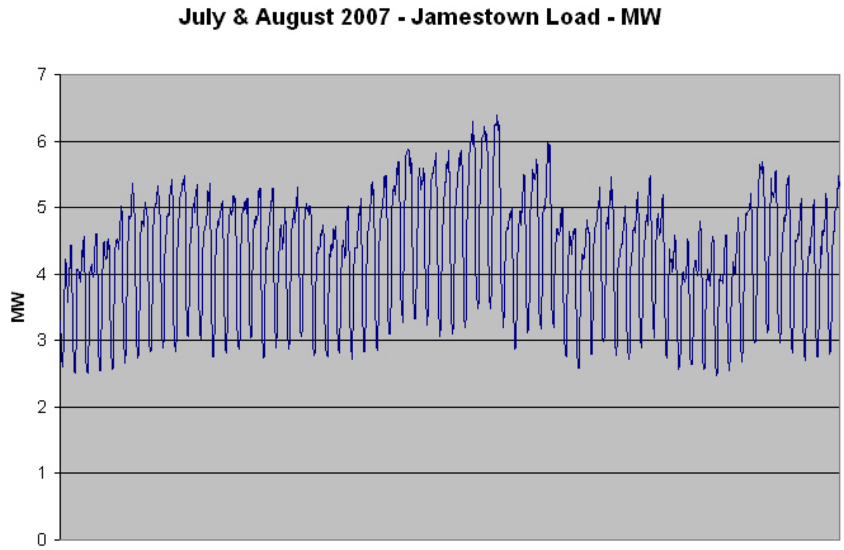

Figure 6 -July and August 2007 Demand - Jamestown Loads

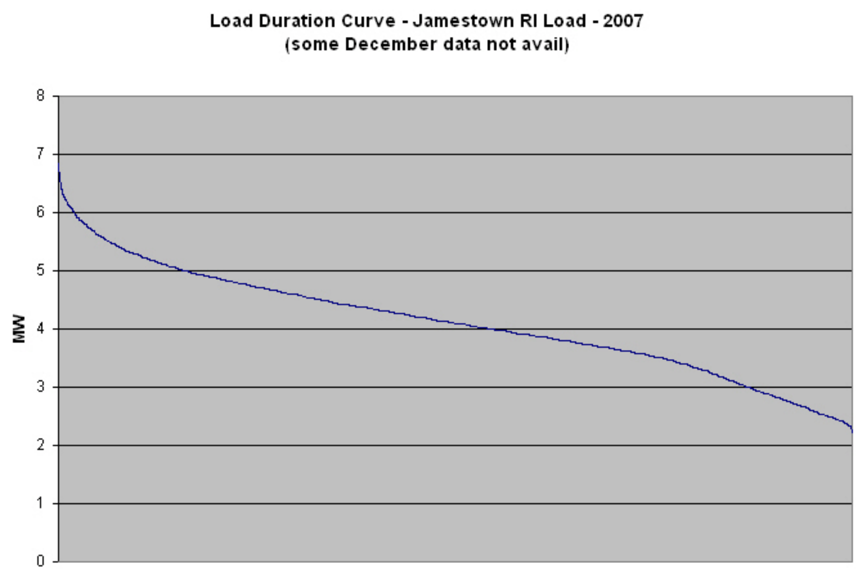

Figure 7 - Jamestown Loads Calendar Year 2007

Peak loads for Jamestown occurred from 5:00 – 6:00 PM on August 4, 2007

<u>Substation load by customer rate class</u>

Figures 8 and 9 illustrate the breakdown of peak by rate classes in each substation. Rate A16 is the residential portion, C06 and G02 are small C/I, and G32 is larger C/I.

