nationalgrid

Thomas R. Teehan
Senior Counsel

March 1, 2011

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Standard Offer Service Procurement Plan – Compliance Report
Docket 4149

Dear Ms. Massaro:

On behalf of National Grid,[1] I am filing ten copies of the Company's report regarding the estimated costs and implementation issues associated with shifting the Company's Industrial group in the state to 100 percent spot market purchases for their electricity needs. This report is submitted in compliance with the Rhode Island Public Utilities Commission ("Commission") order No. 20125 in the Company's 2011 Standard Offer Service ("SOS") Procurement Plan in Docket 4149.

The report contains an overview of the Industrial customer group; discussion regarding mandatory hourly pricing ("MHP") rate mechanisms, pricing options and approaches to energy and capacity procurement; and a description of metering and billing changes and customer outreach and education programs that would be associated with shifting the Company's Industrial group to 100 percent spot market purchases. This report includes estimates of implementation costs in terms of incremental operating expenses and new capital investment as well as an estimated time period for implementation.

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

Very truly yours,

Thomas R. Teehan

Enclosure

cc: Leo Wold, Esq.
Steve Scialabba, Division
4149 Mailing List

[1] National Grid d/b/a Narragansett Electric Company ("National Grid" or "Company")

Docket No. 4149 National Grid – 2011 SOS and RES Procurement Plans
Service List updated 3/19/10

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STUDY ON THE COSTS AND IMPLEMENTATION ISSUES OF TRANSITIONING TO SPOT MARKET PRICING FOR THE NARRAGANSETT ELECTRIC COMPANY'S INDUSTRIAL GROUP CUSTOMERS

Submitted to:

The Rhode Island Public Utilities Commission

March 1, 2011

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1. <u>Introduction</u>

Narragansett Electric Company, d/b/a National Grid (the "Company") is pleased to submit this study on the estimated costs and implementation issues associated with shifting the Company's large general service customers in the state to 100% spot market purchases for their electricity needs in response to the Rhode Island Public Utilities Commission ("Commission") order in Docket 4149, which pertained to the Company's 2011 Standard Offer Service ("SOS") Procurement Plan ("2011 SOS Plan").

That order specifically requested the Company to "file a report with the Commission no later than March 1, 2011 regarding an analysis of the implementation issues and investment requirement of transitioning the Industrial Group to 100% spot purchases." (Order 20125, p. 21, para. 2). Among other things, the order approved the procurement of electricity for SOS customers of the Industrial Group receiving service pursuant to the terms of rate classes G-32, B-32, G-62, B-62, and electric propulsion X-01, through three-month contracts with wholesale suppliers. These contracts are designed as full requirements service ("FRS") contracts, which guarantee fixed monthly prices for the load served for a particular period of time, including all energy, capacity and ancillary services. The wholesale provider then serves the applicable customers for the period, while absorbing all price, volume, and customer migration risks.

Transitioning the procurement approach for the Industrial Group to "100% spot purchases" could be accomplished in a number of different ways, as will be discussed in this study. In the simplest arrangement, customers would be charged for their actual hourly usage at the day-ahead or real-time Locational Marginal Price ("LMP") as established for the Rhode Island zone of the Independent System Operator – New England ("ISO-NE"), plus associated charges for ancillary services and capacity. The Company defines this basic approach as a Mandatory Hourly Pricing ("MHP") procurement and commodity rate mechanism. This study contemplates the application of MHP to Industrial Group customers in Rhode Island, which are included in this group by drawing an average monthly demand of more than 200 kW. Also included is a discussion of the estimated costs and benefits of limiting the implementation of MHP to those customers with a minimum average demand of 500 kW.

Through this study, the Company estimates that the implementation of MHP for the Industrial Group could cost approximately $2.75 million in total. This estimate is composed of $1.1 million in new, incremental operating expenses (some one-time, some recurring) and $1.65 million in new capital investment. The Company estimates a time period of 24 months for implementation after receipt of an order from the Commission to make the change to MHP. These costs are based upon preliminary estimates of implementation requirements and are subject to revision as these elements are scoped in greater detail. In addition, the breakdown between capital and operations expenses would be further refined, and the level of expenses would be adjusted to respond to the type of implementation program desired by the Commission.

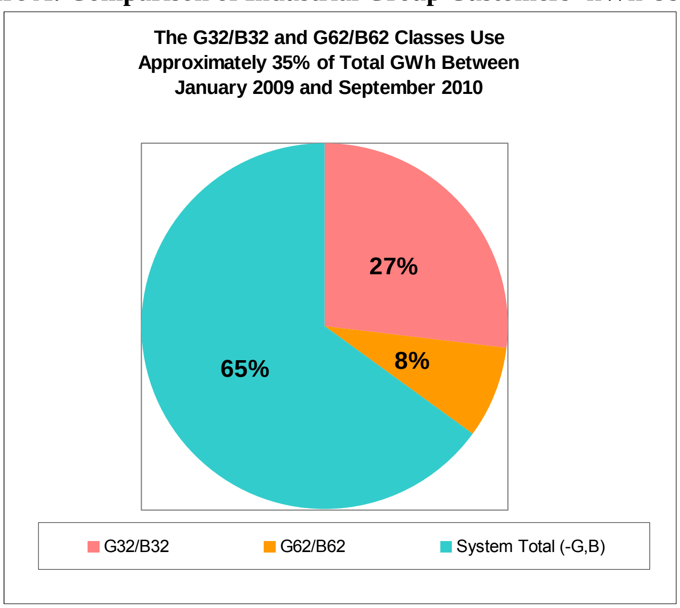
2. Customer Class Overview

As of December 31, 2010, the Company served 1,084 customer accounts under Rates G-32/B-32 and G-62/B-62, and one under Rate X-01,[1] which represent customers with an average billing demand over a 12-month period greater than 200 kW and 3,000 kW, respectively. Rate classes denoted by "B" are provided service on a backup rate; those denoted by "G" are on the general service rate. Standard Offer Service (SOS) was provided to 483 of these accounts and 601 accounts were being supplied by non-regulated power producers ("NPPs"). These statistics are shown in Table A below.
For the period from January 2009 to September 2010, Rate G-32/B-32 and Rate G-62/B-62 customers account for 27% and 8%, respectively of the total kWh deliveries by the company. This is shown in Figure A below.

