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RAAB ASSOCIATES, LTD.

April 5, 2017

Luly Massaro, Commission Clerk
RI Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

Dear Ms. Massaro:

As the facilitator/mediator for the Rhode Island 4600 Working Group, it gives me great pleasure to convey to the Commission the Working Group's Final Report.

The Working Group met for nine, day-long meetings between May 2016 and March 2017 (two of these meetings occurred before we started), with many additional sub-group meetings and assignments between meetings. During the course of this process the Working Group members had detailed discussions focused primarily on two topics: 1) how to better evaluate the benefits and costs of a wide range of technologies, programs, and investments; and 2) how rate design should evolve in Rhode Island over time.

The Report includes detailed principles, insights, and recommendations on these two topics. It also includes recommendations regarding potential next steps for the Commission both on this Report as well as on additional related topics not covered by this phase of 4600 but of great importance to the Working Group members.

All of the recommendations in the Report are by consensus of the Working Group (i.e., unanimity of all twelve Members), except one issue. For that one issue (whether the opt out from time varying rates for default service should be to the competitive market or another default service option) the two alternatives are presented along with the Working Group members who support each alternative.

Paul Centolella from Paul Centolella & Associates (and TCR), who served as the consultant on the project, and I are available to discuss with the Commission any aspect of this Final Report or the process itself at the upcoming Technical Session or otherwise.

Thank you for undertaking this important process, and we hope that you have what you need to move productively forward on these issues in Rhode Island.

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Docket 4600:
Stakeholder Working Group Process

Report to the Rhode Island Public Utilities Commission

April 5, 2017

Facilitation (Mediation)/Consulting Team:

Raab Associates, Ltd. with
Paul Centolella & Associates and
Tabors Caramanis Rudkevich (TCR)

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1. INTRODUCTION, REPORT OVERVIEW, AND WORKING GROUP GOALS

1.1 Introduction

On March 18, 2016 the Rhode Island PUC opened up Docket 4600. According to the PUC:

> The purpose of the docket will be to develop a report that will guide the PUC's review of the Narragansett Electric Company d/b/a National Grid's (National Grid) rate structure in future proceedings. In order to determine the factors necessary for determining rates pursuant to the Renewable Energy Growth Program, and to improve consistency within and across programs, the PUC needs to develop an improved understanding of the costs and benefits caused by various activities on the system. More specifically, in Docket 4600 the PUC seeks answers to the following overarching question: What attributes are possible to measure on the electric system and why should they be measured?

This overarching question can be further broken down into three broad questions:

1. What are the costs and benefits that can be applied across any and/or all programs, identifying each and whether each is aligned with state policy?
2. At what level should these costs and benefits be quantified—where physically on the system and where in cost-allocation and rates?
3. How can we best measure these costs and benefits at these levels–what level of visibility is required on the system and how is that visibility accomplished?

The PUC solicited stakeholders who wanted to participate in 4600, and issued an RFP to retain professional consulting and facilitation services to help run the stakeholder process. The following dozen stakeholder groups in Table 1 participated as full-members of the 4600 Working Group, plus the PUC staff also participated as ex officio members (not taking part in the recommendations included in this Report.) The lead representatives and their alternates (and consultants) from each Stakeholder group can be found in Appendix A.

Table 1: Rhode Island Docket 4600 Working Group Members

Acadia Center
Conservation Law Foundation (CLF)
Direct Energy
George Wiley Center (GWC)
National Grid
New Energy Rhode Island (NERI)
Northeast Clean Energy Council (NECEC)
People's Power & Light (PPL)
RI Division of Public Utilities & Carriers
RI Energy Efficiency and Resource Management Council (EERMC)
RI Office of Energy Resources (OER)
RI Public Utilities Commission (ex officio)
The Energy Council of Rhode Island (TEC-RI)

The Rhode Island PUC selected Raab Associates, Ltd. (along with its subcontractors Paul Centolella & Associates and TCR) to provide facilitation/mediation and consulting services. Prior to Raab Associates being retained, the PUC staff hosted and facilitated two preliminary meetings of the 4600 Working Group. In developing the workplan for the Working Group with Raab Associates, the PUC agreed that the scope of this phase of the Working Group process would include three parts:

- Explication of the full range of relevant costs and benefits
- Refinement of cost-effectiveness testing
- Exploration of rate design and cost recovery principles and issues

Between May 2016 and March 2017, the Working Group met nine times (seven times after Raab Associates was retained) to develop the material and recommendations contained in this Report. Unless otherwise noted, the principles and recommendations represent a consensus of all the stakeholders in the Working Group (except for the PUC staff who participated in an ex officio capacity). Where consensus was not reached (in only one instance), alternatives are provided and the stakeholders representing each alternative are identified.

1.2. Report Overview

Chapter 2 includes the Working Group's recommendations regarding a new benefit-cost framework for Rhode Island including a comprehensive set of recommended benefits and costs that can be applied to diverse resources, programs, and rate designs. **Chapter 3** includes the Working Group's recommendations regarding rate design principles and other important rate design issues including time-varying rates, location-based strategies, protections and opportunities for low income and other customers, and cost recovery. **Chapter 4** includes some recommendations on potential next steps including issues that the Working Group would like to see the PUC and stakeholders pursue piggy-backing on the work already accomplished herein.

Appendix A, as mentioned above, includes the participating stakeholder groups and their representatives, alternates, and consultants. **Appendix B** includes the proposed Rhode Island Benefit-Cost Framework. **Appendix C** includes background information from National Grid (in response to a data request from the Division) on its current rate offerings (and customer participation); its current meters; and current use of behind the meter technologies by customers.

1.3. Goals

We conclude this chapter by laying out goals that the Working Group members embrace related to the following important question: What can and should the new electric system be able to accomplish?

- Provide reliable, safe, clean and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels)
- Strengthen the RI economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures
- Address the challenge of climate change and other forms of pollution
- Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits
- Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society
- Appropriately charge customers for the cost they impose on the grid
- Appropriately compensate the distribution utility for the services it provides
- Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentives

2. RHODE ISLAND BENEFIT-COST FRAMEWORK

2.1. Overview of Framework

To address the PUC's questions in its Notice initiating this docket (delineated at the beginning of Chapter 1), the Working Group developed a framework identifying categories and drivers of benefits and costs. It provides a more detailed definition of costs and benefits and the factors that drive the value of these cost and benefits. The goal of the framework is to assist the Commission in identifying:

- Costs and benefits that can be evaluated across any and all programs or policies;
- The level at which and where physically on the system these costs and benefits can be quantified;
- How to best measure such costs and benefits; and
- The visibility required to measure such costs and benefits.

The Working Group sought to develop and refine a comprehensive framework of costs, benefits, and their key drivers. The final Rhode Island Benefit-Cost Framework (Framework) agreed to by the full Working Group includes thirty-four categories of costs and benefits (Column B). The categories cover specific ISO-New England wholesale and Rhode Island retail market benefits and costs; various distribution system impacts; risk, uncertainty, and option value; direct environmental compliance costs, as well as, societal level externalities; customer, utility, and societal low-income customer impacts; and qualitative consideration of impacts on customer choice and empowerment.

The Working Group's recommended Framework can be viewed at the following link http://www.raabassociates.org/main/projects.asp?proj=146&state=Services (B-C Framework Final) and is included as Appendix B to this Report.

For each cost and benefit category, the Framework includes between one and five different System Attributes/Cost Drivers (Column C) that drive the incurrence of the costs and/or accrual of the benefits. A total of 53 different drivers were defined in the Framework. Individual drivers may be a system, policy, market, technology, customer, or other attribute, or set of related attributes, that impact the value of a cost and/or benefit.