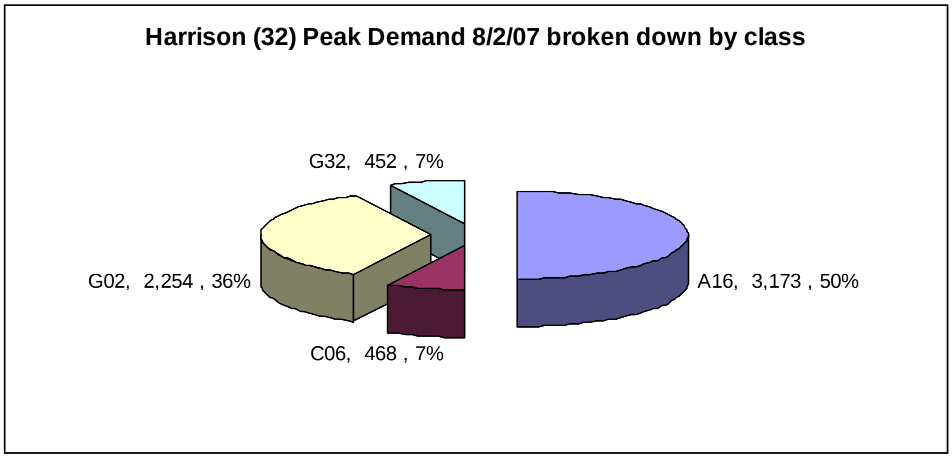

Figure 8 – Peak demand at Harrison Substation by rate class

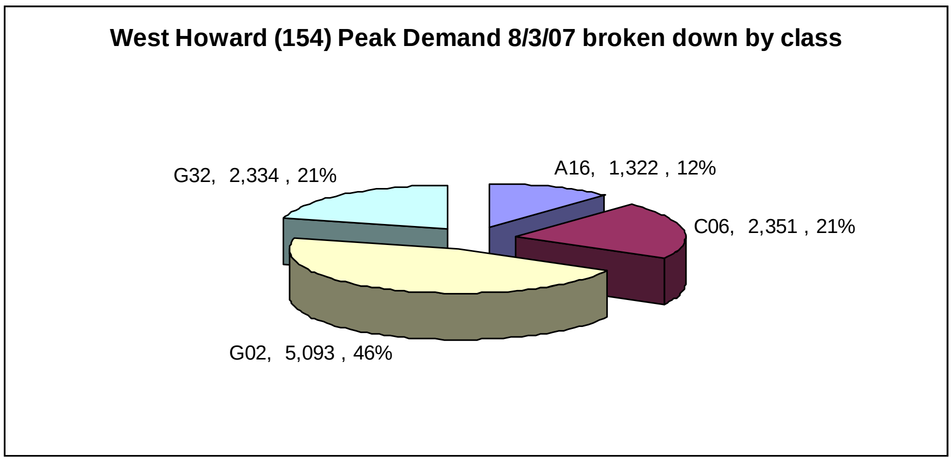

Figure 9 – Peak demand at W. Howard Substation by rate class

As indicated in the Phase 1 plans only, some of the 4 kV feeders out of these two substations are fed from the 23 kV circuit that needs load relief once the work scheduled for the summer of 2009 is completed. Table 2 below shows the customer breakdowns for the 4 kV feeders out of these substations as well as the two substations on Jamestown that ARTs would target.

Table 2. Customer Segmentation for Aquidneck Island

Substation/feeder	Rate class						
	A16 basic residential	A60 low income	C-06 small commercial	G-02 general C/I	G-32 C/I over 200 kWs	Total number of customers	Desired load relief
Harrison #32 – Newport							0.75 MW
32J2	813	19	33	20	1	886	
32J4	656	12	39	3	1	711	
Total	1469	31	72	23	2	1597	
West Howard #154 – Newport							0.75 MW
154J2	93	0	116	17	1	227	
154J4	0	0	57	11	2	70	
154J6	206	3	56	0	0	265	
154J8	486	3	106	15	1	611	
Total	785	6	335	43	4	1173	
Eldred #45 – Jamestown							0.75 MW
45J2	616	14	13	1	0	644	
45J4	493	2	33	4	0	532	
45J6	435	6	14	0	0	455	
Total	1544	22	60	5	0	1631	
Clark St #65 Jamestown							0.75 MW
65J2	661	16	130	24	0	831	
65J12	627	7	73	3	0	710	
Total	1288	23	203	27	0	1541	
overall totals	5086	82	670	98	6	5942	3 MW

