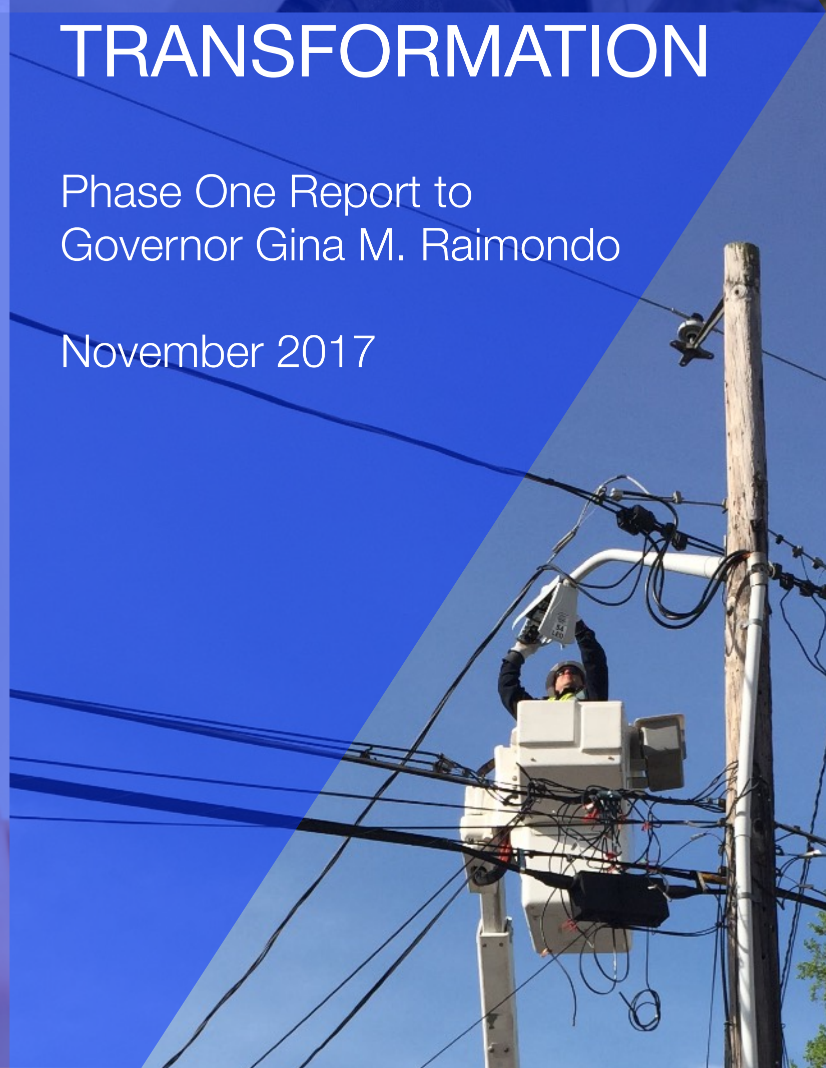
RHODE ISLAND

POWER SECTOR TRANSFORMATION

Phase One Report to
Governor Gina M. Raimondo

November 2017



An inter-agency report from the Division of Public Utilities & Carriers, Office of Energy Resources and Public Utilities Commission

November 2017

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Glossary of Acronyms & Shorthand

AMF – Advanced Meter Functionality

Commission – Public Utilities Commission

DER – Distributed Energy Resources

Division or DPUC – Division of Public Utilities and Carriers

DSP – Distribution System Planning

EVs – Electric Vehicles

ISR – Infrastructure, Safety, and Reliability

KW and KWh – Kilowatt and Kilowatt-hour, respectively

MW and MWh- Megawatt and Megawatt-hour, respectively

MRP – Multiyear Rate Plan

NWA – Non-Wires Alternative

OER – Office of Energy Resources

PIM – Performance Incentive Mechanism

PST -- Power Sector Transformation

ROE – Return on Equity

SRP – System Reliability Procurement

TVR – Time-Varying Rates

The Utility – National Grid

Acknowledgements

The authors of this report would like to thank the Rhode Island stakeholders and national experts who provided valuable input and helped shape the recommendations in this report.

This report represents the collective effort of state agency staff, assisted by a group of national experts and informed by dozens of Rhode Island stakeholders. National experts contributed valuable insights from across the country, including Doug Scott and Judi Greenwald from the Great Plains Institute, Rich Sedano, David Littell, Rudy Stegemoeller, and David Farnsworth of the Regulatory Assistance Project, Tim Woolf of Synapse Energy Economics, Katherine Hamilton of 38 North Solutions, Sonia Aggarwal of Energy Innovations, Julia Bovey and Ron Gerwatowski. We also wish to thank the National Governors Association Center for Best Practices for selecting Rhode Island to participate in the Policy Academy on Power Sector Modernization. The support of the Barr Foundation was essential throughout this process, and we are extremely grateful for their engagement in Rhode Island. Lawrence Berkeley National Laboratories provided valuable research on advanced meter functionalities. We are sincerely grateful to the time and insights provided by those who presented at various PST stakeholder sessions: Anbaric, Black & VeTach, Brattle Group, conEdison, DNV GL, Itron Inc., MJ Bradley & Associates, National Grid, Nexant, and Silver Spring Networks.

Rhode Island stakeholders provided significant comment to help shape this report. Commenting organizations include: Acadia Center, Advanced Energy Economy Institute, Agile Fractal Grid, Alevo USA Inc., Ampion, Bloom Energy, Center for Justice, ChargePoint, City of Providence, Clean Energy Developers, Conservation Law Foundation, Dynamic Energy Group, Electricity Policy, EntryPoint Networks, Environmental Defense Fund, Greenlots, Handy Law, LLC, Heartwood Group, GridUnity, National Grid, Northeast Clean Energy Council, Newport Solar, Northeast Energy Efficiency Partnerships, People's Power & Light, Peter Galvin, Rhode Island Emergency Management Agency, Rhode Island Housing, Siemens, Sierra Club, Sunrun, The Utility Reform Network, and VCharge.

In addition, over 215 individuals including representatives from 65 organizations participated in one or more stakeholder engagement sessions. The specific stakeholder views are publicly available at http://www.ripuc.ri.gov/utilityinfo/electric/PST_home.html. The views expressed in this report should not be attributed to any individual participant.

Special Note: The Public Utilities Commission's Role in the Power Sector Transformation Process

From February through September 2017, staff from the Division of Public Utilities and Carriers (Division), Office of Energy Resources (OER), and Public Utilities Commission (Commission) worked together to address topics related to Rhode Island's future electricity system. The inter-agency team collaborated closely and managed the Power Sector Transformation (PST) Initiative with four work-streams: 1) utility business models, 2) grid connectivity and functionality, 3) distribution system planning, and 4) beneficial electrification. The recommendations in this Phase One Report are based on significant stakeholder engagement, staff expertise, and consultation with national experts. The stakeholder engagement process and summary of stakeholder feedback is explained in each chapter. The recommendations in this report build upon the inter-agency working group, but are solely the recommendations of the Division and OER.

The Commission, through its staff, collaborated with the Division and OER on each of the four work streams. The PST process assisted staff in valuable learning opportunities and provided the project team with staff's expertise on existing regulatory processes and issues. Given the Commission's quasi-judicial function, it is important that the Commissioners and their staff avoid even the appearance of having pre-judged an issue. For this reason, Commission staff was careful to avoid discussions of actual implementation pathways and decisions once the exploratory phase of the project ended and shifted toward identifying deployment strategies. In particular, Commission staff avoided substantive PST decision-making to avoid a conflict such that Commission staff could not assist the Commission in its review of any future regulatory filings.[1]

The Commission was the lead agency on the Beneficial Electrification work stream, primarily through staff. The Commission focused its contribution on developing a draft whitepaper to explain what information should be required for review by the Commission in a utility proposal regarding beneficial electrification and what principles the Commission should apply in reviewing such a proposal. Consistent with the Commission's general engagement on PST described above, to avoid the appearance of pre-judging future utility proposals, the Commission refrained from collaborating on specific deployment proposals for beneficial electrification.

The result of the Commission's work was the development of a body of background information, including stakeholder comments, research on other jurisdictions, and general electrification research. The intent was to include the information with the draft whitepaper to support the Division and OER's development of additional implementation and deployment policies. Accordingly, on September 25, 2017, the Commission led a final stakeholder discussion on the Beneficial Electrification work stream and then transferred the draft whitepaper to the Division and OER, thus ending its role as lead agency. At that point, while the Commission also ended its active collaboration on this project with the other agencies, it continued to be in favor of the PST process and provided procedural and administrative support when necessary.

[1] Commission staff did provide some input on procedural issues, such as what existing regulatory processes might be germane for considering certain PST concepts.

Executive Summary

The demands on Rhode Island's electric distribution system are rapidly evolving, driven by consumer choice, technological advancement and transformative information. The state's electric utility and regulatory framework were developed in an era in which demand for electricity consistently increased, technology changed incrementally, customers exerted little control over their electricity demand, electricity flowed one-way from the utility to customers, and the risks of climate change were unknown. Today, none of those factors is true: demand for electricity has plateaued; many customers generate their own power; electricity flows to and from customers; technologies are being introduced at rapid pace; and the need to mitigate and adapt to climate change is real. In these new circumstances, the traditional regulatory framework will not continue to serve the public interest. It will continue to push consumer prices upward without a corresponding increase in value for customers. This report presents recommendations to transform the power sector for these new circumstances and help control long term costs for consumers.

Rhode Island now has the opportunity to permanently change how the electric system serves its residents and businesses. As illustrated in Figure 1, the levelized cost of some renewable energy generation has declined dramatically over the last decade. As businesses and residents continue to build renewable energy, Governor Gina M. Raimondo set a goal for the state to procure 1,000 megawatts of new renewable energy generation by 2020, putting Rhode Island on a pathway to clean, reliable and affordable generation.

At the same time, the rapid advancement of information management, communications, power distribution, and consumer products have shown the potential to transform our electrical grid. That potential can be unleashed only by reforming regulatory frameworks that today inhibit the utility from pursuing new technologies and limit the ability of third-party businesses from selling their innovative technologies and services to customers.

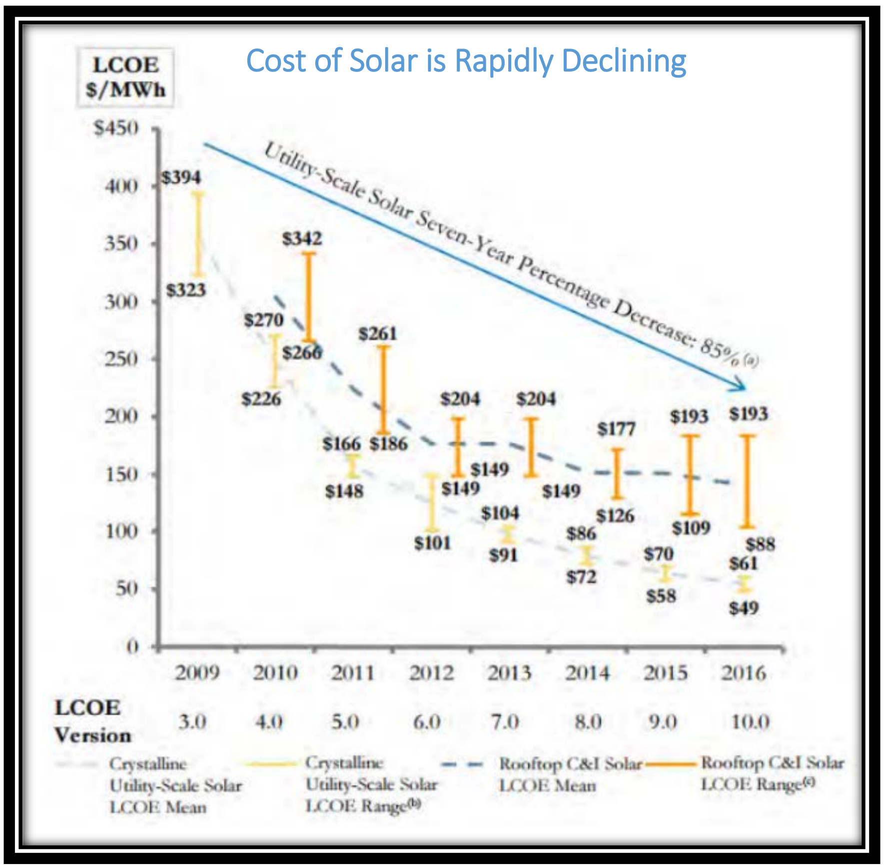

Figure 1: Levelized Cost of Large Scale Solar.
Source: ACORE, 2017[1]

As illustrated in Figure 2, the cost of electricity will continue to increase if nothing changes. A new regulatory framework will fundamentally change the trajectory of costs both by avoiding system costs and by forcing the utility to find more value from our electric distribution system, creating additional revenue streams.

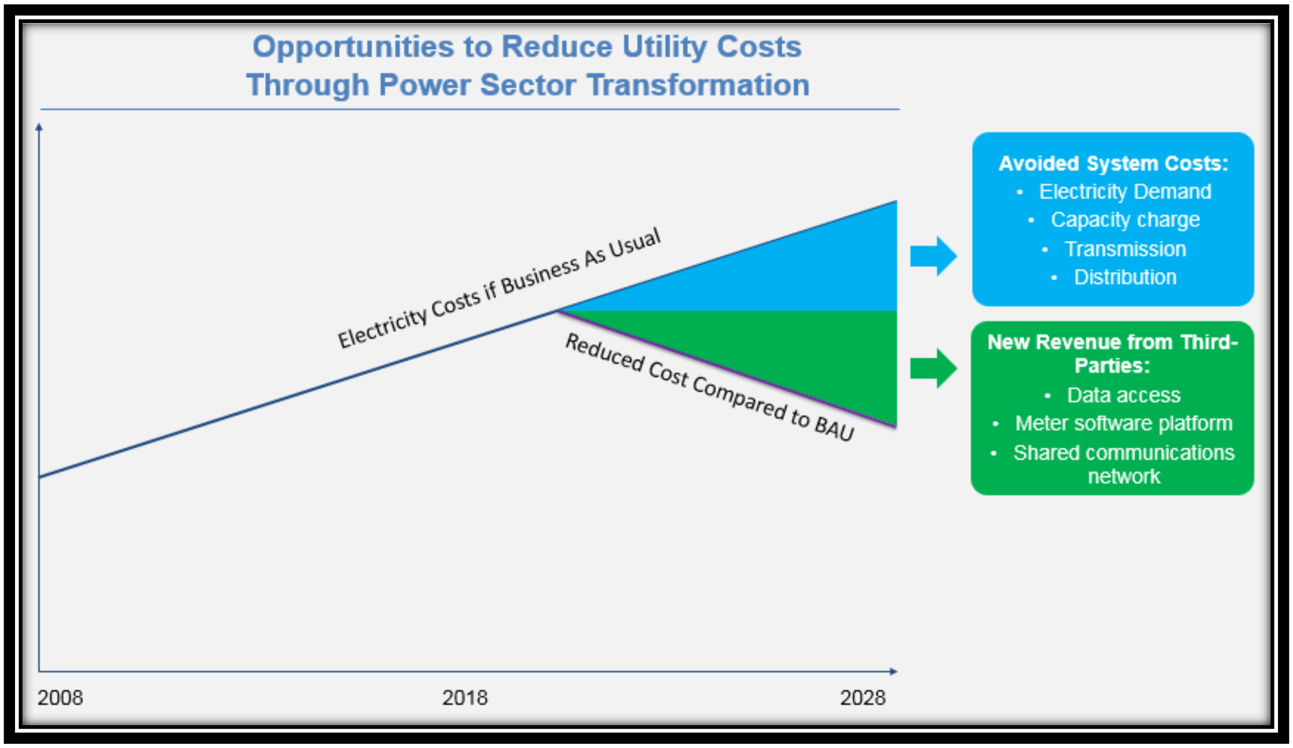

Figure 2: Conceptual Illustration of Cost Saving Opportunities from PST.
Source: DPUC, 2017

To address the need for change, Governor Raimondo directed the Division of Public Utilities and Carriers (Division), Office of Energy Resources (OER) and Public Utilities Commission (Commission) to collaborate in developing a more dynamic regulatory framework that will enable Rhode Island and its major investor-owned utility to advance a cleaner, more affordable, and reliable energy system for the twenty-first century.[2] The new regulatory framework should seek to achieve the following goals:

Goals

1. **Control the long-term costs of the electric system.** The regulatory framework should promote a broad range of resources to help right-size the electric system and control costs for Rhode Islanders. Today's electric system is built for peak usage. New technology provides us with more ways to meet peak demand and lower costs.

2. **Give customers more energy choices and information.** The regulatory framework should allow customers to use commercial products and services to reduce energy expenses, increase renewable

[2] Directive from the Governor on March 2, 2017 is included in Appendix I.

energy, and increase resilience in the face of storm outages. Clean energy technologies are becoming more affordable. Our utility rules should allow customers to access solutions to manage their energy production and use.

3. **Build a flexible grid to integrate more clean energy generation.** The regulatory framework should promote the flexibility needed to incorporate more clean energy resources into the electric grid. These resources would help Rhode Island meet the greenhouse gas emission reduction goals specified in the Resilient Rhode Island Act of 2014 and consistent with Governor Raimondo's goal of 1,000 megawatts of clean energy, equal to roughly half of Rhode Island's peak demand, by 2020.

Levers of Reform

Building on the *Energy 2035 Rhode Island State Energy Plan* and the work of stakeholders in the Commission's Docket 4600, the blueprint for regulatory reform has identified the following levers of reform:

Pay for Performance. We recommend shifting the traditional utility business model away from a system that rewards the utility for investment without regard to outcomes towards one that relies more upon performance-based compensation, which relies on a set of regulatory tools to improve the utility's performance based on outcomes aligned with the public interest and ties that performance to financial incentives

Invest in Intelligence and Connectivity. We recommend investment in advanced meter functionalities. Advanced meters provide a range of capabilities, including serving as a software platform for third-parties to provide new services, similar to how cell phones allow third-party application development.

Replace ratepayer funds with new sources of utility revenue. There is an opportunity for the utility to better realize the value inherent to the existing distribution network by providing new kinds of services and entering in to new kinds of partnerships. The revenue from these new services and partnerships has the potential to lower the amount of revenue needed to be recovered directly from ratepayers to operate the system.

Leverage the power of information. Underpinning all of the following recommendations are considerations of access to information and cyber security. Innovation in the electricity sector depends on allowing new market entrants increased access to information from the grid, while ensuring that customer privacy and cyber resiliency considerations are accounted for.

Increase the reliability and resilience of the electric distribution system. Investment in grid connectivity and advanced meter functionality will help a utility shorten the time of outages by instantly communicating the scope and location of power outages, predict where a future outage might occur by reporting abnormal grid activity, and allow regulators to better hold utilities accountable by tracking the length of outages.

Recommended Actions

The above policy goals can be advanced by the following recommendations.

1.0 **Modernize the utility business model through the following actions:**

1.1 **Create a multi-year rate plan and budget with a revenue cap to incent cost savings.** The utility should submit a multi-year rate plan with a revenue cap that incents cost saving and shares those savings with ratepayers. This will better align the utility's financial incentives with economic efficiency and sound investments in capital and non-capital expenditures, and ultimately pass reduced costs on to customers.

1.2 **Shift to a pay for performance model by developing performance incentive mechanisms for system efficiency, distributed energy resources, and customer and network support.** The utility's earnings growth will shift away from being based on the amount of capital it invests and towards a reflection of its performance. Incentives will encourage prudent investments in system efficiency, increasing distributed energy resources, network support services, and customer engagement.

1.3 **Develop new value-streams from the distribution grid to generate third-party revenue and reduce the burden on ratepayers.** The modernization of the distribution grid will yield opportunities to get more value from the grid. It will involve the creation of at least three valuable platforms, the communications network that supports advanced meters, the advanced meters themselves, and the data portal. These platforms must appropriately be monetized by the utility by charging third parties for access and services, according to the principles established by the Commission.

1.4 **Update service quality metrics to address today's priorities, including power outage prevention, cyber-resiliency and customer engagement.** In some areas, such as cyber-security, the utility should demonstrate it meets threshold performance levels consistent with its role in managing critical infrastructure.

1.5 **Assess the existing split-treatment of capital and operating expenses.** The Division should convene a collaborative of stakeholders to consider opportunities for a total expenditure approach for future implementation to remove capital bias of the regulatory framework that currently drives cost increases.

2.0 **Build a connected distribution grid through the following actions:**

2.1 **Deploy advanced meters.** National Grid should develop an advanced meter roll-out plan that includes: a business case, time-varying rates, an aggressive implementation schedule, and list of planned capabilities that includes the capabilities identified by the Power Sector Transformation process. The plan must include protections for low income ratepayers as well as a platform upgrade model to protect all ratepayers from a growing obsolescence risk. The plan must include a proposal to provide third-party access to the advanced meter platform data to ensure fair market access for grid upgrade opportunities.

2.2 **Plan for third-party access and innovation.** National Grid should submit a plan for how advanced meter capabilities can be accessed by third-party providers. The plan should address consumer privacy and cyber resiliency protections.

2.3 **Share the cost burden through partnerships.** The utility should share communication infrastructure through partnerships to reduce costs. The utility's proposal must include consideration of shared communications network to supply connectivity to meters and other automated grid components to deliver greater customer value. Leveraging already planned deployment of advanced wireless networks by major carriers should significantly lower the incremental costs to ratepayers of the new infrastructure.

2.4 **Focus on capabilities to avoid technological obsolescence**. Rather than address particular technologies, the regulatory process should advance a benefit-cost analysis for advanced meter capabilities using the categories established in Docket 4600 and based on a business case, making the utility responsible for technology selection risk. The utility should conduct an in-depth assessment of benefits and costs for each grid function identified by through this initiative and integrate the results in its business case.

2.5 **Proactively manage cyber resilience.** The utility should provide annual cybersecurity briefings to the Commission on threats, responses, and proactive measures. Additionally, each of the advanced grid functionality actions listed above should explain cybersecurity issues and plans to address them.

3.0 Leverage distribution system information to increase system efficiency through the following actions:

3.1 **Synchronize filings related to Distribution System Planning.** The utility should begin filing the Infrastructure, Safety, and Reliability (ISR) Plan and System Reliability Procurement (SRP) Plan as two linked, synchronized, and cross-referenced distribution system planning (DSP) filings each year. Linking these two filings and including key DSP-related content will: (1) provide increased transparency and a codified mechanism for stakeholder and regulatory input into the improvement of DSP analytics and tools over time and (2) enable the Commission and stakeholders to consider investments proposed in the ISR and SRP in a comprehensive and holistic manner.

3.2 **Improve forecasting.** The utility should include detailed information on distribution system planning forecasts in annual SRP/ISR filings and implement a stakeholder engagement plan during forecast development.

3.3 **Establish customer and third-party data access plans.** The utility should develop a plan for establishing seamless customer and third-party access to data. Implementation of data access plans should enable customers to share their data with third-parties and allow distributed energy resource providers to easily access system data in order to identify where non-wires alternatives opportunities exist to provide value to ratepayers and the system.

3.4 **Compensate locational value.** State regulators and policymakers should develop a strategy to compensate the value of distributed energy resources based, in part, on their location on the distribution system.

4.0 Advance electrification that is beneficial to system efficiency and greenhouse gas emission

reductions, especially through electrification of transportation and space heating, through the following actions:

4.1 **Design rates to increase system efficiency.** The utility should design electricity rates to encourage electric vehicle users to charge their cars outside of peak demand time and make their batteries available to the grid in order to maximize system benefits.

4.2 **Establish outcome-based metrics.** Beneficial electrification proposals should include tracking of outcome-based metrics that are relevant to consumers and public policy objectives.

4.3 **Beneficial heating proposals should be consistent with principles outlined in the Commission White Paper on beneficial electrification.**

Implementation

Transforming the power sector will not occur overnight. This report provides the starting point for substantial change. As a national leader in clean energy innovation, Rhode Island is no stranger to the complex issues posed by our changing electric distribution system. Over the past years, the state has curated a strong foundation of policy thought on the evolving utility system through the work of the Energy Efficiency and Resource Management Council, the Distributed Generation Board, the Systems Integration Rhode Island Working Group, the Commission's Docket 4600, and National Grid's continuing innovation across its service territory. This report draws on lessons from this collective work and proposes a broad-reaching vision for moving forward in key areas. It proposes concrete, tangible, and no-regrets actions that Rhode Island can take to move toward a more performance-oriented and information-driven utility over the next three to five years.

During the coming year, the recommendations of this report will begin the evolution of the power sector through a variety of regulatory vehicles. In particular, National Grid's distribution rate case filing expected in December 2017 represents a strategic opportunity to modernize the utility business model, deploy advanced meters, enhance distribution system planning, and pursue beneficial electrification. Other regulatory dockets that will be used to implement the recommendations may include, but are not limited to, the Infrastructure Safety and Reliability (ISR) Plan, the System Reliability Procurement (SRP) Plan, and Energy Efficiency Plans. The implementation vehicles will be determined in collaboration with National Grid, stakeholders, and regulators. The precise implementation pathway will depend on future decisions that National Grid, the Commission and stakeholders will each make. There are many available tools for the state's policymakers and regulators to pursue change.

