Systems Integration Rhode Island Vision Document

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Glossary of Acronyms

ALM	Active load management
AMI	Advanced metering infrastructure
CVR	Conservation voltage reduction
DEM	Department of Environmental Management
DER	Distributed energy resources
DG	Distributed generation
DOT	Department of Transportation
DPUC	Division of Public Utilities and Carriers
DR	Demand response
DSM	Demand side management
EE	Energy efficiency
EERMC	Energy Efficiency and Resource Management Council
EV	Electric vehicle
GHG	Greenhouse gas
ISR	Infrastructure, Safety, and Reliability
kW	Kilowatt
kWh	Kilowatt-hour
LCP	Least-Cost Procurement
LTC	Long-Term Contracting
MW	Megawatt
MWh	Megawatt-hour
NWA	Non-wires alternative
OER	Office of Energy Resources
OSCC	Ocean State Clean Cities
PBI	Performance-based incentive
PUC	Public Utilities Commission
PV	Photovoltaics
RDM	Revenue decoupling mechanism
RE	Renewable energy
REC	Renewable energy certificate
REG	Renewable Energy Growth
RES	Renewable Energy Standard
RGGI	Regional Greenhouse Gas Initiative
ROE	Return on equity
SIRI	Systems Integration Rhode Island
SOS	Standard Offer Supply
SRP	System Reliability Procurement
TRC	Total resource cost
TVR	Time-varying rates
VVO	Volt/VAR optimization
ZEV	Zero emission vehicle

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1. Introduction

Rhode Island's energy system is at the cusp of a fundamental long-term transformation. Our electric grid is becoming increasingly more complex as consumers adopt distributed energy resources—energy efficiency, demand response, renewable energy, and energy storage, among others. New electric technologies are entering the home heating and transportation markets—from highly efficient cold climate heat pumps to electric vehicles. These resources and technologies are becoming more affordable and widely available; many of them benefit from Rhode Island's strong state support, public policies, and goals for clean energy deployment and greenhouse gas emissions reduction. The changing nature and growth of customer resources holds significant implications for the state's electric grid and grid managers.

As Rhode Island's energy system evolves, we face new challenges and opportunities. Utility operators will need to manage distributed generation in a system originally designed for centralized production and one-way power flow. This new requirement at the distribution level will entail new types of investment and operating expertise to allow management of distributed resources in a manner that enables more efficient solutions for customers. At the same time, some distributed energy resources offer the promise of creative new ways to manage and optimize energy demand. Furthermore, utility planners can reduce, defer, or possibly avoid traditional investments in certain types of grid infrastructure to meet growing electric demand by using strategically deployed energy efficiency, renewable energy, or other "non-wires alternatives" projects. For utility regulators, the changing system may raise new questions about traditional utility planning processes, rate structures, cost recovery mechanisms, incentives and weighing the benefits and costs of new investments. As Rhode Island successfully facilitates a transition to a more distributed grid that values, integrates, and plans for growth in customer resources, it will stimulate further economic development in its clean energy industry sector; give consumers and communities more opportunities to take control of and manage their energy costs and preferences for greater system efficiency; lower costs than would otherwise be experienced in the future; and help the state meet climate goals by reducing greenhouse gas emissions.

In order to better understand the challenges and capitalize on the opportunities described above, representatives from the Office of Energy Resources (OER), the Energy Efficiency and Resource Management Council (EERMC), the Distributed Generation Board (DG Board), and National Grid convened a "Systems Integration Rhode Island" (SIRI) working group during 2014-2015. The idea of "systems integration" recognizes that Rhode Island already has several focused, strong, and effective energy processes that can be built upon to support the achievement of future objectives for the electric grid. **The purpose of the SIRI group was to take a first step at mapping out key issues related to the future of Rhode Island's electric grid and offer early stage recommendations for addressing opportunities, filling gaps, and gaining efficiencies in existing state processes[7].** SIRI is particularly focused on the short to medium

[7] This SIRI report is intended to be a resource for decision-makers. The document itself holds no regulatory authority. The purpose of this report is to provide a framework of understanding and a collective roadmap for interested parties—including the utility, utility regulators, and key energy stakeholders—in order to identify areas of mutual collaboration, guide near-term efforts, assist in acquiring and applying new information, and facilitate the development of future proposals. Some recommendations from this report may rise to the level of needing PUC attention; others may not.

term, but is also motivated by longer term technology trends and clean energy goals. This report raises prospective recommendations for Rhode Island processes in order to advance outcomes relative to state priorities, including achieving energy, economic, and environmental goals while providing safe, reliable and efficient service to customers at a reasonable price. Members approach these recommendations from the perspective that regulators, the utility, and other stakeholders have been working diligently to meet obligations under current programs and expectations; the recommendations of this report both acknowledges the good work done to date, but also focuses on future opportunities and process improvements that will lead to beneficial outcomes from utility and regulatory activities. The SIRI members undertook the following tasks, which are documented in this SIRI vision document:

- Define what "systems integration" means for Rhode Island within the context of the newly-approved State Energy Plan and ongoing energy/grid planning, procurement, and investment processes;
- Inventory and map out the applicable existing energy policy/regulatory processes in Rhode Island and their interaction;
- Propose preliminary approaches and recommendations for addressing key issues; and
- Establish a work plan, based on the recommendations, that defines next steps and milestones related to systems integration.

2. Defining "Systems Integration"

In this SIRI vision document, a few words are used to describe activities and actors that contribute to managing the energy system in Rhode Island. These terms include *process*, *stakeholder*, and *system*. To ensure this report communicates clearly, these terms are defined and distinguished below.

- **"Process"** is a specific activity related to energy/grid planning, procurement, or investment that is named in statute, or performed in Public Utilities Commission (PUC) practice. For example, System Reliability Procurement (SRP) is a process called for in Rhode Island statute that specifically involves the utility, the Energy Efficiency and Resource Management Council (EERMC), the Office of Energy Resources (OER), and the PUC.
- **"Stakeholder"** is an agency, council, or other participating group in a process. For example, the utility, the PUC, the EERMC, OER, and the Demand Side Management (DSM) Collaborative are the typical involved stakeholders in SRP. See Table 1 for further information.
- **"System"** refers to how processes and stakeholders may interact to form an overall result. For example, many processes and stakeholders are involved with determining how energy efficiency is deployed in Rhode Island.
- **"Systems Integration"** refers to the intentional and thoughtful coordination of existing systems (i.e. processes and stakeholders), so as to harmonize them with the ability to achieve stated goals. While there is currently some coordination among processes and stakeholders, SIRI asks the following questions to examine potential improvements:

- **What steps can Rhode Island take today to put us on a path to achieve our energy goals?**
- **What can Rhode Island achieve if all processes are tuned to work optimally together?**
- **After considering how the integration of existing processes can be improved and maximized, what are the remaining gaps, and what new or revised processes will address them?**

3. SIRI Goals, Foundations, and Principles

Through a series of discussions and meetings, the SIRI team developed an articulation of goals, foundations, and principles. These goals, foundations, and principles guided the overall SIRI effort and approach. The SIRI team offers the following definitions for goals, foundations, and principles:

- **"Goals"** are desired energy, economic, and environmental outcomes for the state's energy system, as established in Rhode Island's public policy and by previous stakeholder- and data-driven energy planning efforts.
- **"Foundations"** describe attributes Rhode Island stakeholders seek in the state's energy/grid planning, procurement, and investment processes in order to enable the attainment of the stated goals.
- **"Principles"** were used to guide the SIRI team's evaluation of state processes and embody the participants' approach to considering systems integration.

Goals

The SIRI effort proceeds within the context of overarching goals set by Rhode Island for the future of the state's energy system. These goals are established in the recently adopted 10-year update to the Rhode Island State Energy Plan[8] (RISEP, or Plan).

The vision of the Plan is to provide energy services across all sectors—electricity, thermal, and transportation—using a secure, cost-effective, and sustainable energy system. The Plan's data-driven scenario modeling showed that Rhode Island can: (1) increase fuel diversity in each sector above current levels, (2) produce economy-wide net benefits, and (3) reduce greenhouse gas emissions by 45 percent (below 1990 levels) by 2035 with an "all-of-the-above" clean energy framework to:

- **Maximize energy efficiency in all sectors;**
- **Promote local and regional renewable energy;**
- **Develop markets for alternative thermal and transportation fuels;**
- **Make strategic investments in energy infrastructure;**
- **Mobilize capital and reduce costs;**
- **Reduce greenhouse gas emissions; and**
- **Lead by example.**

[8] http://www.planning.ri.gov/documents/LU/energy/energy15.pdf

Based on the results of the Plan, SIRI recognizes that Rhode Island is committed to goals for its energy sector that position the state for future economic, environmental, and social imperatives while managing present realities, balancing costs, and furthering state priorities.

Foundations

Achieving Rhode Island's energy goals is anticipated to involve significant changes in the electric sector, which will become more distributed and will converge with the thermal and transportation sectors. The SIRI team notes the following foundations relative to utilities and utility regulation as existing processes and systems are evaluated:

- **Enable Customers:** Customers will be viable sources of energy resources ("prosumers"[9]) through a proper balance of both utility regulation and markets. Rhode Island will embrace cost-effective customer/distributed energy solutions as integral elements of the vision for its energy system.
- **Manage Costs:** Clean energy goals and desired services will cost no more to achieve than necessary.
- **Reveal, Monetize Value:** Processes and systems will motivate value-based resource investments from customers and the utility.
- **Minimize Barriers:** Decision-makers will work to improve the existing regulatory process if it proves to be an obstacle to effective investments by the utility and customers, while still protecting the public interest.
- **Maintain Strong, Capable Delivery Utility:** Rhode Island citizens, businesses and institutions will be served by a strong, capable utility enabled by appropriate regulatory oversight.
- **Simplify the Experience:** As the evolving distribution system increases customer choice and introduces new technical, planning, and regulatory complexities, decision-makers will adapt processes and systems to simplify the new paradigm for customers, regulated companies, and market participants where possible to facilitate understanding and informed decision-making.

Principles

On paths toward the goals stated above, Rhode Island has already seen significant steady progress. Learning from experiences and methods in Rhode Island and elsewhere, while gradually applying those lessons and deploying new technologies as appropriate, will continue this trend.

Current processes for grid system planning and investment are robust, support the state's goals, and will continue to be important (these processes are discussed in the following section). However, essential gaps and areas for improvement exist. Many of these processes are under the supervision of the PUC and directly engage key stakeholders: the utility, the DPUC, OER, and

[9] Prosumer in the context of electricity is a word appropriated from futurist Alvin Toffler and other technology areas. Smart Grid Library describes the Prosumer as having an interdependent relationship in which the utility may rely on commitments to reduce electricity use (negawatt production) or supply electricity to the grid (kilowatt production) at specified times. At other times, the Prosumer may be reliant on the utility to supply kilowatts.

other groups that routinely demonstrate commitment to helping Rhode Island arrive at sound results. The transparency of the PUC process provides a public window into these processes. These processes can be periodically assessed and potentially updated to assure they are integrated well, informing each other and maximizing their value. This SIRI document represents the assessment underway in 2015.

SIRI is a process considering all elements of the Rhode Island energy system, engaging many stakeholders with a full range of roles, and ultimately, all Rhode Islanders. The SIRI effort will proceed with the following principles:

- **Promote an integrated and strategic approach across all regulatory and planning processes;**
- **Build on existing processes and systems;**
- **Identify gaps and missed connections, then consider adjustments or additions to processes and systems to fill gaps and make connections;**
- **Identify and use metrics to measure progress; and**
- **Use public input to inform actions and keep the process to consider and execute SIRI report recommendations transparent.**

4. Mapping Existing Processes

To better characterize the opportunities for systems integration, the SIRI team inventoried and mapped out the applicable existing energy policy/regulatory processes in Rhode Island and their interaction.

Rhode Island is already taking important steps to transition to the future envisioned in the State Energy Plan. These steps include several existing processes and systems related to planning for energy supply, infrastructure, non-wires strategies, and distributed energy resources (DER) investment. **This SIRI report identifies thirteen distinct processes in which state regulation influences electricity consumers, utilities, and private sector actors to consider the state's priorities on climate, clean energy, and customers.** To help readers build a framework to appreciate these processes, the SIRI report bins the processes into three categories: (1) Customer-Facing, (2) Renewable Energy Promotion, and (3) Grid Planning, Procurement and Investment. **Table 1** displays a summary table of these processes. In the table, the list of stakeholders represents those involved on a routine basis in each process; it is not intended to represent an exclusive list. The table lists primarily public entity stakeholders; some other stakeholders including industry representatives and advocacy groups also regularly engage in certain processes.