Specific ARTs suggested for use

Since the loading issue is resolved with work in Phase 2, load relief of approximately 0.75 MW per 4 kV substation is desired. Within this group of customers, the following ARTs would be offered to residential and small commercial customers over the period 2009-2011:

1) Demand response
    a. Voluntary and direct load control (DLC) for residential and small business customers
        i. HVAC and appliance DLC through the use of thermostat and/or smart plug load controllers
        ii. Requires customers to have broadband internet access in their homes and/or small businesses
        iii. The Company plans to determine if controlling thermostats during peak conditions on the gas distribution system would alleviate gas pressure issues during these peak hours.

b. Conduct demand response audits for customers for the medium and large customers
    i. Develop specific load shed plans
    ii. Evaluate and install automated load shed equipment
c. Evaluate an optional critical peak pricing program utilizing DLC hardware and hourly metering systems.
    i. Develop pilot time of use tariffs to test with different customers
    ii. Customers would still be billed as normal, but if their use pattern and optional tariff show a savings off the standard bill, they would get a credit for the difference, no customer will pay more than under standard billing

2) Renewables
    a. Company owned solar photo-voltaic panels
        i. Target is to install 500 kWs
        ii. Since the Company is in the process of a 25 to 50 MW solar RFP for its MA subsidiary, the cost is estimated to be $6/watt plus administration for a total of $3.5 million
    b. Company owned wind
        i. Work with the municipalities to initiate a wind turbine studies that may be appropriate
        ii. $100,000 proposed to be allocated for studies in Newport and Jamestown

3) CHP
    a. Continue to work on current evaluation of current CHP installations through the gas efficiency program
    b. Target this area for the Phase 2 opportunity report on CHP as directed by the EERMC.

For all the ARTs above, analyses would be conducted to determine the cost/benefit of these resources. The costs for this plan would be recovered from RI customers through the necessary filings reviewed and approved by the Public Utilities Commission.

Table 3 below shows the estimated cost and load relief expected from this pilot program.

Table 3. Aquidneck Pilot Budget and Savings, 2009-2011

Demand Response		Population	Penetration	kW per customer	Total kW	Cost per customer	Total Cost
Residential DLC [1]		5168	20%	1	1033.6	$2,000	$2,067,200
Small Commercial DLC[1]		670	20%	5	670	$5,000	$670,000
Medium Commercial[2]		98	25%	15	367.5	$7,000	$171,500
Large Commercial[2]		6	50%	75	225	$25,000	$75,000
Demand Response Totals					**2296.1**		**$2,983,700**
Renewable Energy[3]							
Solar PV		5942	2%	4.2	500	$25,200	$3,000,000
Wind		1	100%			$100,000	$100,000
Renewable Energy Total					**500**		**$3,100,000**
Grand Total					**2796.1**		**$6,083,700**

1 The Company would offer enrolled customers in a time-of-use pricing option. The Customer would receive the lower of the standard bill or a bill based on the time-of-use pricing.

2 The Company would consider the use of targeted demand response credits as used in the 2004 through 2007 projects: capacity payments of $3.00 per kW-month (for June, July and August) and energy payments of 50¢ per kWh curtailed.

3 The Company would plan to rate-base these assets

Cost-Effectiveness Test:

The Standards approved by the Commission have established that the Total Resource Cost Test (TRC) is to be used for evaluating the cost-effectiveness of efficiency and conservation resources. It is National Grid's position that that same TRC test should be used to evaluate the cost-effectiveness of system reliability resources.

While we are familiar with applying the TRC in assessment of efficiency measures, we will need to apply the TRC methodology to some of the different characteristics of system reliability resources. These system reliability resources are known as Alternative Resource Technologies (ARTs). Among the unique cost and benefits of ARTs that will be considered for inclusion in the TRC test are: reliability and stability benefits, fuel input costs of CHP, tax treatment of renewable resources, environmental benefits of generation alternatives, and the value of T&D deferral or avoidance.