Table A: Rhode Island Industrial Group Customers by Demand Rate

		SOS	NPP	Total
B	32	1	4	7
	62	0	2	
G	32	480	586	1,077
	62	2	9	
Total		483	601	1,084

Figure A: Comparison of Industrial Group Customers' kWh Usage*



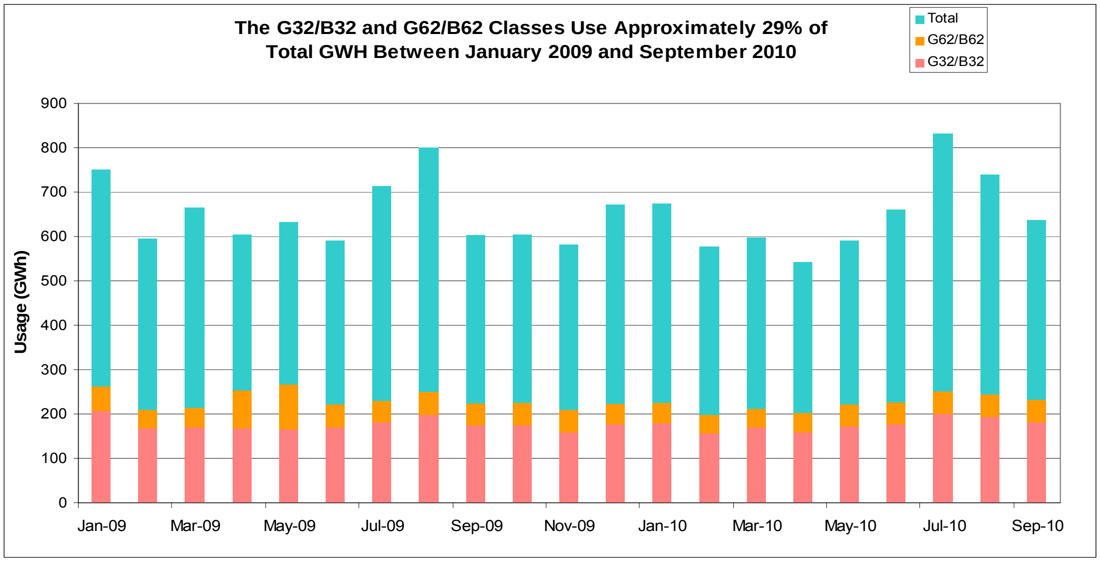
*Does not include Rate X-01 Customer Data in breakout

A monthly comparison of usage levels between Rate G-32/B-32, Rate G-62/B-62 and total GWh consumed each month by all National Grid customers in Rhode Island is

[1] Because of the special nature of the single X-01 customer, for electric propulsion service, the use and demand of that customer is not included in the following analyses. The X-01 customer used approximately 0.3% of the total customer kWh usage, and 0.87% of the Industrial Group usage, in 2010.

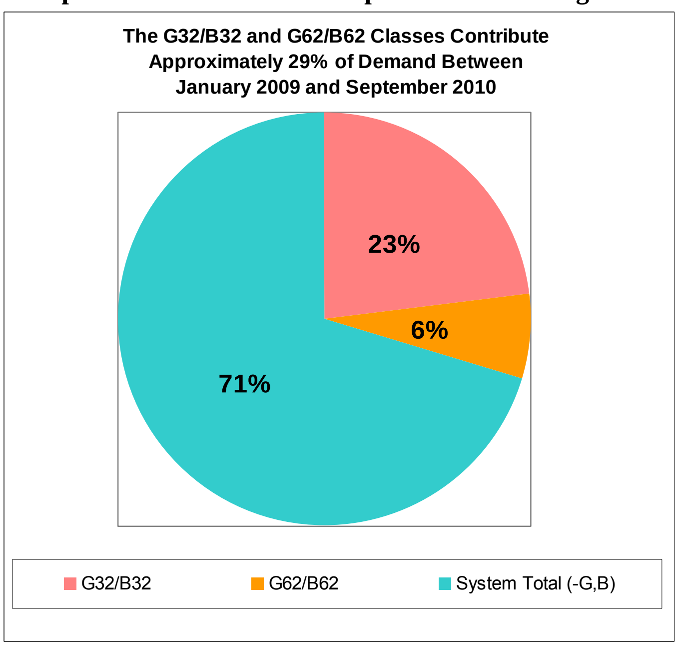
presented in Figure B. In this graph, each class' segment represents the number of GWh consumed by that class; the total height of the bar corresponds to the total monthly GWh deliveries to all customers in Rhode Island plus unaccounted for energy.