The SIRI team took the following approach to consider these processes through the lens of systems integration:

- List and characterize current Rhode Island energy processes;
- Reflect on how the processes interact with and inform each other;
- Note gaps or barriers in the ways the processes interact and inform each other; and
- Identify and discuss opportunities for improvements in the performance of the processes to further Rhode Island energy goals.

Appendix A provides a detailed treatment of the existing processes and their relationships. The appendix gives a brief summary of each process, and then examines how each process interacts with the other processes as nested in the three categories noted above. Gaps were identified where processes did not address state priorities, and recommendations to address these gaps are noted in the "Recommendations" section below.

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Table 1. Rhode Island Grid/Energy Planning, Procurement, and Investment Processes

Cate-gory	Process	Typical Stakeholders[10]	Description
Customer-Facing Processes	Energy Efficiency Program/Least-Cost Procurement[i,ii]	PUC, NGRID, EERMC, OER, DPUC, DSM Collaborative	Requires electric distribution companies to invest in all cost-effective electric and natural gas energy efficiency before the acquisition of additional supply
	Ratemaking – Delivery Prices[iii,iv,v,vi]	PUC, NGRID, DPUC	Sets rates for delivery service by the distribution utility
	Retail Choice[vii]	PUC, NGRID, Competitive Suppliers	Allows consumers and businesses to choose a competitive power provider for their electricity service, while still relying on the local electric utility for distribution service
	Interconnection Standards[viii]	PUC, NGRID	Sets the process and requirements for connecting a power-generating facility to the electric distribution system, including technical and operating requirements, metering and billing options
Renewable Energy Promotion Processes	Renewable Energy Growth Program[ix,x]	PUC, NGRID, DG Board, OER	Establishes a system of performance-based incentives set in PUC tariffs to support the development of 160 MW of new in-state renewable energy projects between 2015 and 2019
	Net Metering[xi,xii]	PUC, NGRID	Requires electric distribution companies to credit energy produced by small renewable energy systems (under 5 MW) installed on the customer's side of the electric meter
	Renewable Energy Standard[xiii,xiv]	PUC, NGRID, Competitive Suppliers	Requires state retail electricity providers to supply 14.5 percent of retail electricity sales from eligible renewable energy resources by 2019
	Long-Term Contracting Standard for Renewable Energy[xv]	PUC, NGRID	Requires electric distribution companies to enter into long-term contracts for a minimum of 90 MW of newly developed renewable energy resources by December 31, 2014. Also provides for the consideration of a long-term contract for up to 150 MW of offshore wind.
Grid Planning, Procurement and Investment Processes	System Reliability Procurement/ Least-Cost Procurement [xvi,xvii]	PUC, NGRID, EERMC, OER, DSM Collaborative	Requires electric distribution companies to strategically consider customer- and utility-sited energy resources ("non-wires alternatives") in distribution system planning
	Infrastructure, Safety, and Reliability Plan[11,xviii,xix,xx]	PUC, NGRID, DPUC	Provides for prospective recovery of forecasted investment in the electric distribution system with a full reconciliation to actual investment after the fiscal year
	Utility Financial Incentive	PUC, NGRID	Sets the structure and rate at which the utility is compensated for services it provides to customers
	Standard Offer Supply Plan[xxi,xxii]	PUC, NGRID	Requires electric distribution companies to plan and procure a standard power supply offer for customers that are not buying electricity from a competitive supplier
	Environmental Regulation[xxiii,xxiv]	DEM, OER, NGRID	Sets requirements for environmental compliance through the federal Clean Air Act, Regional Greenhouse Gas Initiative, and state Resilient Rhode Island Act

[10] Because both the PUC and DEM hold regulatory authority, they may be considered to have a distinct role (i.e. decision-making) in processes as compared to other typical stakeholders.

[11] Throughout this document, both *ISR* and *distribution planning* are referenced. *ISR* and *distribution planning* are related, but distinct processes. *ISR* is a spending plan for the next fiscal year while distribution planning is focused on future years. *Distribution planning* is where load forecasting occurs, infrastructure needs are identified, and projects are proposed. This is the stage where infrastructure projects are evaluated for eligibility for "non-wires alternatives" solutions. *ISR* is the stage where National Grid selects infrastructure projects already identified in *distribution planning* to be considered by the PUC for prospective recovery of forecasted investment for the next fiscal year.

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5. Test Cases

The SIRI team considered five "test case" scenarios to better understand the effect of the existing processes on key issues related to Rhode Island's evolving electric grid and the state's energy goals. **The team evaluated how a select group of resource, end use, and grid planning outcomes would be promoted or inhibited by existing processes**. The following test cases were examined:

- Non-wires solutions in utility planning: Chosen as a test case because of the current limited focus of SRP and the desire to see broader application.
- Solar PV deployment: Chosen because of the number of processes focused on renewables in Rhode Island, particularly solar PV.
- Strategic electrification – heating: Chosen because it was already recognized as an area where current processes are not adequately addressing the perceived opportunity.
- Strategic electrification – transportation: Chosen because it represents a significant potentially transformative change to the electric grid.
- Active load management: Chosen because it is the prototypical example of a more dynamic two-way electricity grid.

The test cases were chosen for strategic reasons. All the test cases reflect a common theme of electricity customers becoming more integrated with the power grid with regard to both how the grid operates and also how investment flows to change the grid over time. **Appendix B** provides a detailed treatment of the test cases. For each test case, the appendix provides a summary of the current status of the applicable resource, end use, or grid planning outcome. Then, the test case is considered through the lens of each existing process as it currently operates. A list of synergies and barriers are identified within each existing process for the applicable test case. Gaps and recommendations are identified where processes do not adequately address the test case, which are synthesized in the "Recommendations" section below[12].

6. Recommendations

The body of this report concludes with this section presenting six overarching recommendations for systems integration in Rhode Island distilled from the process mapping and test case exercises. Each recommendation includes a "Description of Need" and a list of next step recommendations with a time estimate from SIRI members for when action on each step is realistic. In some cases background information is useful to appreciate the recommendations, and in those situations it precedes these elements.

[12] It should be noted that the test cases as represented in **Appendix B** are working documents developed by the SIRI team, and not every member may agree with every statement in the test cases. The test cases have been included as an appendix in order to exhibit the detailed group reflections and discussions that informed the development of recommendations. The recommendations that follow in the next section—not the bulleted recommendations in the individual test cases—represent the consensus recommendations of the SIRI team. Furthermore, although the recommendations sprung from the test cases, the recommendations were not intended to be solely linked with the test cases; the recommendations are broader than just the test cases themselves.

The following recommendations should be considered as early stage, near-term recommendations for systems integration in Rhode Island[13]. The list of recommended actions is not necessarily comprehensive, nor does it attempt to grapple with the full scope of policy, regulatory, and technical challenges that Rhode Island will face as its electric distribution grid evolves in the coming years. The SIRI team recognizes that further efforts and discussions will certainly be needed to flesh out the full range of issues at hand, as well as to delve deeper into the details of the recommendations described below.

Furthermore, the following recommendations should be understood as forward-looking. The SIRI team recognizes that both National Grid and other stakeholders have been working diligently to meet obligations under current programs and expectations. The SIRI report recommendations both acknowledge the good work done to date, but also focus on future opportunities and needs to unlock new potential in our future electric grid planning and investments.

The recommendations contain individual follow-up items and work tasks, with associated timeframes. Members have estimated when each recommendation can see action. Note that the group has not done a detailed planning exercise that identifies all conflicts and contingencies among these recommendations. Thus, some dates may be found after future analysis in follow on work to this report to be optimistic or unrealistic.

One overarching observation made by the SIRI team (not presented as an individual recommendation here) is the value to creating complementary ways to assure that customers can be aware of opportunities for and pursue all cost-effective investments in distributed energy resources at their premises. Over the last several years, Rhode Islanders have had increased access to many opportunities to invest in distributed energy resources, including an array of state programs. Energy consumers may not appreciate (and do not necessarily need to appreciate) the opportunities that EE, load management, and DG offer to the grid and the ways in which these technologies could interact. Optimal investment by customers in energy systems and services for themselves and as resources for the power system will require additional awareness and educational outreach and may depend in part on accurate price and other signals presented through utility regulation, vendor proposals, and the market. Customers should have greater opportunities for comprehensive energy efficiency and clean on-site generation services with proper attention to protecting consumers as they consider these investments. Consistent messaging and streamlined processes for consumers will support systems integration in Rhode Island.

[13] It should be noted that each recommendation has potential paths for implementation: change in process, regulatory, and legislative. Consistent with the principle of building on existing processes, the SIRI team expressly recommends seeking regulatory changes only where a change in process cannot address the issue at hand, and likewise, seeking a legislative solution only where a regulatory change or change in process is insufficient.

Recommendation #1: Identify ways to promote more cost-effective, comprehensive NWA distribution planning.

Description of Need

Rhode Island has a unique System Reliability Procurement (SRP) law, which requires the utility to strategically consider an array of diverse energy resources and strategies to maximize their benefit to the state's energy system. The Energy Efficiency and Resource Management Council (EERMC) originally interpreted the SRP law to mean "non-wires alternatives" (NWA), which include resources such as cost-effective energy efficiency measures targeted to reduce peak loads; distributed generation at or near loads; and demand response measures that reduce peak loads on the electricity grid. Subsequently, the EERMC developed SRP Standards[14] with National Grid to lay out a specific process for identifying and implementing NWA solutions that could cost-effectively defer or avoid certain types of traditional distribution system investments. These distribution system capital upgrades are identified in the distribution planning process and considered by the PUC for prospective recovery of forecasted investment in the annual Infrastructure, Safety, and Reliability (ISR) Plans. There are currently several gaps and barriers[15], however, to more fully utilize cost-effective NWA solutions in distribution planning in Rhode Island (in no particular ranking):

- **Limited opportunities for stakeholder engagement:** Although all parties may intervene in PUC dockets, currently there is no established process for stakeholders to provide collaborative input into the utility's distribution planning process. Other processes such as EE, SRP, and REG draw on collaborative review processes involving a broader range of stakeholders. There are interested stakeholders (e.g. OER, the EERMC, and the DG Board) who would benefit from a robust understanding of the details of the distribution planning process and an efficient and effective channel with which to engage and provide input.
- **Incomplete coordination between processes:** At present, it does appear that SRP is beginning to integrate with distribution planning and EE. However, SRP and the current utility distribution planning process do not formally integrate with any renewable energy promotion processes, in particular, REG and net metering. The locational value of renewable energy is not currently reflected in REG or net metering, and forecasts of DG deployed through these processes are not incorporated into distribution planning. Currently, locational decisions are customer choices which are not known to the utility until the customer applies for interconnection services. In addition to renewable energy,

[14] Per § 39-1-27.7(c)(2), "The commission shall issue standards not later than June 1, 2008, with regard to plans for system reliability and energy efficiency and conservation procurement." The EE and SRP Standards are updated triennially and were last revised in 2014. They may be found here: http://www.ripuc.org/eventsactions/docket/4443-EERMC-LCPS-Final_5-27-14.pdf.

[15] A primary, ongoing experience with NWA planning is the current SRP pilot "DemandLink" in Tiverton and Little Compton. In addition to the systems integration gaps and barriers listed in this recommendation, National Grid has also learned from other program implementation challenges with the DemandLink pilot. Specifically, Grid has found that marketing and customer engagement is a key hurdle to recruit and retain customers to provide sustained load relief through a multi-year EE- and DR-focused NWA program.

there are also other promising NWA technologies with distribution benefits—such as conservation voltage reduction (CVR) and Volt/VAR optimization (VVO)—that are deployed through existing processes that do not link clearly to SRP. Finally, there are technologies/strategies eligible under the SRP Standards for which there aren't other existing utility or state processes (e.g. EVs, storage, time-varying rates).