With the exception of CHP resources, for which National Grid currently offers financial incentives through its energy efficiency programs, and renewable resources, the other ARTs proposed in this plan (varying pricing tariffs and demand response) have not yet been implemented on a wider commercial scale. It is possible that application of TRC test will determine that a particular system reliability resource is not cost-effective. We note that neither the law nor the standards require that system reliability resources be cost effective. In this context, the TRC test may be used to judge the relative cost-effectiveness of the ARTs—to help determine how close to cost effectiveness an ART may be—and help guide National Grid's further investments in a technology .

We propose that the Commission approve the use of the TRC test in analyzing the cost-effectiveness of system reliability resources. National Grid, in consultation with the EERMC, will clarify the details of how the test will be implemented in assessing these resources.

In addition, the new incentives allowed within the recently enacted "Emergency Economic Stabilization Bill of 2008" should make all the ARTs in the plan more economically attractive to end-use customers.

IV. Funding Plan

Funding for this System Reliability Procurement Plan is proposed to be separate from the funding for the energy efficiency procurement plan. Although some ARTs such as enhanced demand response and direct load control may qualify as energy efficiency, these technologies have not yet been proven to be cost-effective on a commercial scale in Rhode Island. National Grid was concerned that, in this first year of System Reliability Procurement, funding and implementation of these technologies through the energy efficiency programs might have adversely affected the cost-effectiveness of the energy efficiency programs and the optimal acquisition of cost effective energy efficiency. An objective of the 2009 SRPP effort will be to study the cost effectiveness of the SRPP elements.

CHP incentives are currently offered through the gas energy efficiency programs. National Grid proposes to continue funding this program through the gas efficiency programs and evaluating it for cost effectiveness there. Once we know more about it that context, National Grid may propose to include it in future SRPPs. The attached excel spreadsheet outlines the proposed 3 year funding plan.

Projected System Reliability
Procurement Plan Costs

Year	Program	Program Planning and Administration	Program Marketing & Trade Ally	Customer Incentives or Services	Program Implementation	Evaluation & Market Research	Performance Incentive	Total Utility Cost
2009	Residential Pricing Pilot with Load Control	$75,000	$60,000	$500,000	$40,000	$20,000	$0	$695,000
2010	Residential Pricing Pilot with Load Control	$40,000	$90,000	$850,000	$50,000	$10,000	$0	$1,040,000
2011	Residential Pricing Pilot with Load Control	$40,000	$60,000	$300,000	$50,000	$30,000	$0	$480,000
Total 2009-11	Residential Pricing Pilot with Load Control	$155,000	$210,000	$1,650,000	$140,000	$60,000	$0	$2,215,000

Year	Program	Program Planning and Administration	Program Marketing & Trade Ally	Customer Incentives or Services	Program Implementation	Evaluation & Market Research	Performance Incentive	Total Utility Cost
2009	Small C/I Pricing Pilot with Load Control	$20,000	$15,000	$100,000	$20,000	$10,000	$0	$165,000
2010	Small C/I Pricing Pilot with Load Control	$10,000	$10,000	$250,000	$30,000	$5,000	$0	$305,000
2011	Small C/I Pricing Pilot with Load Control	$10,000	$10,000	$80,000	$30,000	$15,000	$0	$145,000
Total 2009-11	Small C/I Pricing Pilot with Load Control	$40,000	$35,000	$430,000	$80,000	$30,000	$0	$615,000

Year	Program	Program Planning and Administration	Program Marketing & Trade Ally	Customer Incentives or Services	Program Implementation	Evaluation & Market Research	Performance Incentive	Total Utility Cost
2009	Medium C/I Demand Response	$5,000	$5,000	$30,000	$10,000	$5,000	$0	$55,000
2010	Medium C/I Demand Response	$5,000	$5,000	$50,000	$10,000	$5,000	$0	$75,000
2011	Medium C/I Demand Response	$5,000	$0	$40,000	$10,000	$15,000	$0	$70,000
Total 2009-11	Medium C/I Demand Response	$15,000	$10,000	$120,000	$30,000	$25,000	$0	$200,000