Figure B: Monthly Comparison of Industrial Group Customers' kWh Usage*



*Does not include Rate X-01 Customer Data in breakout

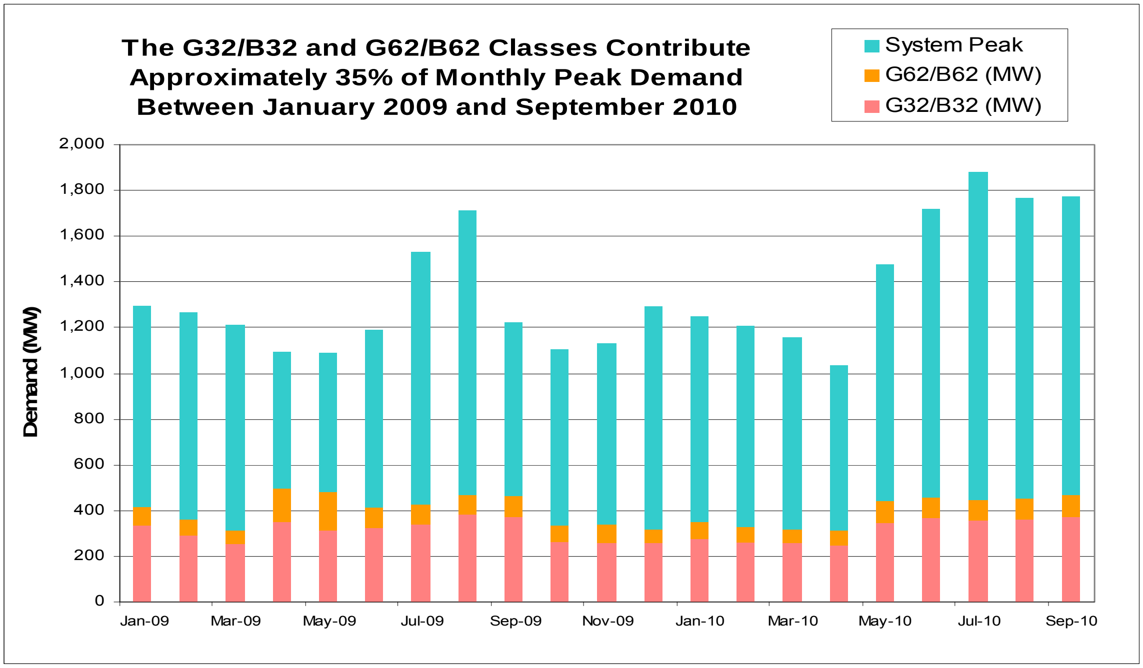
Figure C: Comparison of Industrial Group's Demand During the NECO Peak*



*Does not include Rate X-01 Customer Data in breakout

Rate G-32/B-32 and Rate G-62/B-62 customers contributed 23% and 6%, respectively, of the total demand by the Company's customers in Rhode Island during the Company's monthly Rhode Island system peak between January 2009 and September 2010, as seen in Figure C. A more specific graph, showing individual demand of each of the groups during the Company's Rhode Island system peak each month can be seen in Figure D.

Figure D: Comparisons of Industrial Group Demand During the NECO System Peak Each Month*



*Does not include Rate X-01 Customer Data in breakout

Figure E compares the usage of Rate G-32 customers on SOS and NPPs; Figure F makes the same comparison for Rate G-62 customers. The average use of Rate G-32 customers procuring electricity through NPPs is approximately 57% higher than the average use of the 480 customers on SOS; the average use of the nine Rate G-62 customers with NPPs is approximately 42% higher than the average use of their two SOS counterparts.

Figure E: Comparison of G-32 Customers on Standard Offer and NPP

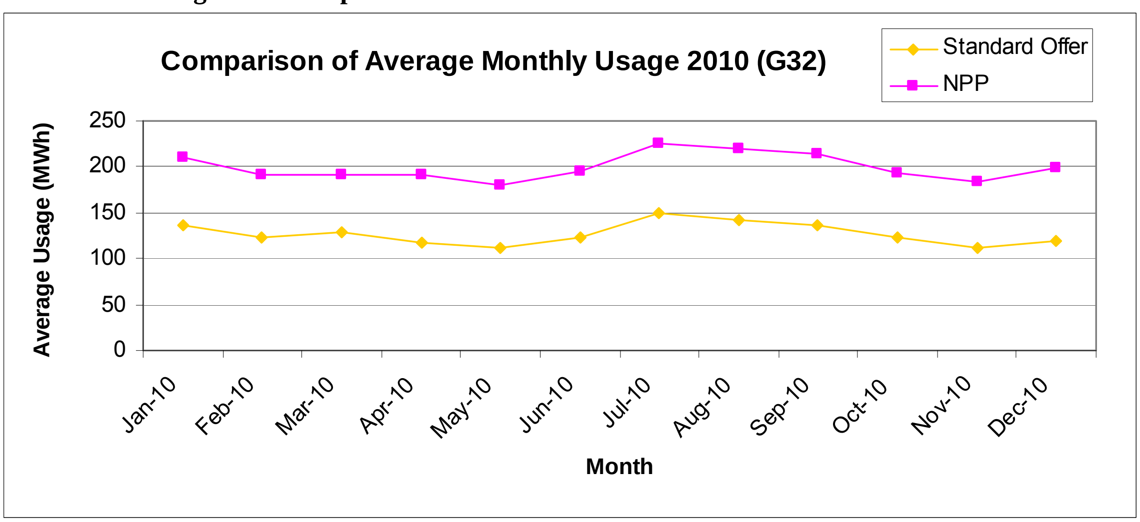
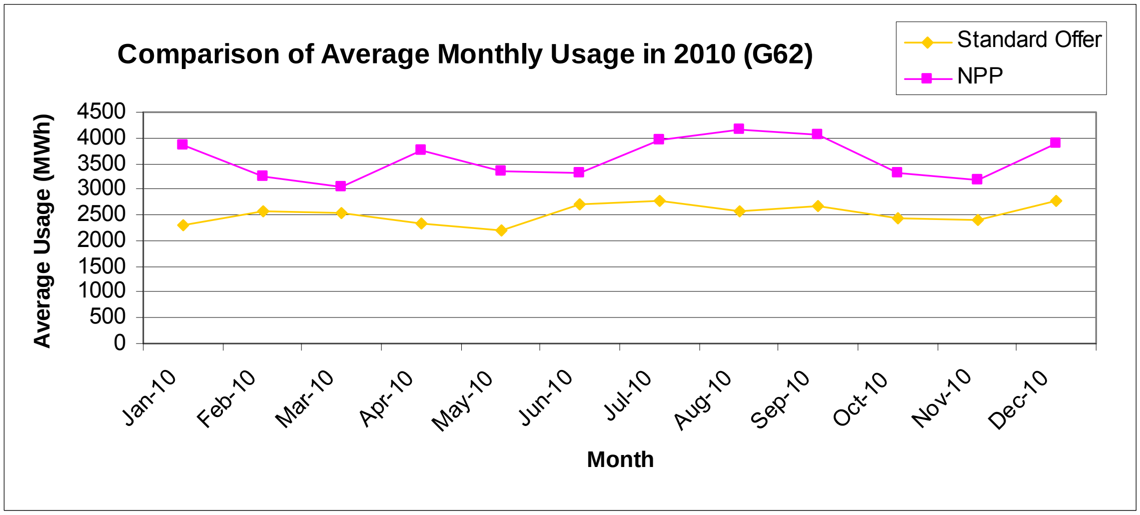


Figure F: Comparison of G-62 Customers on Standard Offer and NPP



A distribution of Rate G-32 and Rate G-62 customers' load factors can be seen in Figures G and H.