This report calls for a higher degree of stakeholder engagement with key issues related to utility planning, operations, and investment decision-making. Regulators and policymakers will work with National Grid to create the proper forums for stakeholder participation and input into key implementation areas such as data access, distributed energy resource compensation, and distribution forecasting.

The OER and Division look forward to working with stakeholders, regulators, and National Grid to advance Rhode Island's position as a national leader in utility regulatory reform in order to achieve our collective policy goals of controlling long-term system costs, enhancing customer choice, unleashing third-party innovation and integrating more clean energy into our electric grid.

PART I

UTILITY BUSINESS MODEL

Utility Business Model Principles and Recommendations

Introduction

This chapter addresses the utility business model and the regulatory framework for electric utilities in Rhode Island. The chapter first examines the rationale for reform of the utility business model and the regulatory framework. Next, the chapter describes measures the Rhode Island General Assembly and Commission have taken over the last decade to advance utility performance-incentives. Third, it describes a long-term vision of the utility as a performance-based and information-driven enterprise. Finally, the chapter advances a set of recommendations.

As the architect and operator of the local electric distribution system, the electric utility plays a central role in the power sector. The functions the utility performs, the way it recovers its costs, and the incentives under which it operates create the utility business model. The utility business model has emerged, in large part, in response to the regulatory framework established by the Rhode Island General Assembly and the Commission. Utilities perform the functions that they are incentivized and obligated to perform by the regulatory framework.

Rhode Island's utility business model and regulatory framework have developed in an era characterized by relative constancy. From 1950 to 2000, demand for electricity consistently increased, technology changed incrementally, customers exerted little control over their electricity demand, electricity flowed one-way from the utility to customers, and the risks of climate change were unknown. Today, none of those factors are true. Demand for electricity has plateaued; many customers generate their own power; electricity flows to and from customers; technologies are being introduced at rapid pace; and the need to mitigate and adapt to climate change is real. In these new circumstances, it is appropriate for state policymakers to ask whether the traditional regulatory framework and utility business model continues to advance the public interest and state objectives.

Rationale for Reform to the Utility Business Model and Regulatory Framework

The current utility business model in Rhode Island is based on a regulated compensation framework that allows the utility a return on its capital investment and recovery of its prudent operating costs. The utility projects these costs for a single future "test year". This revenue requirement is collected from customers largely through a volumetric charge on each kilowatt hour of electricity consumed. A decoupling true-up mechanism allows the utility to recover its revenue requirement regardless of the amount of electricity actually consumed.

System Efficiency

One indication of how the utility business model and regulatory framework are out-of-step with today's expectations for a clean, cost-effective and resilient electricity system is the electric grid's system efficiency, defined as the ratio of peak to average demand. While many industries have become more efficient over the last few decades by leveraging information technologies to more fully utilize capital investment, Rhode Island's peak to average demand ratio is 1.98, meaning that nearly half of the utility's capital investment is not utilized most of the time.[3]

The number of megawatts (MW) demanded in Rhode Island each hour of the year, ranked from greatest to lowest volume demanded, is illustrated in Figure 3. Each colored line represents one year from 2006-2016. Over the last decade, Rhode Island did not need more than 1200 MW of capacity during most hours. The electric grid has been built to ensure that those few hours a year that approach 2000 MW of demand can be met. The top 1% of hours cost the state ratepayers around 9% of spending, at around $23 million, while the top 10% of hours cost 26% of costs at $67 million, as illustrated in Figure 4. To meet peak demand, our system currently invests in solutions that are more expensive than is necessary. We have the technological opportunity to shift the hours of demand and thereby reduce everyone's utility bills.

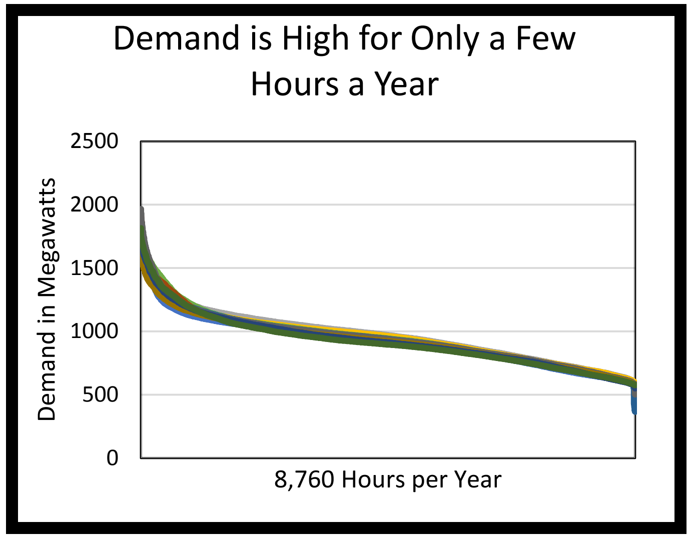

Figure 3: Demand is High for Only a Few Hours of the Year. One Year (8760 Hours) of Rhode Island's Peak Demand Ordered by Scale of Demand Source: DPUC, 2017

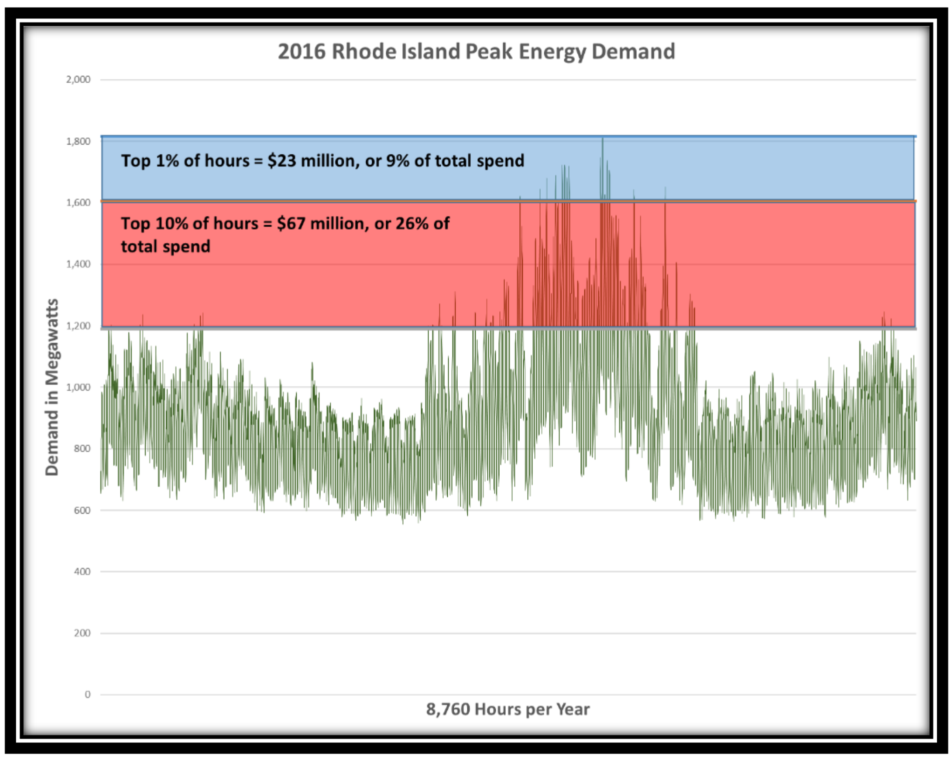

Figure 4: 2016 Rhode Island Peak Energy Demand and Spend
Source: DPUC, 2017

[3] For 2016, the ratio of National Grid's peak-to-average demand was 1817 MW to 915 MW, which is a ratio of 1.98.

This relative inefficiency is not unique to Rhode Island. According to the U.S. Energy Information Administration, New England's wholesale electricity market has the fastest growing gap between peak and average electricity demand.[4] The trend across New England from 1993 to 2012 is illustrated in Figure 5. For both Rhode Island's electric distribution system and New England's wholesale electricity supply market, the gap between peak and average demand means that capital assets are not fully utilized, increasing costs for customers.

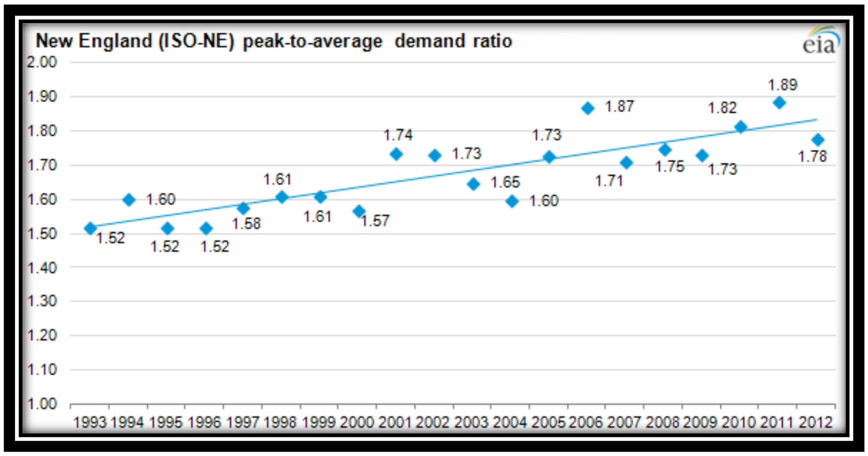

Figure 5: Increasing Peak-to-Average Demand in New England.
Source: US Energy Information Administration

Although the gap between peak and average demand is a longstanding attribute of the electricity sector, today new controllable distributed energy resources (DERs) paired with information technologies justify state policymakers to ask whether this long-standing inefficiency, is in fact, necessary. The distribution system's relatively low system efficiency has a significant impact on the overall cost of electricity for customers, and therefore the public interest. There are four main ways in which low system efficiency increases system costs. First, the cost of energy in wholesale markets is highest during hours of peak use. Although reduced demand by Rhode Island customers may not have an impact on regional prices, it is more valuable to customers to reduce energy during the hours when it costs most. Second, low system efficiency means Rhode Islanders pay more in annual forward capacity market charges than necessary. Third, low system efficiency means we pay more in monthly transmission charges than necessary. Fourth, low system efficiency means we use our distribution system unevenly, building it bigger in some places to meet peak demand, creating additional cost.

The reason for the system's relative inefficiency lies within the regulatory framework, rather than the utility itself. Utilities are required to maintain reliability and to ensure that the system can provide service on the days of the year in the summer and winter when demand is at its highest. While this ensures reliability, it has a negative impact as well, by creating a system in which a significant portion of infrastructure is used for a small fraction of the year, increasing the size and cost of the electric system. DER and grid control

[4] See: U.S. Energy Information Administration, "Peak to Average Electricity Demand Rising in New England and Many Other Regions" February 18, 2014. Available at: https://www.eia.gov/todayinenergy/detail.php?id=15051

technologies may offer new opportunities to provide reliable service with lower capital investment, reducing long-term system costs.

In the traditional regulatory model, electric utilities earn a return on investments based largely on the cumulative depreciated cost of the prudent capital investments. This model may exert a "capital bias" on the utility to deploy capital-intensive solutions. This occurs because the primary financial means through which the utility can grow its business and enhance earnings for shareholders is to invest in capital projects. This bias, created by the regulatory framework rather than by the utility itself, discourages the utility from seeking more efficient solutions that do not depend on large capital investments.

Innovation

A second way in which the traditional utility business model and regulatory framework may be out-of-step with today's technology opportunities and customer needs is innovation. In an age in which many opportunities for customer savings depend on appropriate adoption of quickly evolving technologies, the existing regulatory framework may inhibit the utility from innovating in a manner that would produce lower system costs. For the utility to continue to recover its investment, the infrastructure or system component must still be used to serve customers. Obsolescence will result either in system components being removed from service or the utility continuing to operate with out-of-date equipment. In turn, removing obsolete systems from service could result in the utility incurring a financial loss for the un-depreciated portion of the investment. Rhode Islanders risk losing the opportunity to achieve innovation gains that have shaped other areas of our life by having a regulatory system that directs the utility to be overly cautious and avoids experimentation.

The current regulatory framework tends to make utilities reluctant to invest in innovative technologies because they might not be allowed compensation if the Commission decides it was not prudent. This risk is particularly high when a technology is undergoing rapid change. The utility hesitates out of fear that it may be too easy for regulators to second-guess an investment in a technology when after-the-fact evidence emerges that the technological solution was likely to change quickly. This can hinder a utility's incentive to invest in certain DER or technologies that support them, such as advanced metering infrastructure, data collection and management systems, and communication systems. Similarly, the current regulatory framework does not incentivize the utility to consider inter-operability or long-term technology evolution.

One specific attribute of the regulatory framework that tends to inhibit innovation and long-term planning is the one-year rate case. The current regulatory model sets rates for only one year at a time. This means that during the second or third year following a rate case, as costs change quickly, there is no means for the utility to recover them. As a result, utilities either do not innovate to avoid incurring the costs or they file for changes in rates more frequently. Either of these decisions impede long-term planning and provide a disincentive for the utility to incur non-capital expenses in one year that only yield savings in later years.

Bi-Directional Energy Flow

A third way the current regulatory framework and utility business model is out of step with existing conditions is the need for bi-directional energy flow. Rhode Island customers and policy objectives are seeking more renewable energy, such as rooftop solar, which requires bi-directional energy flow. Rhode Island currently has 230MW of renewable energy projects that produce energy that at times, provides energy in to the distribution system. The State General Assembly has twice passed bills authorizing the

Renewable Energy Growth Program, enabling more resources to sell energy in to the distribution grid. Supporting bi-directional energy flow will be an important aspect of the utility's future role, and the current regulatory model and rate structure does not support it.[5]

Connectivity and Software Solutions

A fourth way in which the traditional utility business model and regulatory framework may be out-of-step with today's technology opportunities and customer needs is with respect to data connectivity and the interplay between software-based management systems and conventional capital solutions. A more modernized and dynamic electric system will depend on operation of data networks to allow the utility to gain visibility and control of the electric system. Many of the functions associated with operation of a data network are outside of the electric utility's traditional area of operations and include strategically important -- but not capital intensive -- software, and "cloud services" components. The distinction within the regulatory framework between operating expenses and capital expenses may result in investment choices by the utility that do not fully use new software tools to replace capital investment and inhibit the utility from developing the organizational structures and capabilities needed to undertake many of the information-oriented functions that are the key to future system savings.

Energy Supply and Security

A fifth way in which the traditional utility business model and regulatory framework may be out-of-step with today's technology opportunities and customer needs, is with respect to the distribution utility's role in connecting customers with electricity supply. Since the electric utility business was restructured in Rhode Island in 1996, National Grid's primary business has been to deliver the electricity produced by non-affiliated generators in the regional market and maintain local service reliability.[6] The service and rates associated with the distribution of electricity is regulated by the Commission. While National Grid sells commodity electric supply – referred to as "Standard Offer Service" – this commodity service is only supplied to customers who have not otherwise selected a third-party supplier for their power. The Company earns no profit on the sale of commodity electric supply.

[5] http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-26.6/INDEX.HTM
[6] Rhode Island Utility Restructuring Act of 1996 (H-8124) is found at: http://www.energy.ri.gov/policies-programs/ri-energy-laws/rhode-island-utility-restructuring-act-1996.php

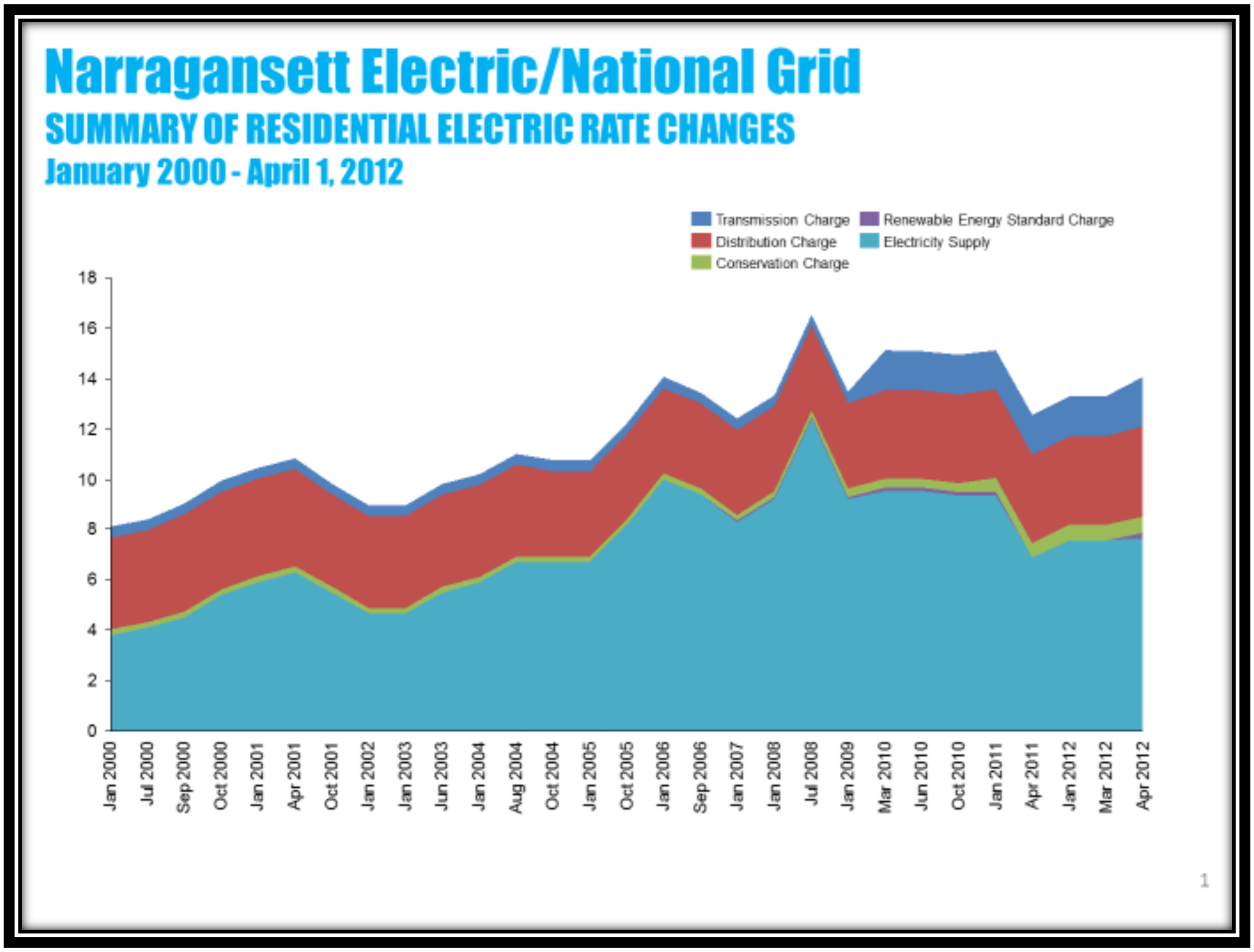

Figure 5: Rhode Island Prices Steadily Increasing. Source: DPUC with National Grid data, 2017

As Figure 5 shows, the cost of electricity supply and, more recently, transmission, have been increasing and represent the largest portion of our electric bills. Although the utility does not benefit from its role as a supplier of wholesale electricity supply, the current regulatory framework does not incent the utility to maximize integration of DER, which would reduce customer exposure to increasing wholesale supply costs and also increase the region's energy security. That is, the regulatory framework may not sufficiently incent the utility to build a DER-centered system, consistent with the state's Least-Cost Procurement statute. Instead, under the current regulatory framework the utility neither benefits nor is penalized from increasing electricity supply costs that customers pay. Enabling Rhode Islanders to invest in DER solutions is not currently a core goal of the utility regulatory framework or utility compensation, even though it is in the public interest to reduce wholesale market costs, improve environmental impacts, and increase resilience.

Rhode Island's Existing Performance Incentive Context

In light of these dynamics, over the last decade, Rhode Island has recognized many of these shortcomings and took steps to reform the regulatory framework and utility business model to better align the utility's financial incentives with state energy policy objectives.[7] Beginning in 2006, state policymakers sought to reform the utility's business model through development of focused performance incentives. For example, the 2006 System Reliability and Least-Cost Procurement law, the 2009 Long Term Contracting Standard for Renewable Energy, and the 2014 Renewable Energy Growth Program each establish topical, performance-based incentives to correct perceived gaps in cost of service regulation.[8]

In recognition of the potential for DER to provide less capital-intensive grid solutions, the General Assembly has established a series of performance incentive mechanisms (PIMs) focused on particular performance areas. The following are the sections of the General Laws that set forth a provision for the Commission to calculate a performance-based incentive or issue an expressed percentage for remuneration to National Grid for its implementation of and participation in a particular program.

Incentive for Energy Efficiency, System Reliability & Least-Cost Procurement

The Commission is authorized to formulate a performance-based incentive based on the level of success of National Grid achieves for reducing the cost of electric and gas services through procurement portfolios. If the utility achieves the energy efficiency target, shareholders can earn a 5% bonus incentive of program budget. In 2017, the 5% incentive totaled \$4.4 million for electric efficiency and \$1.38 million for gas efficiency. In 2011, the Commission ordered that the utility was entitled to earn an incentive of 10% of all funding secured from outside funding sources by National Grid for implementation of the Energy Efficiency Plan.[9]

Incentive for Long-Term Contracts for Renewable Energy

The electric distribution company is entitled to financial incentives for accepting the financial obligation of the long-term contracts and shall be entitled to 2.75% of annual payments for projects reaching commercial operations.[10]

Incentive for Renewable Energy Growth Program

This law authorizes a feed-in tariff and requires National Grid to enroll 400 MW of nameplate renewable energy over a ten year period.[11] The electric distribution company is entitled to earn an incentive of 1.75% of the annual value of all payments issued to distributed generation facilities.[12]

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[7] See the Clean Energy Jobs Program Act Chapter 26.6 of Title 39 for the Renewable Energy Growth program. National Grid's combined operating revenues for all of its consolidated electric and gas businesses in Rhode Island were approximately \$1.26 billion in fiscal year 2017. The total net investment (i.e., rate base) that National Grid has made in Rhode Island is \$1.3 billion, approximately \$665 million in the electric distribution system and 640 million for the gas distribution.

[8] See R.I.G.L. § 39-26.6, §39-26, and § 39-1-27.7 e.

[9] See Docket 4295. It is not clear how much of an incentive sum, if any, has ever been earned by National Grid by reason of this particular incentive.

[10] See R.I. Gen. Laws § 39-26.1-4 and Commission Docket 4371 Attachment 10-2 (a)–(b) *RIPC* Long Term Contracting For Renewable Energy Provision, Tariff R.I.P.U.C. No. 2174, Sheet 1 and Attachment 3, Contract Incentives & Remuneration LTC & DG, Table pgs. 1-12, January 5, 2017.

[11] See R.I. Gen. Laws § 39-26.6-12 (3)

[12] *See,* Attachment 4, Renewable Energy Growth Program Cost Recovery Provision, Tariff R.I.P.U.C. No. 2176, Sheet 1.

Taken together, these performance incentives represent an important first step by Rhode Island's General Assembly and Commission to implement a performance-based regulatory framework. However, there are several reasons why it is now appropriate to review whether these initial performance incentive reforms are sufficient. First, they are largely input-based incentives that reward the utility for the cost of the resource, which is sometimes out of the utility's control, rather than the outcome the program seeks to achieve. Second, they have been developed without coordination. Third, they are topically-focused in ways that advance a particular program rather than outcomes of the system as a whole. Finally, taken as a whole they comprise only a modest incentive in the context of the utility's earned return on its invested capital.

Figure 6 presents a preliminary analysis of the scale and scope of existing performance-based incentives. The incentives, which accrue to shareholders, incent the utility to undertake activities that are beneficial for ratepayers. These incentives are designed based on a level of performance and as a percentage of the cost. Converting these into the share of net income is a way to understand their value to the utility. Current performance-based incentives total roughly 0.44% or 8.1% of net income. Comparing this to the utility's allowed ROE of 9.5% for capital investments, indicates the different scale of incentives.[13]

Program	Program Costs (2017$)	Shareholder Incentives			
		(2017$)	(% of cost)	(basis points)	(% of net income)
EE - Electricity	88,511,000	4,425,550	5.00%	24	4.5%
EE - Gas	27,751,000	1,387,550	5.00%	8	1.4%
SRP	400,300	20,015	5.00%	0	0.0%
Long-Term Contracts	72,275,022	1,987,563	2.75%	11	2.0%
DG Standard Contracts	7,063,354	194,242	2.75%	1	0.2%
RE Growth DG Facilities	1,821,337	31,873	1.75%	0	0.0%
Total	197,822,013	8,046,794	4.07%	44	8.1%

Figure 6: Comparison of Existing Incentive Mechanisms for 2017. Source: DPUC, 2017

Given Rhode Island's existing policy preference for performance incentives, the existing regulatory tools provide significant potential to reform the incentive structure of the distribution utility. The current utility business model is a cost of service regulatory framework with some additional performance incentive mechanisms. Expanding the performance incentive mechanisms offers significant potential to meet our contemporary goals.