The costs and benefits of individual electric distribution, energy efficiency, renewable energy, and/or distributed energy resource technologies and specific applications or deployments of these technologies can be evaluated using the Framework. The specific cost and benefit drivers identified in the Framework are key factors that will affect the value of the associated cost or benefit in the context of specific plans or deployments. In an early step in the development of the Framework, Working Group members were asked to consider how to evaluate the benefits and costs of different technologies. It was useful to start by thinking about the benefits and costs of technologies, rather than of programs, since deployment of a given technology might be supported under more than one program and programs often cover multiple technologies. The Commission asked, "What … costs and benefits that can be applied across any and/or all programs…?" The cost and benefit categories identified by the Working Group can be applied in evaluating technologies, programs, and rate designs.

The Framework recognizes that the value of a cost or benefit may vary by time, location, electrical product (real power, reactive power, or reserves), technology, or customer. There is, for example, no single distribution value of distributed energy resources. Rather than specifying cost or benefit values, the Framework includes a list of Candidate Methodologies (Column D) that could be used to quantify costs and benefits. The list provides a high level identification of approaches to valuation. The candidate methods are illustrative and not meant to be exclusive. Values for technology deployments would be developed in the context of specific plans and proceedings. For some drivers, the Framework lists multiple options as candidate methodologies. These are generally listed in order of increasing detail and granularity. It is assumed that, over time and as necessary to address issues in specific proceedings, the methods used in valuation may become increasingly sophisticated and precise.[1]

Additionally, the Framework was extended to address the Potential Visibility Requirements (Column E) that may be needed to use different valuation methods. The Framework identifies methods that may require additional sensors, advanced or interval meters, detailed modeling, planning studies, and/or customer surveys. With greater visibility, additional valuation methods will become available.

The Framework is intended to be a guide for identifying and valuing different costs and benefits in the context of Rhode Island specific benefit-cost analysis. As the Commission and parties gain experience with the use of these cost and benefit categories and drivers, standard practices may develop and become more sophisticated over time. And, the definition of specific cost and benefit categories and drivers may be refined or modified either by the Commission, by practice in the field, or in the course of future proceedings. This important work remains to be done and should recognize the work done in other states.

2.2. Benefit-Cost and Business Case Analyses

Benefit-cost analysis is a tool that can be used to inform decisions regarding regulatory policies and utility investments. However, the results of a benefit-cost analysis should not necessarily be used in isolation when making such decisions. Additional considerations may need to be addressed. These additional considerations include, for example: statutory requirements; reliability and resiliency needs; customer equity issues; limited utility or customer funding; and rate impacts.

These additional considerations might mean that a resource that is found to be cost-effective according to the Rhode Island Benefit-Cost Framework might not be undertaken, or vice versa. Some states have begun using the term "business case" to describe an approach where additional

[1] The framework is a guide to potential costs and benefits. However, the existence of the different categories does not imply that every possible technology deployment necessarily will be associated with a measurable cost or benefit in each of the categories. There can be examples where a driver is not directly impacted and the most appropriate value for the cost or benefit in a given category might be zero.

considerations (which are often qualitative or not monetized) are accounted for in addition to the monetized costs and benefits.

2.3. Applications of the Benefit-Cost Framework

Benefit-cost analyses can be used for several purposes, and can be applied in different contexts. It is important to describe the purpose and the application of the benefit-cost analysis, to be clear on what is being compared with what, and what question the analysis will answer.

The Framework can be used for the following purposes and contexts.

2.3.1. Distributed Energy Resources (DER/DERs) Programs and Technologies

The Framework can be used to analyze different DER programs and technologies, including energy efficiency programs, demand response programs, distributed generation resources, storage technologies, net metering programs, and the Renewable Energy Growth Program.

A single program or resource (e.g., energy efficiency programs) is compared in isolation with a reference future scenario (i.e., base case), to indicate the relative costs and benefits of that single program or resource.

This type of analysis would be applied in the context of approving utility investments for a particular type of DER program or technology. This is how energy efficiency programs are currently assessed in Rhode Island.

2.3.2. Conventional Distribution Projects

The Framework can be used to analyze conventional distribution investments, including those needed to maintain, upgrade, or expand the distribution system. Initially, the framework can be applied to significant discretionary distribution projects, and may ultimately also be applied to certain non-discretionary (mandatory) projects.

A specific conventional distribution project, or set of projects, is compared with alternative conventional distribution projects.

This type of analysis might be applied in the context of a future rate case, where the utility is proposing to recover costs from capital investments in conventional distribution technologies.

2.3.3. Grid Modernization Projects

The Framework can be used to analyze grid modernization projects, including advanced metering functionality (AMF), other customer-facing grid modernization technologies, and grid-facing technologies.

A specific grid modernization project, or set of projects, is compared with conventional distribution projects. Some grid modernization projects, such as AMF, might enable other types of resources, such as demand response. In such cases, the cost and benefits of the enabled resources should be embedded in the costs and benefits of the grid modernization project in question.

This type of analysis might be applied in a docket where a utility is seeking guidance on whether to make proposed grid modernization investments, or in a rate case where the utility is seeking to recover the costs of grid modernization investments.

2.3.4. Rate Designs

The Rhode Island Benefit-Cost Framework can be used to support the evaluation of different rate design proposals including but not limited to increased fixed charges, demand charges, and a variety of time-varying rates. First, it is important to note that in practice rate designs are typically evaluated on the basis of how well they meet rate design principles – but not necessarily with benefit-cost analysis. Nonetheless, the RI Benefit-Cost Framework may identify information relevant to the application of rate design principles and can be used to provide additional information regarding the extent to which rate design benefits might exceed costs.

For example, the rate design benefit cost analysis could include the following steps.

1. Identify different rate design proposals to compare.

2. Each rate design proposal would be compared with the current rate design for the relevant class.

3. For each rate design proposal, rate components may change customer behavior and usage patterns and may impact the costs and benefits of several different customer activities, such as improving consumption patterns, participating in demand response programs, installing storage technologies, or purchasing and managing the charging of electric vehicles.

4. For each customer activity, identify any increased or decreased costs associated with the rate design proposals, based upon the costs in the Rhode Island Benefit-Cost Framework.

5. For each customer activity, identify any benefits associated with the two rate design proposals, based on the benefits included in the Rhode Island Benefit-Cost Framework.

6. For each customer activity, compare the costs to the benefits to indicate the relative value of the individual activity.

7. Combine all of the costs of each activity and all of the benefits of each activity, to provide total costs and benefit results for each rate design proposal.

8. Consider other factors that were not addressed in the benefit-cost analysis described above (e.g., customer equity, simplicity, and gradualism[2]).

This approach will likely need to be refined and improved, once the analysis begins and the stakeholders develop a better sense of what needs to be done.

[2] James Bonbright (1961) in his historic principles for rate design defines gradualism as "stability of the rates themselves with a minimum of unexpected changes seriously adverse to existing customers."

2.3.5. Comparison Across Resources, Technologies, or Policies

The Framework can be used to compare across different resources and policies. For example,

- Different types of DERs can be compared with each other to indicate which DERs or DER programs have the lowest cost, has the highest benefit-cost ratio, or results in the greatest net benefits.
- Conventional distribution projects can be compared with DERs, for example to see the costs and benefits of a particular non-wires alternative (NWA) relative to a conventional distribution project. This is the approach that is currently used in System Reliability Procurement (SRP).
- A variety of resource options can be optimized, where conventional distribution projects are compared with DERs, customer-facing grid modernization projects, and grid-facing grid modernization projects. This methodology is used in integrated resource planning practices, and is being explored in several states for use in distribution system planning. It uses detailed modeling practices to optimize an entire portfolio of resources.