Figure G: Distribution of G-32 Customers' Load Factors (Lowest to Highest)

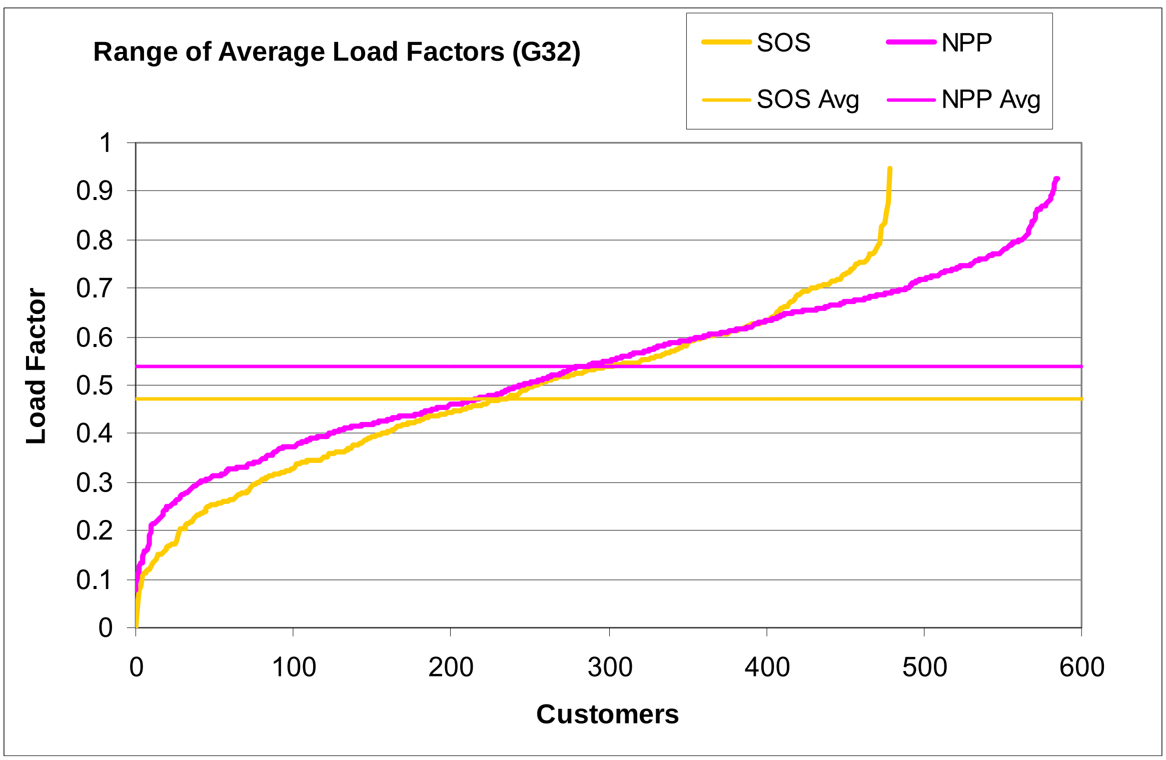
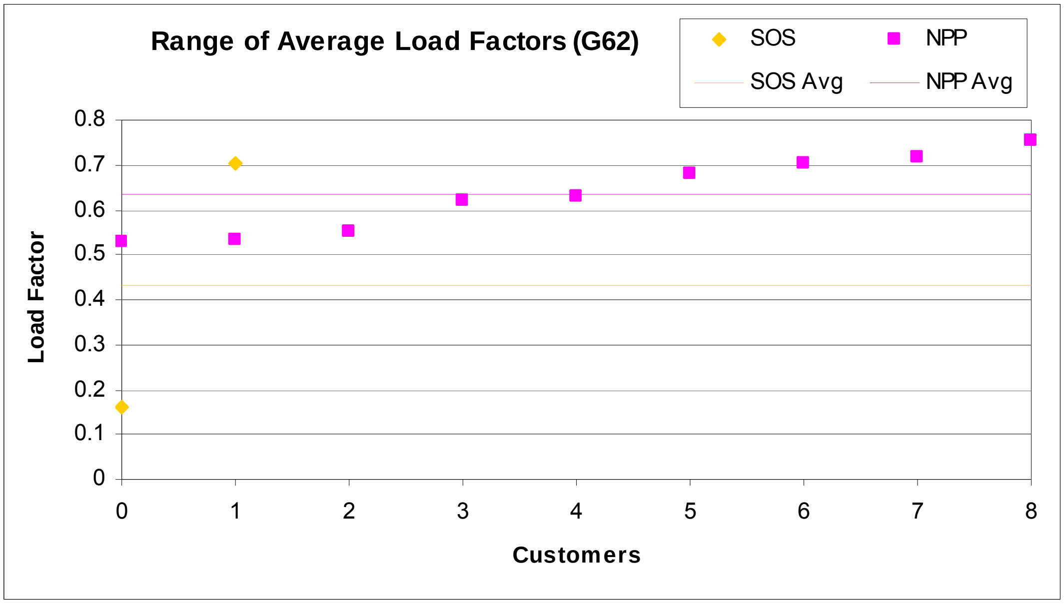


Figure H: Distribution of G-62 Customers' Load Factors (Lowest to Highest)



The distribution of G-32 customers shows an average load factor of 47% and 54% for customers on standard offer and those with an NPP, respectively. The G-62 distribution shows an average load factor of 43% and 64%, respectively, for their 11 total customers. As can be seen, customers with more stable usage (i.e., a higher load factor) are more likely to receive commodity service from a competitive supplier at present.