Vision for an Information-Driven Utility

To help Rhode Island transition to a cleaner, more cost-effective and more resilient energy system, Rhode Island's regulatory framework will need to incentivize development of significant new capabilities over the coming decade and beyond. Electric utilities should have an opportunity to augment the significant infrastructure deployment capabilities they have developed with new capabilities in information

[13]The term 100 basis points means 1% return on investment, and 8 basis points means 0.08%, etc.

management and communications technologies. For an electricity utility to best serve Rhode Islanders, it will need to gather, analyze and leverage information that will allow it to better engage customers and to better enable other businesses to use the electric grid for new kinds of services. Whether as a platform for other service providers or as a customer-focused energy service firm, Rhode Island's electric utility will need to become an information-driven enterprise. The transition to an information-driven utility will enable Rhode Island to control long term costs, increase customer choice, and enhance the flexibility needed to incorporate more clean energy resources.

There are many potential commercial arrangements that may evolve in coming years to realize an information-driven electric distribution system. The regulatory framework should be flexible enough to allow market and technology developments to evolve, sorting out the commercial arrangements that will be most successful. It is the role of state policymakers and utility regulators to change the incentive structure for utilities such that they begin to develop the technological and organizational capabilities they will need to continue to serve the public interest.

The desired functions of a modern utility can be grouped into three broad areas:

Core Distribution & Reliability Functions

The traditional functions of ensuring electricity delivery and reliability are going to remain an essential responsibility of the utility. It is done through ownership and management of assets such as: poles, wires, transformers, fuse cutouts, reclosers, service drops, substations, transmission interconnections, and a multitude of other equipment. Tied to these assets are the operation and maintenance expenses associated with trucks, line workers, support staff, buildings, warehouses, systems, and administrative costs. These reliability assets and expenses make up the vast majority of today's distribution charge.

Energy Integrator Functions

This category covers functions that allow the utility to serve as a platform to facilitate the transactions and businesses of others on the grid. These functions may include, but are not limited to: management of consumer energy consumption, customer usage data gathering, management of customer information, provision of information to policymakers, and facilitating the connection of distributed generation to the system, among others. The platform function would be for the utility to facilitate the means for third parties to manage energy-related transactions that take place among participants, such as sale of energy from distributed resources from one location to the other, aggregating demand response among groups of customers, and providing the means for customers to join together to advance renewable energy projects. These functions may become a source of revenue for utilities independent from the end-use customer.

Energy Service Functions

This category of functions would include ownership and maintenance of electric meters, billing system management, provision of energy efficiency, making service connections, and other functions that relate to direct interactions between the utility service provider and the consumers receiving basic utility services. Some of these functions clearly can be performed by third parties on behalf of the utilities. One example is ownership of communication components that may be associated with advanced metering infrastructure. However, these are not services that can be set at a "market price" for electric customers, except to the extent that the communication function (beyond metering of consumption for billing purposes) is used to create a new service.

Recommendations

Based on the recommendations of stakeholders, Rhode Island's experience with performance incentives and the analysis presented here, the Division and OER recommend comprehensive performance-based regulation (PBR) framework where the utility's business model is foundationally aligned towards public interest while still fairly compensating its shareholders. The proposals included here represent incremental steps in that direction.

PBR describes a set of regulatory tools that align utility performance with outcomes favorable to customers and the public interest. The two primary goals of PBR mechanisms are to: 1) stabilize utility bills by addressing economic inefficiencies of cost of service regulation by mitigating the rising trajectory of energy costs; and 2) improve performance of non-monetized outcomes such as customer satisfaction, air emission reductions, and system reliability. The policy recommendations provided in this report take steps to address each of these two functions. The first goal of stabilizing utility bills by improving economic efficiencies is addressed through the proposal of a multi-year rate plan that sets a revenue cap, creating an incentive for the utility to more effectively manage costs and share the savings between its shareholders and customers. The second goal of improved performance of outcomes is addressed through a set of performance incentive mechanisms that offer financial incentives based on performance against defined metrics.

1.1 Create a multi-year rate plan and budget with rate cap to incent cost savings.

Multi-year rate plans (MRPs) are a ratemaking construct designed to strengthen utility financial incentives to operate efficiently, make sound investments in capital and non-capital expenditures, and ultimately pass cost savings on to customers.[14] At a transitionary moment in the utility industry, it will be a significant reform to change the rate case process to one in which the utility must set forth a multi-year plan for operating its distribution business. Although about half of the rates relate to non-controllable costs that are subject to cost trackers, there remains a substantial part of the distribution business that is addressed in the rate case that an MRP would address. These costs will change over time as the industry changes as well. It is this portion of costs that is most relevant to the multi-year rate case and, relevant to how the business of the utility may change. It represents most of the costs needed to maintain reliable distribution service for the distribution customer base. Equally important for the utility, the rate case sets the ROE that is used in the Infrastructure, Safety and Reliability (ISR) rate-setting processes prospectively. More broadly, an MRP would provide a regulatory tool to ensure the utility's projected costs are consistent with the intent of the new public policies that will take time to implement.

The components of the MRP proposed here include:

Rate plan period

The MRP should cover a 3-5 year period. This means that National Grid will not be allowed to file a rate case to change base distribution rates for this period. The Company should file a Business Plan to cover all initiatives and all costs during this multi-year period. In the future, National Grid will file a new rate case

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[14] For a very useful description and discussion of MRPs, see Lowry et. al., *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, Grid Modernization Laboratory Consortium, July 2017.

and business plan to cover the subsequent period. In selecting the precise period for an MRP, regulators should consider that a shorter period allows greater flexibility to account for lessons learned over time while a period longer than five years might increase consumer risk.

Business Plan

The core of the MRP depends on a Business Plan that should include the utility's proposal for all costs that it expects to incur during the multi-year rate plan. The Business Plan should represent a system-wide integrated distribution plan, incorporating the recommendations of the Rhode Island DSP work stream, including but not limited to, detailed information on forecasting and a plan to establish and improve customer and third-party data access. The goal of the Business Plan should be to identify the least-cost portfolio of distribution system investments, considering both distribution infrastructure investments and DER, while recognizing reliability, statutory, and non-discretionary constraints. The Business Plan should incorporate all the analysis that is currently done in the ISR, but for a full MRP period. It should also incorporate the evolving initiatives under the System Reliability Procurement (SRP) process, as well as any other DER initiatives underway.

National Grid should develop the Business Plan, and allow for robust stakeholder input, before and during the development of the plan. The stakeholder input process should be developed in detail as this MRP straw proposal moves forward. This approach will enable the Commission, the Division, OER and other stakeholders to provide direct guidance on the utility's initiatives and capital investments, including those related to grid modernization, DER, and other innovative developments.

Cost Recovery: Capital Costs

The capital costs included in the Business Plan should be used to set rates for each year in the rate plan and cover a similar period of years. Post-rate case review of the capital costs would still take place annually through the ISR proceeding. However, any changes in capital investments should be limited in the ISR process to only those matters that result from events or issues crucial to system reliability that were not reasonably foreseeable at the time the MRP was implemented. Absent a special issue identified in the annual ISR there would be no reconciliation of actual to budgeted costs. If the utility spends more than was budgeted, then it absorbs the difference. If it spends less, then it keeps the difference. This approach provides the utility with needed capital to implement the Business Plan, and the certainty that the Commission will allow for recovery of capital costs associated with innovative projects and helps provide incentive for the utility to spend efficiently. In turn, the utility gets pre-approval of its capital investments.[15]

Cost Recovery: Non-Capital Costs

Non-capital costs included in the Business Plan should be used to set rates for each of the years in the rate plan. There will be no reconciliation of actual to budgeted costs. If the utility spends more than was budgeted, then it absorbs the difference. If it spends less, then it keeps the difference.

Earnings Sharing Mechanism

An earnings sharing mechanism (ESM) should be established to protect both customers and the utility from extreme outcomes. The ESM should measure the resulting ROE after the PIM revenues are applied for the

[15] The capital cost recovery provisions described here may require review of Section 39-1-27 of Rhode Island General Laws.

given year. This prevents manipulation or perverse incentives from playing the PIMs off of the MRP. For example, a deadband of 1-2 percent could be set around each side of the allowed ROE. This would be a relatively broad deadband, to reflect the fact that PIMs could bring the actual ROE above the allowed ROE. Profit sharing above that deadband should be split with the customer earning 50% and the sharholders earning 50%. This would allow the utility to earn a relatively large amount of profit above the deadband, so as to maintain a relatively strong incentive for the utility to pursue the PIM targets once it reaches this range of ROE. Loss sharing below that deadband could be shared with the customer paying 20% and the shareholders paying 80%. This example would require the utility to absorb most of the losses if the ROE turns out to be really low, so as to provide a strong incentive to comply with the Business Plan and achieve the PIM targets.

1.2 Shift to a pay for performance model by developing performance incentive mechanisms for system efficiency, DER, and customer and network support.

Performance Incentive Mechanisms are intended to encourage the utility to achieve specific objectives in specific performance areas. PIMs should be founded on clearly defined metrics and should address goals that provide clear benefits to ratepayers, such as improving system efficiency. The incentive payment must not exceed the savings for ratepayers. Most PIMs in place in the US today only provide financial incentives for a small number of performance areas, and therefore have a small impact on the utility's overall financial performance. To meaningfully counteract the utility's incentive to build rate base inefficiently, it is necessary to establish significant, coordinated financial incentives in both the MRP and the PIMs. If the financial rewards available from PIMs are large enough and based on achievable metrics and targets they can significantly enhance the conventional allowed revenues needed to earn attractive returns for the utility.

The following suite of performance incentive mechanisms include financial incentives and reporting-only metrics. They are arranged in three broad groups designed to address a range of utility actions. The first area of performance incentive mechanism is System Efficiency, designed as a broad metric to achieve savings for ratepayers from the utility controlling long-term utility costs. The second area is DER, which includes targeted incentives for a range of DER that require utility action to implement. The third area is Network Support Services which includes actions that the utility will need to demonstrate capabilities essential for the future utility.

PIMs can be used to mitigate the infrastructure bias described above, by partially tying returns on capital investments to performance outcomes. This could be achieved in a number of ways that allow the Company fair earned returns.

System Efficiency

These broad metrics are designed to be outcome-based with financial incentives that are sufficiently large to affect the Company's decision-making.

- <u>Monthly Transmission Peak Demand</u>
    - Description: To encourage the utility to reduce transmission peak demand, to reduce its share of New England transmission costs.
    - Metric: Narragansett Electric contribution to the ISO-NE coincident peak, by month.
    - Target: TBD.

        - Incentive: TBD.
- Forward Capacity Market Peak Demand
    - Description: To encourage the utility to reduce annual demand in the Forward Capacity Market peak demand, to reduce its distribution costs.
    - Metric: Narragansett Electric peak distribution demand, annual.
    - Target: TBD.
    - Incentive: TBD.
- Time-Varying Rates
    - Description: To encourage the utility to promote customer participation in time-varying rates to influence consumption patterns
    - Metrics: Percent of load on time varying rates, by customer sector, by year.
    - Target: TBD.
    - Incentive: TBD.
- Time-Varying Rates – Electric Vehicles
    - Description: To avoid adverse system effects from increasing EV growth, this incentive encourages the utility to promote customer participation in time-varying rates to influence consumption patterns.
    - Metrics: Percent of customers with EVs, or percent of EV load, enrolled in a time-varying rate, by month and by year.
    - Target: TBD.
    - Incentive: TBD.

Distributed Energy Resources

This category of performance incentive mechanisms includes existing mechanisms and several new mechanisms designed to incent cost-effective DER. They are designed to augment the broader system efficiency mechanisms.

- Energy Efficiency --Electric
    - Description: To encourage the utility to optimize the use of the electric energy efficiency program to maximize deployment of cost-effective energy efficiency.
    - Metric: MWh and MW of electricity savings.
    - Target: Set in annual Energy Efficiency Plans.
    - Incentive: Based on MWh and MW saved, up to 5% of program budgets subject to adjustment in future Energy Efficiency Plans.
- Long-Term Renewable Contracts
    - Description: To encourage the utility to implement renewable long-term contracts to achieve state renewable energy targets and minimize carbon in the generation serving Rhode Island, as set by statute.
    - Metric: Payments made through PPAs.
    - Target: None.
    - Incentive: 2.75% of payments made through PPAs.
- RE Growth DG Facilities
    - Description: To encourage the utility to support RE Growth facilities to support state renewable energy policy, as set by statute.
    - Metric: Incentives issued to DG owners.

- Target: None.
- Incentive: 1.75% of incentives issued to DG owners.

- System Reliability Procurement, Non-Wires Alternatives and Access to Distribution System Data
  - Description: To encourage the utility to develop non-wires alternatives to reduce distribution system costs.
    - Metrics: (1) Provide distribution system datasets to empower customers and third parties to identify opportunities to install DER in constrained areas of the grid; (2) Performance metrics related to user experience, costs/benefits, and other performance of the DSP Data Portal.
- Demand Response
  - Description: To encourage the utility to foster successful demand response programs to manage costs associated with peak demand.
  - Metrics: (1) percent of customer load served annually, by customer class; (2) annual capacity savings (MW); (3) program costs per capacity saved ($/kW)
- Electric Vehicles
  - Description: To encourage the utility to assist with the development of EVs and charging stations in an efficient and cost-effective manner to meet state transportation and climate change goals.
  - Metrics: (1) Percent of customer load from customers who own EVS, by customer sector, by month and by year, by circuit. (2) Preparation of an EV hosting map. (3) Number of charging stations independently-owned by customer or third party – to be measured by month, year, and circuit. (4) Investment in make-ready work for EV charging stations. (5) Provision of and participation in customer awareness and education events.
- Behind-the-Meter Storage
  - Description: To encourage the utility to promote cost-effective behind-the-meter storage to accelerate deployment of a new flexible resource.
  - Metrics: percent of customer load with storage, annual and cumulative, by customer class.
  - Target: TBD after sufficient metrics information is collected.
  - Incentive: TBD. Options include dollar per customer and dollar per kW of storage.
- Utility-Scale Storage
  - Description: To encourage the utility to assess and implement storage technologies where cost-effective to accelerate the deployment of a new flexible resource.
  - Metrics: (1) Number of substations served by utility storage. (2) MW of utility storage installed.
- Beneficial Heating
  - Description: To encourage conversion of fossil fuel heating customers to efficient electric heat.
  - Metric: MW of electric heating capacity installed
  - Targets: TBD

Customer Engagement and Network Support Services

These performance incentive mechanisms are designed to support functions we expect the utility will need to undertake to transition to a customer-focused and information-driven utility.

- Access to Customer Info
  - Description: To encourage the utility to increase customer and third-party access to customer consumption information to improve market performance and customer decision-making. This will depend upon the implementation of Advanced Meter Functionalities.
    - Metrics: (1) Percent of customers able to access hourly or sub-hourly usage data, by customer sector, by year; (2) Percent of customers that provide hourly or sub-hourly usage data to third-parties, by customer sector, by year; (3) Provision of aggregated customer datasets and other customer-oriented datasets identified in the Company's customer and third-party data access plan.
  - Targets: TBD. This should begin with current levels and reflect reasonable increases from those.
  - Incentive: TBD. This should be based on the targets developed.
- Interconnection Support
  - Description: To encourage the utility to reduce time and cost of interconnection to better serve customers who want to generate or store electricity. This performance area is expected to be addressed in an upcoming Commission docket.
  - Metrics: (1) Average days for customer interconnection, by month, by customer sector. (2) Average cost of interconnection, annually, by customer sector (3) Difference between initial estimate and actual cost of interconnection.
  - Target: TBD. This should be based upon reasonable improvements over past practices, depending upon the extent to which these practices have been a problem in the past.
  - Incentive: TBD. This should be based on the targets developed. Options include dollars per reduction in interconnection time; dollars per average cost of interconnection; dollars per reduction in actual costs.
- Distribution System Planning
  - Description: To encourage the utility to use DSP to provide network support and encourage the implementation of DER that reflect system value.
  - Metrics: (1) Preparation of forecasts of utility, customer, and third-party DER, by customer sector, by year, by circuit if feasible; (2) Preparation of forecasts of locations and magnitudes of independent EV charging stations;
- Income Eligible Customers
  - Description: To encourage the utility to recruit eligible customers to participate in discounted rate plans.
  - Metric: The percent of census based population participating in the income eligible rate.
  - Target: TBD. Current participation rate is about 50 percent. California utilities have achieved 90 percent participation.
- Customer Engagement
  - Description: To encourage the utility to increase customer engagement in DER and network support services to enable customers to play their part in the energy market, and motivate a support structure of aggregators and service providers to help.

- Metrics: (1) Customer engagement surveys; (2) Transaction conversion rate at customer portals and platforms; (3) Customer participation rates in specific initiatives (e.g., energy efficiency, demand response program, distributed generation programs, AMF offerings, TVR offerings); (4) Customer education programs.

Reporting-Only Metrics

In addition to these financial incentives, there are some performance incentives that are worthy of reporting only. These include:

- Substation Capacity Factor
  - Description: To indicate the extent to which specific substations are stressed to signal attention from the utility, regulators and stakeholders.
  - Metric: For a select number of the most stressed substations, the ratio of capacity utilized during peak hour to the nominal capacity rating of the substation, by month and annually.
  - Target: None. One should be developed after assessment of historic capacity factors.

- DG-Friendly Substations
  - Description: To indicate the portion of substations that are capable of readily installing distributed generation.
  - Metric: Ratio of substations that can accept DG without upgrades, to all substations.
  - Target: None. One should be developed after assessment of historic ratios.

- Distribution Load Factor
  - Description: To indicate the efficiency with which the distribution system is being used, regarding the relationship between peak demand and energy consumption to assess the utilization of capital and its influence on unit delivery rates. In general, a higher load factor means that the system is being used more efficiently.
  - Metric: The ratio of distribution deliveries during the peak hour to distribution deliveries in all hours, by month and annually.
  - Target: None. While this is a useful metric to monitor, there are risks with assigning targets or incentives: load factor can be increased by simply increasing electricity sales; this metric is subject to other PIMs; and load factor can be influenced by factors outside utility control.

- Customer Load Factor
  - Description: To indicate customer demand relative to energy consumption. In general, a higher load factor is more efficient is less costly to serve.
  - Metric: Ratio of distribution deliveries during peak hour to distribution deliveries in all hours, by month and annually, by customer sector. Requires interval metering.
  - Target: None. While this is a useful metric to monitor, there are risks with assigning targets or incentives: load factor can be increased by simply increasing electricity sales; this metric is subject to other PIMs; and load factor can be influenced by factors outside utility control.

- Customer Intensity
  - Description: To indicate the amount of consumption by each customer class, and how that might change over time.
  - Metric: Ratio of kilowatt hour deliveries to number of customers, by customer sector, annually.
  - Target: None. While this is a useful metric to monitor, there are risks with assigning targets or incentives: developing a baseline is challenging; this metric is affected by factors outside of utility control; and this metric is subject to other PIMs.

1.3 Develop new value-streams from the distribution grid to generate third-party revenue and reduce the burden on ratepayers.

The modernization of the distribution grid will yield opportunities to get more value from the grid. It will involve the creation of at least three valuable platforms, the communications network that supports advanced meters, the advanced meters themselves, and the data portal. These platforms must appropriately be monetized by the utility by charging third parties for access and services, according to the principles established by the Commission.

In the traditional regulatory framework, the electric utility collects all of its revenue from end-use electric customers. With new technologies, the electric distribution system may become a source of new revenue from other parties through fuller utilization of the distribution network. There are at least four areas in which the electric utility may seek to leverage the performance incentive mechanisms described here to increase the utilization of its network and reduce the revenue burden on ratepayers.[16]

We outline broad terms in these areas and potential commercial arrangements to solicit stakeholder feedback and to allow market parties to innovate. Even beyond these individual areas for innovation partnership, utilities should be cognizant of how different technologies and partners may enable additional revenue from innovative utilization of the distribution network.

Utilization of shared communications infrastructure

A communications infrastructure is essential to many of the functionalities identified in the Grid Connectivity and Functionality work stream, including advanced meter infrastructure and time of use rates. To realize a shared communications network among various infrastructure providers we can envision three potential commercial arrangements:

- Use of public next generation connectivity for the electrical system in which the electric utility purchases a bulk amount of bandwidth and electricity ratepayers act as a kind of anchor tenant.
- Ownership of a communications infrastructure by the electric utility with sales to other bulk infrastructure customers in which electric ratepayers fund the communications network and have costs reduced.
- Participation by the utility in a special purpose vehicle with private vendors as a layer to support multiple infrastructure applications.

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[16] Carl Shapiro and Hal R. Varian (1999). *Information Rules*. Harvard Business Press.

Advanced Meters as a Third-Party Software Platform

National Grid has identified ownership of the meter as an important operational requirement for reliability. However, ownership and control are not barriers to allowing one or more third parties to operate the meter as a platform for data-based services. For example, energy efficiency, voltage conservation, health care monitoring or even home security services could be effected through software applications hosted on the advanced electric meter. The license to operate such a platform could become a source of revenue for National Grid.

Data Analytics

The distinction between "data" and "information" represents an important commercial opportunity for the utility and third parties to provide both public access to basic data and commercial access to information as the digested and improved product for market use. The emergent data and information portal discussed in the Distribution System Planning chapter could become a source of revenue for National Grid which could be used to offset other expenses for the benefit of ratepayers. DER developers would have access to some data without charge and might subscribe to have access to other information if they find it of value.

Beneficial Electrification of Heating

The electric utility should become a strategic partner with existing thermal heating vendors in conversion of space heating.

1.4 Update service quality metrics to address today's priorities, including power outage prevention, cyber-resiliency and customer engagement.

The Commission should open a docket to revise the utility's current service quality standards. In particular, service quality standards should address cyber-security preparedness and customer engagement to meet today's technological advances.

In addition, the Commission should review existing storm restoration standards to address the new role that electricity plays in ensuring communications and the way that advanced meter functionality (AMF) and other grid intelligence can support storm outage restoration.

Finally, the utility should fully map the ways in which AMF can improve storm restoration service quality. In particular, improvements in communicating to a utility the scope and location of power outages, rather than relying on customer phone calls or utility inspection crews to identify outage areas, will help shorten the time of outages after a storm.

1.5 Assess the existing split-treatment of capital and operating expenses.

The recommendations outlined here take significant steps towards aligning the regulated utility's economic incentives with the state's interests and policy goals. There are additional reforms that require further discussion and investigation. State policymakers should convene a collaborative of stakeholders to consider opportunities for a "total expenditure" approach for future implementation to remove capital bias of the regulatory framework that currently drives cost increases. The results of the process would be applied in the utility's next rate-case in 2020.

The proposed robust performance incentive mechanisms are designed to leverage the utility's desire to maximize its overall return on equity to achieve state objectives that will benefit ratepayers. However, even in the presence of these incentives, there will remain an inherent financial bias for the utility to apply capital expense solutions rather than operational expense solutions, because the utility's authorized return on equity applies to capital expenses, not operational expenses.

A total expenditure approach employs rate recovery mechanisms that make the utility relatively indifferent to whether it invests in capital or employs solutions that arise out of non-capital expenditures. Under this system, a utility may decide to invest in maintenance rather than a more expensive capital replacement without facing a penalty of lost profit opportunity.

Taken together, these considerations guide the definition of what the utility of the 21st century should do, how it should earn revenue, and what kind of metrics should shape its operation. They represent a significant step on a multi-year process to change the incentive structure of the electric utility. That process will succeed only if the utilities and decision-makers maintain their determination to learn, adapt, and implement over the coming decade.

PART II

GRID CONNECTIVITY & FUNCTIONALITY

Grid Connectivity and Meter Functionality Principles and Recommendations

Introduction

Information and communications technology now shapes every facet of our lives. Increasingly, our homes, schools and offices host many devices that communicate with each other and automatically respond to signals they receive. This transformation has already changed many aspects of our daily lives and is now, finally, shaping the electricity sector. As we modernize the electric grid, we have the opportunity to create greater "intelligence at the grid edge," that may fundamentally transform the capabilities, costs, and control of both the electric utility and the customers they serve. This opens opportunities for Rhode Islanders to transform the way we connect with each other, information, and energy. How we navigate this transformation will play a critical role in the economic vitality and well-being of our state and those who live here.

The 20th century distribution grid was designed for one-directional power flow from large central power plants to distant loads. As a result, it required little situational awareness and could be designed with analog self-correcting controls. There were no digital controls until the end of the 20th century. In the 21st century, DER – such as rooftop photovoltaics – are leading to multi-directional power flows on the distribution grid. The emerging complexity of distribution grid power flows now needs real-time situational awareness to keep the lights on, increase renewable energy usage, and minimize procurement and distribution costs for ratepayers. Technologies are required that can: 1) exchange information between all generating and consuming energy resources; 2) perform system-management using programmable controls; 3) integrate data from ubiquitous sensors and computer-based analytics; and 4) interface with increasingly intelligent devices within the home to help system operators manage peaks. The underlying foundation beneath all of these capabilities is network connectivity.

To take advantage of this opportunity, Rhode Island will need to invest in AMF, which consists of state-of-the-art digital hardware ("advanced meter") and software platforms that measure customer usage and voltage data and communicate them rapidly through the internet. The advantages enabled by AMF for the consumer are: outage prevention, faster outage restoration, access to various pricing options that can save them money, access to energy efficiency and renewable services tailored to their usage, and more efficient use of the distribution system that creates consumer savings. To unlock these consumer benefits, we need to modernize our technology and utility regulations.