- **Limited application of NWA solutions to date:** Utility distribution planning does not currently screen for "partial" NWA solutions; however, a methodology for "partial" NWAs will be examined during 2016. Additionally, based on the current eligibility criteria for NWA consideration, very few NWA solutions have been proposed in recent years. Furthermore, traditional wires solutions typically address the grid's capacity and asset condition issues in a combined manner as a result of the comprehensive nature of these projects. In these cases, while a non-wires solution could defer the project from a capacity perspective, it cannot defer the project from an asset condition perspective.
- **Restricted funding:** NWA solutions are proposed in the SRP, which currently relies on funding raised through the EE Program. Therefore, SRP in essence competes for funding with the EE Program (and by extension, other items on the distribution bill), which is subject to perennial budget pressures.
- **Inadequate utility financial incentive:** National Grid receives no incentive at all for successfully implementing NWA solutions in SRP. Therefore, the incentive structure in place does not encourage the utility to maximize the use of NWA solutions or encourage the utility to commit long-term resources toward NWA development.

Recommendations

SIRI finds that a broader interpretation of the SRP law could provide greater benefits to consumers and the grid, and SIRI finds that opportunities exist to expand the SRP Standards to align with other processes like distribution planning, REG, and net metering. All recommendations below should proceed with the timetable of the upcoming triennial EE and SRP Standards review process in mind. This update will occur in late 2016 to early 2017. Many of the following recommendations will generate key findings, outcomes, and understandings that are necessary ingredients for the Standards review and update. In addition, there are a wide variety of customer- and grid-side resources, technologies, and strategies that have the potential to provide distribution benefits to the grid, which include, but are not limited to: energy efficiency (EE), renewable energy (RE), demand response (DR), combined heat and power (CHP), energy storage, electric vehicles (EV), active load management (ALM), rate design, and conservation voltage reduction (CVR) and Volt/VAR optimization (VVO). As implementation of the recommendations below proceeds, efforts should be made to account for the full range and diversity of strategies and technologies, and integrate all cost-effective opportunities for these various NWA into distribution planning and investment.

1. **Increase collaborative engagement in the distribution planning process**
   Discuss with electric distribution planning staff at National Grid ways to address a gap in stakeholder engagement. Start by confirming the set of interested stakeholders (e.g. OER, the EERMC, and the DG Board), then identify or create opportunities outside of PUC dockets for these stakeholders to engage with the utility on distribution investments pertaining to load growth. Ideal solutions would be meetings with stakeholders and utility planners. (Late 2015 – Early 2016).

2. **Improve coordination of distribution planning/SRP with other processes**
   Once appropriate stakeholders are identified, they should work with National Grid to explicitly clarify the relationship between ISR, distribution planning, SRP, EE, REG, net metering, and any other applicable processes. Without pre-judging how the distribution planning process or any other process would produce different results, outcomes should include the following:
   a. Implement the "locational incentive" provision of the REG in order to provide price signals to develop solar and other renewables where they are needed the most and enable solar markets to proceed reflecting this value.
      i. Establish a sub-group for National Grid work with OER, the EERMC, and the DG Board identify the required information and data. Determine if a follow-on study to the Peregrine report[16] is needed to identify the locational value of solar in throughout the state in REG or net metering (Late 2015).
      ii. As part of this process, ensure that renewable energy companies have access to regularly updated information about optimal circuits and feeders to propose projects. Work with the utility and stakeholders to identify key issues with integrating DER and ways to enhance the ability of the grid to do so (Mid 2016 – 2017).
   b. Concurrently, determine if and how distribution planning/SRP can be coordinated with net metering to offer enhanced incentives above what is currently available to promote the development of DG where it is most needed, if determined to be cost-effective. Available solutions may be limited by the structure of the current net metering statute (Early – Late 2016).
   c. Work with National Grid distribution planning to determine how and to what extent forecasted DG from REG, net metering, and any other applicable renewable energy promotion processes can be incorporated into distribution planning. Also consider how this can be done for other forms of DER and for strategic electrification in the longer term. All forecasts should address probabilistic issues—in other words, the relative certainty of the DG projections (2016 – 2017).
   d. Ensure that any resulting information from 2.c above is coordinated with Grid's current "long-range capacity plan" and future distribution planning where appropriate. Gain an understanding of how the long-range capacity plan and ISR could be used to merge traditional "poles and wires" approaches with new technologies in a multi-year, strategic approach (2016 – 2017).
   e. Consider whether conservation voltage reduction (CVR) and Volt/VAR optimization (VVO) should be developed in distribution planning /ISR as a system performance and capacity project or in energy efficiency as an efficiency

[16] "Solar PV for Distribution Grid Support: The Rhode Island System Reliability Procurement Solar Distributed Generation Pilot Project" by Peregrine Energy Group, Inc., accessible at http://www.energy.ri.gov/documents/SRP/RI-SRP-PV_Report_Peregrine-team_07-16-2014.pdf.

measure that saves energy in the affected portion of the distribution network. Explore characterization of CVR/VVO as EE technologies/measures as part of this consideration. Also, consider how to treat other eligible NWA for which there are no existing utility or state processes (e.g. EVs, storage) (2016).

3. **Fulfill objective of executing on all cost-effective NWA opportunities**
    a. Work with National Grid to better understand the overlap between "asset condition" and "load relief" projects as identified in distribution planning and proposed in the ISR. There is a significant and growing portion of the planning process and ISR related to load relief projects, but National Grid has indicated that, in many cases, some portion of these projects typically address asset condition and reliability improvements. Furthermore, National Grid has indicated that asset condition is the primary criteria in the SRP Standards that projects tend to fail. Therefore, understanding the dynamic between asset condition and load relief projects is necessary information for the future update of the Standards to potentially open up more projects to NWA eligibility (Late 2015 – Early 2016).
    b. Work with National Grid as part of their 2016 SRP Plan to develop and review a methodology for considering "partial" NWA options. It is anticipated that the methodology could be applied in the 2017 SRP Plan, with application of criteria and possible inclusion of partial NWA in the 2017 SRP Plan (2016 – 2017).
    c. Determine viability of obtaining information to better quantify the value of NWA/EE on the grid by looking back retroactively to see what the $ value of the EE/NWA would have been. Determine viability of assessing to what extent Rhode Island's deep levels of EE investment are avoiding capacity-related upgrade projects before they are even identified (2016).
    d. Identify the proper cost-effectiveness test to use for the value proposition of NWA. Such a test would need to appropriately consider the pros and cons of different options in a way that makes sense for comparing wires versus non-wires solutions (2016).
    e. In triennial SRP Standards review process, re-draft Standards to include guidance for partial NWA screening, coordination with REG/net metering if found appropriate, and any other important considerations (Late 2016 – Early 2017).

4. **Explore ways to address funding issues**
    a. NWA solutions are proposed in the SRP, which currently relies on funding raised through the EE Program. Therefore, SRP in essence competes for funding with the EE Program (and by extension, other items on the distribution bill), which is subject to perennial budget pressures. Convene interested stakeholders to examine this issue (Mid 2016).

5. **Create a suitable financial incentive for NWA distribution planning**
    a. See Recommendation #6 below.

DRAFT

Recommendation #2: Assess market potential, costs, and benefits of strategic electrification and active load management.

Description of Need

There are several promising strategies that may provide cost-effective energy, economic, and environmental benefits to Rhode Island. Two such strategies identified by the SIRI team are strategic electrification for heating and active load management (ALM). These strategies have been explored only on a very limited basis to date in Rhode Island. Some aspects of these strategies could require enabling technology—e.g., advanced metering infrastructure—to be implemented. Both would likely require additional incremental funding above investments currently being made through existing processes such as the Energy Efficiency Program, System Reliability Procurement or the Infrastructure, Safety, and Reliability Plan. However, they might provide benefits that outweigh the costs. In either case, limited or no information is available on the market potential, costs, and benefits of implementing these strategies. Additionally, the issue of how customer load and demand management can reduce actual supply costs to customers (by enabling lower cost purchases for Standard Offer Service, for instance) is not clear in a retail choice state.

In addition to the funding gap, other barriers currently prevent these strategies from being pursued through existing processes, such as the EE Program. In the case of strategic electrification, for instance, the goals and incentive structure of the EE Program are not a good fit since strategic electrification may increase electric use (see test case for further details). Therefore, goal-setting and screening might have to proceed in a separate but parallel manner to existing processes.

Recommendations

Improving our understanding of the energy system impacts of high-efficiency electric heat and ALM will be critical for: 1) determining Rhode Island's energy savings targets for 2018-2020; 2) updating the EE and SRP Standards; and 3) developing the 2018-2020 EE and SRP Plans. Below are recommended steps to improving our understanding of heat pumps and ALM.

1. **Continue to gather data and information through ongoing programs and pilot experiences**
    a. Review results of Cool Smart evaluation study on field performance of RI and MA cold climate heat pumps and customer experiences when completed (Late 2015 – Early 2016).
    b. Determine information-gathering needs pertaining to characterizing potential impacts of new summer and/or winter peaks on distribution system due to increasing heat pump use (2016).
    c. Review results of Tabors Caramanis Rudkevich (TCR) study for National Grid to obtain avoided cost value for super peak time period to enable screening of demand response in the EE Plans in time for the implementation of the 2016 Plan (Late 2015).
    d. Obtain lessons from National Grid's "Smart Energy Solutions" pilot in Worcester, MA (2016).

e. Complete market assessment regarding potential for DR. For example, what part of the market is already being served by companies and what initiatives would provide the most benefit to address market gaps and fulfill capturing DR potential? (2016).
f. In the EE program, assess utilizing Wi-Fi thermostats and communicating appliances for DR program (2016).
g. In the EE Program, examine the potential for a pilot that can promote ALM without meters (i.e. radio, internet Wi-Fi, etc.) (2016).

2. **Explore formal incorporation of strategic electrification and ALM into EE Program process**
    a. Request that National Grid provide an updated version of its current fuel switching policy (Fall 2015).
    b. Draft a formal document analyzing the justification for strategic electrification and ALM within the LCP framework. Obtain legal opinion on whether the LCP law authorizes the use of strategic electrification and/or ALM under the EE Program. Following this, request that the PUC issue a clarification on the status of fuel switching as a utility activity. If statutory changes are needed, consider pursuing such changes in the 2016 legislative session (Fall 2015).
    c. Contingent on result of legal opinion, recommend that the EERMC commission two new "potential studies" that examine the market potential, costs, and benefits of ALM and strategic electrification (Fall 2015).
    d. Based on results of the potential studies, determine viability of tracks for ALM and strategic electrification under LCP alongside traditional EE (Late 2016).
    e. Assess the need for unique goals, budgets, and incentive structures for ALM[17] and strategic electrification—aiming for completion in time for the next round of 3-year target-setting. This could also include an assessment of potential new revenue by selling aggregated ALM into ISO markets (Mid 2016).
    f. In triennial EE and SRP Standards review process, re-draft Standards to include guidance for screening and deploying ALM and strategic electrification (Early 2017).
    g. Conduct additional pilot, evaluation, or demonstration studies as needed to supplement information necessary before taking any recommendation to scale (2016 – 2017).
    h. Aim to fully incorporate EE, strategic electrification, and ALM into the next 3-Year Plan (Mid 2017).

[17] Traditional targets as expressed in total kWh saved are likely not appropriate for ALM. The design could instead focus on threshold levels of demand or prices.

Recommendation #3: Pave the way for accelerated use of electric vehicles.

Description of Need

Electrification of the transportation sector through the increasing use of electric vehicles will help Rhode Island achieve energy, economic, climate, and air quality goals. Rhode Island is a signatory to the Zero Emission Vehicle (ZEV) Memorandum of Understanding (MOU), which is an agreement among eight states to promote the adoption of ZEVs. The signatory states have a goal of at least 3.3 million ZEVs operating on their roadways by 2025. Rhode Island's individual portion of this goal is 43,000 EVs in the state by 2025, or approximately 6% of the state's light duty vehicle fleet.

Rhode Island established a ZEV Working Group in 2014 in order to discuss actions necessary to promote the responsible growth of the ZEV market in Rhode Island. Members of the group include OER, the Department of Environmental Management (DEM), the Department of Transportation (DOT), Ocean State Clean Cities (OSCC), other state and quasi-state agencies, private and nonprofit companies, auto dealers, and utility providers. The working group has been tasked with exploring issues critical to the efficient and effective deployment of ZEV solutions across the policy, regulatory, and business landscapes. As of the writing of this report, the working group is in the midst of completing a State of Rhode Island Zero Emission Vehicle Action Plan, anticipated to be completed by the end of 2015.