From this information in total, one can conclude that larger use, higher demand customers are more likely to receive their energy needs from NPPs. Changing the price provided to SOS customers, which are on average smaller, from the current monthly fixed rate to a dynamic hourly rate may provide some of these customers with incentives to find fixed rate options in the market. At the same time, larger customers that have gone to the market seeking more dynamic prices could migrate back to SOS if MHP were adopted. Thus, there is some uncertainty as to which customers would use SOS if MHP were the default procurement and pricing method for this group.

3. Rationale for MHP Rates

More than 70 utilities in the U.S. have at one time implemented mandatory or optional hourly pricing for their largest commercial/industrial customers. Implementations of mandatory hourly pricing for large customers have generally been for the largest of those customers, above either 1 MW or 500 kW of demand. As stated above, Industrial Group customers have a minimum average demand of 200 kW.

In general, interest by regulators, system operators, and utilities in MHP for commodity supply has evolved due to the expectation of multiple benefits for customers. MHP with use of Day-Ahead LMPs provides customers price signals that reflect a greater sense of real-time costs for commodity service without exposing them directly to the more volatile

Real-Time LMP. The improved pricing signal from MHP could possibly influence customers' behavior over the long term, either through reducing energy consumption at high cost times or finding a different price from the market. If customers reduce their load at peak times, their actions may contribute to lower commodity prices generally if the cumulative impact of reductions is sufficient to reduce the use of peaking, high-cost generation assets, and, longer term, the need for increased capacity to meet demands during peak periods.

Charging customers for the demand-varying cost of electricity includes no added costs or premiums for the management of price volatility and over the long term may result in lower overall costs for electricity. The potential savings related to the removal of the small premiums inherent in FRS contracting from energy prices in exchange for exposure to increased price volatility has been discussed in the Company's 2011 SOS Plan in the Northbridge study,[2] recognized by the Rhode Island Division of Public Utilities and Carriers in its expert witness testimony in that same docket,[3] and addressed by leading experts on dynamic pricing.[4] This opportunity for savings would be available for all customers in the Industrial Group.

Some customers may not choose or be able to shift or reduce loads significantly during peak periods, and some of these customers may experience increased costs under MHP if they are peak-intensive. Customers that cannot shift load are typically those with relatively stable usage (i.e., a high load factor), and those in high-value or time-sensitive industrial processes or service industries that cannot significantly shift their usage to other times (e.g., continuous process manufacturers, financial services providers, grocery stores, hospitals, or restaurants). For example, customer interviews in the two-year evaluation of the Company's MHP program in New York revealed that 84% of participating customers did not have the flexibility to shift their usage in response to hourly prices. Other barriers included insufficient resources to pay attention to hourly pricing and potentially increased costs related to tracking and shifting usage from peak to off-peak periods.

In addition, customers who now purchase SOS are able to choose to purchase energy from an NPP at any time. At the end of 2010, 55% of large general service customer accounts and 72% of those customers' most recent annual energy usage was already purchased from NPPs rather than from the Company, an increase over prior years. Customers wanting a guaranteed energy price may switch to competitive supply after the implementation of MHP. Because of this potential for migration, the Company would recommend that, if MHP is approved for the large customers, all costs associated with an

[2] "National Grid's Report Regarding Its Comprehensive Review of Standard Offer Procurement Strategies," Docket 4041. p. 4

[3] "In the Matter of National Grid's Standard Offer Supply Procurement Plan for 2011." Direct Testimony of Richard Hahn, Docket 4149 p. 10-11.

[4] For example, on recent paper stated, "The hedging premium is inversely related to customer exposure to wholesale market prices…As rates become more dynamic, the premium decreases. Under a 'Real Time Price,' the premium is equal to zero." Faruqui, Sergici & Wood (2009) "Moving Toward Utility Scale Deployment of Dynamic Pricing in Mass Markets." Institute for Electric Efficiency. p. 5

implementation of MHP be borne by all customers in the Industrial Group, as described more in the Conclusion section below.

In short, MHP would provide Industrial Group customers with improved price signals and the opportunity to make decisions to save money by shifting usage if they can. At a minimum, customers would receive prices that are more reflective of the actual commodity cost to serve them. In addition, the relationship between historical FRS prices and spot market prices from the New England market indicate that the Industrial Group would have paid slightly less for energy delivered in recent years. Finally, MHP may encourage additional retail choice by Industrial customers. The Commission may view these potential benefits as favoring the implementation of MHP for Industrial Group customers. Consideration of specific elements of the rate design, such as how capacity charges are billed, as described below in Section 4, may offer enhancements that provide more incentive to customers to respond to hourly prices.

4. Pricing Options

This section describes two dynamic pricing options that could be implemented to allow customers to purchase their electricity from the spot market. In choosing a pricing methodology for this class, the following criteria should be considered.

- Prices should reflect underlying costs as closely as possible in order to communicate appropriate price signals to customers and to minimize the potential for over or under collection of costs.
- The pricing method chosen should be easy to understand and acceptable to customers.
- The cost to implement and administer the chosen pricing method should be weighed against the potential benefits.
- The pricing method chosen should result in fair allocations of costs and avoid cross-customer subsidization as much as possible.

With these criteria in mind, the Company has identified the following potential SOS pricing options that could be implemented for the Industrial Group. The following section provides a brief overview of the different options and some of the advantages and disadvantages of each.

Option 1: Hourly energy prices with fixed capacity charges. Under this approach, SOS pricing would consist of an hourly charge for market energy costs, and a fixed monthly capacity charge. Hourly energy charges would be based upon the Day-Ahead Locational Marginal Price for energy (DALMP) provided by the ISO-NE as a result of bidding by generators in the energy market. Ancillary costs and thermal losses would be added to the per kWh component of the rate. A small amount of real-time energy would also be purchased in this structure for balancing, and differences between the DALMP and the real-time LMP would be reconciled regularly as part of the new MHP mechanism.