AMF is vital to accomplish many of the goals expressed in the Power Sector Transformation (PST) Initiative. The rapid pace of technological development in AMF capabilities means that technological obsolescence is a risk, and this paper offers options for proactively managing that risk to minimize avoidable expenses for ratepayers. Finally, implementation of the initiatives discussed in this chapter will need to be accomplished with a careful examination of the cybersecurity principles that will protect the system and its customers. All of this can be accomplished in the near future, and will need to be accomplished if Rhode Island is to benefit from the technology changes sweeping electric distribution systems in this country.

The time for Rhode Island to invest in advanced meters is now. The meters installed in Rhode Island take 18 years to depreciate and are now reaching the end of their useful life for residential, commercial and industrial customers, as illustrated in Figure 7.[17] National Grid data shows that around 50 percent of meters have depreciated on book value and are being replaced at an annual rate of around 10,000-17,000 traditional meters and 100 advanced meters a year. As such, regulatory action today can redirect replacements of traditional meters to advanced meters, where appropriate.

This chapter addresses: 1) benefits of AMF; 2) context for interconnection of internet and grid; 3) desired network characteristics; 4) public policy considerations for "future-proofing" internet connectivity; 5) need for innovative ownership and access models; and 6) policy and regulatory recommendations.

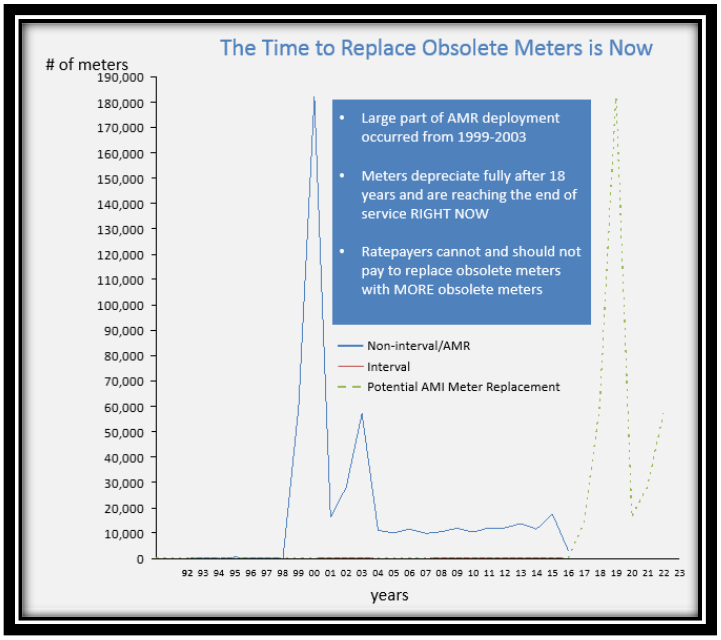

Figure 7: Historical and Illustrative Future Meter Deployment in Rhode Island. Source: DPUC with National Grid data, 2017

AMF Infrastructure is Evolving and Can Provide Significant Benefit to Customers

Traditional meters measure electricity use in a one-way flow of electricity. In contrast, advanced meter functionalities can measure real-time two-way flow of electricity and information. As illustrated in Figure 8, today's electricity system has a variety of ways to change the load curve, and advanced meters can disclose the data to animate the market for those value streams.

[17] This figure is based National Grid's data, submitted to the Division in response to an informal data request for information on July 24, 2017.

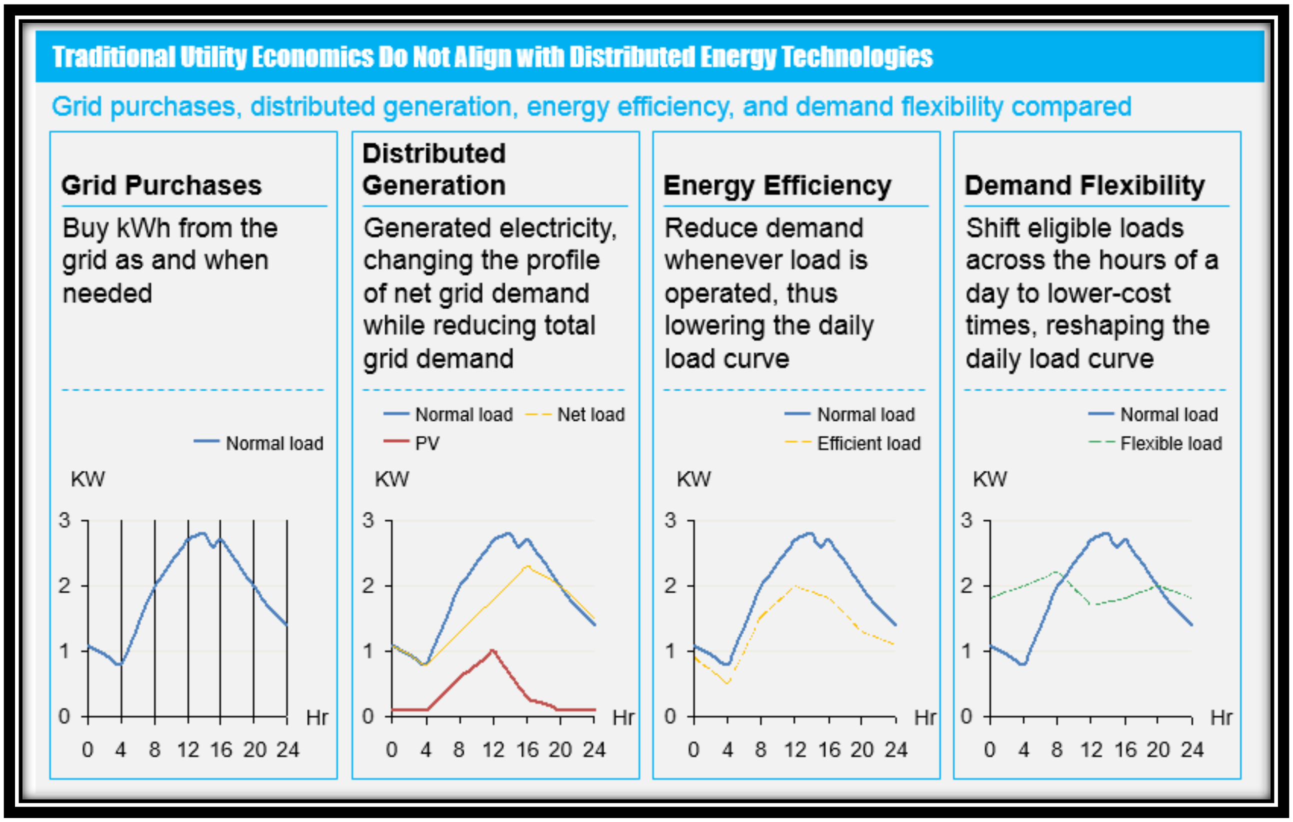

Figure 8: Changing Economics of Electricity. Source: Rocky Mountain Institute

An illustrative list of direct and indirect benefits that AMF can provide follows. The State would like to see the deployment of the specific set of capabilities that were identified through the Commission's Docket 4600 and are listed in Appendix II.

AMF's Direct Residential Benefits

Historically, advanced meters were utilized primarily by commercial and industrial customers, giving them the ability to shift their time of operations in exchange for more attractive pricing. For residential customers, the savings were more limited with the net benefits being primarily for customers who have solar power net metering. Historically, advanced meters reduced residential costs for meter reading but were not always offset by the upfront capital expense. Going forward, with technology advances to link the advanced meters to grid functionality, there are additional benefits for most residents, as illustrated in Figure 9. Some of the direct benefits to residents are:

- Provides substantial usage data to tailor pricing and service programs;
- Identifies locations on the grid where renewable distributed energy would be particularly helpful or harmful;
- Provides real-time operational awareness and accurate power status calls, as opposed to the past, where often the utility did not know a customer was without power unless the customer called them;

- Enables efficiencies for the grid system's need to balance power that can result in potential customer savings;
- Reduces costs of manual meter reading, and an increase in the accuracy of the reads, thereby reducing the estimated bills, which can be very inaccurate and can result in unmanageable bills;
- Enables time-based programs such as demand response and time-of-use rates – that can result in shaving peak load, which provides cost savings for all customers and additional cost savings to customers who participate in the program;
- Avoids service calls when the problem is on the customer side of the meter because the utility is better able to pinpoint the source and nature of problems;
- Expedites turn on/off service;
- Identifies location of low voltage or other difficulties on the system in real time, enabling proactive maintenance that can avoid outages and verification of voltage complaints;
- Enables tailored energy efficiency programs that show customers how their usage compares to similar residences in their neighborhood, which has been demonstrated to be a powerful tool to help customers understand and moderate their power usage;
- Assists with more accurate planning data for the utility by identifying parts of the distribution network that need refurbishment or could benefit from alternative technology, such as microgrids or storage;
- Shares data for status of DER, such as rooftop solar, allowing for better planning of how to support variable energy sources;
- Shortens power outage time by enabling the utility to rapidly identify and limit the scope of the outage area, with limited intrusion to customers.

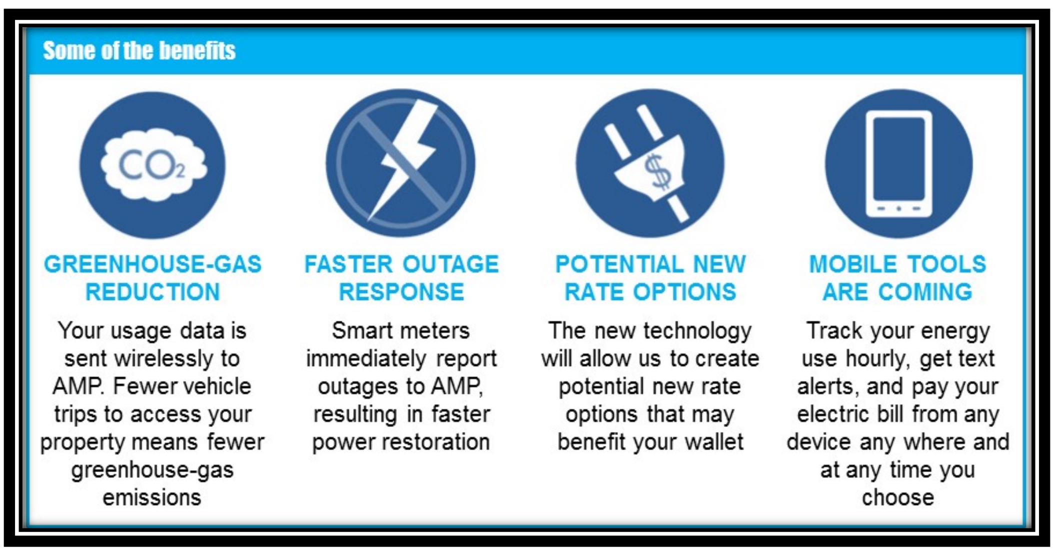

Figure 9: Benefits of Advanced Meters. Source: LBNL to DPUC, 2017

AMF's Indirect Services and Benefits

AMF is a tool that benefits customers and utilities directly and it is also a vehicle that can support additional technology thereby enabling additional indirect benefits for the customer, utility and the environment. The following is not an exhaustive list, but can indicate the important technology that is supported by AMF. In many cases, optimization of this technology will require time of use rates, or some other pricing system.

Enables Demand-Side Management - Demand-side management is when the utility or a third-party provider provides an incentive for customers not to use power at expensive high peak times. In the commercial and industrial sectors, the savings to the customer and the utility can be significant. It can also integrate with household systems to lower peak times by controlling thermostats and certain appliances remotely. For instance, a dishwasher can be programed to turn on outside of peak hours, thereby saving money.

Increases Distributed Generation Capacity - Smart meters can enable different sources of energy, from residential rooftop solar, to larger photovoltaic solar arrays, including community solar programs, wind farms, combined heat and power, renewable biomass, or other sources of energy that are not large centralized power plants. The more modern grid can support these different sources of energy, which can provide more choices for customers.

Supports Deployment of Energy Storage - Storage systems help shave peak load, provide ancillary services to the grid such as voltage control, and enable more variable renewable energy to the system by backing them up when the sun and wind are not available. They can be thermal or mechanical, as found in dedicated batteries, electric vehicles (EVs), and other beneficial electrification units such as heating.

Upgrades Legacy Infrastructure - As the internet of things (IoT) and enterprise big data emerge and as Rhode Islanders demand more bandwidth, the existing network infrastructure will not be able to meet the connectivity needs of businesses and residents. By investing and leading in the development of next generation networks, the state can attract, retain, and grow businesses by providing the internet bandwidth they need.

Development of Civic Internet of Things and the Smart Grid - The emergence of the civic internet of things will have a host of applications for improving the lives of Rhode Islanders, including enabling a smart grid that can maximize the efficiency of energy in the state to save ratepayers money, increase energy efficiency, and decrease outages. Figure 10 illustrates the advances in advanced meters due to increased internet connectivity. To take advantage of this, the state will need next generation networks that can handle significantly more data, with lower latency, and lower costs per bit.

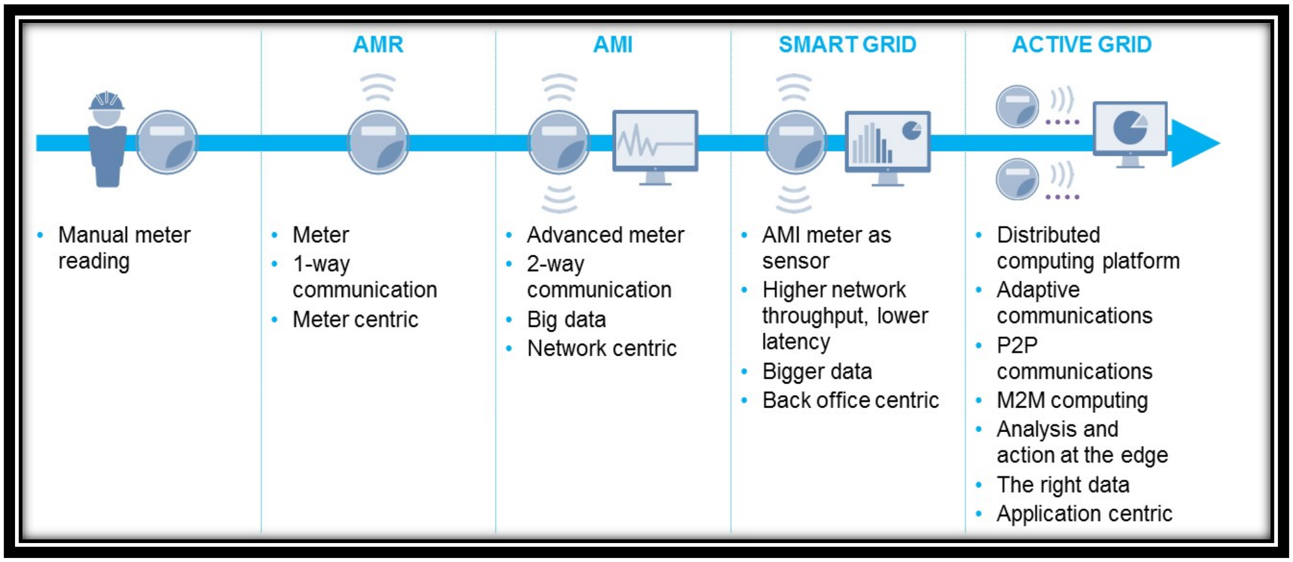

Figure 10: Electricity Meter Advances with Internet of Things
Source: Itron in presentation to PUC and DPUC, June 15, 2017

Ubiquitous Access to High Speed Connectivity - Investment in next generation networks will provide a critical opportunity to both close the adoption gap among low-income Rhode Islanders and the remaining last mile access gaps in areas such as Block Island. Currently, 26% of Rhode Island households are still disconnected from high speed internet and as a result face a digital equity gap limiting their educational and economic opportunities. Ubiquitous connectivity will improve the quality of life and economic opportunities available to Rhode Islanders.

Residential Technologies that Communicate with Grid-edge Devices - There are a number of devices that can communicate with grid-edge devices and control platforms to provide greater customer choice and value. These may be owned by parties other than the utility or the customer. Among these devices are: programmable thermostats, irrigation and lighting controllers, pool filter pump controllers, entertainment systems, routers, cable boxes, smart TVs, security systems, intrusion detection systems, fire alarms, washers and dryers, dishwashers, refrigerators and freezers, and home energy management systems that can reside on security and entertainment system platforms.

Context on the Interconnectivity of Residential Internet and Grid Connectivity

Consumer Demand and Connectivity. The U.S. economy is increasingly shifting from producing goods to producing knowledge and services. For a knowledge economy, broadband is the commons of collaboration and it is critical that the cost and availability of bandwidth in Rhode Island never constrains economic or social progress. To ensure that our residents enjoy the benefits of affordable, abundant bandwidth, the State, as well as its municipalities, wish to work with all stakeholders to accelerate, and lower the cost of deployment and operation of next generation broadband networks.

Equity and Access. One of the greatest challenges for our existing communications infrastructure is ensuring equal access to all communities urban and rural, rich and poor. Any future network buildout must address these issues proactively to be viable.

Risk of Duplicative Infrastructure. As the demand for communications capabilities on all types of infrastructure increases, there is a risk of overlapping and duplicating communications infrastructure, which could increase costs for consumers and ratepayers alike. As the steward and architect of the electric distribution system, the electric utility occupies a central place in the changing power sector. At the same time the ubiquity of electricity infrastructure, and its growing need to support two-way information flow, make it an excellent candidate to lead the rollout of shared next generation wireless infrastructure for the current and future needs of infrastructure operators and consumers.

Utility Business Model. The traditional regulatory model for electric utilities, in which the electric utility earns a return based largely on the cumulative value of the prudent infrastructure it has deployed, may exert an “infrastructure bias” to deploy capital-intensive solutions. As DER and grid control technologies offer new opportunities to provide reliable service at low cost, the impact of this infrastructure bias on ratepayers will grow. Topical incentives may correct this infrastructure bias. As corrective incentives become more widespread a broader evaluation may be needed. This issue is discussed at length in the affiliated chapter on Utility Business Model Principles and Recommendations.

Risk of Technology Obsolescence. The electric system of the twenty-first century will be asked to deploy a range of new technology systems and to manage the risk of technology obsolescence, creating new challenges for the current business model in which operational costs are usually recovered directly based on a prudency test.

Cybersecurity. Grid modernization provides an opportunity to address existing cyber security issues and also raises new issues. The utility is increasingly in need of detecting, responding and recovering from cyber threats as well as addressing customer data protection with new generations of distributed cryptography. With respect to detection, response and recovery, having redundancy of systems to narrow the surface of potential attack is important. As discussed in the Utility Business Model chapter, the key is outcome-based, not technology-based.

Advanced Meter Firewall Location Defines the Grid Edge. Equipment and firewalls need to have the following characteristics:

- Firewalls need to clearly limit physical and informational access;
- Future solutions will need to be layered, as applications will need to be replaceable without adversely affecting other applications;
- Layers will need to have well-defined interface with neighboring layers;
- Equipment controls need to be software-based, remotely fixable, and able to be upgraded without the need to go into the meter to change them;
- Communications protocols need to be secure at every layer

Desired Network Characteristics

Stakeholders across industry generally agree that the key network characteristics of next generation networks in Rhode Island include the following:

Leverage Existing Infrastructure - The next generation networks should leverage existing network infrastructure rather than build redundant infrastructure side by side. Rhode Island is already one of the most broadband-ready states in the nation with an extensive fiber backbone and high speed broadband available to 98% of Rhode Islanders. This fiber has the capacity to and will provide the backhaul for Next Generation networks. By leveraging this infrastructure, next generation networks can be constructed in Rhode Island in a more cost-effective and timely manner.

Small Cells and Network Densification - Network densification is the process of adding more cell sites to increase the amount of available capacity. It will be a major component of next generation networks in Rhode Island. This includes the construction of a heavy concentrations of small cells and the continued development of macro-cell sites. This will create the ultra-dense network configurations, particularly in metro areas that will be foundational to technologies such as 5G.

Last Mile Connectivity - Investment in next generation connectivity should be used to provide last mile connections in Rhode Island so that every Rhode Islander has access to high speed connectivity.

Public Policy Considerations for "Future-Proofing" Internet Connectivity

In order to effectively plan for the rapidly approaching future of connectivity and avoid shortsighted investment, this section explains public policy considerations relevant to the existing broadband and communication technologies coming down the pipeline.

Legacy Systems Are a Cybersecurity Problem. Legacy systems are inherently insecure because they were not built to be secure against the serious cyber security threats that we face today. As a result, cybersecurity solutions for connectivity and the grid are an afterthought rather than a critical function of our grid and networks. In the construction of next generation networks, cyber security must be baked into the design and incentives must be put into the marketplace to prevent consumers from compromising network security.

Sharing Electric, Water, Transportation and Internet Connectivity. The opportunity exists to leverage the connectivity needs of the public sector and utility providers to bring additional value to broadband investments without compromising the safety and security of sensitive data. This could allow us to efficiently and cost effectively reach rural and sparsely populated areas. Similarly, the opportunity exists to develop a single set of connectivity assets to serve a range of infrastructure sectors, such as water, electricity, and transportation. Realizing the opportunity of new information and communication technologies will require electric utilities to leverage data communications systems, potentially through some form of partnership with firms in the data communications industry.

Focusing on Software Rather than Hardware. The advanced meter functionalities can largely be achieved by the software applications that are installed on top of the meter hardware. Therefore, government can mitigate the risks of technological obsolescence by focusing investments on the basic hardware and network functions needed to enable software systems, or applications, to be installed. As illustrated in Figure 11 below, the physical meters and network are the base levels needed and the software applications are where the majority of innovation is occurring for modernizing the grid.

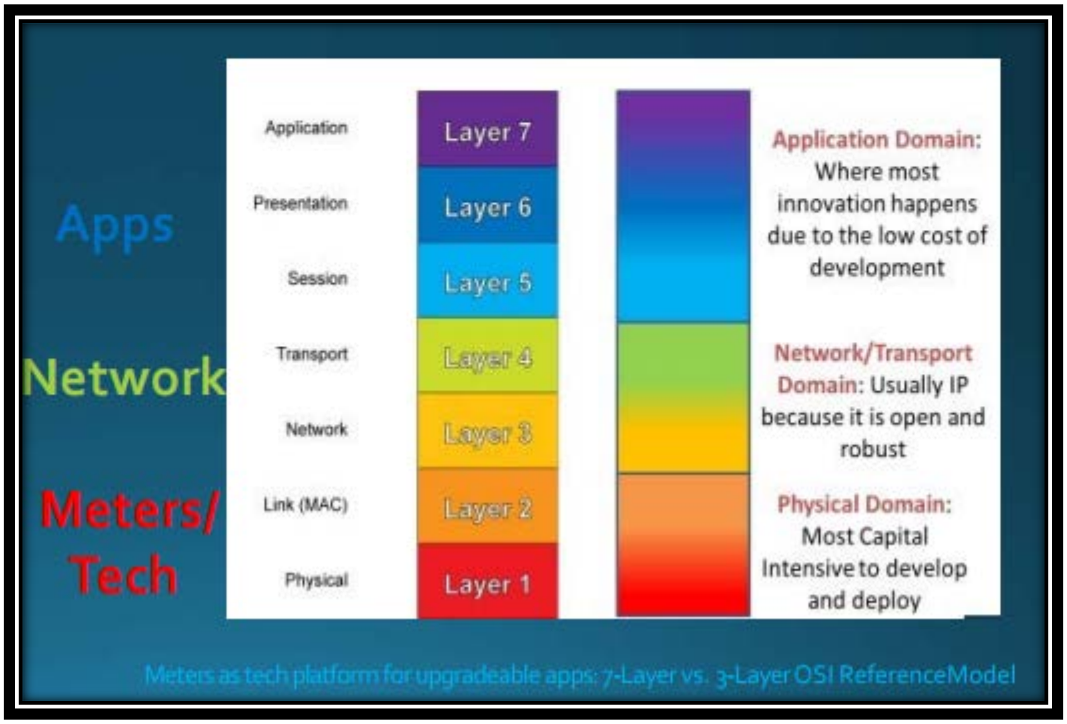

Figure 11: Meters as Technology Platform for Upgradeable Applications. Source: LBNL

Need for Innovation in Ownership & Access Models

The interrelated public policy considerations listed above highlight the reason there is a need to consider new models of cost-sharing for the risks and benefits of the underlying enabling technology. The pace of regulatory change is generally slower than changes in technology. As such, we must ensure that customers are not paying for quickly-obsolescent technologies, while also encouraging prudent and value-adding technologies. Technologies are becoming available and adopted by electric utilities at an increasingly rapid pace and yet sometimes system needs are changing more quickly than solutions are becoming available. For rapidly changing technology, there is never a right time to buy, as the next iteration will include features that are desirable. However, customers cannot be expected to pay for every new functionality. This is especially true of technology such as meters, which generally take some period of time to bring to every customer. Often, the earliest advanced meters to be installed are obsolete before the last of the customers are receiving the technology. In some states, the period of time that customers pay for advanced meter assets, through the regulated depreciation rate, has often been much longer than the actual rate of meters' usefulness. Furthermore, in many states, utilities deployed smart meters but did not deploy the energy services that are enabled by them, leaving customers with net losses.