As of August 2015, 421 electric vehicles were registered in Rhode Island. Almost all have been registered in the past four years. Achieving a goal of 43,000 ZEVs in the state by 2025 would represent a significant growth in electric vehicle use in Rhode Island. No information has been developed yet on the impacts of achieving this goal: What does the increased electric load look like? Where will it be located? How will that load be served? How can these new resources bring benefits to the grid and be seamlessly integrated into planning and ultimately, grid operations?

Recommendations

The ZEV working group has identified high- and/or near-term priority action items regarding the EV market in Rhode Island. Specific items were highlighted relative to regulatory and utility issues pertaining to EVs. The Action Plan specifies lead and supporting parties for each action item. The following list of recommended next steps draws on the action items listed by the ZEV working group, and blends in some additional observations on EVs made by the SIRI team:

1. Request clarification from the PUC to ensure electric vehicle service providers or others that operate charging facilities for the sole purpose of providing electricity as a transportation fuel are not defined as a "public utility" and therefore are not subject to regulation as a utility (Fall 2015).
2. Identify necessary legislation, regulations, standards, or certifications to enable the commercial sale of electric vehicle charging as transportation fuel, including on a per-kilowatt-hour or on a per-kilogram basis, and ensure transparent pricing (2016).
3. Determine the appropriate level of consumer protection and regulatory oversight for providers of charging facilities, including utilities and non-utilities (ongoing).
4. Change Home Energy Reports and benchmarking so that customers with EVs are compared to other customers with EVs (2016).

5. Evaluate rate structures, including time-variable rate design, that encourage EV owners to charge during off-peak periods. The findings of Recommendation #5 should inform this effort. Promoting off-peak charging may not be an urgent issue; rather a longer-term priority for when there is a threshold level of EVs in place (2017 – ongoing).
6. Explore the role utilities, energy service companies, and other public or private entities can play in the deployment of ZEV fueling infrastructure, particularly with respect to fast charging to facilitate long distance travel and charging for those without dedicated home charging (2016 – ongoing).
7. Establish a schedule for forecasting loads as EVs are integrated into the system, including the impacts of charging on peak demand. Consider recommending scenario modeling of EV growth in load forecasting—also create a tracking mechanism where actual EV growth can be tracked and analyzed. Do this in a manner that also includes projected distributed generation growth if feasible so that coordination potential is enhanced (2016 – 2017).

Recommendation #4: Map Rhode Island's current renewable energy promotion processes and assess adequacy and gaps.

Description of Need

Rhode Island has four major processes that promote renewable energy: the Renewable Energy Growth Program, Net Metering, the Renewable Energy Standard, and the Long-Term Contracting Standard for Renewable Energy. Each process serves a distinct purpose; however, based on the process mapping and test case exercises, there appear to be some ways in which the different programs do overlap, as well as some gaps not covered by the current suite of programs. Furthermore, some technologies and markets are starting to move to the next stages of development (e.g. solar), while others are just beginning to develop (e.g. offshore wind), therefore programs and policies may need to evolve to support the unique circumstances of the different types of renewable energy in Rhode Island.

Recommendations

An effort should be made to review Rhode Island's existing suite of renewable energy promotion processes and confirm that the processes are adequately serving the state's clean energy goals. The SIRI effort identified some gaps and overlaps, but gaining a complete picture would necessitate a deeper review with the complete set of relevant stakeholders at the table. As Rhode Island's efforts to expand renewable energy proceed, close attention must be paid to the integration of the different processes so as to simplify the experience of customers and developers, optimally stimulate the state's growing clean energy industry, and achieve clean energy goals at maximum benefit and minimum cost. Any review of renewable energy programs and goals should also take into account the potential role for hydroelectric power and Class I renewable resources that may be procured regionally under the Affordable Clean Energy Security Act, in meeting Rhode Island's greenhouse gas and renewable energy goals.

1. Maintain commitment to renewable energy deployment in Rhode Island through processes that properly account for the benefits and costs of renewable energy to the distribution system and to Rhode Island consumers.

2. Determine if Rhode Island's existing suite of renewable energy promotion processes are adequately serving the state's clean energy goals. Task the DG Board and interested stakeholders with reviewing processes to assess the complementary nature of the programs and what improvements could improve their effectiveness. As a starting point, stakeholders should develop criteria to apply to this exercise (2016 – 2017).
3. Coordinate among renewable incentive programs to ensure optimal design and delivery.
4. Integrate renewable programs into utility planning (see Recommendation #1).
5. Use the results and findings of the previous items to inform future policy discussions about any updates, changes, or additions to Rhode Island's renewable energy processes.

Recommendation #5: Assess market potential, costs, and benefits of AMI and TVR.

Description of Need

There are promising rate design models that may provide cost-effective energy, economic, and environmental benefits to Rhode Island. Time-varying rates (TVR) is one of these models. TVR requires enabling technology—such as advanced metering infrastructure—to be implemented. Installing AMI and/or other enabling technology will require additional funding above investments currently being made through existing processes such as the Energy Efficiency Program, System Reliability Procurement or the Infrastructure, Safety, and Reliability Plan. TVR (or other alternative rate designs) can provide opportunities for consumer, grid, and environmental benefits, and should be included in a cost-benefit analysis of AMI. Limited or no information is available on the market potential, costs, and benefits of implementing AMI (and/or other enabling technology) and TVR in Rhode Island specifically.

Recommendations

1. **Study the business case for AMI and TVR in Rhode Island**
   An effort should be initiated to understand alternative options for rate design and to quantify the full range of costs and benefits from AMI and TVR, including supply cost reductions[18].
   a. Monitor the National Grid "Smart Energy Solutions" pilot in Worcester, MA and review results as they become available. Discuss if a pilot with AMI in Rhode Island that can also do ALM would add value (Early 2016).
   b. A collaborative study hosted either by the PUC or the OER and supported by the utility should be conducted that engages stakeholders in the business case (i.e. potential, costs, and benefits) of AMI (and/or other enabling technology) and TVR in Rhode Island (Late 2015 – 2016).

[18] PUC Docket 4568 "Review of Electric Distribution Design Pursuant to R.I. Gen. Laws § 39-26.6-24" is ongoing as this SIRI report is being completed. This docket is considering a revenue neutral rate design proposal that currently proposes to shift a portion of the cost recovery for the distribution system to fixed charges. Rate designs such as TVR that rely on the installation of AMI are not currently under consideration in this docket.

c. Assure that experiences with TVR across the US, notably as part of the ARRA-funded Smart Grid Implementation Grants, are considered as part of Rhode Island discussions on AMI and TVR (2015 – 2016).

Recommendation #6: Consider whether methods of performance regulation can be implemented to further the public good.

Background and Definitions

Cost of service regulation is universally done in the US in the investor-owned utility sector to determine the revenue requirement for utility delivery service. In cost of service regulation, the regulator determines the expenses and investment necessary to deliver safe and reliable service, meeting all state requirements, and it also sets a return on equity investment in order to assure adequate availability of reasonably priced capital to maintain the ability of the utility system to do its job. This rate of return on equity investment is applied to the accumulated undepreciated rate base of the utility. This is principally the remaining book value of all the assets in the company's accounts, as well as other assets created by accounting orders, known as regulatory assets. The product of the rate base and the return on equity is added to expenses to create the utility revenue requirement. In Rhode Island, the specific capital investment requirements to maintain the system are identified in distribution planning and selected for prospective recovery of forecasted investment in the Infrastructure, Safety, and Reliability (ISR) Plan.

Performance regulation is a variant of cost of service regulation. Instead of only relying on a return on equity for the amount in the revenue requirement associated with return on investment, regulators identify factors related to utility performance that can be readily measured, and a compensation or reward is available for exemplary performance relative to these factors. A state can have a small element of performance regulation, applying it to just one or a few utility activities and associating a modest amount of return to these. Many states fall into this category[19]. Or a state can attach performance metrics across the spectrum of utility activities and attach significant earnings potential to sufficient performance in this portfolio of factors. No states are currently in this camp, though the idea is being raised in some states[20].

Description of Need

There are several different financial structures by which the utility earns revenue and recovers costs that vary across all processes examined, as shown in **Table 2**. In some cases, relatively stronger performance incentives exist. One is the Energy Efficiency Program, and the other is the return on equity discussed above from distribution delivery services. National Grid delivers shareholder value if it achieves established savings targets for energy efficiency savings and runs the distribution system efficiently, and is at some risk for both over and under spending to achieve these savings. However, for other processes like SRP, there is no incentive or financial structure in place.

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[19] See the 2015 ACEEE EE Scorecard for a recent accounting of states with performance metrics associated with energy efficiency. Vermont has utility Service Quality Plans: http://psb.vermont.gov/utilityindustries/electric/backgroundinfo/sqrp

[20] The Track 2 staff proposal in NY REV, and the Phase 1 Report from the e21 process in Minnesota for leading examples. Also Utility of the Future proposal in MA Grid Mod report to the DPU July 2013.

Table 2. Summary of Utility Financial Structures or Incentives for RI SIRI Processes

Category	Process	Utility Financial Structure or Incentive
Customer-Facing	Energy Efficiency Program	Up to 5%[21] of EE Program spending budget based on achieving EE savings targets[22]
	Ratemaking – Delivery Prices	Return on rate base is included in delivery prices.
	Retail Choice	N/A
	Interconnection Standards	None
Renewable Energy Promotion	Renewable Energy Growth Program	1.75% of the annual value of performance-based incentives[23]
	Net Metering	None
	Renewable Energy Standard	None
	Long-Term Contracting Standard for RE	2.75% of the actual annual payments made under the contracts for those projects that are commercially operating[24]
Grid Planning, Procurement, and Investment	System Reliability Procurement	None
	Infrastructure, Safety, and Reliability Plan	Utility earns and recovers allowed weighted average cost of capital (WACC) return on net ISR investments.
	Utility Financial Incentive	N/A
	Standard Offer Supply Plan	None
	Environmental Regulation	None

Recommendations

1. **Establish forum to explore the expanded use of performance incentives in Rhode Island**

   As part of this effort, examine opportunities to better align the utility's incentives across various processes with policy goals and priorities, including SRP and NWAs. Consider the possibility of mechanisms that would reward activities that yield system, customer, and environmental savings beyond just EE. This report is expressly not recommending a docket be opened. Ultimately the results of these conversations may result in a docket proceeding, but the SIRI team recommends that an informal, interactive forum is the best place to start these discussions[25].

   a. Identify relevant set of interested stakeholders to participate in the discussion (Early 2016).
   b. Begin by identifying areas of interest to the state that are inadequately incentivized (e.g. SRP, environmental goals) and articulate goals. Then determine ways to incentivize these areas of interest under existing structures

[21] The utility can also earn above 5% if it exceeds the savings targets.

[22] http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-1/39-1-27.7.HTM "The commission shall conduct a contested case proceeding to establish a performance based incentive plan which allows for additional compensation for each electric distribution company and each company providing gas to end-users and/or retail customers based on the level of its success in mitigating the cost and variability of electric and gas services through procurement portfolios."

[23] http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-26.6/39-26.6-12.HTM "The commission is authorized to establish more specific performance standards to implement the provisions of this paragraph"

[24] http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-26.1/39-26.1-4.HTM

[25] Financial incentives for long term contracting and energy efficiency are provided for by statute.

or through new structures. Identify candidate metrics against which performance incentives could be offered, or which would simply be reported. Based on the results of the effort, determine opportunities for performance incentives to reward utility activities that yield system, customer, equity, and environmental savings (Mid 2016 – ongoing).

c. Establish a utility performance incentive for individual processes that have already been identified by stakeholders as priority areas for performance regulation—for example, SRP[26]. Develop a financial incentive for reaching SRP targets, or for successfully deferring or avoiding a wires capital investment and address any impediments in statute (Early 2017).
d. Consider other opportunities to use utility performance metrics and rewards to promote the public interest (ongoing).

DRAFT

[26] To date, stakeholders have discussed and identified one process in particular—SRP—that would benefit substantially from a utility performance incentive. Exploring an incentive for SRP alongside other processes (per Recommendation 6.1.b) would bring the benefit of a holistic approach; however, it also could potentially prolong the effort to establish a performance incentive for this particular process. In either case, it appears that the earliest an SRP incentive could be implemented would be in the next triennial update to the EE and SRP Standards in 2017.