When comparing or evaluating resources, planners and policy makers will have to account for the fact that in a market environment some DERs will be deployed and operated by customers and/or third parties and that they will do so based upon their perceptions of their own costs and benefits and in response to specific rate designs, incentives, and/or compensation mechanisms.

The Benefit-Cost Framework should be applied through a methodology that:

- Identifies and justifies preferred characterization and quantification methods for each component attribute or effect.
- Addresses uncertainty and the appropriate adjustments for less than comprehensive data.
- Establishes the timeframe for assessing component attributes and effects, or the cost and benefit impacts perspective that should be used for each (e.g., impacts on participants, non-participants, the utility, and society at large).
- Integrates these decisions in a unified manner and includes instructions for its use.

2.4. Next Steps for Developing the Benefit-Cost Framework in Rhode Island

Rhode Island already has a well-established practice for assessing the cost-effectiveness of energy efficiency resources. The new Framework should be developed by incrementally expanding upon current practices. A step-by-step approach should make the analyses more feasible and practical, and should allow stakeholders to assess the implications of the framework each step of the way—with the goal of refining the framework, establishing best practices for assessing each type of cost and benefit, and generally making it more robust with experience.

The Framework should be used to evaluate:

- Energy efficiency programs

- Demand response programs
- Distributed generation programs, such as the Renewable Energy Growth Program and the Rhode Island net metering provisions
- Different distributed energy resource programs against each other
- Alternative rate designs
- Major proposed distribution capital investments
- Benefits and costs of conversion to advanced metering functionality, taking into account the full range of potential opportunities that advanced metering functionality could enable
- Dynamic portfolio optimization (eventually).

The results of each of the analyses should be presented in terms of benefit-cost ratios and net benefits for each program (in present value dollars). The results should also be put in terms of $/MWh, $/kW, $/MMBtu, and $/ton of CO_2 avoided; to allow for comparison across resources and policies. However, as described in section 2.2 above the results of a benefit-cost analysis should not necessarily be used in isolation when making such decisions. Additional considerations may need to be addressed.

3. RATE DESIGN

This chapter begins with a listing of rate design principles that should be considered when designing and evaluating effective rates. Rates are generally designed to both send appropriate price signals to customers and to allow utilities (and 3rd party suppliers) to recover reasonable costs associated with maintaining, operating, and modernizing the electric grid (and for supplying electricity).

The second part of this chapter includes the Working Group's recommendations on the design of time-varying rates (TVR) and of location-based strategies. The third describes the Working Group's recommendations around low-income and customer protections. In the final part of this chapter, the Working Group discusses general rate design concepts, and then provides a shared perspective on long-term distribution rate design.

3.1. Rate Design Principles

The Working Group agrees on the following rate design principles that the Commission, utility, and stakeholders should take into account when designing and evaluating rate design options.

- Ensure safe, reliable, affordable, and environmentally responsible electricity service today and in the future
- Promote economic efficiency over the short and long term
- Provide efficient price signals that reflect long-run marginal cost
- Future rates and rate structures should appropriately address "externalities" that are not adequately counted in current rate structures
- Empower consumers to manage their costs
- Enable a fair opportunity for utility cost recovery of prudently incurred costs and revenue stability
- All parties should provide fair compensation for value and services received and should receive fair compensation for value and benefits delivered
- Be transparent and understandable to all customers
- Any changes in rate structures should be implemented with due consideration to the principle of gradualism in order to allow ample time for customers (including DER customers) to understand new rates and to lessen immediate bill impacts
- Provide opportunities to reduce energy burden, and address low income and vulnerable customers needs
- Be consistent with policy goals (e.g. environmental, climate (Resilient Rhode Island Act), energy diversity, competition, innovation, power/data security, least cost procurement, etc.)
- Rate structures should be evaluated on whether they encourage or discourage appropriate investments that enable the evolution of the future energy system

3.2. Time-Varying Rates

The purpose of time-varying rates (TVR) is to send better and more accurate price signals to customers regarding when the use of electricity is relatively expensive or relatively cheap so that customers can make more efficient decisions regarding when to use and not use electricity. TVR can be used for sending more accurate price signals regarding production, transmission, and distribution. There are a wide range of TVR options including most commonly time-of-use (TOU) pricing; critical peak pricing (CPP); peak-time rebates (PTR); and real-time pricing (RPP).

The Working Group has the following important observations and recommendations regarding the design and implementation of TVR in Rhode Island—made by consensus unless otherwise noted.

For TVR to be successful extensive consumer education is needed, as is the ready availability of various control technologies to help facilitate price responsiveness. Education should cover the purpose, potential impacts (to customer, system, environment), and ways to use technology and adjust behavior to reduce customer' bills. Consumer education strategies on TVR and control technologies should be multi-faceted, including:

- Community outreach strategies;
- Customized strategies for different customer classes and customer types (e.g., homeowners and renters);
- Integration into existing programs (to leverage them) such as energy efficiency program design and delivery; and

Well-designed TVR should be offered as a default service for energy supply on an opt-out basis as soon as practical (e.g., the presence of advanced metering functionality and related communications and billing changes in place).

- National Grid, Direct Energy, NECEC, TEC-RI, and CLF: Offering a single (TVR) Standard Offer Service rate option will allow customers to easily compare the Company's default commodity rate to options available in the competitive market. This approach is consistent with the long-standing policy of facilitating a competitive market for commodity supply.
- Division, Wiley Center, Acadia, PPL, OER, NERI, and EERMC: During an initial transitional phase, residential customers who opt out of time varying rates should be provided with the option of using National Grid's standard offer service, as well as the opportunity to access the competitive market. Residential customers should not be forced to use a Non-regulated Power Producer. Providing an alternative default rate similar to the current A-60 and A-16 rates through National Grid will provide a stable, known option for those customers who initially elect to opt out of time varying rates. Over the medium term, rate design should seek innovative products and design strategies to encourage customers to choose time varying rates. Over the long term, changing customer opportunities and expectations around rate design may support reevaluation of the opt-out alternative.

An opt-in approach should be considered for any transition period to any opt-out requirement. Also, once the opt-out paradigm is in place any customer that choses to opt out, should be able to opt back in at a later date.

Any roll out of TVR should address low-income and all other customer challenges and opportunities.

When and if advanced metering functionality is in place, interval meter data for residential and small commercial customers should be made available to 3rd party providers (with customer approval), so that 3rd parties could offer rate design alternatives and energy management services more cost-effectively than they can today.

Third parties, in addition to utilities, should be permitted to provide consolidated bills that could breakdown customer usage by end use, suggest targeted energy savings improvements, and other related services (e.g., on-bill financing). The Working Group acknowledges that this would require numerous changes, and recommends that the Commission investigate this further.

Regarding default TVR rates for different customer classes, instead of specific TVR recommendations for each customer class at this point in time, the Working Group prefers to lay out the following recommended parameters/considerations, as well as recommended process for determining TVR design at a later date.