Therefore, it is critical that policy proposals regarding technology, including AMF, need to describe the plan for avoiding this obsolescence, to give the consumer the benefit of technology as it evolves. The utility also needs to plan so that they do not strand their assets.

While there broad agreement on both the network characteristics of next generation connectivity in Rhode Island there are strongly diverging opinions on how this network should be built and who should own it. As a result, there are multiple models for ownership and access for regulators to consider when investing in next generation networks. Three primary models often discussed are:

Broadband as the Commons: This model imagines broadband infrastructure as a public utility that should be owned by the State and accessible to anyone. This would require public-private partnership between the State and a private sector firm. The State would own the infrastructure while the private sector would build and maintain this network. Proponents of this model believe that the government will serve as a neutral owner of infrastructure and will drive greater competition for service providers and more ubiquitous and equitable access.

Private Market Solution: This model sees the private market as continuing to be able to deliver the connectivity that Rhode Island needs with non-profits like OSHEAN filling in the gaps of service where it is not cost-effective for the private sector. In this model, existing telecom firms would build and operate the next generation networks.

Infrastructure/Utility Led Partnership: The connectivity needs of the electric grid, and other major types of infrastructure, would drive the utility to partner with a wireless service provider to expand and upgrade the existing wireless infrastructure. A cost-sharing agreement will be negotiated to support the benefits and risks to both the internet provider and utility.

Recommendations

The State's grid connectivity and functionality goals will guide the communications network and control technology investment for the coming decade to achieve the following goals: 1) greater connectivity; 2) two-way information flow; and 3) enhanced cybersecurity.

To accomplish these three policy goals, it is important that the utility achieve the following through the regulatory process:

2.1 Deploy advanced meters.

National Grid should develop an advanced meter roll-out plan to support two-way energy flow that includes: a business case, time-varying rates, implementation schedule and list of capabilities to be delivered in response to the PST initiative. The business case should describe potential scenarios for advanced meter roll out and include the meter infrastructure, time-varying rates, and data management components. Any advanced meter rollout plan must include protections for low income ratepayers as well as a platform upgrade model to protect all ratepayers from a growing obsolescence risk. The specific list of capabilities are listed in Appendix II.

2.2 Plan for third-party access and innovation.

National Grid should submit a plan for how advanced meter capabilities can be accessed by third-party providers, with proper privacy and security protections. This will include a list of known capabilities (i.e., load shifting, peak shaving) along with an aggressive implementation schedule driven by advanced meter penetration. It will also include a plan to provide third-party access to the advanced meter platform to deploy new grid facing and consumer facing applications.

2.3 Share the cost burden through partnerships.

National Grid should share communication infrastructure through partnership to reduce costs to ratepayers. This will include potential innovative partnership opportunities to use a shared communications network to supply connectivity to meters and other components of the automated grid to provide greater customer value. Piggybacking, expanding and accelerating the already planned deployment of advanced wireless networks by major carriers should significantly reduce capital costs for ratepayers. Such cost savings should be spelled out. Any such plans should also include an accounting of the efforts necessary to ensure the security of the connections against possible cyber incursions.

2.4 Focus on capabilities to avoid technological obsolescence.

Rather than address particular technologies, the regulatory process should advance a benefit-cost analysis for advanced meter capabilities using the categories established in Docket 4600 and based on a business case, making the utility responsible for technology selection risk. The utility should conduct an in-depth assessment of benefits and costs for each grid function identified by through this initiative and integrate the results in its business case. The desired capabilities for an advanced meter are summarized in the table found in Appendix II.

2.5 Proactively manage cybersecurity.

National Grid should meet with the Commission on at least an annual basis, and provide to the Commission a classified report, which explains their efforts to proactively detect, respond and recover from cyber threats. This should include an explanation of the layering of technology designed to accomplish the goal of preventing threats. This recommendation is also discussed in the Utility Business Model chapter.

PART III

DISTRIBUTION SYSTEM PLANNING

Distribution System Planning Principles & Recommendations

Introduction

The evolving energy system will place increasing demands on the electric utility beyond its traditional charge of maintaining the safe and reliable operation of the electric distribution system. Rhode Island has set ambitious goals for a resilient, affordable, and clean energy system, and the electric utility will play a central role in helping to facilitate this desired future. Distribution system planning (DSP) is at the heart of this effort.

DSP is a set of activities to assess the grid's performance under changing future conditions and recommend solutions to proactively address identified needs. Because the utility uses DSP to inform grid investment decisions, the results of the planning process impact the costs incurred on bills for delivery service and the value received from the electric grid.

Traditional utility infrastructure – substations, feeders, transformers, etc. – form the conventional set of solutions in the utility toolbox to address system requirements. In today's changing technology landscape, however, a diverse set of resources and strategies[18] – such as energy efficiency, renewable energy, energy storage, and dynamic electric rates – offer the potential to substitute for conventional infrastructure solutions. In many instances, these solutions may be financed, implemented, or owned by customers or third parties, as opposed to the utility. Although many of these solutions are not new, their pace of deployment is accelerating as falling technology costs drive maturing markets and broader consumer adoption.

This paradigm shift of increased customer and third-party investment on the electric grid could offer a variety of economic and environmental benefits including, but not limited to, the possibility of reducing the need for rate payer-funded distribution infrastructure projects. For example, under Rhode Island's SRP planning process, pilot projects have tested the ability for a variety of customer- and grid-side strategies – including energy efficiency, demand response, solar PV and energy storage – to defer the need for a substation feeder upgrade by providing load reductions coincident with periods of peak demand.

In other words, not only are customers and third parties[19] impacting the system in new – and potentially significant – ways, but they are also now able to become part of the solution set to address grid needs through their own investment choices. DSP, a process which identifies and characterizes areas of need on the grid, must adapt to changing technologies, markets, and policy and become a valuable tool for guiding not only utility investment, but also customer and marketplace activity, which can provide value to the grid and the system.

To provide critical guidance to clean energy deployment and customer investment decisions, DSP can leverage a new and growing availability of data. The ongoing modernization of the electric grid includes

[18] E.g., DER, but also technologies and strategies including dynamic rate designs and grid-side optimization technologies.
[19] E.g., DER providers.

deployment of devices that yield significant amounts of data about the time, location, and magnitude of electricity consumption and flow. Data pertaining to the electric grid may include customer-specific data emanating from a customer meter or system data emanating from devices located on the grid to monitor the reliability and operation of the electric distribution system. Looking ahead, the abundance of customer and system data – with the proper security and privacy protections in place – offers an opportunity to guide investment decision-making by customers and third parties in addition to utilities.

In summary, in the past, the utility would use DSP to identify system needs and implement infrastructure solutions. In the future, the utility will use DSP to reveal value opportunities on the system and source DER solutions from the marketplace, and implement infrastructure projects where third-party providers cannot meet system needs.

Accordingly, the Division and OER recommend the following long-term vision for DSP in Rhode Island: DSP will cultivate and make available an abundance of system and customer data – subject to the appropriate privacy and security protections, and working toward real-time provision of data – in order to identify and reveal spatiotemporal value on the system and guide investment decisions by the utility, customers, and third parties.

Regulatory Context

In Rhode Island, the current DSP practice at National Grid is based on the following elements:

- **Forecasting,** where energy demands are projected to determine future system peak requirements;
- **System assessment**, to test whether the existing system can accommodate forecasted demands and maintain voltages within established standards, and to determine the health of system components and develop replacement strategies before failure; and
- **Solution identification**, where options are selected to address identified needs – the solution could be an operational change by the utility operator (e.g., reconfiguring a feeder), a traditional utility infrastructure project (e.g., a new feeder), a "non-wires" alternative (e.g., customer investments in energy efficiency, renewables, or storage), or a combination of any of the above.

National Grid undertakes these DSP activities in order to develop investment plans for maintaining safe and reliable service in Rhode Island. Today National Grid's DSP process supplies information to two distinct planning and investment processes: (1) The Infrastructure, Safety, and Reliability Plan (ISR), and (2) The System Reliability Procurement Plan (SRP).[20] The costs of infrastructure projects are recovered in the ISR; the costs of implementing NWA solutions are recovered in the SRP.[21] The ISR and SRP are considered in separate dockets, filed annually with the Commission, however, each has its own distinct

[20] ISR: http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-1/39-1-27.7.1.HTM; SRP: http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-1/39-1-27.7.HTM

[21] The SRP Standards include a broad and inclusive list of eligible NWA, including but not limited to strategies such as energy efficiency, demand response, distributed generation, energy storage, time-varying rates, voltage management, and grid optimization technologies. See pages 11-12: http://www.ripuc.org/eventsactions/docket/4684-LCP-Standards_7-27-17.pdf

planning cycles.[22] This dichotomy can result in siloed processes among stakeholders and within the utility and is an obstacle to holistic assessment of how National Grid should best implement DSP.

Although National Grid screens all capital projects for NWA eligibility according to a set of suitability criteria outlined in the SRP Standards,[23] few NWA opportunities have been identified, and investment in traditional utility infrastructure solutions has dwarfed investment in NWA solutions in recent years, as illustrated in Figure 12.

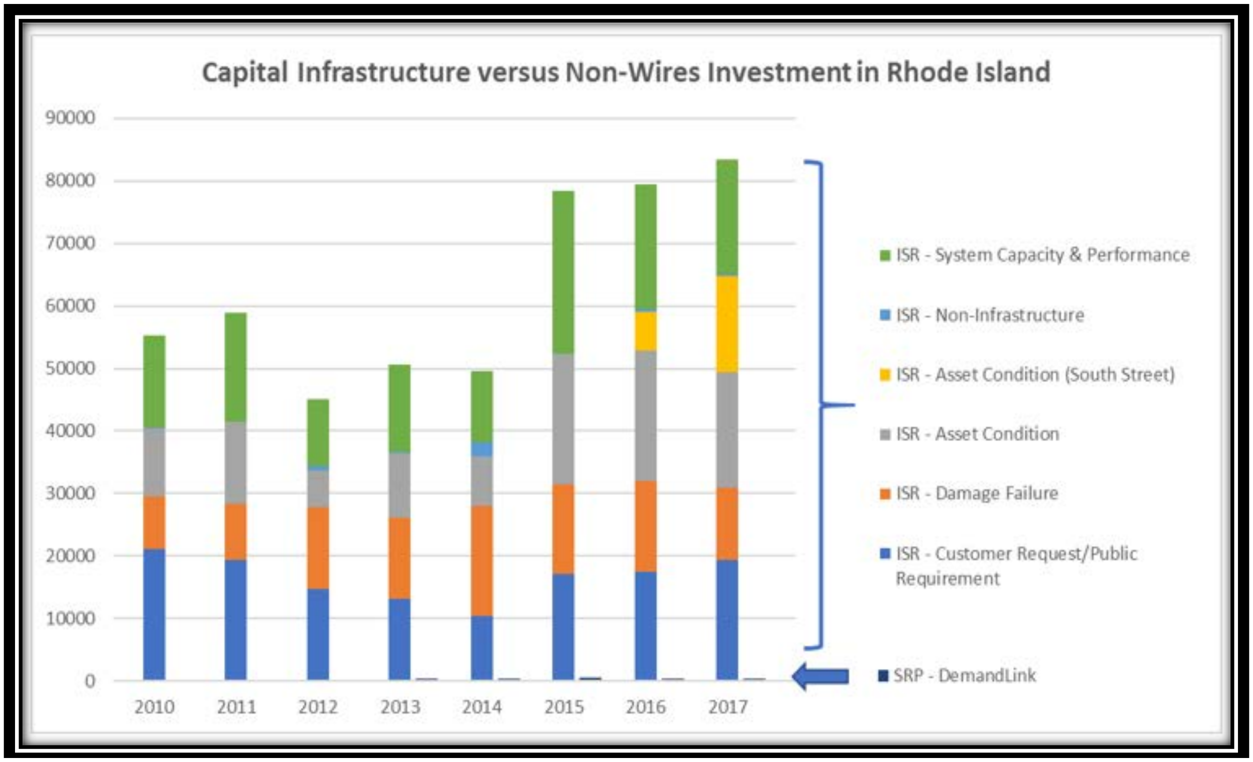

Figure 12: Infrastructure Versus Non-Wires Investment in Rhode Island (2010 to 2018). Source: OER, 2017

*Sources: FY2018 Infrastructure, Safety, and Reliability Plan, Section 2, page 9 of 43 (*http://www.ripuc.org/eventsactions/docket/4682-NGrid-Elec-ISR-FY2018_12-21-16.pdf*); 2017 System Reliability Procurement Report, Page 13 or 29 (*http://www.ripuc.org/eventsactions/docket/4655-NGrid-SRP2017(10-17-16).pdf)

A variety of reasons have been cited to explain the limited opportunities for NWA to date. National Grid has indicated that the vast majority of capital projects are driven by an asset condition[24] need (for which NWA are ineligible) due to the aging nature of Rhode Island's distribution infrastructure. Additionally, due to the success of the state's nation-leading energy efficiency programs, electricity consumption has

[22] ISR: http://www.ripuc.org/eventsactions/docket/4682page.html; SRP: http://www.ripuc.org/eventsactions/docket/4655page.html

[23] The SRP Standards guide implementation of the System Reliability provisions of the Least-Cost Procurement statute and are available at: http://www.ripuc.org/eventsactions/docket/4684-LCP-Standards_7-27-17.pdf

[24] Asset condition refers to the susceptibility of distribution infrastructure equipment to failure, malfunction, or otherwise compromised performance (often due to age) that could impair safe and reliable service to customers.

flattened, presenting limited opportunities for deferral of load growth-related investments. As illustrated in Figure 12, however, significant capital investment persists to address system capacity issues (i.e., circuit peaks driven by load growth). According to National Grid, many of these projects address an asset condition issue in tandem with a load issue, which can be viewed as representing bargain value for ratepayers.

In recent years, regulatory updates have sought to address the aforementioned challenges and broaden consideration of NWA. A 2017 update to the SRP Standards encouraged an expanded focus on new NWA applications beyond the primary focus to date on load growth-related issues. Potential NWA applications include addressing voltage performance, reactive power compensation, and constraints related to DER. These changes align SRP more consistently with salient distribution system cost drivers in Rhode Island, where in the context of flat load growth, system capacity issues are increasingly taking a backseat to contingency-related considerations. Additionally, the updated SRP Standards introduced the concept of a "partial NWA," which would be used to reduce the scope of a traditional utility investment, rather than deferring the entire project. For example, in an instance where a capital project is proposed to address a system capacity need in tandem with an asset condition need, a partial NWA should theoretically address the system capacity component. (To date, no opportunities for partial NWA have been identified.) Finally, the updated SRP Standards included a proposal to add a new "heat map" approach to NWA, where planners can proactively target "highly-utilized" areas of the distribution system with NWA to extend the life of existing equipment. Such highly-utilized areas are locations where no infrastructure projects have been proposed yet, but improvements will likely be needed in the future.

Given where Rhode Island currently stands with DSP, the following principles should guide implementation of DSP reforms to achieve the long-term vision stated above.

Principles for DSP Reforms

- DSP reforms should establish clear and specific intermediate milestones to achieving the long-term vision, guided by National Grid's growing sophistication in DSP data analytics and enabled by increasing visibility into the system due to improvements in grid connectivity and functionality.
- National Grid should identify the required resources – staff, information systems, or otherwise – necessary to achieve material improvements to DSP capabilities and achieve the long-term vision, and include investments in such resources in its rate case filings. National Grid should view DSP as a critical function and key center of investment of Company resources.
- For all DSP reforms, there must be an ongoing process for meaningful review, input, and update of DSP products including, but not limited to: forecasting, data access, DSP data portal, and heat and hosting capacity maps.
- As DSP reforms drive increased customer and third-party access to data, National Grid and regulators must address all key data privacy and security protections.
- Implementation of DSP reforms should achieve consistency across all programs and policies. For example, operationalization of heat maps and locational incentives should be implemented uniformly across all energy efficiency, DER, NWA, and capital planning and procurement processes.

Recommendations

To achieve the long-term DSP vision, the Division and OER propose four reforms to DSP in Rhode Island:

- **Coordinated DSP Filings**;
- **Forecast Improvements**;
- **Customer and Third-Party Data Access**; and
- **DER Sourcing and Compensation**.

Coordinated DSP Filings

To date, National Grid has performed DSP entirely in house. Stakeholders and regulators have gained occasional glimpses into DSP activities through Commission docket proceedings such as the ISR and the SRP dockets. The need for more open engagement with DSP, however, will only increase in importance as DER growth in Rhode Island accelerates. Existing filings such as SRP and ISR offer useful platforms for building more transparency into key DSP-related activities such as forecasting, customer and third-party data access, and DER sourcing and compensation. These dockets can serve as coordinated vehicles to house ongoing DSP policy deliberation and stakeholder engagement.

Additionally, both SRP and ISR represent critical and complementary areas of utility investment. In principle, the Commission and stakeholders should be able to consider investments made in both these processes in an integrated manner. Achieving closer integration of these two efforts should also advance the utility's ability to align internal teams and achieve further synchronization between capital and NWA planning. There may be regulatory and/or statutory considerations to work through to better achieve this objective, however, in the near-term, simply coordinating filing times may result in better outcomes.

3.1 Synchronize filings related to Distribution System Planning.

National Grid should begin filing the ISR and SRP as two linked, synchronized, and cross-referenced DSP filings each year. Linking these two filings and including key DSP-related content will: (1) provide increased transparency and a codified mechanism for stakeholder and regulatory input into the improvement of DSP analytics and tools over time, and (2) enable the Commission and stakeholders to consider investments proposed in the ISR and SRP in a comprehensive and holistic manner. Coordinating these filings should account for the sequencing necessary by National Grid to develop the plans, including considerations related to the differing planning horizons associated with infrastructure projects versus NWA. ISR/SRP filings should include the following elements:[25]

- Methodologies, assumptions, and results of the annual forecasting process;
- Any amendments to customer and third-party data access plans and procedures;
- Proposed updates to the Rhode Island DSP Data Portal based on stakeholder input; and
- Description of updates and improvements to publicly-provided datasets such as heat and hosting capacity maps.

[25] Further information and minimum requirements for each of these elements are spelled out in the sections below.

Forecast Improvements

National Grid develops a peak load forecast for its Rhode Island service territory on an annual basis. This forecast is important because distribution planners assess current and future system needs based on models which incorporate this forecast as an assumption. This in turn affects capital planning decisions, recommended levels of investment on the system, and finally, costs borne by ratepayers.

The current model of a statewide forecast of peak hour net demand is not sufficient for future DSP with high levels of DER. With more DER on the system, forecasts will need to become increasingly granular. This is because the impact of a DER installation on the distribution system will depend on where it is located on the system as well as the unique operating characteristics of the specific DER technology. While National Grid currently takes into account some forecasted DER (e.g., energy efficiency and expected amounts of DER from renewable programs), there may be a need to more fully account for the impacts of state policies and goals in forecasting (e.g., increasing electrification of heating and transportation). Additionally, whereas traditional forecasting techniques have tended to focus on addressing system needs at the peak, in the future, net demand in shoulder months may also stress the grid and threaten curtailment of renewables. These conditions will be of increasing interest in forecasting.

New approaches to enhance forecasting in a high-DER future should include scenario analysis and probabilistic planning. Scenario forecasts consider a range of possible futures where varying levels of DER are adopted on the system. Probabilistic planning, as opposed to the current deterministic approach, would account for uncertainties introduced by factors including increasing DER penetration and weather variability.

3.2 Improve forecasting.

National Grid should include detailed information on its forecasts used for DSP in annual SRP/ISR filings. Inclusion of forecasts within the SRP/ISR filings will provide regulators and stakeholders with the opportunity to provide ongoing review and feedback. In addition, National Grid should implement a robust stakeholder engagement plan during forecast development to provide policymakers and third parties the opportunity to review and provide input on forecasting assumptions and methodology. Forecasting information in future filings should include the following elements:

- Description of current process for developing forecasts. National Grid should describe the following information:
  - What information/metrics do forecasts contain?
  - How are these forecasts used in DSP and how do they affect capital and NWA planning?
  - What are the limitations of current forecasting techniques and, in particular, what impact will increased DER penetration have on the forecasting process?
  - What improvements are needed to forecasting to achieve the objectives of PST and why? How will new DER-related factors be reflected in forecasting?
- Description of process for reassessing forecasting as technologies and data-gathering capabilities improve. National Grid should describe the following information:
  - What information/metrics should forecasts contain going forward as technologies and capabilities improve?
  - How will the utility ensure accuracy of forecasts as DER penetration levels increase?

  - What role should scenario analysis and probabilistic planning play in forecasting and DSP? In other words, how would scenarios inform planning?

Customer and Third-Party Data Access

Access to data – system data and customer data – could help customers and third parties contribute towards meeting grid needs and maximizing the net benefits of their investments in clean energy technologies.[26] For example, clean energy companies might be able to use information on the location and characteristics of grid needs to target offerings to customers located in beneficial areas. The ability to retrieve customer data – with the proper privacy and security protections in place – could allow clean energy companies to tailor offerings to customers or for customers themselves to take action on their energy use.

National Grid should develop data sharing procedures to make key system and customer data available to customers and third parties. Third parties may include, but are not limited to: DER providers and other private energy technology companies; regulators and policymakers; researchers and academics; and local governments. Each of these users may have unique needs, interests, and requirements for datasets, as well as specific use cases for certain datasets they would like to obtain. Enhancing data access should enable customers to more effectively implement solutions to their own energy needs, as well as guide informed investment by DER providers and thereby help the market provide optimal value to customers and the system. The Division and OER have identified low-cost, low-risk improvements to data sharing – with privacy and security protections – that can be implemented in the near term. These initial steps should provide learnings that will inform a thoughtful approach to long-term data access strategy.

3.3 Establish customer and third-party data access plans.

National Grid should include and seek approval of a plan for establishing and improving customer and third-party data access in the upcoming rate case. Updated data access plans should be included in future annual SRP/ISR filings.[27] Inclusion of data access plans within the SRP/ISR filings will provide regulators and stakeholders with the opportunity to provide ongoing review and feedback. These plans should include the following elements:

System Data

- Description of data types to be provided
  - Existing Datasets: National Grid should provide an up-to-date, comprehensive inventory of datasets (system data) that it already collects and provides through existing filings, web pages, or other means. National Grid should indicate the location, format, and frequency of update of these datasets, as well as any fee structure currently in place for third-party access.

[26] For a good overview of the policy and market benefits of data access, see the following report, starting on page 4: http://scholarship.law.berkeley.edu/cleepubs/17/

[27] The utility should also file any necessary tariffs for data services and fees associated with providing value-added system and customer data.

- Near-Term Datasets: National Grid should develop specific, near-term, new datasets of importance to DSP objectives – hosting capacity maps and heat maps:[28]
  - A hosting capacity map identifies any substations on the utility's distribution system that cannot host additional DER (DG and EV), due to system constraints. The map, or set of maps, should provide information for a time span into the future consistent with National Grid's planning horizon.
  - A heat map (i.e., distribution constraint map) identifies the extent to which each substation on the utility's system is constrained. The map, or set of maps, should provide information for a time span into the future consistent with National Grid's planning horizon.
- Future Datasets: Using the lists of system data provided in the Northeast Clean Energy Council (NECEC) stakeholder comments[29] and the New York Supplemental Distributed System Implementation Plan (DSIP)[30] as starting points, National Grid should engage DER providers to propose a schedule for provision of new datasets over time. National Grid should work with DER providers and regulators to define use cases[31] for future datasets and receive input on data formats and prioritization. The schedule should be informed by National Grid's ability to collect and generate new datasets when enabled by implementation of advanced grid connectivity and functionality.

- Description of how data will be made available to users
  - Data Portal: A new Rhode Island DSP Data Portal[32] should serve as a clearinghouse for users to access key distribution system and planning data in a central and publicly-accessible online location. Peak/load forecasts, capital plans, DSP process descriptions, heat maps, hosting capacity maps, and other key data should be made available through the Portal. Where possible and appropriate, data should be made available in machine-readable format. Annual reporting on Portal performance should occur through the SRP/ISR and include tracking of key user experience metrics, evaluation of qualitative and/or quantitative costs and benefits, stakeholder feedback, and any proposed improvements.

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[28] Hosting capacity analysis determines the maximum amount of DER that a substation feeder can support without additional upgrades. Heat maps show where DER can help address system needs such as load growth or voltage regulation in areas such as highly-utilized feeders in order to prolong the useful lifetime of existing systems. Hosting capacity maps provide a complementary benefit to heat maps: whereas heat maps reveal where DER can help address problems (e.g., by reducing congestion or peak loads on an overloaded feeder), hosting capacity maps show where DER can avoid creating problems (e.g., by indicating where there is sufficient "headroom" for DER to interconnect without spurring the need for incremental system investment). Hosting capacity maps can help streamline interconnection processes and create an environment that encourages the addition of DER to the grid, in line with Rhode Island's state policy objectives. Heat maps could help direct third-party investment toward areas on the grid where DER can help reduce, defer, or avoid conventional utility infrastructure projects.