Year	Program	Program Planning and Administration	Program Marketing & Trade Ally	Customer Incentives or Services	Program Implementation	Evaluation & Market Research	Performance Incentive	Total Utility Cost
2009	Large C/I Demand Response	$2,000	$0	$15,000	$3,000	$0	$0	$20,000
2010	Large C/I Demand Response	$2,000	$0	$20,000	$3,000	$0	$0	$25,000
2011	Large C/I Demand Response	$2,000	$0	$20,000	$3,000	$5,000	$0	$30,000
Total 2009-11	Large C/I Demand Response	$6,000	$0	$55,000	$9,000	$5,000	$0	$75,000

Year	Program	Program Planning and Administration	Program Marketing & Trade Ally	Customer Incentives or Services	Program Implementation	Evaluation & Market Research	Performance Incentive	Total Utility Cost
2009	C/I Audit and Automation Demand Response	$10,000	$5,000	$380,000	$25,000	$5,000	$0	$425,000
2010	C/I Audit and Automation Demand Response	$5,000	$5,000	$900,000	$25,000	$5,000	$0	$940,000
2011	C/I Audit and Automation Demand Response	$5,000	$5,000	$1,500,000	$25,000	$30,000	$0	$1,565,000
Total 2009-11	C/I Audit and Automation Demand Response	$20,000	$15,000	$2,780,000	$75,000	$40,000	$0	$2,930,000

Total for all Programs

Year	Program Planning and Administration	Program Marketing & Trade Ally	Customer Incentives or Services	Program Implementation	Evaluation & Market Research	Performance Incentive	Total Utility Cost	Estimated kWh sales	Per kWh charge
2009	$112,000	$85,000	$1,025,000	$98,000	$40,000	$0	$1,360,000	7,875,447,453	$0.000173
2010	$62,000	$110,000	$2,070,000	$118,000	$25,000	$0	$2,385,000	8,021,461,251	$0.000297
2011	$62,000	$75,000	$1,940,000	$118,000	$95,000	$0	$2,290,000	8,139,609,642	$0.000281
Total 2009-11	$236,000	$270,000	$5,035,000	$334,000	$160,000	$0	$6,035,000		

Appendix A:
Company history with targeted demand response

The Company has been actively promoting the current generation of targeted demand response programs since 2002. There are a number of design elements that facilitate the development of a targeted demand response program in a specific area. The first element is a capacity shortfall on transmission system over the course of the project. Due to the nature of distribution and transmission system planning and the lead time for construction projects to be planned and completed, the Company works to select an area which is not in imminent danger of insufficient capacity even without the specific distribution or transmission upgrade, but in the event of delays or extraordinary weather, could become overloaded.

A second element in designing the program is the amount of time the estimated capacity shortfall would exist. If the capacity shortfall requires many hours of interruption to manage properly, customers may not participate enough to provide the needed load relief. However, if the shortfall can be identified to a limited number of days and a limited number of peak load hours during those days, then a load curtailment program may provide the necessary load relief if needed, and typically in New England, heat waves are limited to just a few weeks.

The third component is to determine if the existing population of large accounts could provide the necessary load relief.

Finally, the fourth component is the willingness of customers to modify their electrical loads and to evaluate the amount of financial incentive required to induce this modification. According to a 2001 E-Source report 'Making Peak Load Management Work for the Mid-market Industrials, a payment of at least $0.50 per kWh appears to be the minimum value for successful projects.

History of targeted demand response at the Company

- In 2004 the Company undertook a targeted demand response program (filed with the RI PUC as the Summer Load Relief Program) in the Warwick/Cranston area. This program was initiated to provide area load relief in the event the Company's proposed new substation on Kilvert St., in Warwick, were to experience unexpected construction delays which may prevent it from coming on-line before the heat of the summer, and the need to serve the higher electrical loads that come with the heat.