- Different rate designs should be considered for different customer classes reflecting their unique characteristics and capabilities
- Alternative rate designs should be evaluated for relative benefits and costs using the Rhode Island Benefit-Cost Framework (See Chapter 2)
- Alternative rate designs should also be evaluated for their potential relative effectiveness and impacts on equity
- TVR approaches should be used to complement and support technologies and programs to reduce peak demand
- TVR should be considered for not just energy supply, but also distribution and transmission rates
- Capacity should be developed to consider impacts of rates on goals that include both DERs and electrification (heat pumps and vehicles) to replace fossil fuels
- Although the Working Group is not prepared to recommend specific TVR rate designs for each customer class at this juncture, it does recommend that the Commission consider the following types of rate designs (peak time rebates, time-of-use (including seasonal) critical peak pricing, and real time pricing) for each of the customer classes (large C&I, small C&I, and residential)
- The Commission should consider establishing performance metrics for the utility's achievement of specific peak demand reductions over time, and should also consider establishing financial incentives for the utility to do so

3.3. Location-Based Strategies

The Working Group recommends that the Commission investigate the following potential strategies related to the specific location of production and consumption of electricity:

- Administratively-based programs to identify the areas of the National Grid service territory with the greatest transmission and/or distribution constraints, as well as identifying potential non-wires alternative solutions (for example through use a targeted procurement process) that could cost-effectively defer or down-size traditional distribution investments.

- Targeting DERs (e.g., microgrids, EV infrastructure, DG) to neighborhoods with high economic and/or environmental locational value
- Use both existing and new targeted incentives, pricing, or both in areas with greatest distribution constraints to incentivize demand reduction
- Broad-based location-based pricing (once more granular information is readily available)
- Congestion-based pricing

The Working Group also recommends that the Commission investigate the magnitude and variance in locational costs across Rhode Island.

3.4. Low Income/Customer Protections (and Opportunities)

The Working Group recommends the following low income/customer protections broadly related to rate design:

- Investigate income-sensitive payment plans;
- Arrearage management with capped maximum monthly arrearage payment and forgiveness;
- Redesign of the low-income A-60 rate to take a fixed percent reduction from residential rates;
- Temporary additional discounts or other mechanisms as needed for low-income consumers related to rate increases driven by programs, infrastructure changes, or uneven access to new programs or resources (i.e., where the benefit of the new programs or resources will not accrue to low-income consumers), or as required by principles of equity or burden.
- Possibility of accommodations in certain rate design elements as appropriate

The Working Group also recommends that the Commission investigate opportunities to animate customers to better manage their energy consumption/costs; as well as ways to maintain customer equity, and mitigate any customer equity concerns.

3.5. General Rate Design Concepts

The Working Group agrees to the following principles about cost recovery and statement about decoupling:

- National Grid should have a reasonable opportunity to recover its prudently incurred costs.
- Rhode Island already has a decoupling mechanism in place to true up under (or over) collection of allowed base rate revenue requirements by National Grid.

The Working Group also wanted to convey to the Commission some collective insights and observations related to rate design based on the exercises and discussions that took place during the 4600 process.

- Rate designs that provide meaningful price signals to customers who have the tools and opportunity to respond can improve customers' consumption patterns
- Different rate designs can create higher or lower incentives for the pursuit of distributed energy resources
- TVR offers an opportunity to provide efficient price signals across all resources. TVR also appears to be most robust across the rate design principles listed above, although other

rate designs also meet multiple principles reasonably well

- Until some form of advanced metering functionality that provides data on time-specific usage is in place, TVR is not practical in Rhode Island
- Certain rate design types appear better suited for incentivizing particular resource types. For instance, all things being equal under existing rate design (i.e., in the absence of TVR):
  - Higher volumetric charges (kWh) appear to provide higher incentives for energy efficiency and for distributed generation (particularly given net metering),
  - Demand charges based on coincident peak demand (kW) provide higher incentives for distributed storage and responsive demand if consumers have sufficient information and opportunities to respond
  - Lower volumetric charges (kWh) appear to provide higher incentives for electrification strategies
- The Commission should investigate potential cost shifting and equity concerns over time as distributed generation and other types of DERs become more widespread.

The Working Group also has the following perspective (below in 3.6) on how rate design should evolve in Rhode Island in the near- and longer-term as technology that can measure consumption data on an interval basis (e.g., every 5 minutes) become more practical, and technology for customers to better manage their energy use is more readily available.

3.6 Perspective on Long-Term Distribution Rate Design

Rate design should be evaluated not only for its ability to recover costs, but also for the role that it can play in supporting the evolution of the system. As the grid modernizes, consideration should be given to how distribution rate design, in combination with advancements in energy efficiency, demand response, and other DERs, can help the system evolve in an efficient manner to ultimately benefit all customers. Therefore, the Commission should investigate long-term rate design options that will provide price signals to customers, promote a more efficient use of the electric system, and compensate the utility and others for services to customers.

The members of the Working Group all agree with the application of TVR over the long term. In addition, changes to customer charges and consideration of demand charges (e.g., specific time blocks where demand would be measured) for both small and large customers warrant investigation. The following changes will be needed to enable or support TVR:

- Metering, communications, and data management technologies capable of sending and receiving time-based rates at a certain level of granularity.
- Customer-side technologies that automate end-use response to TVR.
- Customer education and engagement programs to provide all customers (including hard-to-reach customers) with the information and tools to optimize their electricity consumption.
- Statutory changes may be needed to enable TVR for residential customers.

As technology develops, utilities and retail suppliers may be able to offer, and consumers may be able to understand and benefit from more complex and granular rate design options. As DER integration improves, customers will have the potential to provide a greater number of services to the distribution utility, for example, when technologies such as solar PV are combined with smart inverters or storage and operated in a manner to provide particular services to the distribution utility. Other examples of these services include demand response, energy efficiency, generation and VAR support. These services may allow the utility to defer investments that would have otherwise been made in order to address reliability or system stability issues. Pricing that appropriately compensates customers for these services can provide incentives for customers to embrace opportunities that benefit the system and will also advance equity principles if DER credit values are aligned with economic values.

When retail rates for generation and delivery appropriately reflect the underlying cost of the system, it will be possible to accurately charge and credit consumers for the grid services they use and provide in a technology-neutral manner. It is important to note that peak periods of usage and costs may change and rate design needs to be flexible enough to account for this.

In the meantime, the Commission should consider:

- What is the appropriate way to measure any cost-shift between DER and non-DER customers and at what level does it become unreasonable? (How does this compare to cost-shifting in rates today – e.g., rural versus urban, large versus small within rate classes?)
- What are the proper steps to take to recover costs associated with resources and investments required by legislation or regulation, such as funding for the energy efficiency programs or net metering programs?
- As significant rate innovations are implemented, gradualism should be an important principle to the extent necessary to ensure maximum consumer benefits, understanding, and adoption.

4. Next Steps and Potential Future Processes

The Working Group has potential next step recommendations to the Commission in two areas 1) what the Commission should do with this Report; and 2) additional topics and processes the Commission and other state agencies may want to initiate.

4.1. Related to Recommendations in Report

- File report in April
- Invite public comment
- Working group members may submit letters of support (including comments on next steps)
- PUC should hold one technical session on the Report, and potentially additional technical sessions on specific topics (e.g., low income issues, economic and manufacturing competitive issues, etc.)
- Commission feedback on recommendations (e.g., order)—next steps
- Reflect findings and recommendations in next National Grid rate case filing (i.e., November)
    - Consider consultation w/stakeholders prior to filing
- Caveat: Report is starting point, but expect modifications and improvements over time (e.g., the Benefit-Cost Framework)

4.2. Additional Topics and Processes

The issues addressed in this report – a Benefit-Cost Framework, principles of rate design, and the importance of time varying rates – comprise a significant contribution to discussions on the future of Rhode Island's electricity grid. However, stakeholders believe that there are additional topics that are essential for stakeholders, the Commission, and other state agencies of Rhode Island to address in order to achieve our energy vision.