[29] See pages 6-8: http://www.ripuc.ri.gov/utilityinfo/electric/PST_DSP_SC_1.pdf

[30] See pages 127-133: http://jointutilitiesofny.org/wp-content/uploads/2016/10/3A80BFC9-CBD4-4DFD-AE62-831271013816.pdf

[31] See for example: http://jointutilitiesofny.org/wp-content/uploads/2017/09/Joint-Utilities-of-New-York-Summary-of-System-Data-Stakeholder-EG-Meeting-08-17-2017-Draft-v.2.pdf

[32] See National Grid's New York System Data Portal for a model: http://ngrid.maps.arcgis.com/apps/MapSeries/index.html?appid=4c8cfd75800b469abb8febca4d5dab59&folderid=8ffa8a74bf834613a04c19a68eefb43b

        - All existing datasets should be provided on the Portal by a date determined by regulators in consultation with National Grid and stakeholders.
        - All near-term datasets should be provided on the Portal by a date determined by regulators in consultation with National Grid and stakeholders.
    - Data Requests: Initially, decisions on the inclusion of new datasets in the Portal should be considered on an annual basis through SRP/ISR filings. After evaluating initial experience and success of the Portal, the Commission should consider the merits of National Grid building capabilities to field on-demand data requests submitted by third parties through a standardized application, built-in form on the DSP Data Portal, or another appropriate formalized process.[33]
- Description of conditions when the utility should be able to charge for data
    - Value-Added Data: National Grid should be able to charge market rates to third parties in exchange for developing and providing "value-added" data. National Grid should work in consultation with stakeholders to make a proposal to regulators on guidelines for what datasets should be subject to charge and what fee structures might look like. As a general rule, there should be no charge for third parties to access data produced as a matter of normal course of business at the utility. However, if there is additional processing required to create the data, consideration of a cost-based charge may be warranted. Once guidelines for value-added data are determined, summaries of types of value-added datasets and associated fee structures should be published on the Portal.
- Description of data security measures
    - Data Security: National Grid should highlight any security concerns and propose adequate security protections for data sharing.

Customer Data

- Description of customer rights to data
    - Individual Customers: All customers should have the right to access their own usage and billing data for free in an easily-organized and standard format (e.g., consumption data for each rate element used for billing on the monthly statement, consumption during peak-time events [once enabling metering is in place]).
    - Third-Party Authorization: Customers should be able to authorize third-party access to their data.
- Description of data types to be provided
    - Existing Datasets: National Grid should provide an up-to-date, comprehensive inventory of datasets (customer-specific data as well as aggregated customer data) that it already collects and provides through existing filings, customer accounts, billing, subscription services, or other means.[34] National Grid should indicate the location, format, and

[33] As Rhode Island gains experience with data sharing over time, the utility may need to respond to an increasingly diverse array of third-party data requests. If an on-demand system of data requests is implemented, the utility may be in the position of interpreting established guidelines to determine whether an individual third-party data request is subject to charge and what the requisite fee is. Regulators will need to consider how to ensure fair treatment of individual on-demand data requests, recourse for the requester, and dispute resolution.

[34] Subscription services, e.g. Energy Profiler Online™: https://www9.nationalgridus.com/narragansett/business/programs/3_energy_profiler.asp

frequency of update of these datasets, as well as any fee structure currently in place for access.

- Aggregated Customer Data: National Grid should make available a basic set of uniform aggregated customer datasets at no charge: monthly kW and/or installed capacity, customer counts, and kWh data aggregated by zip code and/or tax district, and segmented by rate class. For rate classes with time-of-use periods, kW and kWh data should be aggregated by time-of-use periods and in total.
  - All aggregated customer datasets should be provided by a date determined by regulators in consultation with National Grid and stakeholders.
- Future Datasets: National Grid should engage DER providers to identify any additional customer-oriented datasets of value and propose a schedule for provision of new datasets over time. National Grid should work with DER providers and regulators to define use cases[35] for future datasets and receive input on data formats and prioritization. The schedule should be informed by National Grid's ability to collect and generate new datasets when enabled by implementation of advanced grid connectivity and functionality.

- Description of how data will be made available to users
  - Methods and Tools: National Grid should indicate methods and/or tools currently in place to support the exchange of customer-specific and aggregated customer data. National Grid should propose tools that will be developed to make these data more easily accessible and/or retrievable on a more real-time basis.[36] Minimum requirements for data sharing methods include:
    - Capability to transfer granular usage data in machine readable format.
    - Implementation plan for "Green Button Connect My Data," an existing trademark-protected industry standard protocol for customers to obtain and share their granular usage data with authorized third parties.
    - Ability to supply usage data in "real-time" or "near real-time" once AMF infrastructure is in place.
- Description of conditions when the utility should be able to charge for data
  - Value-Added Data: National Grid should be able to charge market rates to third parties in exchange for developing and providing "value-added" data. National Grid should work in consultation with stakeholders to define guidelines for what datasets should be subject to charge and what fee structures might look like. As a general rule, there should be no charge for third parties to access data produced as a matter of normal course of business at the utility. However, if there is additional processing required to create the data, consideration of a cost-based charge is warranted. Once guidelines for value-added data are determined, summaries of types of value-added datasets and associated fee structures should be published.
- Description of data privacy measures
  - Privacy / Aggregation Standard: Aggregated data is data that have been summed or combined across a group of multiple accounts in order to preserve individual customer privacy. In order to appropriately protect customer privacy, National Grid should propose an aggregation or privacy standard to be used for supplying whole-building aggregated

[35] See for example: http://jointutilitiesofny.org/wp-content/uploads/2017/09/Joint-Utilities-of-New-York-Summary-of-System-Data-Stakeholder-EG-Meeting-08-17-2017-Draft-v.2.pdf

[36] Examples of data sharing platforms for customer data may be found on page 138: http://jointutilitiesofny.org/wp-content/uploads/2016/10/3A80BFC9-CBD4-4DFD-AE62-831271013816.pdf

energy data to building owners or their authorized third-parties. National Grid should adopt as a starting point the 4/50 privacy standard for aggregated data adopted in New York, which would require data to be drawn from a minimum of four accounts and limits the load of any single account to less than 50% of the total load for the dataset. National Grid should indicate, however, whether there are any unique features to Rhode Island's grid or customer profile that would merit a more flexible standard or require a more stringent one.

DER Sourcing and Compensation

Deployment of DER on Rhode Island's distribution grid will impact performance of the system. In some cases, DER may provide value – for instance, by reducing local peak loading and deferring the need for infrastructure investment. In other cases, DER may impose costs. In other words, the value of DER will vary according to when and where operation of the DER occurs on the system.

A goal of PST is to control the long-term costs of the electricity system. Directing DER toward locations where such investments provide more value to the system is an important means of achieving this policy objective.

To date, Rhode Island has incentivized the system-wide development of DER with only limited experience to date on incentivizing DER in beneficial locations or at beneficial times (e.g., the Tiverton/Little Compton SRP Pilot). In the future, a variety of programmatic and market mechanisms should be used to direct DER development to optimal locations and encourage performance at times of grid need. Broadly referred to as "locational incentives" or "value of DER," specific methods of sourcing and compensating DER are: pricing, programs, and procurements. According to ICF International,[37] these may be defined as:

- Prices – DER response through time-varying rates, tariffs and market-based prices
- Programs – DER developed through programs operated by the utility or third parties with funding by utility customers through retail rates or by the State
- Procurements – DER services sourced through competitive procurements

3.4 Compensate locational value.

State policymakers and regulators should develop an implementation strategy for locational incentives/value of DER in Rhode Island, in consultation with National Grid and stakeholders. The strategy should address the following components:

- Identify locationally-varying value components of interest
    - For each kWh generated (or other unit of performance), a DER produces a set of value components. Value of DER inquiries typically investigate and develop methodologies to

[37] See page 18: https://energy.gov/sites/prod/files/2016/09/f33/DOE%20MPUC%20Integrated%20Distribution%20Planning%208312016.pdf

quantify these different value components, or "value stack," of DER. Some of these values, such as avoided capacity or environmental attributes, do not vary locationally (within the distribution system). Others, such as distribution system avoided costs, do vary locationally.
    - The Docket 4600 Benefit/Cost Framework provides a comprehensive list of the value components of distribution system and/or DER investments. It can be used as a basis for considering the value of DER question.
- Describe how beneficial locations are identified
    - Once the locationally-varying value components of interest are identified, beneficial locations on the distribution system must be identified. Beneficial locations would be areas where services of interest – such as peak load reduction or voltage regulation – are needed, and DER that could provide these services would provide value. By providing peak load reduction, for instance, DER could avoid distribution capacity costs.
    - Two candidate paths for identifying beneficial locations in Rhode Island should be evaluated:
        - <u>Annual screen</u>: An annual "Excel-based" screen of National Grid's feeders. This screen can sort feeders according to basic parameters such as % loading, asset condition, and expected load growth.
        - <u>Heat map</u>: A "modeling-based" heat map, which provides more detail on sectional analysis and voltage issues.
- Determine approach to sourcing and compensating DER at these locations
    - Determine the expected performance of the DER during the time period of need
        - An intermittent DER resource – such as a solar PV installation – will only contribute a portion of its MW capacity at the time of local peak. Until advanced metering functionality is available, a methodology to determine what portion of the capacity can be "counted on" is needed. The methodology could differ according to technology type and/or other characteristics (e.g., intermittent versus non-intermittent).
    - Determine the value of the benefit provided by the DER
        - Once the expected performance of the DER is determined, a $ benefit per unit of value component must be determined. Various methodologies should be considered, such as an avoided marginal cost of distribution system investment (system-wide, or local if available), an average feeder $ cost per mile multiplied by actual length of feeder, or other options. Calculating the $ benefit provided by a DER installation in a beneficial location could have several applications, including but not limited to: informing the structure, level, and design of an incentive to the DER provider or aiding in cost/benefit analysis of NWA proposals.
    - Determine the level and structure of incentive for DER
        - The compensation framework for a DER developed in a beneficial location must be determined. This includes:
            - How the level of incentive is calculated (e.g., Equivalent to calculated benefit, or is some portion of the benefit reserved for ratepayers? Based off of incremental costs or lost revenues to configure the DER to serve the local need [e.g., orienting a PV system west and sacrificing overall production, or incorporating tracking technology at incremental cost?]); and

            - How the incentive is structured (e.g., Is a flat incentive offered [e.g., similar to a one-time grant award]? Or, is a tariff-based incentive offered [similar to net metering, for instance]? Or, are incentives not predetermined, but simply determined on a competitive basis via RFP's issued for DER in beneficial locations?).
    - Determine how the DER are sourced
        - A process needs to be agreed upon whereby the utility communicates the identified beneficial locations to the marketplace at some regular interval, or on a continuous basis. Then DER providers need to be able to take advantage of locational incentives available for those specific locations. Incentives would be issued to DER providers via one of the options identified above (e.g. flat payment, tariff-based incentives, or competitively-bid awards).
    - Determine how value of DER interacts with existing programs and tariffs
        - Net-metering and Renewable Energy Growth tariffs do not vary by time or location in Rhode Island. Could these mechanisms be adapted to incorporate locational incentive features? Or could new locational incentives be coordinated with these mechanisms? Some statutory change may be necessary due to the value of net metering compensation being defined in statute, for instance.

PART IV

BENEFICIAL ELECTRIFICATION

Beneficial Electrification Principles and Recommendations

The following chapter was written by the Commission staff as a draft White Paper on Beneficial Electrification Principles and Recommendations, released on October 13, 217. It is followed by a Special Note on Beneficial Electrification that was written by the DPUC and OER.

Introduction

Rhode Island recognizes that its electric sector is undergoing significant changes.[38] Due to the interplay of technology innovation, public policy, and market forces, the nation's electric grid is getting cleaner and more distributed, and customers are consuming, saving, and producing energy in many new ways.

"Beneficial electrification" is one of the significant changes underway. It is a term that describes the electrification of end-uses, like light-duty transportation and space and water heating, in order to reduce costs and greenhouse gas and other air emissions of these products that historically have been powered by fossil fuels.

Beneficial electrification offers promising ways to manage demand and to avoid unnecessary stress on the system that could increase costs and air emissions. With the growth of intermittent resources (e.g., wind and solar), balancing grid systems is a very different task today than in the past. Grid operators recognize that managing demand through a combination of policies, pricing options, and program offerings can make the system more flexible and lower its overall costs. Electrification of both transportation and heating should allow the shifting of load in time, and would thereby meet the growing need for flexible resources to better manage the grid and help integrate renewable energy.

Beneficial electrification is possible due to significant increases in the efficiency of end-use equipment (e.g., heat pumps and batteries), technological advances in other sectors (e.g., EVs), and declining electric sector emission rates. The opportunity exists to reduce electric sector emissions and electric system costs while lowering individual Rhode Islanders' energy burden. Electrification is also an emerging business opportunity for utilities to allow entities, in some cases including the utility itself, to develop new and innovative services for customers.

For these reasons and given Rhode Island state policy, it is appropriate to consider proposals from electric distribution utilities to advance the adoption of beneficial electrification. Such electrification proposals for

[38] The Public Utilities Commission opened Docket No. 4600 to address issues related to the changing electric distribution system (*see* http://www.ripuc.org/eventsactions/docket/4600page.html). The Office of Energy Resources, the Energy Efficiency and Resource Management Council, the Distributed Generation Board, and National Grid convened a working group known as the Systems Integration Rhode Island or SIRI, to make recommendations on important issues related to developing Rhode Island's future electric grid, and to achieve the state's policy goals related to modernizing the energy sector. *See* www.energy.ri.gov/electric-gas/future-grid/systems-integration-ri.php. Additionally, Governor Gina Raimondo has asked state agencies to address a wide range of issues developing on the system, which was a direct cause of the work presented in this document. *See* http://www.ripuc.ri.gov/utilityinfo/electric/GridMod_ltr.pdf.

Rhode Island must demonstrate that they will produce the aforementioned and other net benefits,[39] and that they are consistent with relevant state policy goals. To ensure this outcome, utility proposals should incorporate these goals, and proponents should be prepared to demonstrate how proposals will help meet them.

Fortunately, we expect there are many different program designs that would achieve net benefits and further state policy goals. While different in scope and design, all proposals should adhere to some basic principles. Since successful electrification depends on innovation and market transformation, state policies and the utility's role will need to allow for experimentation, be adaptive, and co-evolve with technologies and markets. Program goals must be clearly articulated, and each program design element must be clearly tied to program goals. To this end, proposals should be designed with appropriate metrics to demonstrate progress and to enable mid-course corrections if necessary. Furthermore, any electrification program proposal should provide a platform for technology innovation, meaning that it should establish equipment performance objectives such as improving system flexibility and visibility, rather than specifying particular technologies.

This draft whitepaper outlines important goals and basic principles the Draft Project Team, comprising Commission staff, Division, and OER, have developed based on stakeholder input, interagency deliberation, and research. The principles cover four key issues that emerge when considering a regulatory perspective on efficient electrification of the transportation system by increasing use of plug-in electric and plug-in hybrid EVs to meet state policy goals: Goals and Benefits of Electrification, the Utility Role, Cost Recovery, and Implementation Design and Adaptive Learning.[40] Highlights of stakeholder comments related to each issue can be found in Appendix III. We seek further input from stakeholders on these principles and identification of program design preferences. A future draft – to be completed by Division and OER without collaboration of the Commission or its staff – may include further policy determinations and refinements on program design preferences based on stakeholder responses.

Goals and Benefits of Electrification

On June 14, 2017, the Commission, Division, and OER issued a Notice of Inquiry and Request for Stakeholder Comment Regarding a Utility's Role in Deploying Beneficial Electrification with Focus on Plug-in Electric Vehicles (Notice). The Notice included the following list of beneficial electrification program goals:

- 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 Rhode Island 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;

[39] Costs and benefits are defined by the Rhode Island Benefit Cost Framework and Test adopted for application to energy efficiency program review in the Commission's Standards for Least-Cost Procurement in Docket No. 4684 and for broader program assessment in Docket No. 4600.

[40] Electrification of heating is part of Rhode Island's power sector transformation strategy, but is progressing on a different schedule from EVs in the PST project. This is in part because National Grid currently has existing and proposed programs as part of its Energy Efficiency and SRP Plans.

- Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentives.
- Prioritize and facilitate increasing customer investment in their facilities (efficiency, DER, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits;
- Appropriately compensate DER for the value they provide to the electricity system, customers, and society;
- Appropriately charge customers for the cost they impose on the grid; and
- Appropriately compensate the distribution utility for the services it provides.

The Draft Project Team notes that standards for goals and net benefits have been developed in other Commission processes.[41] The Notice also included Rhode Island's EV deployment goals, including:

- The Rhode Island Zero Emission Vehicle Plan goal of 43,000 EVs by 2025.
- The Executive Climate Change Coordinating Council (EC4) greenhouse gas emissions reduction scenario targeting the electrification of 34% of on-road vehicle miles travelled by 2035 and 76% by 2050.

Commenters on the Notice generally affirmed the goals presented. Key additional goals proposed by commenters included: educate customers about the benefits of EVs, accelerate and scale the electric vehicle market, address key market failures, and ensure fairness.

Utility Role

Commenters noted, and Draft Project Team agrees, that the utility, as manager of the electric grid, will play a key role in transportation electrification. Moreover, it was agreed that the utility in fact has multiple roles, some of which will likely change over time. In the early years of any electrification proposal, the utility should consider how Rhode Island's transportation market must transform to meet state greenhouse gas emission goals. The transportation sector is the second largest consumer of energy in the United States (behind electric power generation) and yet 92% of the energy consumed in transportation today comes from petroleum.[42] Electrification promises to transform the current transportation market, enabling utilities to capture revenues currently spent on fossil fuels, enhance their ability to manage the grid, and provide their consumers with new products and services. As the market transforms, utilities must provide nondiscriminatory service and ensure that incremental electrification load is incorporated in a safe, reliable, and efficient manner. An electrification proposal should explain how the utility's role would support the program, achieve net benefits, and help ensure the achievement of state goals.

More specifically, a proposal should articulate what the utility expects to own, operate, execute, measure, and enable, as well as explain how the utility's role relates to the potential roles of other participants in the market. For example, customer education and outreach – potentially a key role for the utility – will be important in early years, and the utility would be expected to provide a plan setting out how it expects to conduct those efforts. Proposals should also outline how other entities (for example the Department of Transportation, auto dealers, or appliance manufacturers) might share that role. As another example, a

[41] *See* footnote 3 *supra*.
[42] Based US Energy Information Administration data. *See* www.eia.gov/totalenergy/data/monthly/pdf/sec2_11.pdf.

proposal that includes the utility owning EV supply equipment should be supported by a demonstration of benefits this model achieves over other ownership models and the context in which the utility seeks this outcome. The utility may seek to develop and own EV supply equipment in areas where, absent utility intervention, market barriers might exist to deployment.

Cost Recovery

Commenters submitted numerous suggestions for cost recovery mechanisms and articulated various points regarding the types of investments that should be eligible for cost recovery. Several commenters also made the case for combining and leveraging ratepayer funds with other sources and made several suggestions as to what those sources might be.

The Draft Project Team expects that recovery of electrification program costs should be subject to the same considerations as other ratepayer-funded utility projects. In particular, such cost recovery mechanisms should be consistent with least-cost procurement policy and considerations of the relative risks borne by each party. Proponents of using ratepayer funding to support an electrification program would also be expected to justify the degree to which the proposal leverages other program spending, private investment, government funding, and any other sources of capital.

Implementation Design and Adaptive Learning

The Draft Project Team agrees with many commenters that a beneficial electrification proposal should be designed to encourage experimentation, adaptive learning, and innovation. Such approach requires that proposals include outcome-based metrics (rather than picking any specific technologies) and commit to providing regulators with sufficiently meaningful data to demonstrate performance and enable meaningful regulatory review. Use of outcome-based metrics will allow sponsors of electrification proposals to engage meaningfully in periodic program reviews by all stakeholders, with opportunities for mid-course corrections.

A research element is another acceptable component to include in a proposal. A research project may allow adaptive learning and can include pilot projects designed to test ideas and inform broader programmatic decision-making.

Highlights from Pilots in other States. Numerous pilot projects are underway around the country. The pilots range widely in terms of scope, intent, and outcomes. A number of projects simply fund EV supply equipment or distribution system "make-ready" work to learn about costs and utilization of the infrastructure. Other projects put in place consumer rebates to test their efficacy and uptake. Still others examine the efficacy of time-of-use rates and other cost recovery mechanisms in maximizing the benefits and minimizing the costs to the grid of EV expansion, and in allocating costs and benefits to customers. To the extent practical, Rhode Island will learn from and share with other states, and National Grid will do the same with other utilities, to ensure that each proposed pilot project is value added.

An EV proposal should present a set of metrics to measure the efficacy of the program. Stakeholders suggested numerous useful metrics. The Draft Project Team agrees that proposals should be accompanied by performance metrics that will help measure the proposals' achievement of relevant goals.[43] As noted, these metrics should be outcome-focused. They also should be relevant to consumers and public policy objectives, quantifiable, and verifiable. In some cases, metrics should be related to activities the utility can affect or control through its investments and its management. If methodologies for these metrics do not exist or are not in use in Rhode Island, a methodology and justification should be included with a proposal or responses to a proposal.

It is important to understand the degree to which an electrification proposal will affect existing state and utility programs, such as energy efficiency programs or distribution system investment plans. Additionally, proposals should address training and workforce development. There are also factors beyond the purview of the Commission that could influence the success of an electrification proposal and should be considered, and so should be considered in a proposal, such as building codes and zoning requirements.

The scope of any electrification program will also be an important consideration. Proponents should address questions like: what types of customers will be directly affected? how many customers are expected to participate? what types of transportation are included? An EV proposal, for example, will necessarily have to address issues such as how targeting different end-users can affect the efficacy of the program (e.g., single-vehicle versus fleet ownership); and reasons to include or exclude other forms of transportation (e.g., industrial, train, maritime, etc.).

Rates associated with beneficial electrification proposals, like other utility programs, should be just and reasonable. Rates, such as time-of-use rates, should be designed to maximize system benefits through, for example, smart charging and should promote other benefits as well. But, given likely limits on which customers can participate in, directly benefit from, and are affected by a proposal, among other limiting conditions, rates must be implemented in a way that is equitable for all classes of electricity users.

Beneficial Electrification of Heating Systems

Many commenters supported including electrification of heating as part of Rhode Island's Power Sector Transformation. National Grid has energy efficiency programs to lower the barrier to replacing inefficient heating systems with efficient electric heating systems, although currently the programs do not actively promote fuel switching (such as from oil to electric heat pumps). Nation Grid has proposed updates to these programs as part of its 2018-2020 Energy Efficiency and SRP Plans in Commission Docket No. 4684.[44] Those plans will be reviewed in the context of the Commission's Least-Cost Procurement Standards,[45] which are generally consistent with the principles outlined in this document. Should National Grid propose a program to encourage beneficial electrification of heating outside of any Energy Efficiency and SRP Plan, that proposal should also be consistent with the principles described above in a manner that is analogous to heating systems and the heating sector.

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[43] *See* discussion of electrification and EV deployment goals in Section II *supra*.
[44] Docket material can be found at http://www.ripuc.org/eventsactions/docket/4684page.html.
[45] The Least-Cost Procurement Standards can be found at http://www.ripuc.org/eventsactions/docket/4684-LCP-Standards_7-27-17.pdf

Special Note on Beneficial Electrification Recommendations and Stakeholder Input

The above draft White Paper on beneficial electrification was developed by the Public Utilities Commission. The Division and OER decided not to further refine the draft White Paper to respect the independent nature of the Commission’s role.

Following circulation of the draft PUC White Paper on September 11, 2017, stakeholders provided comments at an in-person technical meeting, in written sumissions to the PUC and in a second round of comments to the DPUC and OER. Stakeholders expressed a wide-range of views on a range of topics, with particular debate around the appropriate role ofutility ownership of electric vehicle charging infrastructure. In light of stakeholder views on beneficial electrification, the Division and OER intend to appropriately engage stakeholders to clarify their views in response to any electric vehicle program proposal that may be forthcoing from National Grid.

Conclusion

This report represents an important milestone in Rhode Island's ongoing Power Sector Transformation. It draws on lessons from a broad set of stakeholders and national best practices. It proposes concrete, tangible, and no-regrets actions that Rhode Island can take to move toward a more performance-oriented and information-driven utility over the next three to five years.

During the coming year, Rhode Island regulators and policymakers will advance the recommendations of this report through a variety of regulatory vehicles. In particular, National Grid's upcoming rate case represents a strategic opportunity to modernize the utility model, deploy advanced meters, enhance DSP, and pursue beneficial electrification. Other regulatory dockets including, but not limited to, the Infrastructure, Safety, and Reliability Plan, the System Reliability Procurement Plan, and the Energy Efficiency Plans will be used to implement PST recommendations in collaboration with National Grid, stakeholders, and regulators. The precise implementation pathway will depend on future decisions that the utility, the Commission and stakeholders will each make. However, there are many available tools for the State's policymakers to pursue change.

This report calls for a higher degree of stakeholder engagement with key issues related to utility planning, operations, and investment decision-making. Regulators and policymakers will work with National Grid to create the proper forums for stakeholder participation and input into key implementation areas such as data access, DER compensation, and distribution forecasting.