  The Company visited 35 customers with demands over 200 kWs who had Company distribution service from either the Pontiac substation in Cranston or the Lincoln Ave. substation in Warwick. Twenty-three of these accounts were offered load shed audits to help them determine specifically how they could participate in any load shed request. This project was initiated due to potential construction delays for the new substation as outlined above. The substation was energized in mid-June, and by the end of June, the other substations (Pontiac and Lincoln Ave) had been off-loaded by approximately 20 MWs. Since no above-average loads were experienced in the early summer, the Company did not call any load shed events prior to the substation being energized. As of that date, the Company has only received 4 agreements back from customers willing to participate in the program. Many customers were interested in the program but were reluctant to sign an agreement to participate, even though no penalties existed for non-performance. The Company coordinated its promotion of the targeted demand response area with the ISO-NE's programs, in response to the increased number of price response events called by the ISO. The Company viewed the ISO programs as something all medium to large Commercial and Industrial customers should be interested in. The Company broadly marketed the ISO programs with this in mind, offering audits for customers enrolled in either the Company's demand response program or the ISO-NE programs. The audits provided customer education, efficiency project opportunities, as well as guidance for maximizing benefits from participation in the Company's and ISO-New England's demand response programs.

- In 2005, the Company identified the area that served the area fed by the L190 115 kV expansion project. This consisted of loads fed from the Ashaway, Hope Valley, Wakefield, Bonnet, Westerly, Kenyon, LaFayette, Wood River and Peacedale substations. This was an area in its service territory where there are a sufficient number of large customers who have the ability to shed load in a manner that could help the Company meet potential extreme peak loads or unexpected contingency events in the area prior to completion of the transmission upgrade or resulting from delays in the L190 project. Even though the amount of load relief needed was over 50 MWs if there was a failure of one of the 115 kV lines in place, a smaller program was begun with the understanding that, if needed, a significantly larger program might be built off the smaller one. The program was designed for retail delivery service customers in the area who had a minimum monthly billing demand of 200 kilowatts, and who could curtail load by at least 50 kilowatts on short notice.

  The Company paid participating customers capacity payments as well as energy payments based upon the amount of load curtailed in each hour of called interruptions. Capacity payments were $3.00 per kw-month (for three summer months) and energy payments were 50¢ per kWh curtailed. Performance was measured using the same methodology utilized by ISO-NE in their demand response programs. The payments were provided to customers in the form of a bill credit after the end of the season.

  Based on the results of NG-RI's sister company, NG-MA, in its Targeted Demand Response Program (also knows as the Brockton Pilot), NG-RI anticipated enrolling approximately forty percent (40%) of the eligible customers in the area that could shed 8% of their total load when called upon. In this selected area, there were 51 large customers that represent approximately 34,000 kW of load. Using the percentages above, the Company anticipated enrolling 20-25 customers, and targeting 2,000 to 2,700 kWs of load relief. Twenty-one customers were enrolled in the program for a total of 1.95 MWs. No calls were made for the summer of 2005 due to cooler than normal weather.

- In 2006 the Company made three calls for load shed in the area and saw peak load reductions ranging from a low of 1.5 MWs, to a high of 2.1 MWs. Twenty-one customers earned credits totaling over $32,000.
- No calls were made for the summer of 2007 for the same reasons as in 2005.
- In 2008, The L190 transmission line upgrade was energized, and should meet the needs of the area for a projected 10-year period based on the area's historical load growth. Therefore, targeted load relief in the area is no longer needed.

Attachments:

- **RI law**
- **Standards**

Relevant RI law is cited below:

§ 39-1-27.7 System reliability and least-cost procurement. – *Least-cost procurement shall comprise system reliability and energy efficiency and conservation procurement as provided for in this section and supply procurement as provided for in § 39-1-27.8, as complementary but distinct activities that have as common purpose meeting electrical energy needs in Rhode Island, in a manner that is optimally cost-effective, reliable, prudent and environmentally responsible.*

(a) The commission shall establish not later than June 1, 2008, standards for system reliability and energy efficiency and conservation procurement, which shall include standards and guidelines for:

(1) System reliability procurement, including but not limited to:

(i) Procurement of energy supply from diverse sources, including, but not limited to, renewable energy resources as defined in chapter 26 of this title;

(ii) Distributed generation, including, but not limited to, renewable energy resources and thermally leading combined heat and power systems, which is reliable and is cost-effective, with measurable, net system benefits;

(iii) Demand response, including, but not limited to, distributed generation, back-up generation and on-demand usage reduction, which shall be designed to facilitate electric customer participation in regional demand response programs, including those administered by the independent service operator of New England ("ISO-NE") and/or are designed to provide local system reliability benefits through load control or using on-site generating capability;

(iv) To effectuate the purposes of this division, the commission may establish standards and/or rates (A) for qualifying distributed generation, demand response, and renewable energy resources, (B) for net-metering, (C) for back-up power and/or standby rates that reasonably facilitate the development of distributed generation, and (D) for such other matters as the commission may find necessary or appropriate.