Appendix A. Mapping Existing Rhode Island Energy Processes

This SIRI report identifies thirteen distinct processes in which state regulation influences electricity consumers, utilities, and private sector actors to consider the state's priorities on climate, clean energy, and customers. This section briefly describes each process and then examines how each one interacts with the other processes. To help readers build a framework to appreciate these processes, the SIRI report bins the processes into three groups: **Customer-Facing**, **Renewable Energy Promotion**, and **Grid Planning, Procurement and Investment**.

Descriptions of the 13 Processes

Customer-Facing Processes

Energy Efficiency Program

Rhode Island energy policy prioritizes energy efficiency because of its low cost and ubiquitous opportunities to improve customer buildings and processes. The utility is required to manage energy efficiency programs and to acquire all cost-effective energy efficiency under the "Least-Cost Procurement" (LCP) policy. Programs are under the supervision of the PUC. More detailed advisory oversight occurs with the Energy Efficiency and Resource Management Council (EERMC).

Ratemaking — Delivery Prices

All connected electric utility customers in Rhode Island take service under a delivery tariff. This tariff covers the customer's interconnection, delivery of electric power, and administration costs including customer service. This part of the bill does not include the actual electricity that customers use. Delivery prices are reconciled annually in the revenue decoupling mechanism (RDM) to correct for sales deviations from the rate case forecast and recalibrating rates to collect revenues previously calculated to represent the amount needed to deliver safe and reliable service. The RDM is designed to make the utility indifferent to sales levels.

Retail Choice

Electric customers in Rhode Island have the opportunity to choose competitive retail electric providers. The utility must deliver the power purchased by the customers of the competitive providers. These retailers can tailor their electric product as they wish, can add services and must follow rules about fair practices and clear marketing. They are accountable to the PUC. If a customer chooses not to select one of these providers, the utility provides a default "standard offer" service.

Interconnection Standards

Customer-sited generation that provides power to the grid must be the subject of an interconnection agreement between the customer and the utility. Some customer generation, typically smaller in output and standardized, can be subject to a more simplified interconnection standard. Larger or more unusual set-ups require a more customized agreement.

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Renewable Energy Promotion Processes

Renewable Energy Growth Program

A tariff-based system designed to finance 160 MW of renewable energy resources located in Rhode Island between 2015 and 2019. This program builds on a prior program, the 40 MW Distributed Generation Standard Contracts Program.

Net Metering

Net metering requires the utility to credit energy produced by small renewable energy systems (under 5 MW) installed on the customer's side of an electric meter. Systems are sized based on a three-year average of electricity consumption at the property. Credit for the full retail rate applies to 100% of on-site loads, and customers receive credit at an avoided energy cost rate (thus excluding the delivery rate) for up to 125 percent of the customer's load during a billing period. To participate in net metering, a renewable energy system must be sited on the customer's premises, with exceptions for virtual net metering for public sector and farm projects.

Renewable Energy Standard

Each retail electricity provider in Rhode Island must assure that it has acquired sufficient renewable energy certificates (RECs) to meet the state's Renewable Energy Standard. Buyers include the utility standard offer service and competitive electricity providers. RECs are created for every MWh generated by a qualifying power producer, and these are tracked by NEPOOL-GIS as they are produced, traded, and finally retired by the entity that takes credit for the attribute. Each company subject to this requirement does not have to buy power from a renewable source, or own a renewable source, but it does have to buy the required number RECs each year, or make a compliance payment to the state's Renewable Energy Fund to support renewable energy development in Rhode Island for any REC shortfall. State retail electricity providers must supply 14.5 percent of retail electricity sales from eligible renewable energy resources by 2019.

Long-Term Contracting Standard for Renewable Energy

Requires electric distribution utilities to enter into long-term contracts for a minimum of 90 MW of newly developed renewable energy resources by after December 31, 2014. Also provides for the consideration of a long-term contract for up to 150 MW of offshore wind[27].

Grid Planning, Procurement and Investment Processes

System Reliability Procurement

Every year, the utility must submit to the PUC a System Reliability Procurement (SRP) plan. This plan must strategically consider diverse "non-wires alternatives" (NWA)—including utility-scale energy sources and resources sited at customer premises—if they are cost-effective alternatives to making "poles and wires" investment upgrades in the distribution system. Eligible NWA include energy efficiency, renewable energy, demand response, customer generation, EVs, energy storage, and combined heat and power.

[27] National Grid has satisfied the 90 MW statutory long term contract requirement with the most recent Power Purchase Agreement approved by the PUC on October 29, 2015.

Infrastructure, Safety, and Reliability Plan

Electric and gas utilities are required to submit an ISR spending plan annually to the PUC. The Plan is designed to reconcile costs for certain anticipated capital investments and other spending pursuant to an annual pre-approved budget for certain designated categories relating to enhancing the safety and reliability of the distribution system. The utility is statutorily required to review the Plan with the Division of Public Utilities and Carriers (DPUC) prior to its submission to the PUC. The Plan addresses spending for utility infrastructure, repairing failed or damaged equipment, load growth/migration, sustaining system viability, continuing a level of feeder hardening and cutout replacement, and operating a cost-effective vegetation management program. The Plan is intended to achieve safety and reliability goals through a cost-effective, comprehensive spending plan. In order to inform the selection of projects proposed for the ISR, the utility performs *distribution planning*, which forecasts loads, identifies distribution system needs, and proposed infrastructure or NWA solutions.

Utility Financial Incentive

The utility is an investor-owned company. In order to provide for the capital needs and financial stability of the utility, the PUC provides an opportunity for the utility to earn a return (or profit) for the owners. The way the utility earns this return is thought to influence its priorities and behavior. Presently, the utility earns its return based on an annual percentage on the invested capital (the rate base). To a smaller degree, the utility is also eligible to earn an incentive based on its performance on energy efficiency programs, as well as incentives associated with spending for the REG and LTC Programs.

Standard Offer Supply Plan

The utility is obligated to offer a market-based electricity supply to all Rhode Island electricity customers who have not chosen a competitive provider.

Environmental Regulation

Rhode Island, like all other states, implements federal environmental regulations like the Clean Air Act. For some pollutants, the state creates implementation plans that explain how it will control pollution in the state to comply with the science-based in Clean Air Act regulations. A significant share of pollution comes from electric power production. Anticipating regulation of greenhouse gases (GHG) from power generation, Rhode Island and other northeast states created the Regional Greenhouse Gas Initiative in 2005. RGGI is an agreement among member states to create comparable state programs that allocate carbon pollution allowances to each state and provides a platform for member states to sell those allowances to generators over 25 MW that emit carbon dioxide, a greenhouse gas. Each allowance represents one ton of carbon pollution. States can use the revenue for any purpose, except that they agreed to use at least 25% of the revenue for energy efficiency. The RGGI program went into effect in 2009. It is unknown at the time of this report whether Rhode Island's membership in RGGI will be sufficient to comply with EPA GHG regulations. If not incremental investments in clean energy (i.e. energy efficiency and renewable energy) may be needed. In addition to participating in RGGI, Rhode Island has also set state targets for total GHG emissions reduction through the 2014 Resilient Rhode Island Act. The Act takes an economy-wide perspective, putting planned GHG reductions from transportation and industry sectors in comparison to reductions from electric power and obligating the state to consider reduction from all major sources for GHG.

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SIRI Customer-Facing Processes

Process: Energy Efficiency Program

Customer-Facing Processes

Funding for *energy efficiency programs* is collected through a rider on utility delivery rates that all customers pay. PUC Docket 4568 is considering changes to utility *rate design*, which could impact energy efficiency if the new rate structure disincentivizes conservation and fails to advance load management.

Competitive suppliers of electricity can offer energy efficiency (and other) services to their customers—these are not supported by the surcharge.

Renewable Energy Promotion Processes

The utility can specify that up to half of the small and medium solar MW under the *REG Program* have incentives tied with EE program incentives.

Net metering limits full retail rate compensation based on the quantity of annual sales. A second tranche of production above 100% and up to 125% of annual sales can receive the then current *standard offer service (SOS)* rate as compensation. A customer that invests in energy efficiency lowers the annual quantity of kWhs eligible for compensation in both tiers (at the full retail rate and the additional amount at the *SOS* rate). Because net metered systems are sized based on historical average usage, there may be a disincentive for customers to invest in energy efficiency after the system is installed.

Renewable Energy Growth does not limit investment in energy efficiency. Compensation is based on total generation and applied first as a bill credit. Any excess is paid out as cash to the owner of the system. Residential and small scale solar REG applicants are limited to the system size limits of net metering.

The state's *RES* is based on a percentage of total sales. Energy efficiency reduces sales and reduces the quantity of renewable energy needed to meet the standard. The energy efficiency programs count this benefit as part of the avoided costs of the programs.

Grid Planning, Procurement and Investment Processes

The utility *SRP* process uses geographically-focused energy efficiency strategies. These lead to localized differences in marketing energy efficiency programs where they would be more valuable.

The *distribution planning* process factors energy efficiency from customer sources in its forecast of load. The process also assesses non-wires alternatives to capital requirements. The influence of electrification of thermal and transportation remains too small to make a difference in the planning process. EE gains on the utility side of the meter (e.g. conservation voltage reduction, or CVR) are not currently factored in distribution load forecasts. Finally, it is unclear (and likely

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not possible to evaluate with existing sensors and data) whether high levels of EE are proactively reducing the likelihood or frequency of load constraints.

The utility/program administrator receives a *performance incentive* for energy efficiency savings targets.

The delivery company procures power to support *standard offer supply* service to customers who do not choose a competitive supplier. If energy efficiency investments are made, less SOS service is required. Annual EE Plans are used by Grid to influence and inform how much SOS procurement Grid plans for.

Energy efficiency contributes to reductions in emissions associated with electricity production since fossil fuels, including higher-emitting sources such as oil, are usually on the margin in Rhode Island's electricity market. Energy efficiency also helps Rhode Island meet its GHG and other emissions targets under the Clean Air Act. GHG revenues from the Regional Greenhouse Gas Initiative and some consideration of reduced emissions (future federal carbon costs) factor into the screening test (total resource cost test) for energy efficiency programs, while other environmental benefits from energy efficiency are not included.

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Process: Ratemaking — Delivery prices

Customer-Facing Processes

According to the EE and SRP Standards, the EERMC and the utility/program administrator can work in concert to propose adjustments to *rates* as needed to improve alignment of utility and consumer incentives in *energy efficiency* programs with the objectives of LCP and SRP. There is a rider on all customer bills to pay for energy efficiency. There is a revenue decoupling mechanism in place that enables the utility to recover fixed costs if revenues are reduced due to lower retail sales from energy efficiency programs.

Renewable Energy Promotion Processes

The utility can recover costs from all distribution customers to comply with the *REG* Program.

Customers using *net metering* for compensation for their own generation from PV or other qualifying forms of DG are exempt from back-up service rates. If there is a shortfall in utility revenues due to sales reductions owing to net metering, the revenue decoupling mechanism will adjust rates to make up the shortfall.

RES compliance costs and costs for LTC are recovered in rates from all distribution customers.

Grid Planning, Procurement and Investment Processes

The EERMC and the utility/program administrator can work in concert to propose adjustments in rates as needed to align utility and consumer incentives with the objectives of LCP and SRP. Costs associated with SRP solutions are recovered through the rider on customer bills for energy efficiency.

Costs for investments and expenses associated with deploying the *ISR* plan are recovered in delivery rates from all customers. Standard Offer Supply service costs are recovered in the commodity rate.

There is a *revenue decoupling mechanism* in place that enables the utility to recover fixed costs if revenues are reduced due to lower retail sales from energy efficiency programs.

Some costs for *environmental regulation* flow through to customers in the delivery and commodity rates, while others are absorbed by independent power producers. Some revenue from the sale of carbon allowances in the Regional Greenhouse Gas Initiative is used for energy efficiency and other clean energy investments. The design of the rates can encourage or discourage conservation, efficiency, and use of renewable DG.

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Process: Retail Choice

Customer-Facing Processes

Retail suppliers may deliver *energy efficiency* services though they are not required to and many do not.