The OER and Division look forward to working with stakeholders, regulators, and National Grid to advance Rhode Island's position as a national leader in utility regulatory reform in order to achieve our collective policy goals of controlling long-term system costs, enhancing customer choice, and integrating more clean energy into our electric grid.

Appendix I: Letter from Governor Gina Raimondo

State of Rhode Island and Providence Plantations
State House
Providence, Rhode Island 02903-1196
401-222-2080

Gina M. Raimondo
Governor

March 2, 2017

Margaret E. Curran	Carol J. Grant	Macky McCleary
Chairperson	Commissioner	Administrator
Public Utilities Commission	RI Office of Energy Resources	Division of Public Utilities and Carriers
89 Jefferson Boulevard	One Capitol Hill	89 Jefferson Boulevard
Warwick, RI 02888	Providence, RI 02908	Warwick, RI 02888

Dear Chairperson Curran, Commissioner Grant, and Administrator McCleary:

Rhode Island has taken great strides towards realizing a cleaner, more sustainable energy future. To continue on this path, we must ensure that our energy system continues to evolve in a manner that benefits all Rhode Island residents and businesses; fosters job growth and innovation; leverages emerging clean energy technologies to reduce system-wide costs; and enables a more flexible, lower-carbon grid.

My recent announcement that Rhode Island will procure an additional 1,000 megawatts of clean energy resources to further diversify and decarbonize our energy supply is another important step forward, but there is more that we must do. Critical to our long-term success is a more nimble electric grid that can strategically integrate clean energy resources and enable Rhode Islanders to take advantage of new clean energy technologies.

With this letter, I am asking your respective agencies to collaborate in the development of a more dynamic regulatory framework that will enable Rhode Island and its utilities to advance a cleaner, more affordable, and reliable energy system for the 21st century and beyond. Based on your agencies' work with each other and with stakeholders, I expect the Public Utilities Commission, the Office of Energy Resources and the Division of Public Utilities and Carriers to develop a package of draft regulatory frameworks, proposals or deployment strategies, as appropriate, by November 1st, 2017.

In particular, I ask that your agencies, in coordination with stakeholders, address the following questions:

- What functions should the future electric utility perform, and how should it be compensated for those services?

- How can adoption of electric vehicles and electric heating help to optimize our system, while maximizing economic and environmental efficiencies?

- How can the electric utility improve grid planning to enable customers and third parties to participate in the clean energy revolution while prioritizing investments for a reliable and least-cost energy system?

These questions matter now for Rhode Island. The improvements in system efficiency, customer choice, and clean energy integration necessary to achieve our energy goals depend upon our realizing the benefits of rapidly advancing products for information management, communications, power distribution, and behind-the-meter services. Our regulatory system must therefore remove barriers to adoption of these tools and establish incentives for the electric utility to achieve meaningful, performance-driven results.

I ask that you consider, build upon and extend the work achieved to date through the Energy Efficiency and Resource Management Council, the Distributed Generation Board, the Systems Integration Rhode Island Working Group, the Public Utilities Commission's docketed investigation of the changing electric system, and lessons from National Grid's continuing innovation across its service territory as your agencies develop regulatory frameworks and proposals. I encourage you to work with the National Governors Association, the Regulatory Assistance Project and others to draw upon expertise from around the region and the country.

Ocean State residents and businesses seek a new energy compact among our utilities, our regulators and each other. The work that I have charged you with here will sustain that compact for years to come, and ensure that Rhode Islanders can benefit from new clean energy technologies. I look forward to working with you to improve energy affordability across our state, grow jobs and attract new investment, reduce our carbon footprint, and strengthen the quality of life for all Rhode Islanders, now and into the future.

Thank you.

Sincerely,

Gina M. Raimondo
Governor

Appendix II. Functions Desires from an Advanced Meter

The following is a list of grid capabilities desired from an advanced meter platform, organized by the goals of: 1) security and resiliency; 2) facilitating consumer choice; 3) integrate renewable energy; 4) workforce management; and 5) market functionality.

Security and Resiliency Goal

1) **Automated islanding and reconnection (microgrid) control** is achieved by automated separation and subsequent reconnection (autonomous synchronization) of an independently operated portion of the T&D system (i.e., microgrid) from the interconnected electric grid. A microgrid is an integrated energy system consisting of interconnected loads and distributed energy resources which, as an integrated system, can operate in parallel with the grid or as an island.
2) **Fault Location, Isolation, Service Restoration** (FLISR) is a collective term for the process of identifying the location of a fault condition on the system through the use of current and voltage monitoring devices; isolating the fault between two devices adjacent to the fault (e.g., opening two switches on either side of the fault); and, restoring service to the customers in the unaffected areas (i.e., not in the isolated section where the fault occurred). Next generation systems may use pre-programmed restoration scenarios that rapidly respond to equipment load ratings and real-time system load measurements. Such advanced applications require a robust, scalable two-way communications network. Although FDIR is sometimes referred to as a “self-healing grid,” it is important to note that the fault is not corrected until Distribution Company workers correct the cause of the fault and return the affected section back into service.
3) **Automated feeder reconfiguration** refers to the constant monitoring of the status of the distribution system (e.g. voltage and load conditions) and the ability of the system to respond by using alternate sources of supply to avoid an overload situation. Some FDIR systems also support automated feeder reconfiguration capability that enables restoration of service to the greatest number of customers possible through real time load monitoring.
4) **Remote monitoring and diagnostics for system conditions** consists of data collected via SCADA systems, to include voltage, loading, current, power factor and frequency. A Distribution Company may use these data to feed planning models, support advanced load forecasting and enable analytics that can improve and optimize system planning and operations. Remote monitoring and diagnostics enable Distribution Companies to collect more frequent data on the status of system equipment (e.g., oil samples from substation transformers). A Distribution Company may use these data to identify concerns (e.g., abnormal equipment performance), optimize day-to-day asset utilization and support condition-based maintenance programs.

5) **Adaptive protection** uses adjustable protective relay settings (e.g., current, voltage, feeders, and equipment) in real time based on signals from local sensors or a central control system. This is particularly useful for feeder transfers and two-way power flow issues associated with high DER penetration.
6) **Outage and restoration notification** provides power status information down to the customer service point. Upon loss of power or restoration of power, status sensors will send a notification message to a central monitoring system that can analyze and deliver the message to a reliability operator or system. Sensors should be capable of measuring load side power status and sending a notification message upon change of state or request from another system.
7) **Dynamic event notification** is automatic notification by the DSPP to market participants of events including, but not limited to: price changes, incentives, penalities, or special circumstances; events or conditions that may effect market operations; events or conditions that may effect electrical network performance or availability such as equipment failure, weather or other hazards; achieving or exceeding various production or consumption targets or thresholds. Such notification would be intended to provide market participants the ability to respond to important situations or conditions in a timely manner.

Facilitate Consumer Choice Goal

1) **Time varying rates** changes the price customers pay based on time of day such that the rate is higher during periods of peak demand. At the most extreme, customers can pay a different price every hour based on wholesale market prices. In more traditional pricing structures, customers pay a different rate for a given number of hours every weekday, coincident with the time of system peak demand. Another form of time varying rates is a critical peak price or peak-time rebate that is typically implemented for a limited number of critical peak events when the system is constrained due to very high demand. A critical peak pricing program entails a higher price during critical peak periods, whereas a peak-time rebate provides customers with a credit or rebate for reducing usage during the same critical peak periods.
2) **Home area network** (HAN) is a network of energy management devices, digital consumer electronics, signal-controlled or enabled appliances, and applications within a home environment that is on the customer side of the electric meter13. A HAN provides customers with access to usage data in more frequent time increments than once-monthly billing information. Retail pricing information may also be communicated to customers through a HAN. For example, a customer may program controls in the home to increase the set-point on the air conditioner in response to a critical peak signal sent from the Distribution Company. In order to connect a HAN to the customer's meter, the meter must have a HAN communication module installed and activated or be otherwise able to communicate with the HAN. A HAN may also be installed by a customer for a variety of energy management purposes without requiring a connection to the meter.

3) **Energy Usage Visibility** allows customers to view, and to assign others to view, their energy usage data.
4) **Demand side management options** support systems and software to manage a range of customer-side energy resources.

Integrate Renewable Energy Goal

1) **Remote distributed generation disconnect** is technology that enables a Distribution Company to use automation to remotely disconnect a distributed generation facility from the distribution system to protect safety or maintain service to other customers.
2) **Energy storage** of electricity for later use. An electricity storage device can convert electricity into another form of energy in its charging state, and then produce electricity through a reverse conversion process. The electricity storage device can be stationary or mobile depending on its application. Most electricity storage devices include an inverter or converter so as to work with AC electricity.
3) **DER power control** is adjustment of status and power output or consumption for electricity producing/storing distributed energy resources. The purpose is to control the real power production or consumption by these devices. Control could be achieved by delivering an instruction to the DER power inverter/converter, charge controller or similar control system.
4) **DER power factor control** is adjustment of status and power output or consumption for electricity producing/storing distributed energy resources. The purpose is to control the real power production or consumption by these devices. Control could be achieved by delivering an instruction to the DER power inverter/converter, charge controller or similar control system.
5) **DER optimization** determines the values for the controllable factors of one or more DERs to maximize, minimize or balance system performance on either side of the DSPP service point. Optimization goals could include, but are not limited to, energy efficiency, reliability, supplying peak demand, or providing ancillary services such as frequency regulation or reserves.
6) **Algorithms and analytics for customer/DER/microgrid control and optimization.** Software that can utilize operational and non-operational data from network sensors, equipment health sensors, weather instruments, and other operational technology or models to analyze system performance, identify abnormal conditions and determine optimum set points or topologies for network elements.

Control Energy Cost Goal

1) **Integrate and automate Volt/VAR control, conservation voltage reduction.** Volt/VAR management is the term for technology that measures voltage and power factor on the distribution system and corrects imbalances to minimize power quality disturbances and

limit line losses of the system. Next generation systems may include centralized processing with the ability to perform feeder-specific, substation-specific and area/region optimization. Future applications may also incorporate distributed solar photovoltaic (PV) cells and other resources through the use of controllable inverters for VAR support. Conservation voltage reduction refers to the active management of distribution voltage within a tight bandwidth to reduce energy consumptions and peak demand. Next generation systems may include centralized processing with the ability to perform feeder-specific, substation-specific and area/region optimization.

2) Utility/third-party load control. A load control demand response program is one where a signal is sent to a customer device (e.g., programmable controllable thermostats, water heaters, air conditioners, Electric Vehicle Supply Equipment (EVSE)) instructing that device to reduce electricity consumption. A two-way signal allows the sender of the signal to confirm whether the device has responded or the customer has decided to over-ride the signal. A load control program may be implemented by a Distribution Company or third party.
3) Remote monitoring and diagnostics system conditioning.
4) Load leveling and shifting alters the pattern of demand to more closely match output from non-dispatchable, intermittent distributed resources such as solar PV. This technology may help mitigate reverse power flows and localized disturbances typically associated with high levels of intermittent distributed generation. Advanced applications may enable Distribution Companies to use distributed resources for system balancing operations. Such applications may include: on-site battery storage for active energy support; and voltage "ride through" capabilities that enable distributed generators to operate uninterrupted though grid disturbances.
5) Advanced load forecasting is the process of making more accurate and discrete predictions about future system loads based on customer usage data. Improved forecasts enable operators to better schedule and dispatch generation. Such forecasting may also include distributed generation and other resources, including demand response and electric vehicles.
6) Real time load monitoring provides real-time measurement of energy consumption at the customer premise or device level. This could be accomplished using voltage and current sensors housed within a smart meter or other similarly capable sensor. The sensors would be connected to a communications network capable of delivering load measurements to a central monitoring system in intervals of one hour or less (more frequently).
7) Real time network monitoring provides real-time measurement of voltage and current within the transmission and distribution network, including primary distribution feeders, laterals and line transformers. This monitoring can provide a high resolution view of voltage and load profiles throughout the network suitable for use in operations and real-time optimization algorithms. Sensors could be housed in T&D power equipment such as circuit breakers, reclosers, voltage regulators, capacitor banks, transformers, or other dedicated sensor hardware. The sensors would be connected to a communications network

capable of delivering measurements to a central monitoring system in intervals of one hour or less (more frequently).

8) **Real-time load transfer** is achieved through real-time feeder reconfiguration and optimization to relieve load on equipment, improve asset utilization, improve distribution system efficiency, and enhance system performance.
9) **Algorithms and analytics for grid control and optimization** is software that can utilize operational and non-operational data from network sensors, equipment health sensors, weather instruments, and other operational technology or models to analyze system performance, identify abnormal conditions and determine optimum set points or topologies for network elements.
10) **Power flow control** requires techniques that are applied at transmission and distribution levels to influence the path that power (real & reactive) travels. This uses such tools as flexible AC transmission systems (FACTS), phase angle regulating transformers (PARs), series capacitors, and very low impedance superconductors.
11) **Dynamic capability rating** can be achieved through real-time determination of an element's (e.g., line, transformer, DER, etc.) ability to carry load based on electrical and environmental conditions.

Workforce Management Goal

1) **Mobile workforce management system** is the capability to communicate the status of assigned work projects between workers and a dispatch office and to automatically receive updates and changes.
2) **Mobile GIS platform** offers the capability to allow employees to locate themselves and distribution assets through a mobile application.

Market Functionality Goals

1) **Market-based demand response** that can be targeted at certain market participants to optimize system performance. Response incentives and penalties would be calculated based on real-time network conditions including supply, demand, congestion, energy efficiency or other factors.
2) **Dynamic electricity production forecasting** is the calculation and forecasting of electricity production from DER based on geography, forecasted fuel supply, solar insolation, wind speed, electrical network conditions, or other factors that would affect the quantity and quality of electricity. Production forecasts would change with changes in input data. The purpose of the forecasts would be to provide supply information to DSPP grid operations and planning, and to help set supply prices in the DSPP market.
3) **Dynamic electricity consumption forecasting** is the calculation and forecasting of electricity consumption based on ambient temperature, weather, day of week, time of day, electrical network conditions, or other factors that would affect the quantity and quality of electricity. Consumption forecasts would change with changes in input data. The purpose of the

forecasts would be to provide demand information to DSPP grid operations and planning, and to help set demand, energy and ancillary services prices in the DSPP market.

4) Historical DER performance monitoring and archiving of DER performance data including electricity production and services, availability/uptime, pricing, and other factors that would aid the development of detailed dynamic production models and production forecasting. This information would help DSPP grid operations, supply planning and market operations.
5) Historical load monitoring and archiving of customer electricity consumption would aid in the development of detailed dynamic load models and load forecasting. This information would help DSPP grid operations, supply planning and market operations.
6) M&V for producers and consumers is measurement and verification of electricity production and consumption by market participants. This could be done at the DSPP point of service, or at individual appliances or DERs. The purpose of M&V is to ensure accurate billing and payment for market participants, and to help ensure a robust and trustworthy market.
7) Participant registration and relationship management is the qualification (e.g. credit and performance checking) of new participants, management of participant interactions such as service complaints, case management and escalations, monitoring of satisfaction levels. Management of promotions, marketing, customized services and solutions, relationship building.
8) Confirmation and settlement includes receiving confirmation of market participant commitments, e.g. advanced confirmation from DER that energy will be supplied or from DR that demand will be curtailed. Clearing requires comparison of actual energy production or consumption according to commitment in terms of quantity, quality, timing etc., tracking and reconciling discrepancies, managing disputes and escalations. Netting functions may be incorporated to offset outstanding invoice or receivable balances.
9) Billing, receiving and cash management through the generation of invoices and statements. Cash management functions and banking or financial intermediary interfaces resulting in the receipt of cash for net billings owed to the DSPP or net payables due to providers. Credit/collections processes occurring from delinquencies.
10) Free-market trading capability for participants to make offers or bids, likely through a cooperative or other intermediary, enhancing a competitive energy market.
11) Algorithms and analytics for market information and operations through software that can utilize market data from producers and consumers to analyze market performance, identify abnormal conditions and determine key supply and demand relationships. The purpose of this functionality is to continually improve market performance and the value of products and services being transacted.

Appendix III: Summary of Stakeholder Feedback

A summary of stakeholder feedback is outlined below, following the order of the report. Over 215 individuals including representatives from 65 organizations participated in one or more stakeholder engagement sessions. The specific stakeholder views submitted are publicly available at http://www.ripuc.ri.gov/utilityinfo/electric/PST_home.html.

Utility Business Model Feedback

In order to engage stakeholders in the questions discussed above, the Division and OER issued three sets of questions seeking stakeholder feedback in oral and written form. Stakeholders offered a range of views on utility function, utility compensation, multi-year rate plans, and performance incentive mechanisms.

Comments on Utility Functions

All commenting parties agree that the utility should function as an integrator of third-party services that enables companies to own and operate distribution-side services, while different views were expressed on the utility's role in providing those services. The company wants to be allowed to compete in emerging services, while many commentators want the utility to only serve as a market enabler and be restricted from serving non-regulated functions. Because the utility should ensure non-discriminatory access and seamless integration of DER and other clean energy resources, the third-party providers are concerned this will be hindered if the utility is competing with third parties. A consortium of clean energy developers want the distribution utility to be required to divest or separate from related companies that perform functions that are not natural monopoly distribution functions. The utility wants to operate the Distribution System Data Portal, at least initially. No stakeholders expressed disagreement with the utility owning the customer engagement portal.

Divergent views are expressed on the role of the utility in owning and operating DER. Several stakeholders questioned if the utility should administer most of the energy efficiency or DER programs. The utility would like to own the smart meters, while third-party providers want to operate advanced meters. Some stakeholders are agnostic about the utility owning EV charging infrastructure and some are strongly opposed because they see it as unnecessary and duplicative. The utility wants to own and operate smart grid meters, while others want third parties to operate advanced meters. Some expressed interest in allowing, incenting or requiring the utility to outsource functions of administering DER programs (e.g. net metering) to a cloud-based service provider. One stakeholder wants the utility to use demand response as a primary tool and not as a last resort tool.

Most stakeholders expressed a clear desire for the utility to make customer and system data easily sharable with customers and third-parties, including conducting an open and transparent DSP. Commentators noted the need to balance data access with confidentiality.

Reliability, safety, and customer responsiveness should remain the utility's core functions, says the utility. Other stakeholders agree on reliability and safety but think the utility's core function on customer responsiveness is not needed since they want the utility to exclusively serve as a grid system operator.

Several commentators support utility-third party partnership models for shared communications infrastructure, advanced meters, and data analytics. One stakeholder wants the Commission to consider turning operations of an enhanced communications and electrical system to a semi-government agency.

Many comments about the utility business model functions focus on designing the broader electricity market structure. Most commentators want to enable third-party energy developers to participate in grid services directly and as contractors to utility via PPA-like agreement. Some noted it is important to clearly define the separate role of enabling infrastructure versus the provision of services themselves. Regulations should focus on a transparent structure that allows coexisting business entities. The costs and values of network administration roles should be clarified. The regulators should fully value DER and carbon pricing in resource planning.

Comments on Utility Compensation

Most commentators agreed that the utility should increasingly be compensated through performance-based compensation, rather than on their inputs or investments. Most stakeholders said most of the utility's roles can be compensated under performance-based structure. The utility wants a combination of cost of service regulation and incentives for new services. The utility thinks the potential value of new incentive earnings would have be substantially more than any corresponding reduction in ROE to maintain investor confidence. They prefer a cap on total earnings from combined ROE and PIMs with a shared savings mechanism. One proposal offers cost trackers to continue aiming to clarify performance incentive mechanisms to be developed by the end of the first multiyear rate plan. A stakeholder proposes cost trackers only for factors outside of the utility control.

A consortium of clean energy developers wants the utility to have a serious financial incentive to transform into a platform facilitator. Existing investments should be compensated on a cost basis calculated over an amortization period for a specific investment including a small cost of capital consideration. In the long-term, compensation for overhead and profit should be provided only on a performance basis. A third-party provider wants the utility to be compensated for empowering customers and non-utility market participants, demand management, and reducing carbon intensity.

Several commenters expressed interest in capital and non-capital expenses being recovered more equitably to encourage system efficiency. To level the playing field for non-capital strategies – both utility-owned and third-party owned, the utility should be compensated equitable for both types of spending. Performance incentive mechanisms and revenue caps should encompass capital and operational expenditures. The proposal for ROE and innovative utility partnerships needs more refinement.

Shared saving mechanisms give customers a larger share of the upside and smaller side of the downside depending on how the utility performs. One stakeholder proposed incenting the utility for reducing customers' energy costs through distributed resources – with a larger incentive for helping low-income customers in which utility bill is a larger share of consumer's income.

Different views were expressed on the ROE adjustment, with some accepting it so long as it is symmetrical. Some questioned how they work if taken out of ROE. Caution was expressed from diverse stakeholders on the utility charging a fee for data, both from third-party providers (regarding smart meter data) and from the Utility (regarding EV integration because of low market demand).

Several stakeholders stressed the need to define utility functions before compensation. A utility's ability to generate revenue through EV subscription fee services hinges on its ownership of the equipment, so the State needs to consider if it should be encouraging ratepayer funded equipment in a competitive market.

Most stakeholders agreed on the need to align public policy goals with utility compensation. The State should create utility incentives for: higher system utilization, value creation, local energy solutions, greenhouse gas reduction, and consumer protection. The regulators can establish performance criteria for investment efficiency and technology utilization to mitigate obsolescence.

Some stakeholders asked to address the inherent conflict for business units that compete with each other and owned by the parent company by considering not allowing utility to maintain joint ownership of electric and natural gas utilities as well as transmission and distribution companies.

Comments on Multi-year Rate Plans

All stakeholders expressed strong support for an extended rate plan because it will create a powerful cost efficiency incentive for both capital and operational expenses. Some stakeholders would support this if done with a stakeholder developed Integrated Resource Plan and earnings sharing mechanism. Most stakeholders, including the utility, favor a three-year rate plan.

Stakeholders emphasized that the rate cap must be set carefully. Some recommend a revenue cap applied across both operational and capital expenses. One stakeholder asked the Commission to consider how revenue cap and decoupling work together.

Diverse stakeholders are concerned with shifting the attrition relief mechanism to an index. Some say it should be considered in the context of refining the current regulatory mechanisms including forecasts and decoupling, rather than moving to an index. A hybrid approach may be appropriate down the line. The utility believes it should be based on its forecasts as being more accurate but is open to evaluating potential index-based mechanisms. Unforeseen changes can be resolved through a reopener, noted some.

Comments on Performance Incentive Mechanisms

Wide support for PIMs were expressed as a way to ensure service quality and policy outcomes, especially as a counterbalance to the cost-reduction pressure created by the multiyear rate case. One stakeholder expressed concern about the role of PIMs replacing the standard regulatory expectation. Most expressed a desire for PIMs to be used for outcomes that are not ordinarily in the utility's financial interest. The Commission should focus PIMs on creating new consumer values, said one stakeholder.

Suggested PIMs cover the categories of customer equity, system efficiency, and environmental benefits. Specific PIMs are suggested for: security, reliability, asset utilization, non-monetized benefits such as environmental goals, SRP targets, non-wires alternatives, DER integration, stakeholder participation, proactive capacity enhancements. One stakeholder wants to incent areas that stakeholders have already identified as priority areas for performance regulation, such as SRP targets and avoiding wires capital investments. A critical element to track is transactional metrics related to specific actions taken by customers and third parties.

Metrics will help track multiple areas and a smaller set of PIMs would be appropriate, said one stakeholder. The utility and Commission should collect the data for a year and then develop appropriate PIMs. Symmetrical incentives with rewards and penalties are supported by several stakeholders. Some suggested awarding incentives as a fixed sum rather than a change to ROE.

PIMs should be large enough to have desired effect on utility behavior but capped to protect consumers. Different views were expressed on how to weight the PIMs. Some suggest weighting PIMs towards outcomes that will reduce capital expenditures and symmetrical incentives. Others suggest the results of a Docket 4600 cost benefit valuation analysis would be a reasoned basis for weighing the three categories of metrics. If that analysis is not ready, equal weight should be given to each category of metrics.

Advanced Meter Functionality Feedback

Three separate meeting were held with stakeholders on AMF, to both provide information from experts from around the country, and to take stakeholder comments and questions. In addition, questions were sent out to solicit comments from stakeholders.

Advanced Meter Capabilities

All stakeholders agreed with the importance of the list of capabilities provided by the Division, and different views were expressed on the necessity of the utility providing most of them. National Grid agrees with the list of capabilities identified by the Division, but prefers that proposals should focus on objectives rather than capabilities. National Grid agrees that smart grid proposals should be supported by a strong business case with clear evidence of system and customer benefits. Quantifiable system benefits include avoided wholesale energy and capacity market costs, improved reliability and the potential to defer capital and operational costs. Qualitative benefits include enabling GHG reductions, ensuring energy security, enabling more accurate system planning, enhanced safety, enhanced data privacy and security, enhanced customer satisfaction, enhanced outage notification, and a simplified move-in/move-out process. National Grid believes the capabilities should evolve over time, beginning with foundational investments.

Clean energy companies note that a key qualitative function of AMF is the ability to stream information from the customer site in real time. This consumption data, when paired with both tariffs and wholesale market opportunities, enables the provision of signals for and measurement of demand response, creates new price-responsive capabilities, and leads to a more efficient system as a whole. Customer benefits are often what make AMF deployment cost effective. They believe the AMF business case must include a commitment to achieving well-defined and quantifiable customer benefits, and a detailed strategy for achieving customer benefits.