This chapter briefly outlines topics identified by stakeholders throughout discussions in Docket 4600 as essential to achieve a low-carbon, least-cost, reliable electricity system with recommendations for next steps.

Future Utility Business Model. Existing rate design structures are based on electric utilities' collection of revenue from end-users of electricity, and depend on the utility's business model as a provider of kilowatts. However, the emergence of distributed energy resources and access to advanced information and communications technologies has enabled customers to reduce, generate, and better control their own energy usage. Enabled consumers continue to rely on the electric utility, but for integration of resources and reliability rather than solely for basic delivery of energy. Stakeholders believe that a discussion of future rate design must begin from a discussion of the future utility business model and, in particular, discussion of what services the utility should provide, what utility functions would provide greatest value to customers, and how those functions should be compensated. This discussion should include an examination of the relative benefits of existing utility incentive and legislative programs.

Recommendations:
Through collaboration in the policy development process with other agencies and with stakeholders,

- Hold appropriate technical meetings to review the Office of Energy Resources' and the Division of Public Utilities and Carriers' development of a policy vision and regulatory proposals for the future utility business model based upon collaboration with stakeholders and the utility.

Future Grid Functionality and Pathways. New opportunities to achieve utility system efficiency and enabled customers depend on deployment of customer- and grid-facing technologies. Stakeholders recommend development of the business cases for application of various kinds of information and communications technologies to the electric grid to achieve a designated degree of grid connective functionality. Evaluation of the costs and benefits of these technologies is complex because the technologies often function as an integrated package and because current capabilities must allow for future technology evolution. It is important to include clear standards and communications protocols and rules to govern third party participation.

Recommendations:
Through collaboration in the policy development process with other agencies and with stakeholders,

- Request that the Office of Energy Resources and the Division of Public Utilities and Carriers build on and refine the "visibility requirements" column of the Benefit-Cost Framework to identify a more specific set of functionalities and potential technology pathways necessary to achieve a future energy system.
- Hold appropriate technical meetings to review the potential scenarios of deployment of those functionalities on the Rhode Island system, including basic information about relative costs and benefits drawn from the Rhode Island system.

Distribution System Planning. Utilities play a critical role in identifying the value of investments made by the utility itself and by third parties on the distribution system. The Benefit-Cost Framework provides the conceptual framework to compare diverse distributed resources to each other and to conventional utility infrastructure solutions in the context of meeting overall power system, customer, and societal needs. The question remains open, however, of how the utility can best apply the Framework within updated planning and investment decision-making processes that leverage programmatic investments and third-party market activity to yield a least-cost, optimized overall portfolio.

Recommendations:
Through collaboration in the policy development process with other agencies and with stakeholders,

- Request that the Office of Energy Resources and the Division of Public Utilities and Carriers work with stakeholders and the utility to recommend updates to the process and implementation of distribution system planning in order to fully align utility and third-party investment decisions with the goal of a least-cost and reliable utility system that achieves public policy objectives.

Beneficial Electrification. Discussion of the existing and future state of the electric grid appropriately occurs within the context of current industry trends of limited load growth. However, stakeholders recognize that there are tangible opportunities to significantly increase the growth of electric load through adoption of electric vehicles and electrification of space heating. The future needs of the electric system for distribution system planning, compensation and rate design should all reflect and enable these two new industry trends in order to make the electric system function with overall greater efficiency, reliability and contribute to a lower carbon energy system.

Recommendations:

- Define a framework for what the Commission would need and how it would review proposals from the electric utility for electric vehicle infrastructure deployment and integration. Many of the considerations applicable to electric vehicles will also apply to electrification of heating, which is another clean energy strategy of importance to Rhode Island.

Valuing Distributed Generation. Rhode Island policy envisions that our future electric system will include more resources invested in, installed, and operated by non-utility parties, including customers and new energy services businesses. That future grid could be more of a transactional arena than a subscription service from a single provider. The component attributes and effects of all resources must be evaluated for the net value that they offer to the power grid, customer, and society. Until such value is recognized, Rhode Island programs and policies will not send accurate market signals to customers and value will remain unrealized.

Recommendations:

The Working Group has provided several examples of comprehensive valuation methodologies that could be applied in Rhode Island. The Benefit-Cost Framework in Chapter 2 should be applied through a Methodology that:

- Identifies and justifies preferred characterization and quantification methods for each component attribute or effect.
- Addresses uncertainty and the appropriate adjustments for less than comprehensive data.
- Establishes the timeframe for assessing component attributes and effects, and the cost and benefit impacts perspective that should be used for each (e.g., impacts on participants, non-participants, the utility, and society at large).
- Integrates these decisions into a unified methodology, and includes instructions for its use.

Existing programs and policies should inform but not circumscribe the strategies to achieve the value revealed through this comprehensive methodology for valuing distributed energy resources. New and better-designed policies and programs may also be encouraged to more effectively achieve such value.

Although each of these five topics is individually complex, discussions within Docket 4600 have made apparent that they are also highly interdependent. As a result, stakeholders recommend an integrated approach to address these topics, allowing stakeholders an opportunity to calibrate their input on any one topic based on the emergent recommendations in another.

Appendix A: Lead Representatives and Alternates

Organization	Representative	Alternate	Second Alternate
Acadia Center	Abigail Anthony	Mark Lebel	
Conservation Law Foundation	Jerry Elmer		
Direct Energy	Marc Hanks	Chris Kallaher	
George Wiley Center	John Willumsen-Friedman	Camilo Viveiros	
National Grid	Tim Roughan	Jeanne Lloyd	Meghan McGuinness
New Energy Rhode Island	Seth Handy	Karl R. Rábago (Consultant/PACE)	Fred Unger
Northeast Clean Energy Council	Janet Gail Besser	Jamie Dickerson	
People's Power & Light	Kat Burnham		
RI Division of Public Utilities & Carriers	Macky McCleary	Jonathan Schrag	Tim Woolf (Consultant/Synapse)
RI Energy Efficiency and Resource Management Council	Scudder Parker	Kate Desrochers	Mike Guerard
RI Office of Energy Resources	Danny Musher		
RI Public Utilities Commission (Ex Officio)	Todd Bianco	Cynthia Wilson-Frias	
The Energy Council of Rhode Island (TEC-RI)	Butch Roberts	Doug Gablinske	

Appendix B: Benefit-Cost Framework

	Mixed Cost-Benefit, Cost, or Benefit Category	System Attribute Benefit/Cost Driver	Candidate Methodologies (Includes options with increasing specificity where multiple methods per driver)	Potential Visibility Requirements
Power System Level	Energy Supply & Transmission Operating Value of Energy Provided or Saved (Time- & Location-specific LMP)	Bids, Offers, Marginal Losses, Constraints, & Scarcity in Time & Location specific LMP (+ Reactive Power requirements & Impacts on Distribution Assets in DLMP)	AESC Seasonal On- & Off-Peak Energy Price Forecasts	
			Expected Time- & Location-specific Bulk Power LMP for forecast period of resource operation	Requires interval or advanced metering functionality & Tracking of ISO Nodal Prices
			Expected Time-, Location-, & Product-specific Distribution LMP for forecast period of resource operation	Requires interval or advanced metering functionality & analysis of actual power flows
	Renewable Energy Credit Cost / Value	Cost of REC Obligation or REC Revenue Received	AESC Forecast of REC prices	
	Retail Supplier Risk Premium	Differential between retail prices and ISO market prices * retail purchases	Absent AMI + dynamic retail pricing, AESC estimate or risk adjusted observed differentials	Quantitative estimation requires detailed economic modeling
	Forward Commitment: Capacity Value	Whether an FCM Qualified Resource &, if so, FCA bid and Provision of Qualified Capacity	Estimate of likely FCA Auction bid capacity from FCM Qualified Resources	Quantitative estimation requires detailed economic modeling
		Change in Demand reflected (~4 yr. later) in a Revision of FCM forecast Capacity Requirements	Review of FCM capacity requirements & estimate of likely future impacts (Same as Capacity DRIPE below)	Quantitative estimation requires detailed economic modeling
	Forward Commitment: Avoided Ancillary Services Value	Whether it is a Qualified Ancillary Service Resource &, if so, Qualified Capacity	Forecasts of AS requirements / Provision of AS net of Energy supplied * Forecast AS prices	
	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	Direct Cost of New Non-customer Resources (Capital & Operating costs of resources) + Customer Program costs (Participant recruitment, administrative, incentive and EM&V costs)	Cost Estimates	