Renewable Energy Promotion Processes

Customers on Standard Offer Service can offset the cost of *net metered* self-generation at the full retail rate up to 100% of annual usage and payment of the *standard offer service* rate (thus excluding the delivery rate) up to 125% of annual usage. However, customers served by a competitive supplier, and who (1) get a single bill from the Company for competitive energy supply and Company delivery services or (2) are billed directly by the competitive supplier through a second bill, do not receive compensation for excess generation. Competitive suppliers have no obligation to compensate customers for net positive production to the system.

Competitive suppliers are responsible for complying with the *RES*, but not with the *LTC*.

Grid Planning, Procurement and Investment Processes

The *rate design* for *standard offer service* is likely to affect the motivation of customers to switch to competitive suppliers.

Competitive suppliers can offer renewable power in excess of RES requirements in their products so willing customers can support more of the cost of state *environmental compliance*. The cost of carbon from the result of RGGI auctions affects the wholesale price of power in New England.

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Process: Interconnection Standards

Customer-Facing Processes

In Rhode Island, CHP is in the family of *energy efficiency*, and is enabled by present interconnection requirements.

The cost of regular customer connections to the electric distribution system are subject to a construction advance process where estimated revenues are compared to costs to provide their new service. If the revenues are sufficient, this cost is included in delivery rates to all customers; if not, the customer pays the difference. Customers that choose to install DG systems are subject to the same process, but as the estimated new revenue is zero, they pay for all appropriate cost of interconnection associated with that system as determined by the *Standards for Connecting Distributed Generation* tariff.

Renewable Energy Promotion Processes

Qualifying energy systems for the *REG Program*, *net metering*, and the *RES* require interconnection, and are guided by the state's interconnection standards and tariff.

Grid Planning, Procurement and Investment Processes

Interconnection is a cost of renewable programs that are a component of *environmental* compliance costs.

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SIRI Renewable Energy Promotion Processes

Process: Renewable Energy Growth Program

Customer-Facing Processes

Grid can require that certain *EE* standards be met as a prerequisite for awarding a portion of the REG small and medium solar projects that are coordinated with the EE program. SolarWise, a program that will provide additional performance-based incentives for customers who install solar after achieving certain levels of efficiency, is proposed for the 2016 REG program. Plans are underway for National Grid (the EE program administrator) to include solar energy screening suitability in energy efficiency audits and offer enhanced performance-based incentives if EE thresholds are met prior to installing solar.

The growth of DG customers and their contribution to the grid has led to an effort to reassess utility delivery *rate design* (PUC Docket 4568). National Grid recovers any costs associated with REG-qualifying projects through a separate line item in its delivery rates. These costs may include any future added locational incentives for customers.

REG Program participants must apply for *interconnection* and pay appropriate costs.

Renewable Energy Promotion Processes

Net metering is not available for projects participating in the REG Program per se. However, *REG* participants may opt to receive bill credits up to their monthly kWh use, which is similar to net metering, with the difference of the applicable performance based incentive (PBI) for the full generation of the DG project made as a separate payment. Residential customers are required to receive such bill credits. Other customers with on-site load have the same option, or can elect to get paid separately for all the output of the project at the applicable PBI with no bill credits. After the end of the term of the performance-based incentive tariff for an REG project, the project can then begin receiving net-metering credits, if eligible.

Under the terms of the *REG* Program, the utility receives title to all REG system RECs and must sell them to offset the cost of the Program for all distribution customers.

Grid Planning, Procurement and Investment Processes

There is a mechanism to link REG to *distribution planning* via *SRP* by using the locational incentive provision of the REG law but it is not now used.

Achieving and exceeding REG goals helps Rhode Island achieve *GHG reduction* targets.

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Process: Net Metering

Customer-Facing Processes

Competitive energy suppliers do not offer compensation for excess generation from *net metering* customers, while the default supplier (National Grid Standard Offer Service) must offer compensation at the avoided cost of supply for customers generating more energy on-site than they use during the billing period in the form of net metering credits. In addition, a net metered customer receives the per kWh charges for distribution, transmission, and the transition components of the delivery bill.

PUC Docket 4568 on utility delivery *rate design* is addressing any tariff adjustments that may be appropriate in light of increased customer generation, including increased net metering. Net metering costs are recovered through the Renewable Energy Distribution charge on the bill, which consists of the net metering charge and the LTC charge.

Interconnection is required of *net metered* systems and is a necessary part of the net metering process.

Renewable Energy Promotion Processes

If a customer's distributed generation project is receiving performance-based incentives under the *REG* program, the customer cannot receive *net metering credits* for excess generation. After the end of the term of the performance-based incentive tariff for an REG project, the project can then begin receiving net-metering credits, if eligible.

RECs generated from existing net metering projects remain with the customer and are generally not used by the utility for *RES* compliance. The exception: in the event that the *REG* Program or the *Long Term Renewable Contracts* do not provide the RECs necessary to comply with the utility's RES obligations, the utility has the ability to solicit RECs through standalone RES solicitations or through SOS competitive solicitations. The RECs purchased through these solicitations could include RECs sold by virtual net metering projects in Rhode Island, or possibly RECs from regular net metering customers if they have worked with an aggregator to sell their RECs (it is thought that currently most regular net metering customers never sell their RECs and effectively retire them on site).

Grid Planning, Procurement and Investment Processes

More net metering output helps Rhode Island achieve *GHG reduction* targets.

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Process: Renewable Energy Standard

Customer-Facing Processes

Competitive energy suppliers must comply with the state RES, so all customers support the standard whether they choose a supplier or not.

Interconnection standards are in place and apply to systems interconnected in the Rhode Island load zone, including those that qualify for the RES.

Renewable Energy Promotion Processes

National Grid purchases RECs from projects under long-term renewable contracts pursuant to the *LTC* and may use those RECs for RES compliance. Projects in the *REG* program produce RECs. These credits are conveyed to the utility as part of the program so the customer cannot retain and retire them. The utility, Grid, must then sell these credits and cannot use them to satisfy its RES responsibility.

In the case of net metering customers, RECs remain with the customers and are not used by the utility for RES compliance. The exception: in the event that the *REG* Program or the *Long Term Renewable Contracts* do not provide the RECs necessary to comply with the utility's RES obligations, the utility has the ability to solicit RECs through standalone RES solicitations or through SOS competitive solicitations. The RECs purchased through these solicitations could include RECs sold by virtual net metering projects in Rhode Island, or possibly RECs from regular net metering customers if they have worked with an aggregator to sell their RECs (it is thought that currently most regular net metering customers never sell their RECs and effectively retire them on site).

National Grid has an option to purchase RECs from projects entering *long term contracts* for renewable energy for *RES* compliance[28].

Grid Planning, Procurement and Investment Processes

Standard Offer Service provider recovers the cost of RES compliance as a line item on the energy supply portion of the bill—the Renewable Energy Standard Charge.

Increased demand for renewable energy through the RES helps Rhode Island achieve *GHG reduction* targets.

[28] National Grid has satisfied the 90 MW statutory long term contract requirement with the most recent Power Purchase Agreement approved by the PUC on October 29, 2015.

Process: Long-Term Contracting Standard for Renewable Energy

Customer-Facing Processes

LTC costs are recovered through the *Renewable Energy Distribution charge* on the bill from all distribution customers, which consists of the net metering charge and the LTC charge. Price risks to the regulated company associated with the LTC cost compared with contract market value are managed in the regulatory process.

Renewable Energy Promotion Processes

National Grid has an option to purchase RECs from eligible renewable energy projects under the *long term contracts* and may use the RECs for renewable energy for *RES* compliance.

Grid Planning, Procurement and Investment Processes

There is no connection between *LTC* and *SRP*.

Planning for transmission and interconnection facilities to deliver output from projects acquired in a *long term contract* may occur outside of National Grid jurisdiction since eligible projects may be located outside of Rhode Island.

More renewable energy helps Rhode Island achieve *GHG reduction* targets.

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SIRI Grid Planning, Procurement and Investment Processes

Process: System Reliability Procurement

Customer-Facing Processes

Utility *energy efficiency* programs are used for load relief in the SRP.

Charges for SRP, including non-wires solutions, are charged to all customers and included in the *energy efficiency rider* on the distribution side of the bill.

Interconnection standards apply to qualifying distributed generation if used in the SRP.

Renewable Energy Promotion Processes

Renewable energy sources brought to the grid through the *REG* program can be an SRP resource. REG allows for a locational incentive to better target resources to address SRP solutions, but it is not currently in place.

Resources qualifying for the *RES* can be used for SRP solutions.

There is no clear link to drive locational development of *net metering* systems through SRP.

Grid Planning, Procurement and Investment Processes

The utility analyzes projects in *distribution planning* for eligibility for a non-wires alternative using the criteria from the SRP Standards. Any that pass criteria for solutions are then considered in the *SRP*. *Distribution planners* consider known non-wires alternatives in their base case. Planning does not include electrification or forecasted DG scenarios.

Utility receives *no incentive for SRP* investments (though energy efficiency incentives operate independently).

There is no explicit connection between *environmental regulation* and SRP.

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Process: Infrastructure, Safety, and Reliability Plan

Customer-Facing Processes

The ISR planning process includes a forecast for *energy efficiency* program savings.

The cost of ISR investments is recovered through distribution *delivery rates*, embedded in the distribution line item.

Renewable Energy Promotion Processes

While there is an energy efficiency forecast in ISR, there is not a comparable forecast for resources brought on line under the *REG* program or *net metering*. It appears that the ISR cannot currently be used to target *net metering* to most valuable locations. There is an option mechanism in *REG* for locational incentives, but it is not in place, so there is no current link to ISR.

Grid Planning, Procurement and Investment Processes

The *SRP* process requires the company to identify wires projects for which non-wires solutions may be more valuable through their ability to defer or avoid more costly investments. However, *utility financial incentives* do not motivate targeting distributed resources to the most valuable places nor do they address the difference in return opportunities between wires investments and non-wires solutions.

The ISR process for electric utilities does not address *GHG outcomes*; however, the process for gas utilities does seek to reduce methane leaks, which results in reduced GHG emissions.

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Process: Utility Financial Incentive

Customer-Facing Processes

According to the EE and SRP Standards, the EERMC and the utility can review existing financial incentive structures and propose adjustments to align utility and consumer incentives with the objectives of least cost planning and the SRP process. At present, there is a shareholder incentive based on *energy efficiency* program performance.

Otherwise, the utility earns a return on rate base which is based on the cost of debt and other capital forms and the cost of equity as determined by the PUC in standard methods. Returns are included in *delivery rates*.

Renewable Energy Promotion Processes

The utility receives an incentive of 1.75% (excluding administrative costs) on the cost of renewable energy in the *REG* program and 2.75% (excluding administrative costs) on costs associated with *LTC*.

There are no utility financial incentives for generation brought on line under the *net metering* and *RES* programs.

Grid Planning, Procurement and Investment Processes

There is no utility financial incentive currently for *SRP* or *environmental regulation* solutions.

The utility gets a return (weighted average cost) on capital investment for *ISR* commitments.

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Process: Standard Offer Supply Plan

Customer-Facing Processes

Costs are recovered from all standard offer customers through the *commodity price*, represented on the energy supply portion of the bill.

Renewable Energy Promotion Processes

The *RES* Procurement Plan is integrated with the *SOS* procurement plan. The utility develops an estimate of its RES obligations for SOS in a given year. In the event that the *Long Term Renewable Contracts* do not provide the RECs necessary to comply with the RES obligations, the utility has the ability to solicit RECs through standalone RES solicitations or through SOS competitive solicitations. The utility complies with the *RES* by purchasing RECs and the cost is recovered through the Renewable Energy Standard Charge in Basic Service rates.

The SOS determines the rate at which *net metered* customers receive compensation for production above 100% and up to 125% of annual sales.

Grid Planning, Procurement and Investment Processes

RGGI can affect the market clearing price of power.

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Process: Environmental Regulation

Customer-Facing Processes

Energy efficiency is a strategic resource to meeting state environmental quality goals at a low cost. Rhode Island's allocations from the RGGI program of selling carbon allowances helps to fund RI energy efficiency programs.

There is no clear signal in electric delivery *rates* consistent with environmental goals.

Some retail commodity competitors provide electricity sourced with low environmental impacts or emissions.

Distributed generation with low environmental impacts require reasonable *interconnection* to gain grid access.