Capacity would be billed as a per kW (demand) charge based upon each customer's individually determined capacity obligation. Under the Forward Capacity Market ("FCM")of the ISO-NE, the system operator bills load serving entities("LSEs") for capacity costs based upon each LSE's aggregate customer annual capacity obligation, also referred to as a capacity or ICAP tag, determined by their load at the time of the ISO-NE annual peak. Once determined, this value remains fixed until a new peak is established in the subsequent production year. In addition, the price charged is largely fixed by the FCM auction for each reliability period, stretching from June 1 to May 31 of each year. Assessing capacity charges on the basis of system peak demand ensures that each customer is held directly responsible for its role in contributing to the prior year's system peak. This method would provide the best alignment of revenue and cost since it is consistent with the way the Company is billed by ISO-NE for capacity charges associated with providing SOS[5].

<u>Option 2: Hourly energy prices with per kWh Capacity Charges.</u> Under this approach, energy prices and ancillary costs would be determined in the same manner as in Option 1. However, capacity costs would be assessed as a per-kWh charge added to the hourly energy prices for a limited number of hours in the year. Such a volumetric charge could be shaped, to be added to the hourly Day Ahead LMP each week-day during specified peak hours, with the greatest expectation of peak demand (i.e., critical peak periods). Thus, a per-kWh capacity adder to the hours with the greatest loads creates an immediate incentive for hourly pricing customers to shift load away from the most critical hours. Customers would immediately understand the risk and opportunity from the pricing each day. However, this option may result in some additional over or under collection of capacity costs throughout a given year, which could be reconciled twice per year, like other reconciliations in Rhode Island.

<u>Phased Implementation.</u> Should the Commission favor the implementation of MHP for the Industrial Group, the Company recommends that the Commission consider a phased approach to the implementation by initially limiting application of MHP to customers with billing demands in excess of 500 kW, currently 278 customer, or 25% of the group. As can be seen in Table B, below, this segmentation would include a more substantial group of larger customers than setting a 1,000 kW limit. Presently, all 12 customers in Rates G-62/B-62 and X-01 have annual billing demands in excess of 500 kW. Customers above 500 kW in demand across the Industrial Group account for approximately 68% of the total kWh deliveries of the Industrial Group. Of the 278 customers, 101 are currently receiving SOS from the Company.

Table B: Industrial Customers Above Given Average Demand Levels in 2010

	Number of Customers		
Demand (kW)	SOS	NPP	Total
500	101	177	278
1000	29	76	105

[5] The Company is aware that the ISO-NE is considering different means to determine capacity tags which may apportion responsibility for capacity costs over a greater number of hours in the year.

Limiting the initial implementation to Industrial Group customers at 500 kW or more of average demand will allow the Company to spend less in the near-term and reduce the time required to install the appropriate metering for the initial group, while capturing the majority of the Industrial Group's annual usage in the program. In addition, limiting the number of initial participants will allow for a more targeted outreach to customers. Once the Company and the Commission have had the opportunity to evaluate customer response to MHP from this limited group of Industrial Group customers, the decision to expand MHP to the entire Industrial Group could be made.

5. <u>Energy and Capacity Procurement</u>

This section discusses the means by which the Company could procure spot market energy and the allocation of ancillary services and capacity charges to the three procurement groups.

Currently, the Company provides SOS to the Industrial Group through quarterly competitive solicitations for FRS contracts, as described in the Introduction, above. If the Commission rules that MHP is the appropriate means by which to procure electricity and price SOS to those customers, the Company would switch to hourly market procurements directly from ISO-NE. The Company would continue to procure and price SOS under the FRS method approved by the Commission until such time as all necessary metering and billing changes are in place and outreach and education of included customers has occurred. Upon successfully completing all phases of an implementation plan, the Company would time the start of market purchases and the billing of MHP SOS prices to commence on the same date.

Beginning April 1, 2011, the Company is approved to procure 5% of the Residential and Commercial Groups' requirements through the ISO-NE spot market, with 10% spot approved for after January 1, 2012. The Company will submit a combined demand bid, for the full amount of forecasted load requirements for both groups, into the ISO-NE Day Ahead Energy Market. If the Commission approves MHP for the Industrial Group, the Company would add 100% of the Industrial Group's requirements to the spot procurement requirements of the Residential and Commercial Groups to determine the daily loads bids. As mentioned above, the difference between the forecasted load requirements and the actual load would be settled in the Real Time Energy Market. Since the Company will have forecasted loads and actual loads for each customer group, the supply power costs can be fairly allocated to the appropriate customer group.

In addition, ISO-NE would charge the Company for other market obligations and ancillary services (e.g., Capacity, Regulation, Operating Reserves, and Net Commitment Period Compensation charges) associated with these load requirements. Unlike the capacity charges, ancillary charges, like the energy market charges, would be allocated by the Company to each customer group by the customer group's load as a percentage of the total load procured by the Company in the spot market. The non-capacity charges allocated to the Industrial Group would then be collected through a per kWh adder to the energy charges.

Capacity charges would similarly be split and allocated by the Company, within the options described in the Pricing Options section above. A customer's capacity obligation, known also as its ICAP tag, is determined by that customer's contribution to the ISO-NE system peak load during the calendar year preceding the start of the capacity capability year in question. Unlike other customer groups, customers within the Industrial Group have individual ICAP tags calculated based on their actual hourly metered load. Thus, the Company would be able to fairly allocate capacity charges to each Industrial Group customer via their individual ICAP tags.

6. Metering and Billing Changes to Implement MHP

Several changes to the Company's existing equipment in the field and its meter data, pricing and billing systems would be required to implement MHP for the Industrial Group. This section will outline these changes and estimated costs for transitioning all customers in the Industrial Group at the same time.