<table>
<tr><th rowspan="9">Power System Level</th><th>Mixed Cost-Benefit, Cost, or Benefit Category</th><th>System Attribute Benefit/Cost Driver</th><th>Candidate Methodologies (Includes options with increasing specificity where multiple methods per driver)</th><th>Potential Visibility Requirements</th></tr>
<tr><td rowspan="2">Electric Transmission Capacity Costs / Value</td><td rowspan="2">Change in transmission capacity requirements associated in change in resource mix</td><td>Annualized statewide transmission capacity value associated with load growth * change in net demand (ICF)</td><td></td></tr>
<tr><td>Forecast impacts of specific resources on transmission planning requirements</td><td>Requires detailed planning studies</td></tr>
<tr><td>Electric transmission infrastructure costs for Site Specific Resources</td><td>Cost to develop new transmission (For peak output + any contingency requirement)</td><td>Direct cost estimates for remotely sited resources (e.g. offshore wind)</td><td>Requires detailed planning studies</td></tr>
<tr><td rowspan="4">Net risk benefits to utility system operations (generation, transmission, distribution) from 1) Ability of flexible resources to adapt, and 2) Resource diversity that limits impacts, taking into account that DER need to be studied to determine if they reduce or increase utility system risk based on their locational, resource, and performance diversity</td><td rowspan="2">Flexible DERs (storage, flexible demand) can reduce risk by enabling the system to respond to disruptive events</td><td>Use proxy value for ability of system to respond to disruptive events</td><td></td></tr>
<tr><td>Model system with additional flexible resources</td><td>Quantitative estimation requires detailed economic modeling</td></tr>
<tr><td rowspan="2">DERs need to be studied to determine if they reduce or increase utility system risk based on their locational, resource, and performance diversity.</td><td>Use proxy values for size and locational and resource diversity.</td><td></td></tr>
<tr><td>Portfolio analysis with risk assessment technique</td><td>Quantitative estimation requires detailed economic modeling</td></tr>
</table>

Power System Level	Mixed Cost-Benefit, Cost, or Benefit Category	System Attribute Benefit/Cost Driver	Candidate Methodologies (Includes options with increasing specificity where multiple methods per driver)	Potential Visibility Requirements
	Option value of individual resources	Impacts of individual resources on the cost of other potential resources	Estimates of impacts of one resource on the costs of others	Quantitative estimation requires detailed economic modeling
			Option value calculation based on scenario analysis of potential future resource choices	Quantitative estimation requires detailed economic modeling
			Portfolio analysis - comparison of alternative portfolios	Quantitative estimation requires detailed economic modeling
	Investment under Uncertainty: Real Options Cost / Value	Impacts of reduced flexibility / discovery of new information	Scenario analysis: calculation of real option value associated with different decision times & resources	Quantitative estimation requires detailed economic modeling
	Energy Demand Reduction Induced Price Effect	Change in Energy price, Net of Any Capacity Cost Change from Net CONE	AESC Estimate of DRIPE (Need to clarify whether accounts for impact on Net CONE)	
			Estimate of Energy Price change with an adjustment of impacts on Net CONE in ISO FCM	Quantitative estimation requires detailed economic modeling

Power System Level	Mixed Cost-Benefit, Cost, or Benefit Category	System Attribute Benefit/Cost Driver	Candidate Methodologies (Includes options with increasing specificity where multiple methods per driver)	Potential Visibility Requirements
	Greenhouse gas compliance costs	Forecast prices under RGGI and other market-based regulations (e.g. Clean Power Plan) + changes other compliance costs under likely environmental regulations	Forecasts of RGGI and CPP prices + estimates of likely compliance costs under any other GHG regulation	Quantitative estimation requires detailed economic modeling
		Forecast compliance costs associated with meeting the GHG emission targets in the Resilient Rhode Island Act	Estimates of likely compliance costs under RI GHG regulation	Quantitative estimation requires detailed economic modeling
		Net marginal emissions or emissions avoided from changes in resource use	Forecast of net emissions impacts from change in regional dispatch and resource mix	Quantitative estimation requires detailed economic modeling
	Criteria air pollutant and other environmental compliance costs	Changes in forecast compliance costs under air pollution or other environmental regulations	Forecasts of the costs of compliance under affected environmental regulations	Quantitative estimation requires detailed economic modeling
		Net marginal emissions or emissions avoided from changes in resource use	Forecast of net environmental impacts from change in regional dispatch and resource mix	Quantitative estimation requires detailed economic modeling
	Innovation and Learning by Doing	Experimentation Costs	Direct costs of innovation / demonstration programs	

		Anticipated rate of cost reduction or performance improvement	Qualitative assessment	
Power System Level	**Mixed Cost-Benefit, Cost, or Benefit Category**	**System Attribute Benefit/Cost Driver**	**Candidate Methodologies (Includes options with increasing specificity where multiple methods per driver)**	**Potential Visibility Requirements**
	Distribution capacity costs	Change in distribution capacity requirements generally with change in resources Forecasted change peak distribution circuit requirements Location-specific DER hosting capacity Impacts on system performance, thermal and reactive power constraints, and associated investment and operating costs	Annualized statewide distribution capacity value associated with load growth * change in net demand (ICF) Distribution planning studies Analysis of capability to host DER with existing and already-planned facilities Distribution planning studies	Requires detailed planning studies Requires detailed planning studies Requires detailed planning studies
	Distribution delivery costs	Location-specific distribution constraints, losses, equipment cycling, DLMP	Dynamic, multi-layered forecasts as a basis for circuit specific DER and Distribution System Plans Analysis of time-, location-, and product-specific DLMP value, potentially leading toward DLMP markets	Requires interval or advanced metering functionality, modeling, and planning studies Requires interval or advanced metering functionality & analysis of actual power flows

	Mixed Cost-Benefit, Cost, or Benefit Category	System Attribute Benefit/Cost Driver	Candidate Methodologies (Includes options with increasing specificity where multiple methods per driver)	Potential Visibility Requirements
Power System Level	Distribution system safety loss/gain	Changes in risks, real-time information on system conditions, and training	Qualitative Assessment, Tracking and Assessment of Safety Metrics	Distribution system safety loss/gain
	Distribution system performance	Performance metrics include: voltage stability and equalization, conservation voltage reduction, operational flexibility, fault current / arc flash avoidance, and effective asset management	Distribution planning and benchmarking to best practices	Requires advanced metering functionality and / or distribution sensors
	Utility low income	Energy efficiency impacts on reducing utility arrearage carrying costs, uncollectibles, customer service and collection costs Incremental utility costs for low income efficiency programs net of system energy cost savings Expected impacts on customer voltages and power quality	Marginal impacts on arrearages, uncollectibles, and other utility costs Direct costs net of system general system benefits Voltage and power quality measurement and assessments	Requires advanced metering functionality and / or distribution sensors