One company said to enable dynamic networks on demand, the infrastructure must be separated from the services running over that infrastructure. Services exist similar to other cloud services, in which subscribers can allocate what they want, when they want; subscribing to a service requires the click of a button. This marketplace will empower the benefits of competition including lower prices, movement toward abundant bandwidth, compelling new services, and growing innovation activity. To achieve this, the network communication core capabilities should include a minimum of: (a) Virtualization; (b) Software Defined Networking (SDN); (c) Orchestration; (d) Scalability; and (e) Separation of Infrastructure and Services.

Some stakeholders stress that the utility should be limited to providing the platform for independent service providers to not stifle functions that are not natural monopolies and unfairly favor the utility over independent providers and ratepayer benefits. One stakeholder noted that to transition to a competitive meter market place, a significant port of the current utility "customer charge" could be shifted to paying for metering services that customers choose. The Commission could hold a bidding process on some regular interval for providers of default metering services. Clean energy stakeholders are agnostic about meter ownership as long as the data and information collected is made available to customers and third parties. National Grid could earn revenue through an emergent data and information portal, whereby the utility and third parties provide access to usage data and information. Furthermore, the utility should include a detailed customer engagement plan as part of the advanced metering proposal to ensure full customer benefits are realized.

Managing Obsolescence

To mitigate obsolescence risk, National Grid pursues solutions that use industry-accepted and open integration standards, has a reasonable maintenance and support plan, and provides for cost-effective and efficient upgrade or replacement of components with the shortest useful life. This requires careful consideration, planning, design and classification of assets and components and the ability to remotely connect and update firmware and software. The same hardware can be used by different, isolated, systems for high-accuracy voltage monitoring and outage notification, and can become a node for extension of a complex, hybrid communication system. National Grid is committed to seeking out innovative/alternative solutions that are in the best interests of customers.

Some stakeholders note that is not necessary for low-income customers to have advanced meters or utilize all their functionalities to benefit from statewide investments and activities of other customers. It may not be useful to include all low-income customers or other low-usage customers in the rollout of AMF if they do not have sufficient load to shift. If these customers are included, they should receive special consideration in rate design, such as opt-in even if advanced rate designs are the default for most customers, and access to low-cost energy management technology.

Third-party ownership of meters and communications infrastructure is one way to mitigate against technology obsolescence, if the owners are responsible for delivering specific outcomes at an agreed-upon price, note clean energy stakeholders. They believe the utility does not need to own the meter and needs to have access to certain information. A cloud-based service can provide metering capabilities with limited obsolescence risk.

One stakeholder believes that utility ownership and control of advanced metering stifles innovation and increases the risk of technology obsolescence. They believe meters should be a tool that DER providers of all kinds can provide in ways that optimize their own services and the value that customers choose to purchase from them, without having to double meter.

Complementary measures for equity

National Grid plans to build off its energy efficiency programs to educate and make the benefits of advanced meters accessible to all customers, including income-eligible customers.

Clean energy stakeholders note that a customer class may benefit from the deployment of advanced meters even when one's own rate class is not affected by the deployment provided that: (a) the meters deployed lead to increased overall system efficiencies, and that b) some of those efficiency benefits positively affect that given rate class. To ensure these outcomes, investment is needed in (a) advanced distribution system management and software-based analytical capabilities; and (b) significant, personalized customer engagement before, during, and after AMF installations.

Platform design

Most stakeholders expressed a desire for a platform to be designed to create a secure, trusted and low-cost digital market place over which all kinds of transactions can be enabled, transacted, recorded, credited and compensated essentially in real time. National Grid plans to create a platform to enable an array of future utility and third-part offerings by coupling AMF with data management systems and customer engagement portals.

Some stakeholders say that as a ratepayer-funded monopoly, any system data, aggregate data and other information collected by the distribution utility should be considered and treated as public information and made easily accessible and easily usable by the public without charge. Clean energy stakeholders say that usage information – properly protected for privacy and cybersecurity – should be made available to consumers and multiple vendors at minimal latencies of one minute or less. The data platform should leverage and enable customer and third party engagement. A customer-facing portal should provide customers with their interval data, personalized insights about that data, and tools to better manage their energy use through energy efficiency and demand response. Utility regulators should request annual reporting.

National Grid agrees that customer benefits are likely to be greatest when third parties can innovate and compete to provide customers with new opportunities, under appropriate terms for security, confidentiality, and customer protection. National Grid expects to apply lessons learned from its Worcester Smart Energy Solutions pilot program, including insights on customer privacy, data and cyber security, vendor capabilities, overall cost structures, and product strategies and platforms.

Shared communications network

National Grid says it plans to provide an assessment of the potential costs and benefits of advanced meter deployment in its upcoming PST initiative proposal. The utility says it is researching opportunities and challenges associated with a multi-user shared network operation model and four important challenges must be addressed: (a) finding a model that can be successfully deployed while demonstrating lower communication costs for the end-user, (b) allocating administrative and technical ownership and accountabilities; (c) any restrictions posed by utility regulation or the Telecommunications Act of 1996; and (d) cybersecurity. They believe there will be mission-critical aspects of distribution and transmission utility operations where it may not be prudent to use a shared network if cyber security issues cannot be clearly and efficiently addressed.

Some stakeholders note that the internet should be able to provide appropriate bandwidth and security without creating a specialized standalone network just for utilities.

Clean energy stakeholders state that three potential approaches to the communications infrastructure could be adopted: (a) The use of public next-generation connectivity for the electrical system in which the electric utility purchases a bulk amount of bandwidth and ratepayers act as a kind of anchor tenant; (b) Ownership of a communications infrastructure by the electric utility with sales to other bulk infrastructure customers in which electric ratepayers fund the communications network and have costs reduced; or (c) Participation by the utility in a special purpose vehicle with private vendors supporting multiple infrastructure applications.

One company notes that Rhode Island already has private partnerships, called Network as a Service, that share communications infrastructure. There is a state middle mile network that could form the backbone of the statewide shared communication infrastructure if arrangements could be made for extending it and supporting the network as a service concept.

Distribution System Planning Feedback

Stakeholder feedback throughout the PST processes revealed general agreement on how DSP processes might evolve and improve over time. Stakeholders uniformly agreed that elements of DSP will need to evolve in response to the growth of DER and the changing needs of the distribution system. Stakeholders agreed that increased access to system and customer data – with the proper privacy and security protections in place – is necessary to facilitate better investment decision-making on the grid by the utility and third parties. Finally, stakeholders agreed on the need for increased DSP transparency and opportunities for stakeholder feedback in the DSP process. Stakeholders did not appear to see a clear need at this time for a separate DSP docket process, but rather that opportunities for engagement and input should be integrated into existing dockets and processes. The following summary provides an overview of stakeholder views on key DSP policy areas:

DSP/ISR Alignment

Clean energy companies wants the SRP/ISR process to only apply to the types of costs not included in the rate cases to maintain integrity of incentives for MRP and PIMs. National Grid is already working on aligning DSP planning processes with stakeholders. However, in its Oct 26, 2017 comments, the utility said it does not think the ISR and SRP can be done simultaneously because it sequences them at different intervals, and that it plans to reference each other in both filings.

Stakeholders stressed the need to have full access to information and be given the capacity to participate in all system planning processes, but that challenges to this outcome abound. One stakeholder said the utility should not oversee or administer any of the DSP functions unless and until incentives are properly reframed in the utility business model. Another stated that the utility plans should include inflection points when decisions can be revisited and adjusted and stakeholder input continually incorporated. More stakeholder engagement in forecasting was a common theme from all stakeholders. One stakeholder wants to see scenario-based planning for different DER adoption scenarios as well as mechanisms like Infrastructure as a Service and Distribution Loading Order to provide the framework for evaluating distribution solutions.

Rhode Island System Data Portal

National Grid indicated that it plans to provide DSP information, including heat maps and hosting capacity maps initially, and expand offerings over time. Other commenters wanted more data and functionality as soon as possible. Several stakeholders suggested a Data Portal working group, potentially through existing working groups. Clean energy companies provided detailed recommendations for specific data, information and tools they want to see in a Portal for customer data, system data, and grid modernization data.

Third-Party Data Access

Several commenters asserted that data needs to be accessible, machine-readable, and in a common format. Clean energy firms recommended a data exchange standard, such as Green Button. National Grid emphasized the need for identifying use cases for datasets in conjunction with stakeholders.

In terms of aggregation standards, National Grid described 15/15 as conservative and temporary until there is a statewide standard. Clean energy firms believe a 15/15 standard would be overly restrictive. One company wants a maximum standard like New York, where utilities proposed a 4/50 privacy standard for aggregated whole building data. One stakeholder stated that a 15/15 standard seems low to get any kind of statistical benefit.

Commenters differed on whether the utility should be allowed to charge market rates for "value-added" data. Several commenters contend that any data or information collected by the distribution utility should be considered and treated as public information and made accessible without charge. Others stated that decisions on what constitutes value-added data and associated fees should be made through a docketed proceeding with stakeholder input.

Commenters agreed that annual forecasts and forecast methodologies should be furnished by National Grid and presented in the Rhode Island System Data Portal. Multiple commenters emphasized the importance of opportunities for meaningful input into the forecast during the course of the development process, with drafts made available with sufficient time to provide input. Because the forecast is developed over multiple months, such feedback will need to be considered by National Grid during the development process before the forecast product is finalized.

Regarding hosting capacity analysis, National Grid noted that hosting capacity analysis will only be useful for small projects and might not be sufficient for fast-track approval or detailed interconnection analysis. Clean energy firms provided very specific comments on what analysis is needed in specific situations, which are publicly available in their full comments.

National Grid intends to present a roadmap for the evolution of the heat map in the pending SRP Plan. Several commenters recommend automatic updating of the heat map. Until that point, they want frequent updating of heat maps – with the utility proposing once a year, and various clean energy firms suggesting twice a year, monthly or weekly.

Treatment of Existing Programs

Clean energy firms assert that there is a need for grandfathering existing DER under current compensation mechanisms. Most stakeholders note the importance of aligning DER program objectives with other PST initiative goals, to avoid things like hitting existing caps for renewable energy. One stakeholder notes that locational incentives are only one of many important values that can be better monetized and addressed through net metering policy. One stakeholder noted the complex nature of oversight can be streamlined by merging existing oversight boards into one entity. The siting stakeholder process underway with OER should be informed of the plan for locational incentives to inform locating future DER. The regional planning at Independent System Operator New England should account for DER in regional capacity to ensure that the State does not pay twice for energy needs.

Beneficial Electrification Feedback

The following are highlights of stakeholders' responses to the Commission' *Notice of Inquiry and Request for Stakeholder Comment Regarding a Utility's Role in Deploying Beneficial Electrification with Focus on Plug-in Electric Vehicles*.

Commenter Highlights on Key Goals and Benefits:

1. Broad goals:
    a. Optimize utility investments for a future with a smarter, cleaner and more distributed grid; optimize benefits of a modern grid
    b. Strategic electrification –i.e., powering end-uses with electricity instead of fossil fuels in a way that increases energy efficiency and reduces pollution, while lowering costs to customers and society, as part of an integrated approach to deep decarbonization
    c. Enable the widespread adoption of car-sharing and autonomous vehicles
    d. Ensure fairness, treat EV charging like other potential load, providing nondiscriminatory electric service when and where requested
    e. Lower transportation emissions
    f. Avoid stranded assets
    g. Increase affordability, reduce cost to ratepayers
    h. Incentivize clean alternatives
2. EV and EV supply equipment goals
    a. Increase charging availability, reduce barriers to EV charging, address range anxiety
    b. Educate consumers on EVs (including financial value and usability), promote customer awareness of EVs
    c. Accelerate and "scale" the market, support competition and choice, attract private investment, address key market failures – e.g., in multi-unit dwellings and public infrastructure, encourage interoperability
    d. Increase demand for EVs
    e. Effectively manage the EV load, efficiently utilize EV supply equipment and distribution system infrastructure, capture the benefits of load control and ultimately vehicle-to-grid technology

Commenter Highlights on Analyzing Net Benefits:

1. Commissions should NOT examine the ownership and operation model based on charging for charging, but should instead examine the market for selling charging software and hardware in the absence versus the presence of the utility role or program
2. Investment in EVs themselves (by consumers and fleet operators) should be included by Rhode

Island and its stakeholders when considering the total costs of transportation electrification

3. Alternatives to traditional rate structures which specifically take into account EV load, should be evaluated across all use cases, along with the grid and societal benefits associated with transportation electrification.

When considering whether to expand the role for utilities on the customer side of the meter and into the competitive market, it is important to consider Rhode Island's market today and how it is growing into the future. The private sector is actively selling EV charging stations around the state.

Commenter Highlights on the Utility Role:

1. Overall utility role
    a. There are several roles for utilities in accelerating EV deployment and managing EV load
    b. Transformation of the EV market in Rhode Island requires a scale of planning, coordination, and investment that may not be possible if left to unregulated private sector actors alone
        i. Need a strong utility role in growing and helping scale transportation electrification in Rhode Island
        ii. A strong utility role may be the key to growing EV adoption and scaling the market for EV charging hardware and software in line with the State's goals
    c. Utilities are ideally suited to ensure that the associated new load is incorporated in a safe, reliable, and efficient manner
        i. As the grid manager, the utility will need to manage charging to better integrate it with grid capabilities and needs
        ii. Effectively manage the new EV load either through price signals to drivers or through programs that enable direct load management by the utility to reduce stress on the electrical grid and facilitate the integration of variable renewables
        iii. Develop processes for capturing the benefits of load control and ultimately vehicle-to-grid technology
    d. The utility will treat EV charging like other potential load, providing nondiscriminatory electric service when and where requested
    e. Providing flexibility for the utility to self-select its role(s) is essential for the utility to be excited about its involvement
    f. Avoid stranded assets through hardware/software interoperability to facilitate competition and future investment
    g. Administer a rate structure that sends appropriate price signals for EV charging
2. The utility's role may evolve over time
    a. The most critical role for the utility to play in the near term is as a market accelerator
    b. A deeper role for a utility in growing EV adoption and EV supply equipment deployment is a strong positive for the market, with EV charging software and hardware sellers benefiting from utility procurement or procurement facilitation in the near term, and benefitting from a more robust market over time
    c. A utility program could represent a relatively larger percentage of a given market in the near term, with a diminishing role over time, while begetting a much stronger market over time
    d. Facilitate the buildout of EV supply equipment, especially for stations that would be publicly available

3. Rhode Island should prioritize fostering the continued growth of the competitive EV charging market
    a. Utility investments in and programs related to EVs and EV charging that support third-party markets benefit ratepayers and consumers, and will help to accelerate growth in the market
    b. The utility's entry into the market as a procurer or facilitator can create opportunities
    c. Replicate current models in energy efficiency and renewable energy program administration to encourage EV businesses and efficient markets
4. Utility ownership of EV supply equipment
    a. Make-ready
        i. Rhode Island should direct EV supply equipment investment using a make-ready model and/or direct utility ownership
        ii. Rhode Island should support a make-ready model
    b. The utility should continue to serve as operator of public and private EV supply equipment, through the installation, ownership, and maintenance of EV supply equipment and associated electrical equipment on both the distribution system and behind customers' meters
    c. The utility should generally not be engaged in the business of vehicle charging, whether providing charging equipment or the charging service
    d. The role utilities should play is that of distribution system ownership, operation, and planning, integration, and optimization up until the point of charging stations
    e. At this stage, utility ownership and operation of EV supply equipment (including charging stations) is appropriate and possibly necessary to accelerate the market, support competition and choice, and attract private investment
    f. In the near to medium term, allowing the utility to operate EV supply equipment that is not being sufficiently developed by competitive charging business operators or individual site hosts, could help achieve the State's Zero Emission Vehicles and greenhouse gas goals
5. Education and outreach to customers. National Grid is likely one of the few organizations in the state that has everyone's contact details, leverage this list to communicate the benefits of these programs to help kick start the program
    a. Utility should execute marketing strategy to facilitate EV adoption by communicating incentives, financial value, and usability
6. Utilities should develop incentives towards EV adoption

Commenter Highlights on Cost Recovery:

1. Cost Recovery mechanisms
    a. EV program costs would best be recovered through a traditional cost of service approach, with a return on the capital portion of the total cost
    b. Under revenue decoupling, the Utility cannot retain any revenue increase from higher sales from end-use electrification, so addressing the evolution of decoupling is important
    c. Consider National Grid's proposal in MA for a tariff for concurrent cost recovery through distribution rates
    d. Consider EVs as a NWA in reliability planning
    e. Utility cost-recovery and compensation should be tied to achieving measurable

outcomes and performance benchmarks, tied to the goals and factors discussed above

2. What should utilities achieve cost recovery for?
    a. Utility customer funding is most appropriate for investments (1) that enhance distribution system reliability; (2) that generate broad system and public benefits that are shared across customers, and are not provided already through competitive markets; and (3) where the utility has a unique strategic role
    b. Utility investments should focus on sites that enable EV ownership and that are presently underserved by private sector investment; at this early stage, the Commission should avoid encouraging substantial utility investment in sites that are not routinely visited by individual drivers such as shopping malls or restaurants
    c. Important to have EV supply equipment in disadvantaged communities
    d. The Commission should require that a significant percentage of the utility investment be directed to promoting electrification and EV access in low-income and disadvantaged communities
    e. Utility investment should be in the public interest, meet a need for advancing EVs, and not hinder the development of the competitive EV charging market
    f. Ratepayer-funded investments are not inherently aligned or misaligned with statewide transportation electrification or broader power sector goals; alignment is driven more by how those investments are made and whether they lead to the creation of widespread grid benefits
    g. Consider prioritizing efforts in environmental justice areas
    h. Need EV purchase incentives and electrification of medium and heavy duty fleets and associated infrastructure
    i. Utility programs should target those use cases for EV supply equipment deployment that face higher barriers than others; Rhode Island should increase access to charging outside of the personal, light-duty vehicle market
3. Leveraging other investment
    a. The most efficient and effective way to deploy EV supply equipment where it needs to be is to leverage private funds
    b. Utility investments should be paired with economic incentives for EV purchases through funds from the VW settlement and through limiting, pricing, and reducing carbon pollution from transportation sector, as considered by House Bill 5369 and the State's participation in the Transportation and Climate Initiative
    c. One potential source is market-based transportation climate policy, such as cap-and-invest; could be modeled after the Regional Greenhouse Gas Initiative; another is the VW settlement funds
    d. Regional Greenhouse Gas Initiative is a potential funding source
    e. Consider how to cost-effectively use the Energy Efficiency Program Charge EVs pay
    f. Sometimes it may make sense to complement private investment with other sources of funding – e.g., in multi-unit dwellings, environmental justice communities, or in underserved markets
    g. Site hosts that make a financial contribution are far more likely to actively support the successful installation and ongoing preventive maintenance of the EV supply equipment because they have "skin in the game
    h. Programs should require private matching payments to stretch the value of public investments, efficiently site equipment, and maintain healthy competition

i. Property owners could be offered matching incentives for dollars they put towards installing and maintaining EV supply equipment

Commenter Highlights on Implementation Design:

1. Principles: Stakeholders from across the auto, utility, EV charging, and nonprofit sectors signed onto a series of Guiding Principles for Electric Vehicles and Charging Infrastructure[46] which were signed by nearly 50 industry members including 18 utilities
2. Process:
    a. The Commission should order utilities to propose EV infrastructure plans comparable to those recently submitted by National Grid and Eversource in Massachusetts
    b. It may be better for the Commission to develop a strawman proposal to solicit public input before the utility files a specific docket of its own and triggers all the accompanying rules of engagement.
    c. Develop charging station location strategy overall in order to optimize EV adoption and utilization and grid management
    d. Utility should work with Department of Transportation and agencies or non-governmental organizations to collect data and plan for distribution system upgrades to enable EV supply equipment
    e. Utility should assist in developing budgets for funding system upgrades to enable mass charging
3. Data and metrics:
    a. Utilities should be required to collect EV supply equipment data (Acadia)
    b. Utility should track deficiencies in product capability and provide information to manufacturers, distributors, and developers (Newport Solar)
    c. Utility should track metrics of success (Newport Solar) Complementary policies
    d. Some of the most impactful policies are unrelated to energy policy. For example, building codes can decrease barriers to EV supply equipment deployment by including "EV Ready" requirements
    e. EV-friendly building codes are key
4. Clarifying the regulatory status of third-party providers of EV supply equipment and services helps to provide the regulatory certainty necessary for a competitive charging market and private investment; Rhode Island should determine that the provision of EV charging services is not the generation, transmission, distribution, or sale of electricity to EV drivers
5. Supporting the electrification of public transportation and rapidly shifting forms of mobility (e.g., ride-sharing and ride-hailing fleets) will support equitable access to clean transportation
6. Training and workforce development are necessary investments to complement other EV goals

[46] *See* https://energy.gov/eere/electricvehicles/articles/guiding-principles-promote-electric-vehicles-and-charging

Commenter Highlights on Potential Program Effectiveness Metrics:

1. Station deployment; number of chargers built; number of installations
2. Station reliability and availability
3. EV supply equipment utilization
4. EV rate or program enrollment
5. MWh of off-peak charging
6. Customer savings
7. Customer conversion to EVs
8. Number of registered EVs in service territory
9. Estimated emissions impact
10. Favorable shift in demand
11. Increased EV purchases in multi-unit dwellings
12. Installation and upgrades of distribution assets to encourage EV charging
13. Percentage of incentives consumed
14. The extent to which utility programs support the competitive EV charging market
15. The ratio of PEV to EV supply equipment by application category
16. Indicators of social equity; EV supply equipment deployed by geographic footprint and demographic profile
17. Effect on the efficient usage of the distribution system and avoidance of load-growth driven infrastructure upgrades

Commenter Highlights on Rates for Charging:

1. Time of use or time-varying rates are essential
2. Public education must also include public education with respect to rate design
3. Attain appropriate rate structures; the utility should prioritize smart rate structures; the rate structure should send appropriate price signals for EV charging
4. Alternatives to traditional rate structures should be evaluated
5. Avoid demand charges
6. Fast-charging stations will require individualized rate design treatment, as demand charges are not a workable rate structure for them

Commenter Highlights on Equipment Decisions:

1. EV charging site hosts should be allowed to choose equipment and services to meet the site's specific needs to support ongoing innovation in equipment and services in the competitive EV charging market
2. EV supply equipment requirements are key
    a. Agencies should consider promulgating guidance relating to Level 2 charging stations, station networking capabilities, interoperability, demand response capability, and other potential requirements
    b. As much as practicable, AMF should be required at customer sites with EV supply equipment
    c. The capabilities offered will help to both create grid benefits and give the utility and regulators visibility into consumption patterns and other relevant factors
    d. Access to DC fast charging stations will be important to increase range confidence; this may require more upfront cost and lower initial usage, but it will be important to prioritize as a way to seed early adoption

Commenter Highlights on Electrification of Heat:

1. Further information on air-source heat pumps.
    a. NEEP worked with regional stakeholders to develop a Regional Air Source Heat Pump Market Transformation Strategy Report that provides a collection of priority strategies to drive adoption of air source heat pumps and achieve long-term market transformation
    b. Strategy areas include consumer/installer education, cost reduction, research, improved performance metrics, integrated controls, and state/local policies
    c. Rhode Island stakeholders, including program administrators can continue to stay engaged with the regional effort and leverage resources
    d. NEEP's Cold-climate ASHP Specification can be used to identify efficient air source heat pumps that maintain efficiency even during cold temperatures and to size air source heat pumps effectively.
    e. NEEP Installer Guides can help improve the sizing, selection and installation of air source heat pumps in cold climates
    f. NEEP's Regional Working Group will continue to be a useful forum for regional stakeholder to discuss and coordinate effective market intervention strategies
2. Utility should be involved to stimulate the replacement of inefficient electric or oil heating systems with high efficiency heat pumps

Feedback on Beneficial Electrification

The draft White Paper includes a summary of stakeholder comments until the date of the White Paper release. The key stakeholder comments submitted on this topic since then are summarized here:

Most stakeholders strongly support the Make-Ready approach and stressed the need for EV plans to be rolled out jointly with time-varying rates. Several stakeholders would like more robust expectations and details of beneficial heating. Some stakeholders wish to see well-defined principles based on consensus for EV proposals. Some want to see the Federal Volkswagen Settlement funds as a key piece of the strategy. One stakeholder wants to call on National Grid to propose an EV docket separate from the rate case to allow technical sessions and further stakeholder engagement. Targets should be set with long-view perspective and not just for one-year impact, notes one stakeholder.

Different views were expressed on the utility ownership of EV charging infrastructure as well as utility role in educating customers, with those opposed to the utility role explaining the functions as not natural monopolies and those supportive of the utility role stressing the public policy goals of beneficial electrification and the low market penetration rates. Some expressed support of utility ownership where the private sector has been demonstrably slow to develop solutions.

Several stakeholders want to see more attention paid to beneficial heating. Several stakeholders noted that the current approach through energy efficiency programs is supported and note the importance of monitoring its impacts in the DSP. One stakeholder proposed adding an incentive for innovative partner model that implements thermal energy solutions on a shared basis.