Renewable Energy Promotion Processes

Renewable energy is a strategic resource to meeting state environmental quality goals at a reasonable cost while balancing supply and economic risks. Renewable energy comes to the grid through the *REG* program, the *net metering* program, the *RES* and through the *LTC*.

Grid Planning, Procurement and Investment Processes

The *SRP* broadens consideration of incremental utility investments in resources to consider non-wires alternatives, including alternatives on the customers' side of the meter that, in aggregate can defer or avoid traditional utility investment solutions. These alternatives can serve to support state environmental goals.

The *ISR* process will identify parts of the system that require special attention and investment to protect against climate change-driven threats. The gas ISR process reduces methane leaks, which contribute to climate change.

Utilities are not *compensated* any more for contributing to environmental goals and standard offer service is not designed to address environmental goals aside from meeting the renewable energy standard.

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Appendix B. SIRI Test Cases[29]

1. Non-Wires Solutions in Utility Planning

Implementing "non-wires alternatives" (NWA) can potentially cost-effectively defer, avoid, or reduce the size/scope of transmission and distribution investments.

Current Status: National Grid identifies load relief projects in distribution planning. If a project meets the eligibility criteria in the SRP Standards, the project can go in SRP and NWA will be considered. If a project goes in SRP, it can also make use of enhanced EE Program incentives. A new process that is expected to figure in the NWA/SRP equation is the REG Program. A provision exists in the REG Program to offer zonal incentives to DG projects in SRP areas. This incentive structure has not yet been developed, and at earliest, would be explored for the 2017 REG Program Year.

Process	Synergies	Barriers	Recommendations
Energy Efficiency Program	• EE measures and programs are used for load relief in SRP • Some EE kW savings are focused in SRP areas to facilitate peak reductions • The EE savings are accounted for in Grid's distribution planning	• Funding for SRP projects is recovered through EE charge, and therefore SRP in essence competes for funding with the EE Program (and by extension, other items on the distribution bill), which is subject to perennial budget pressures • Grid uses an EE forecast based on the program savings targets for distribution planning – this appears to be deterministic, not dynamic based on planning needs	• Use targeted EE (aka enhanced marketing and incentives) in areas with the largest load constraints. SRP evaluation has shown that targeted EE can increase kW savings. • Examine whether changing the way the charge is displayed on bills (ex. within the distribution charge vs line item) would make increasing funds for EE/SRP more feasible. • Determine if SRP/EE satisfies ISR criteria to understand if SRP could be funded as part of the ISR.

[29] The synergies, barriers, and recommendations listed below represent a working document and not the final recommendations of the SIRI working group. The information and ideas provided in this section may not be supported by all members of SIRI.

System Reliability Procurement	• Grid screens ISR projects under the criteria identified in the SRP Standards; if a project screens, it is then reviewed to determine if the current geographic customer mix may be capable of providing the needed duration and amount of load relief over the time needed. If the customer mix is determined to be sufficient, then it is eligible for an NWA solution under SRP	• Grid does not receive financial incentive for SRP projects, but Grid earns and recovers allowed weighted average cost of capital (WACC) return on net ISR investments • Not many NWA opportunities have been identified in recent years - Are the SRP Standards excluding potential viable full or partial NWA opportunities? • There certain criteria in the SRP Standards in particular (asset condition) for which projects frequently fail to pass • There are technologies/strategies eligible under the Standards for which there aren't other existing programs (e.g. EVs, storage, time-varying rates, etc.) • Customer recruitment and retainage over time has proven to be challenging to date	• Create a shareholder incentive for reaching SRP targets – or for successfully avoiding a wires-capital investment. Incentive should be on par with capital rate-of-return to be effective. • Review screening process with system planners to determine what the barriers are. • Review and update the SRP Standards with the objective of executing all cost-effective full and partial NWA opportunities.
Renewable Energy Growth Program	• A provision exists in the REG Program to offer zonal incentives to DG projects in SRP areas • Grid looks at existing DG to see what impact it has on the system and how it works during peak times.	• Funding for zonal incentives would be recovered through the REG program, thus increasing apparent costs to that program • Distribution planning does not account for known REG projects that are proposed, or for projected projects	• Forecasting how to incorporate DG would be appropriate (what circuits can/can't handle more DG, etc.) but should not be used to potentially offset a capital/reliability project without a sufficient likelihood that DG would be built. Using a probabilistic assessment would account for prospect that DG does not get built, or its size changes. • Zonal payments that have benefits to the distribution system should come from the distribution company, with appropriate cost recovery and shareholder incentive. • Examine the planning processes to see how REG projects can be included in the utility's system planning and capacity studies. • As a longer-term outcome, the utility undertakes routine reviews of its circuits and feeders to determine optimal locations for DG where circuits are nearing capacity in the planning horizon. This information is publicly available and also used as National Grid plans for regular system upgrades/maintenance.

Net Metering	• Net metered technologies are eligible in the Standards to be used for load relief in SRP	• Value of net metering does not reflect added geographic value of DG generation in SRP areas. This could require a change to the net metering law • It is unclear whether there is a record of net metered projects used for distribution planning, except through feeder peak loads that may have been reduced by their presence. No projections of future net metered projects are available for planning purposes • Net metered projects have a disincentive to invest in EE after DG installation if on-site production meets or exceeds on-site consumption on annual basis	• Could be potential for SRP to offer an increased incentive to solar projects that are built in SRP areas but having it be part of the net-metering tariff would complicate things. • Determine how/if current and future net metered projects could be incorporated into distribution planning.
Renewable Energy Standard	• RES technologies are eligible in the Standards to be used for load relief in SRP	• RES technologies are currently not used in the SRP	• SRP could offer increased incentives but utility would not build or own projects. • Assure that all values relevant to SRP from RES qualifying projects are identified and included.
Long-Term Contracting Standard for Renewable Energy	•	•	•
Infrastructure, Safety, and Reliability Plan	• Grid screens ISR projects under the criteria identified in the SRP Standards; if a project screens, it is eligible for an NWA solution under SRP • Grid incorporates consideration of EE targets into ISR planning • Conservation Voltage Reduction (CVR) and Volt-Var Optimization (VVO) are used in the ISR and have potential to deliver efficiency on the distribution system	• Grid earns and recovers allowed weighted average cost of capital (WACC) return on net ISR investments. Grid does not receive an incentive for SRP projects • It is clear that the extent to which consideration of NWA is being fully incorporated into the utility's long-range planning efforts (strategic electrification, DG, load management, & gas/electric coordination) needs additional work.	• Create a shareholder incentive for reaching SRP targets—or for successfully avoiding a wires-capital investment. Incentive should be on par with capital rate-of-return to be effective. • Review screening process with system planners to understand what the barriers are. • Explore what NWA-related costs (e.g. AMI for time varying rates) can and should be funded through ISR • Consider whether CVR and VVO should be developed in the ISR process or in energy efficiency.
Standard Offer Supply Plan	•	•	•

Retail Choice	•	• Competitive suppliers are not competing on comprehensive energy services. Possible reasons could include inadequate price signals to their customers, especially those consuming in higher cost parts of the utility system or at times when cost of production is high • Lack of availability of advanced metering functionality including temporal price differentiation and load control support	• Maintain rate structures that incentivize ratepayers to install on their own distributed generation and energy efficiency projects that meet a reasonable economic threshold, stimulating a competitive market for these services. • Consider AMI business case.
Ratemaking – Delivery Prices	•	• Rates lack temporal and locational values and opportunities to unbundle rate elements. Longer-term focus and accurate price signals are important to proper use of some NWA • Funding for SRP projects is recovered through EE charge, which is an adder separate from the base distribution component, under which ISR is recovered	•
Utility Financial Incentive	•	• Grid earns and recovers allowed weighted average cost of capital (WACC) return on net ISR investments. Grid does not receive an incentive for SRP projects	• Create a shareholder incentive for reaching SRP targets—or for successfully avoiding a wires-capital investment. Incentive should be on par with capital rate-of-return to be effective.
Interconnection Standards	•	•	•
Environmental Regulation	• NWA will help Rhode Island meet the Resilient RI emissions reduction targets • NWA in general will help increase load factor and reduce peak demand, and thus emissions from higher-emitting oil/coal plants	•	•

Gaps Summary

1. SRP and EE compete for same funding source
2. Grid does not receive a financial incentive for NWAs
3. Few SRP projects make it to screening phase

4. How does system planning account for zonality?
5. Process for establishing the locational value of solar across the state
6. Establishing cost-effectiveness of NWA solutions, and confirming the capacity and peak reduction contributions from different NWA strategies

Recommendations Summary

1. Review screening process with system planners to determine how to expand eligibility for potential NWA projects, including a review of barriers.
2. Examine whether SRP costs could be included in the ISR or within the distribution charge.
3. Create a shareholder incentive for reaching SRP targets—or for successfully avoiding load-related wires capital investment. Incentive should be on par with capital rate-of-return to be effective, and periodically evaluated to ensure they are appropriate and effective.
4. Maintain rates that would give individual ratepayers incentive to invest in DG and EE on their own. Additional incentive programs are helpful, but if their rates are sending them different price signals, they will respond.
5. Examine the planning processes to see how REG projects can be included in the utility's system planning and capacity studies.
6. As a longer-term outcome, the utility should undertake regular periodic reviews of its circuits and feeders to determine optimal locations for DG/where circuits are nearing capacity. This information should be publicly available and also used as National Grid plans for regular system upgrades/maintenance.
7. Evaluate how improvements to existing processes (and if needed, the establishment of new processes) could create a long-range grid planning process that generates comprehensive, multi-year strategic grid plans to merge traditional "poles and wires" approaches with new technologies. (This process – SIRI 2.0? – could integrate strategic electrification, etc. as well.).
8. Consider updating the benefit/cost test to determine the appropriate benefits to include in NWA assessment.
9. Create a stakeholder process to assess the business case for AMI deployment.

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2. Solar PV Deployment

Expanding solar PV deployment on the distribution grid could test various regulatory, operational, and programmatic aspects of Rhode Island's existing electric distribution system processes.

Current Status: Solar PV systems interconnecting to Rhode Island's distribution system capitalize almost exclusively on one of two processes: Net Metering or the Renewable Energy Growth Program (Rhode Island's Renewable Energy Standard is also a vital related process; it tends to support in-state solar projects in a more indirect way by creating a compliance market for the RECs generated by these systems). PV projects receive net metering credits through net metering or performance-based incentives (PBIs) through REG, both of which are recovered by National Grid through rates. PV projects interconnect to the distribution system according to interconnection standards developed by National Grid and approved by the PUC.

Process	Synergies	Barriers	Recommendations
Energy Efficiency Program	• On-site EE promotes optimal sizing of the PV system • REG "SolarWise" initiative will link solar incentives and EE programs and could promote adoption of PV	• Customer-centric service to enable all clean energy service in one package is lacking • PV vendors interested in closing deals may not alert customers to energy efficiency opportunities or may want to sell larger systems	• Promote message that EE be done prior to installing solar, especially for net metered systems, where there is a disincentive for EE after solar is installed. • Outreach to solar installers on EE programs. • Continue coordination efforts between state solar programs and EE programs.
System Reliability Procurement	• PV can be sited locally in SRP area	• Finding good host sites in SRP area • Marketing and recruitment • Locational value of PV needs to be established for target areas	• Review results of OER SRP/DG Pilot EMV Study as they become available • Calculate locational value of PV throughout state.
Renewable Energy Growth Program	• Provides performance-based incentives ($/kWh) for DG projects • Will support the deployment of 200 MW (total) of DG by 2019 in the RI load zone (likely at least 75% will be solar PV) • This equates to about 2 or 3% or total RI load	• It appears the locational incentives can be used to direct REG projects for load relief, but unclear if they would/could/should be used to reflect potential integration costs in future areas with high local solar penetration (or whether these costs would just be reflected during interconnection) • Does REG overlap with PV deployment through other processes (net metering)?	• Coordination among renewable incentive programs. • Explore whether there is a future need to modify how the REG performance-based incentive levels are established (i.e. not based on installed costs + rate of return) and how locational incentives and other benefits and costs might be factored into the tariff level and accounted for by the utility.