Power System Level	Mixed Cost-Benefit, Cost, or Benefit Category	System Attribute Benefit/Cost Driver	Candidate Methodologies (Includes options with increasing specificity where multiple methods per driver)	Potential Visibility Requirements
	Distribution system and customer reliability / resilience impacts	Customer-specific & critical facility outage costs and value of uninterrupted service	US DOE Interruption Cost Estimator Customer value of uninterrupted service studies	Requires customer surveys
		Expected impacts on the probability of outage	Distribution system risk assessment studies	Requires detailed planning studies
		Expected impacts on the duration of outages	Distribution system / microgrid resilience studies	Requires detailed planning studies
		Expected impacts on customer voltages and power quality	Voltage and power quality measurement and assessments	Requires advanced metering functionality and / or distribution sensors
		Costs of distribution improvements & microgrids	Distribution planning and costing	Requires detailed planning studies
	Distribution system safety loss/gain	Changes in risks, real-time information on system conditions, and training	Qualitative Assessment, Tracking and Assessment of Safety Metrics	

Customer Level	Mixed Cost-Benefit, Cost, or Benefit Category	System Attribute Benefit/Cost Driver	Candidate Methodologies (Includes options with increasing specificity where multiple methods per driver)	Potential Visibility Requirements
	Program participant / prosumer benefits / costs	Direct participant / prosumer cost of technology, investment, and/or program participation costs	Estimates of net direct costs	Requires customer surveys
		Participant indirect costs (includes required behavioral changes and inconvenience costs)	Qualitative assessment Willingness to accept / pay estimates (observation or surveys)	
		Participant non-energy impacts (includes value of improvements in quality of life)	Qualitative value Deemed Benefits Not Reflected in Other Categories - Efficiency Technical Reference Manual Willingness to pay estimates (observation or surveys)	
	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Value of Energy and Water Savings / Requirements	AESC Estimate of Avoided Natural Gas, Oil, and Other Fuel Costs	
			Estimate of Net Costs or Cost Savings	Requires customer surveys

	Mixed Cost-Benefit, Cost, or Benefit Category	System Attribute Benefit/Cost Driver	Candidate Methodologies (Includes options with increasing specificity where multiple methods per driver)	Potential Visibility Requirements
Customer Level	Low-Income Participant Benefits	Improved comfort, reduced noise, increased property value, increased property durability, lower maintenance costs, improved health, and reduced tenant complaints.	Begin with values from Rhode Island EE cost-effectiveness analyses.	May require interval or advanced metering functionality
	Consumer Empowerment & Choice	Retail Competition, Facilitation of Flexible Demand, Integration of Commodity & Energy Services, Development of Platform Market, & Third Party DER Development	Qualitative Assessment	
	Non-participant (equity) rate and bill impacts	Utility revenue requirements, cost allocation and rate design	Long-term rate and bill analysis	
			Analysis of non-participant usage, price elasticity, and income patterns	May require interval or advanced metering functionality

Societal Level	**Mixed Cost-Benefit, Cost, or Benefit Category**	**System Attribute Benefit/Cost Driver**	**Candidate Methodologies (Includes options with increasing specificity where multiple methods per driver)**	**Potential Visibility Requirements**
	Greenhouse gas externality costs	GHG Externality Value net of RGGI costs	Customer willingness to pay for reductions in excess of compliance levels (observation or WTP surveys)	Requires customer surveys
			Societal cost estimates	
		Net marginal emissions or emissions avoided from changes in the use of resources	Forecast of net emissions impacts from change in regional dispatch and resource mix	Quantitative estimation requires detailed economic modeling
	Criteria air pollutant and other environmental externality costs	Criteria Pollutant (e.g. Fine Particulates) and other Environmental Externality Value Net of any Emission Allowance / Emission Credit Value	Customer willingness to pay for reductions in excess of compliance levels (observation or WTP surveys)	Requires customer surveys
			Societal cost estimates	
		Net marginal emissions or emissions avoided from changes in the use of resources	Forecast of net environmental impacts from change in regional dispatch and resource mix	Quantitative estimation requires detailed economic modeling
	Conservation and community benefits	Land use impacts (net of property costs for resource deployments): Loss of sink, habitat, historical value, sense of place	Value of carbon sink per acre	
			Environmental and historical conservation easement cost	
		Equity in distribution of harmful or nuisance infrastructure	Qualitative assessment	
			MW of infrastructure per acre, $ of infrastructure per value of property	

	Mixed Cost-Benefit, Cost, or Benefit Category	System Attribute Benefit/Cost Driver	Candidate Methodologies (Includes options with increasing specificity where multiple methods per driver)	Potential Visibility Requirements
Societal Level	Non-energy costs/benefits: Economic Development	Estimate of Impacts on State Product or Employment, Effects of land use change on property tax revenue	Qualitative Assessment	
			Economic modeling (e.g. input / output life-cycle analysis, property tax base studies)	Quantitative estimation requires detailed economic modeling
	Innovation and knowledge spillover (Related to demonstration projects and other RD&D preceding larger scale deployment)	RD&D, Strength of innovation eco-system, knowledge capture & sharing from public / utility/private sector funded initiatives	Qualitative Assessment	
	Societal Low-Income Impacts	Poverty alleviation, reduced energy burden, reduced involuntary disconnections from service, reductions in the cost of other social services, local economic benefits, etc.	Qualitative assessment or Adder	
			Direct estimate of cost savings	
			Alternate input factor in modeling of local economic impacts	Quantitative estimation requires detailed economic modeling
	Public Health	Indoor air quality, heating, cooling, and noise impacts of efficiency programs (Additional environmental and economic impacts on vulnerable customers addressed elsewhere)	Qualitative Assessment	
	National Security and US international influence	Impacts on oil imports	Analysis of oil imports into Rhode Island and the region	

Informal
Division 1-1

Request:

Please provide the average annual number of customers for each rate class for each of the years 2012-2016.

Response:

Please see Attachment DIV 1-1.

12 Month Average Customer Counts by Year

		A-16	A-60	C-06/C-08	G-02	B-32 / G-32	B-62 / G-62	M1	S-05	S-06	S-10	S-14	X-1
	Customer Counts:												
(1)	2012	389,732	43,068	47,748	8,451	1,071	13	3	-	-	2,446	362	1
(2)	2013	392,904	42,138	49,028	8,460	1,083	15	3	-	-	2,575	376	1
(3)	2014	392,581	43,147	49,210	8,357	1,069	13	3	-	-	2,515	380	1
(4)	2015	393,599	46,157	49,716	8,402	1,069	12	3	-	-	2,469	377	1
(5)	2016	401,314	36,605	49,847	8,402	1,065	13	3	1	-	2,382	368	1

(1) - (5) Per Company Revenue Reports

Informal
Division 1-2

Request:

For each rate class, please provide the number and percentage of customers that currently participate in any one of the following rate offerings:

a. Flat energy rates
b. Inclining block rates
c. Declining block rates
d. Seasonal rates
e. Time of use rates
f. Peak time rebates
g. Critical peak pricing
h. Real-time prices

Response:

Please see Attachment DIV 1-2, for the number of active customers as of January 2017 who currently participate in the rate offerings listed above.