The Approved Standards state:

CHAPTER 2 – System Reliability Procurement

Section 2.1 Distributed/Targeted Resources in Relation to T&D Investments

A. The Utility shall propose pilot distribution and, if appropriate, transmission projects in their first system reliability procurement plan for which they will examine alternative resource strategies as alternatives or enhancements to the distribution or transmission upgrade. These pilot projects should be used to inform or revise the system reliability procurement process in subsequent plans.

B. Alternative Resource Technologies (ART) shall include but not be limited to:

1. Distributed generation generally
2. Combined heat and power
3. Renewables (predominantly wind and solar, but not constrained)
4. Demand response
5. Peak demand and geographically focused energy efficiency programs
6. In order to meet the statute's environmental goals, unless a compelling showing to the contrary, technologies selected or supported should:
    a. achieve a CO_2 emissions rate equal to or better than the ISO New England marginal emissions rate on an output basis (thermal and electric) – current rate ~1,100 lbs/MWh; and
    b. utilize best available control technology for NOx emissions

C. For each pilot the utility should identify an evaluation process that allows for input from the Council and other stakeholders and includes elements such as the following:

1. Identification and description of the T&D investment
2. Description of the need, requirements, and drivers such as demand growth (load curve and timing issues)
3. Description of the business as usual upgrade in terms of technology, costs (capital and O&M), and schedule for the upgrade
4. Identification of the level of peak demand savings required to avoid the need for the upgrade
5. Development of ART alternative investment scenario(s)
    a. Specific ART characteristics
    b. Development of an implementation plan, including ownership and contracting considerations or options
    c. Development of a detailed cost estimate (capital and O&M) and implementation schedule
6. Reporting and recommendations

a. Compare the investment options from a cost perspective – cost assessed on a net-present-value basis to the state's ratepayers (common assumptions across scenarios)

b. Include a summary of environmental impacts and a discussion of any co-benefits such as benefits to local businesses or industry

c. Recommend preferred solutions

D. The utility pilot program(s) should be reviewed and approved by the PUC as part of the System Reliability Procurement Plan submitted on September 1.

Section 2.2 Renewables

A. The utility shall consider opportunities to integrate renewable energy resources with measurable benefits into the system reliability plan and in a coordinated fashion with the implementation of efficiency procurement. Activities may include but not be limited to:

1. Renewable energy projects that compliment the distribution and transmission pilot projects or provide other system benefits;
2. Distributed renewable energy projects such as photovoltaics wind or solar thermal; and
3. Where appropriate, the Utility should coordinate its programs with the renewable energy fund.

B. The utility plan shall document current activities and commitments to increase renewable energy production and contracting and how those activities affect costs, benefits, price stability, fuel diversity, and environmental goals.

Section 2.3 Combined Heat and Power

A. The electric and natural gas efficiency programs should support and expand programs for CHP applications that are cost-effective, deliver net reductions in energy consumption, and provide environmental benefits.

B. The utility plan shall include discussion of CHP potential in the state based on the Opportunity Report and should set targets or goals for CHP penetration and if necessary propose new programs to support the development of CHP. The plan should describe how those activities affect costs, benefits, price stability, fuel diversity, and environmental goals.

C. CHP programs or projects supported by the Utilities should be sited at facilities with adequate thermal loads to ensure high levels of efficiency on an annual basis

Section 2.4 Demand Response

A. The Utility shall examine and implement where cost-effective, demand response measures or programs in coordination with the electric and natural gas efficiency program offerings. Such measures and programs will be designed to supplement cost-effective procurement of long-term energy and capacity savings from efficiency measures.

B. The Demand and capacity value of CHP and other distributed generation strategies shall be identified and quantified.