Metering Infrastructure Changes

At present, the Company employs Interval Data Recorders ("IDR") to determine 15-minute interval demands for its Industrial Group customers. However, the vast majority of these meters are not able to track load data in a manner that would support the hourly pricing requirements for appropriately billing each customer. In addition, data collection for most of the meters in the field is still accomplished by on-site collection methods (both manual and radio-signal) that would not enable a more dynamic, real-time reporting of usage to customers. Dynamic collection would enable customers to better track and vary their energy usage patterns in response to MHP rates. Such dynamic collection is best accomplished through the use of wireless data transmission.

Of the 1,085 Industrial Group customers, the Company estimates that approximately 1,000 meters would need to be replaced at a cost of approximately $1,500 each, including labor cost for the installation and associated company overheads, for an estimated cost of $1.5 million in new capital investment. Additional ongoing expenses would include annual communication fees for data collection of approximately $140 per year, per meter, less some savings from replacement of existing communication channels, for an estimated cost of approximately $100,000 per year. Additional costs would include any incremental operation and maintenance expense involved with troubleshooting the new meters or related new communications issues. It is possible that with further analysis some percentage of existing meters that were more recently installed have features that would allow them to be retrofitted or reprogrammed at a lower cost than replacement. Such detail could be developed as part of a detailed implementation plan.

The early retirement of 1,000 meters for these customers may also result in a stranded cost for meters for which the Company would request recovery from these customers. This amount has not been computed as of the date of this filing.

Meter Data and Pricing Changes

The Price Transmission System ("PTS") is a proprietary software program developed for National Grid by Bridge Technology Systems. For the Company's New York affiliate, the PTS program downloads wholesale day ahead LMPs every day from the New York Independent System Operator ("NYISO") website, then computes and transmits retail hourly day ahead prices to the Customer Service System ("CSS") and the Company's external website.

The existing PTS could be expanded to serve Rhode Island's Industrial Group. PTS runs automatically every morning, and could be altered to import bill components from the ISO-NE website, and then calculate hourly day-ahead retail prices. Calculated prices would be transmitted to the mainframe for CSS billing of SOS customers and to the Company's external web site for customer use.

Because of the existing agreement with Bridge Technology Systems, which was competitively procured, Bridge would be the preferred vendor to expand the existing PTS software. It would commence the requirements analysis and software development within 60 days of receiving a signed copy of the Statement of Work. Implementation of the new program should be completed in nine to 12 months after the contract has been signed. There is also an internal approvals and legal process within the Company to sanction and contract for this work that would take approximately 3 to 6 months before a contract could be signed.

System development for Rhode Island is estimated to be $155,000. On-site implementation and setup at National Grid is estimated to be another $20,000, including incremental internal project management and overhead.

Billing System Changes

Changes to the Company's billing system will be necessary to accommodate the implementation of MHP, including high-level design and analysis, tariff modeling, coding and implementation of pricing, prebill and billing modules, modifications to bill print, system dialogue boxes and screen displays, Electronic Data Interchange ("EDI") transaction modules, website enhancements, revisions to data repair programs and other miscellaneous program revisions. The estimated cost to implement the necessary changes to CSS would be $500,000, and would require approximately six months to implement. In addition, approximately one month of testing would be required prior to implementation. Additional time for internal approvals and contracting for any externally procured services would be similar to those described above for the PTS system.

7. Customer Outreach, Education, and Program Evaluation

This section presents an overview of estimated staff training, customer outreach and marketing expenses, and evaluation program expenses associated with a transition to a MHP mechanism.

Customer Outreach and Education is pivotal to customers' acceptance and understanding of MHP or similar major changes in commodity rate structures. Given the Company's experience with implementing MHP for large customers over the last four years in New York by its affiliate, the Company suggests that an Outreach and Education plan as described below be adopted for any implementation desired in Rhode Island. In addition, to determine the effectiveness of the program, and the reasons for those results, a formal Evaluation Program should be considered.

Outreach & Education

The Company would offer a robust education plan for customers in Rhode Island including at least four bill inserts, four direct mailings, two half-day in-person training/education sessions, and a program of direct customer contact following that roll-out by Industrial Account Executives. This program of direct education would include: bill impact analysis, conference calls, on-line presentations and webinars, and one-on-one meetings. It is estimated that one incremental employee for initial and ongoing customer education on MHP and one incremental employee for ongoing custom bill analysis would be needed, but this would be further studied in any formal implementation plan.

Key parts of our outreach and education program would include internal training in load-management software, provision of custom bill comparisons for customers, and quarterly briefings. In Rhode Island, internal meetings would be held to make sure Account Executives understand hourly commodity billing, why the company is implementing MHP, which customers could best change consumption patterns to save on the new rate, and the important role that Account Executives would play in Outreach and Education efforts. Account Executives would be updated on the program's implementation quarterly via webinars. In addition, commercial customer call center employees would need training to respond to inquiries from both Industrial and Commercial group customers, and to educate them about the transition and which customers are affected. Some of these costs would likely be incremental, and a more detailed assessment would be undertaken as part of any implementation plan. For this analysis, an estimate of $50,000 per year for two years of implementation is included.

The Company uses Energy Profiler On-line, available through its Optional Interval Data Service tariff provision[6], a tool that enables customers to view their hourly energy usage on a next day basis[7]. This information could be useful to customers in evaluating their potential cost savings from forgoing or shifting usage. When surveyed in the Evaluation effort, 72% of customers on National Grid's MHP program found this tool useful.

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[6] The Optional Interval Data Service tariff provision currently in effect is RIPUC No. 2020-A.

[7] EPO provides unedited usage data, not final billing data, which can differ.

Additionally, most other MHP programs in New York incorporated a modeling tool as part of their marketing plans. Rhode Island Account Executives have already been trained to use this tool and, were the transition undertaken, Industrial customers would temporarily have free access to model their usage and understand ways to potentially After that, an annual fee would be charged directly to customers wishing to subscribe to the on-line service pursuant to the Company's tariff. Approximate costs for the outreach and education plan are listed in Table C, below.