Customer Count as of January 2017

		A-16		A-60		C-06/C-08		G-02		B-32 / G-32		B-62 / G-62	
(1)	Customer Counts:	412,354		35,040		51,184		8,675		1,083		14	
		#	%	#	%	#	%	#	%	#	%	#	%
a.	Flat energy rates	412,354	100.00%	35,040	100.00%	51,184	100.00%	8,675	100.00%	1,083	100.00%	14	100.00%
b.	Inclining block rates	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%
c.	Declining block rates	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%
d.	Seasonal rates	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%
e.	Time of use rates	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%
f.	Peak time rebates	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%
g.	Critical peak pricing	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%
h.	Real-time prices	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%

		M1		S-05		S-06		S-10		S-14		X-1	
(2)	Customer Counts:	3		2		2		2,336		362		1	
		#	%	#	%	#	%	#	%	#	%	#	%
a.	Flat energy rates	3	100.00%	2	100.00%	2	100.00%	2,336	100.00%	362	100.00%	1	100.00%
b.	Inclining block rates	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%
c.	Declining block rates	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%
d.	Seasonal rates	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%
e.	Time of use rates	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%
f.	Peak time rebates	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%
g.	Critical peak pricing	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%
h.	Real-time prices	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%

(1) & (2) Per Company Revenue Reports for January 2017

Informal
Division 1-3

Request:

For each rate class, please provide the number and percentage of customers that currently have meters that would allow the Company to offer any one of the following rate options:

a. Demand charges
b. Time-of-use rates: two periods per day
c. Time-of-use rates: more than two periods per day
d. Peak time rebates
e. Critical peak pricing
f. Real-time prices

Response:

Please see Attachment DIV 1-2, for the number of customers who currently have installed meters that are capable of recording usage in 5- or 15-minute intervals. Although these meters are capable of recording the data necessary for the various pricing options listed above (a. through f.), please note that, to implement any of these different pricing options, the Company would need to make changes to its back office processes, such as meter reading, data collection and processing, billing systems, and customer support. Additionally, the 230 meters in the Rate A-16/A-60 class, 156 meters in Rate C-06 class, and 209 meters in Rate G-02 class noted as being capable of recording the data necessary for the various pricing methods listed above (a. through f.) are interval data recorders, or IDRs, currently installed at customer locations for load research purposes only and are rotated periodically.

		A-16 / A60*		C-06/C-08*		G-02*		B-32 / G-32		B-62 / G-62	
(1)	Customer Counts:		447,394		51,184		8,675		1,083		14
	Customers with meters allowing:	#	%	#	%	#	%	#	%	#	%
a.	Demand charges	230	0.05%	156	0.30%	8,675	100.00%	1,083	100.00%	14	100.00%
b.	Time-of-use rates: two periods per day	230	0.05%	156	0.30%	209	2.41%	1,083	100.00%	14	100.00%
c.	Time-of-use rates: more than two periods per day	230	0.05%	156	0.30%	209	2.41%	1,083	100.00%	14	100.00%
d.	Peak time rebates	230	0.05%	156	0.30%	209	2.41%	1,083	100.00%	14	100.00%
e.	Critical peak pricing	230	0.05%	156	0.30%	209	2.41%	1,083	100.00%	14	100.00%
f.	Real-time prices	230	0.05%	156	0.30%	209	2.41%	1,083	100.00%	14	100.00%

		S-05		S-06		S-10		S-14		X-1	
(1)	Customer Counts:		2		2		2,336		362		1
	Customers with meters allowing:	#	%	#	%	#	%	#	%	#	%
a.	Demand charges	-	0.00%	-	0.00%	-	0.00%	-	0.00%	1	100.00%
b.	Time-of-use rates: two periods per day	-	0.00%	-	0.00%	-	0.00%	-	0.00%	1	100.00%
c.	Time-of-use rates: more than two periods per day	-	0.00%	-	0.00%	-	0.00%	-	0.00%	1	100.00%
d.	Peak time rebates	-	0.00%	-	0.00%	-	0.00%	-	0.00%	1	100.00%
e.	Critical peak pricing	-	0.00%	-	0.00%	-	0.00%	-	0.00%	1	100.00%
f.	Real-time prices	-	0.00%	-	0.00%	-	0.00%	-	0.00%	1	100.00%

(1) Per Company Revenue Reports for January 2017
* The 230 meters in A-16/A-60, 156 in C-06 and 209 in G-02 are IDRs in the field for Load Data Research purposes and are rotated periodically.

Informal
Division 1-4

Request:

For each rate class, please provide the following information for all meters NOT capable of interval metering currently installed on the Company's system:

a. Average meter book life
b. Average assumed meter operating life
c. Average meter age
d. Average expected meter life remaining

Response:

a. The average meter book life is 18 years for all meters regardless of rate class. The Company does not have the breakdown of non-interval and interval meters in its plant accounting system.

b. The average meter operating life is assumed to be 30 years for all meters regardless of rate class.

c.-d. Please refer to the table below for the average meter age and average expected meter life remaining for non-interval meters for each rate class.

Rate Group	**Non Interval Meters**	**Avg Non Interval Meter Age (YRS)**	**Avg Non Interval Meter Life Remaining (YRS)**
A16	414,149	12.7	17.3
A60	34,573	12.6	17.4
C06	53,659	11.7	18.3
G02	8,343	10.9	19.1

Informal
Division 1-5

Request:

For each rate class, please provide the following information for all meters capable of interval metering currently installed on the Company's system:

a. Average meter book life
b. Average assumed meter operating life
c. Average meter age
d. Average expected meter life remaining

Response:

a. Please see the response to Division 1-4.

b. Please see the response to Division 1-4.

c.-d. Interval meters are used for load research purposes for all rate classes and the B32, G32, G 62, M1, and X1 rates require interval metering for billing. Please see the table below.

Rate Group	**Interval Meters**	**Avg Interval Meter Age (YRS)**	**Avg Interval Meter Life Remaining (YRS)**
A16	247	9.76	20.24
A60	15	9.51	20.5
B32	7	4.62	25.4
C06	237	7.23	22.8
G02	361	7.29	22.7
G32	1,071	8.23	21.8
G62	13	4.54	25.5
M1	3	11.66	18.3
X01	1	4.22	25.8

Informal
Division 1-6

For each rate class, please provide the number and percentage of customers that currently have each of the following behind-the-meter technologies installed:

a. Photovoltaics
b. Combined heat and power
c. Other types of DG
d. Plug-in electric vehicles
e. Batteries or other storage devices

Response:

Please see table below:

Rate Class	Photovoltaic	Combined Heat and Power	Wind	Other DG	Plug-in Electric Vehicles	Battery or Other Storage Devices
A-16	1391	2	8	0	750	0
% of Custs	0.286	0	0.002	0	0.2	0
A-60	22	0	0	0	0	0
% of Custs	0.005	0	0	0	0	0
B-32/G-32	27	6	4	1	0	0
% of Custs	0.006	0.001	0.001	0	0	0
B-62/G-62	3	3	2	0	0	0
% of Custs	0.001	0.001	0	0	0	0
C-06	93	2	3	2	0	0
% of Custs	0.019	0	0.001	0	0	0
G-02	51	5	5	1	0	0
% of Custs	0.010	0.001	0.001	0	0	0
Grand Total	1587	18	22	4	750	0
% of Custs	0.327	0.004	0.005	0.001	0.2	0

Informal
Division 1-6, page 2

The Company does not track electric vehicles. However, the Company understands that approximately 750 electric vehicles have been registered in the State and has assumed they are all garaged at residential customer locations. The Company is currently evaluating proposals for two solar and storage projects at residential customer locations, but these are not yet interconnected to the distribution system.