Table C: Outreach and Education Plan Projected Costs

Account Manager and Call Center Education	
Account manager training (incl. materials)	$ 20,000
Customer Service Center Training	$ 30,000
(incl. materials)	
Customer Education	
Direct-mail Letters, four	$ 10,000
Bill Inserts, four	$ 10,000
Two Half-day Education Sessions (200 customers, with food and materials)	$ 5,000
Webinars and Other Materials	$ 40,000
One-on-One Customer Visits on MHP	$180,000
(one incremental FTE, with benefits)	
Data Analysis	
Custom Bill Impact Assessments	$180,000
(one incremental FTE, with benefits)	
Total	**$475,000**

<u>Evaluation</u>

The Evaluation program recommended by the Company would include surveys and data analyses of the customer class usage patterns, to determine the impact of the MHP transition. The Company would be looking to see if the goals set out for MHP implementation – including overall price savings, shifted or reduced demand and usage, and proper apportionment of costs – had been realized. Such evaluations would include a one-year and two-year evaluation and would take approximately three months to conduct at each analysis period.

A preliminary evaluation would be conducted one year after implementation of MHP and would survey Account Executives and customers on their view of Outreach and Education efforts. The survey would focus on customer's preparedness prior to implementation, the ease of use of Energy Profiler Online, customer understanding of key issues, and the overall effectiveness of the Company's Outreach and Education efforts. This survey would also help determine customers' industry type, customers' initial views of their ability to respond to MHP, and the expected impact on their business.

A more comprehensive evaluation would take place two years after implementation and would analyze customer usage in addition to surveying Account Executives and customers. The second survey would assess the impact of hourly pricing on customers, test customers' understanding of hourly pricing, and evaluate customer responsiveness to MHP. The survey questionnaire could consist of four sections: demographics, awareness, opinions, and actions. The second portion of this evaluation would analyze customers' usage while on MHP tariff. This analysis would look at whether customers' responses during peak hours had an impact on ISO-NE and whether customers' load shape had changed in response to hourly pricing.

Depending upon the level of evaluation and timing indicated in any final Commission order, and further assessment for a formal implementation plan, there could be incremental cost associated with this activity, but no estimate is included in this study.

8. Conclusion

The total estimated costs for the implementation of MHP for the Industrial Group would be divided between costs that would be considered capital expenses and added to plant in-service, and those costs that would be incremental operating expenses. The Company believes that should the Commission order the implementation of an MHP program, these costs should be recovered from customers on a timely basis. This study does not attempt to estimate any revenue requirement from potential capital investment, nor does it lay out a timeline for the incurrence of new operating expenses. Rather, the total estimated costs expected to be incurred are only listed and summed in the table below.

Table D: Estimated Industrial MHP Implementation Costs, All Customers

Total Estimated Costs for NECO MHP Implementation		
	Capital Investment	Operating Expense
Meter Installations	$1,500,000	
Communication Service		$100,000
MDS-Pricing Software	$155,000	$20,000
CSS-Billing System		$500,000
Outreach and Education		$475,000
Totals	**$1,655,000**	**$1,095,000**

Limiting the implementation of MHP to customers with average demands in excess of 500 kW would reduce some of the cost of these changes, but not all. System changes are generally fixed costs that would be incurred regardless of the number of customers transitioned to the new MHP rate. The table below outlines an estimate of the costs for implementing MHP for customers at 500 kW and above. Savings in Outreach and Education reflect one fewer incremental FTE, and lower printing, mailing and meeting costs.

Implementation of this transition would take an estimated 24 months from the time an order is received to formally develop and execute an implementation plan as shown in the chart in the Appendix, Figure A-1. Of this time, approximately four months would be needed to develop a robust implementation plan, new tariffs and pricing mechanisms, a procurement plan, and to further study metering needs and costs. Approximately another four months is estimated from the time of that filing to a potential approval by the Commission.

Table E: Estimated Industrial MHP Implementation Costs, >500 kW Customers

Total Estimated Costs for NECO MHP >500 kW Demand		
	Capital Investment	Operating. Expense
Meter Installations	$500,000	
Communication Service		$35,000
MDS-Pricing Software	$155,000	$20,000
CSS-Billing System		$500,000
Outreach and Education		$275,000
Totals	**$655,000**	**$830,000**

In conjunction with the implementation of MHP for all or part of the Industrial Group, the Company would propose to implement an appropriately designed cost recovery mechanism to recover the implementation costs of MHP. Such a mechanism would likely propose to recover the cost of the MHP program from all Industrial Group customers, not just those receiving SOS, since the implementation of MHP will require installation of metering and communications equipment on all eligible customers in the class, as all customers in the group would have the option at any time to return to SOS.

Once a formal plan with full cost recovery was approved by the Public Utilities Commission, the Company would launch its implementation plan. Metering and software procurement, development and installation would run concurrently over approximately 16 months. Procurement transition would take only about one month for preparation and two months to cancel FRS procurements as the metering installation and software systems are being finalized. This would imply that should an order by the Commission to commence with MHP implementation planning be received by August 2011, the Company would not be able to commit to making the transition sooner than the fourth quarter of 2013.

In conclusion, there may be benefits for Industrial Group customers if a transition to MHP were made. If the Commission decides to proceed, the Company recommends that a phased implementation should occur with customers above 500 kW of demand being provided service under MHP first. This would reduce the initial costs and allow for a more gradual education process, while capturing the majority of the usage of the Industrial Group. Should the Commission desire this transition to begin, the Company would request the opportunity to propose a formal implementation plan that would include specific cost recovery mechanisms and pricing tariffs, a formal revenue requirement projection, and a refined schedule of implementation.

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Figure A-1: Estimated Timeline for Implementation, All Customers

Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Receive Order to Implement	X																							
Develop and File Implementation Plan																								
Hearings on and Approval of Plan																								
Meter Procurement																								
Meter Test and Install																								
Software/IT Procurement (PTS and CSS)																								
Software Development and Install																								
Training,Outreach & Education																								
Procurement Transition																								
Implementation																								X