Net Metering	• Credits solar PV for excess generation up to 125% of the customer consumption at the standard offer rate • No net metering cap • Public entities and farms can virtually net meter	• Concern for more accurate method of compensation may be appropriate at some future time when effect of roughness of net metering becomes meaningful • Does net metering overlap with PV deployment through other processes (REG)?	• Coordination among renewable incentive programs. • Consider expanding virtual net metering beyond public buildings and the agricultural sector. • Explore whether there is a future need to consider reforms to net metering credits so they reflect the value (benefits & costs) that distributed resources like solar PV provide to the grid.
Renewable Energy Standard	• Both REG and net metered projects sell RECs that are used by obligated entities for RES compliance	•	• Coordination among renewable incentive programs.
Long-Term Contracting Standard for Renewable Energy	•	•	• Coordination among renewable incentive programs.
Infrastructure, Safety, and Reliability Plan	• The utility looks at existing DG to see what impact it has on the system and how it works during peak times	• It is unclear the extent to which consideration of DG growth is being fully incorporated into the utility's long-range planning efforts. The utility does not forecast DG systems that have not yet been built • Forecasting how to incorporate DG would be appropriate (what circuits can/can't handle more DG, etc.) but should not be used to potentially offset a capital/reliability project without a sufficient likelihood that sufficient DG would be built • It is unclear if distribution planning, through the SRP mechanism, can accurately value PV on the system	• Examine the potential to incorporate DG growth forecasting in system planning.
Standard Offer Supply Plan	• Could have potential price suppression effects on standard offer supply	•	•
Retail Choice	•	• Retail choice customers who receive a separate bill for supply do not receive net metering credits for kWh production between 100% and 125% of generation during a billing period.	•

Ratemaking – Delivery Prices	•	• Concern for higher rates as utility sales are reduced • Absence of locational signals in rates discourages consumers to deploy PV equal to its system value in critical locations • Absence of AMI makes it difficult to establish field-verified data on the temporal value that solar provides to the grid. • Rate designs that increase fixed charges and reduce variable rates lower the compensation DG receives under net metering	•
Utility Financial Incentive	• National Grid receives 1.75% remuneration outside of the administrative costs under the REG program	• Current utility financial incentive is tied to costs of the program, not outcomes	• Consider whether performance regulation for clean energy outcomes is appropriate.
Interconnection Standards	•	• What barriers would be encountered under current interconnection standards at a 5% PV deployment threshold? • What is the system impact from greatly increased solar penetration?	•
Environmental Regulation	• Solar PV helps achieve state, regional, and federal environmental goals	•	•

Gaps Summary

1. Role of RE in system planning (forecasting and strategic siting are where the gaps are)
2. Coordination among renewable energy promotion initiatives
3. Price signals to develop solar in areas where it is needed the most

Recommendations Summary

1. Effective program design in RE Growth Program, "SolarWise", will use high energy efficiency as the eligibility criteria for a customer to receive an additional solar incentive on top of the standard ceiling price. (In 2016 EE Plan).
2. Determine whether both REG and net metering could provide an extra incentive to drive locational development of solar.
3. Create coordination between State and Grid distribution planners on estimated solar build-out to ensure Grid is aware of the required solar build-out and how to best plan for it.

4. Consider follow on to Peregrine study to help identify locational value of solar throughout the state.
5. Ensure that customers are adequately compensated for the power they provide to the grid and pay for the services they receive from the grid.
6. Avoid reliance on rate design features that reduce the incentive to invest in solar PV such as high fixed charges.
7. Determine if utility performance regulation tied to clean energy outcomes are appropriate for Rhode Island.

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3. Strategic Electrification – Heating

Emerging electric technologies (e.g. highly efficient heat pump technologies) may provide significant savings not just through increased efficiency of electric use, but also through effective substitution of electric use for applications that have traditionally been dominated by fossil fuels (e.g. heating, transportation). These technologies can be controlled remotely and used for active load management.

Current Status: Both anecdotal evidence and data from the EE Program suggest high customer interest in heat pumps and growing numbers of installations. Under the current EE Program, customers are eligible to receive rebates to install heat pumps regardless of their primary heating fuel. However, current rebates are marketed for cooling only and sized relative to the incremental cooling efficiency benefit (and incremental heating efficiency benefit if electric heating is the baseline). It is unclear—both due to the lack of mention of oil in the LCP law, and also due to a regulatory precedent of avoiding fuel switching (in the EE programs)—whether National Grid is (or should be) allowed to (and under what conditions/criteria) promote fuel switching from fossil fuel heating systems to heat pumps for heating purposes.

Process	Synergies	Barriers	Recommendations

Energy Efficiency Program	• Under the current programs, customers can receive rebates to install heat pumps for cooling regardless of their primary heating fuel
	• The current programs offer weatherization, which can make a home a better fit for an efficient heat pump installation, or reduce the number of units needed
		• Current rebates for heat pumps are marketed for cooling only and sized relative to the cooling efficiency benefit (i.e. they might be richer incentives if heating savings could be confirmed and claimed)
		• Energy, emissions and cost savings from fuel switching to heat pumps have not yet been adequately evaluated, measured, and verified
		• Size of the market potential is unknown. Size of current market is also unknown, but likely growing
		• It is not clear whether a program that encourages fuel switching for a given end use (i.e. heating) is allowed under the current Standards, and under what criteria it would be allowed/desired
		• There are other questions, including how cost-effectiveness and baselines would be determined
		• Fuel switching generates significant benefits (through oil or fossil fuel savings), but marginal electric savings. Therefore, a focus on strategic electrification would:
		  ○ Inhibit achieving annual kWh and kW reduction goals around which the EE programs are structured (in fact, electrification would build load and potentially, peak—and associated costs)
		  ○ Conflict the present structure of Grid's shareholder incentive, which is calculated off of kWh savings achieved and also budget spend (i.e. strategic electrification would reduce kWh savings/$ spent)
			• Ask PUC to issue a clarification on the status of fuel switching as a utility activity (under EE and also under ISR and other processes).
			• Consider creating a separate initiative for strategic electrification—if evaluation results and market study come back detailing a need or sufficient value—that would have its own unique goals, budget, and incentive. Examine whether this can be achieved through a revision to the Standards (or not, if separate).
			• Develop a form of shareholder incentive that is suitable to switching to a high efficiency electric use.

		○ Highlight that energy efficiency goals are inapt to account for benefits from strategic electrification • There are competing demands on the EE budget (i.e. resistance to increased spending for this cost-effective resource). Strategic electrification could require more funds, and we need to figure out how to pay for it • There may be a perception among decision-makers that sales reductions are always good and sales increases are always bad	
System Reliability Procurement	• Heat pump water heaters are being offered in the SRP pilot in Tiverton and Little Compton	• SRP process not currently considering electrifying heating as a dynamic resource—but unclear how growing electricity usage would qualify under SRP; these may be fundamentally contradictory. • Building load in a geographic area may contradict SRP	•
Renewable Energy Growth Program	• Strategic electrification could support increased use of customer-sited distributed generation	• If a customer installs a heat pump after solar has already been installed in their home, this could change the economics of their system payback because the electric load profile is different from the one used to specify the proper solar power investment.	• Coordination between strategic electrification/EE programs and renewable energy processes.
Net Metering	• Strategic electrification could support increased use of customer-sited distributed generation	• If a customer installs a heat pump after solar has already been installed in their home, this could change the economics of their system payback	• Coordination between strategic electrification/EE programs and renewable energy processes.
Renewable Energy Standard	•	•	•
Long-Term Contracting Standard for Renewable Energy	•	•	•
Infrastructure, Safety, and Reliability Plan	•	• It is unclear the extent to which consideration of strategic electrification is being fully incorporated into the utility's long-range planning efforts • Practitioners are unfamiliar with considering electrification as a strategy	• Explore strategic electrification forecasts/use as an NWA as a future strategy in distribution planning.

Standard Offer Supply Plan	• If SOS price goes down, the customer economics improve for those using heat pumps (e.g. more bill savings, shorter paybacks, etc.) • If annual load factor is improved, SOS prices could potentially be reduced.	• More electric sales increases the amount of standard offer supply to be procured; if this increased use exacerbates the state winter peak (and/or peaks on distribution feeders), further electric costs could be created (this is a converse to a synergy and reflects uncertainty about the economic result) • If SOS price goes up, the customer economics deteriorate for those using heat pumps (e.g. fewer bill savings, longer paybacks, etc.)	•
Retail Choice	• Competitive providers can use energy efficiency services as a value-added service	• Competitive providers have no incentive to motivate customers to participate in utility energy efficiency programs and have no comparable incentives to offer themselves	•
Ratemaking – Delivery Prices	•	• Time varying rates, not used in RI, will tend to promote the most valuable thermal electrification applications; other rate structures which base fixed charge on use will discourage strategic electrification • Lack of advanced metering infrastructure precludes time varying rates	•
Utility Financial Incentive	• Grid receives a shareholder incentive under the EE Program, which includes heat pump product offerings	• Grid's shareholder incentive is calculated based off of % of budget spent and % of kWh savings achieved. Replacing or displacing an oil or fossil fuel heating system with a heat pump provides much lower kWh savings for the same $ spent on most other EE measures • Grid has an incentive to add gas customers because it will increase their gas rate base, potentially conflicting with strategic electrification, which is less likely to grow their rate base, at least in the near term	• If evaluation results and market study come back detailing a need, consider creating a separate initiative for strategic electrification under LCP that would have its own unique goals and incentives for achieving those goals.
Interconnection Standards	•	•	•
Environmental Regulation	• Strategic electrification will help Rhode Island meet the Resilient RI emissions reduction targets, which are economy-wide targets and as a new emission reduction method may be a cheaper method than others	• Although strategic electrification will provide a benefit of lower overall emissions due to higher efficiency and different fuel sources, it will also shift energy consumption from the heating sector to the power sector, possibly raising RGGI allowance prices • Likewise, large-scale strategic electrification may make it more difficult than otherwise to comply with the Clean Power Plan, which solely addresses the power sector, if there is a controlling limitation on cost-effective clean power sector resources	•

Gaps Summary

1. It is not clear whether fuel switching to electricity is allowed under the current Standards.
2. Fuel switching would not screen under current planning process and would be detrimental to the utility's ability to reach kWh and KW saving goals and shareholder incentive.
3. Limited funds are presently available for fuel switching.
4. Potential volume and net benefits are unknown.

Recommendations Summary

1. If evaluation results and market study come back detailing a need, consider creating a separate initiative for strategic electrification under LCP that would have its own unique goals, budget, and incentive. Examine whether this can be achieve through a revision to the Standards.
2. Examine how to create additional funds to support strategic electrification.
3. Assess size of market.

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4. Strategic Electrification – Transportation

Emerging electric technologies (e.g. electric vehicles) may provide significant savings and benefits through effective substitution of electric use for applications that have traditionally been dominated by fossil fuels (e.g. transportation). Electric vehicles and their batteries could ultimately be used as a resource for load-shifting and flattening and other ancillary services. For the purposes of this discussion, the assumption is that customers make a decision to purchase an electric vehicle independent of the processes identified below, and subsequently: 1) various features of these processes may impact the customer with the EV, and/or 2) the EV may impact various features of these processes.

Current Status: As of August 2015, 421 electric vehicles were registered in Rhode Island. Almost all have been registered in the past four years. As of August 2015, no state incentives are available to consumers interested in purchasing EVs, however, there is a federal tax credit. Rhode Island has a goal of 43,000 EVs in the state by 2025. No information has been developed yet on the impacts of achieving this goal: What does the increased electric load look like? Where will it be located? How will that load be served?

Process	Synergies	Barriers	Recommendations
Energy Efficiency Program	•	• Behavioral programs like Home Energy Reports aren't sensitive to the distinct EV population • Commercial buildings with EV charging are not distinguished, so benchmarking won't be sensitive to these unique buildings	• Change Home Energy Reports so that customers with EV are compared to other customers with EV.
System Reliability Procurement	• Electric vehicles are an eligible NWA under the SRP Standards	• EVs for load shifting appear less useful from an NWA standpoint because the amount of storage per charging station is expected to be relatively small and scale appears necessary to support the amount of investment to get such an initiative up and running and may outweigh the capacity that would be gained from it. Once EVs hit a threshold level this may be more feasible at a state-wide level and could then structure it to be able to use any stations in whatever pilot area(s) is in need of it • In New England, current EV adoption levels appear to be below levels that would provide much value • The utility does not offer an EV charging rate. Customer can take advantage of TOU rates but those currently have very low adoption. Currently difficult to incent customers to shift to off peak	• OER with stakeholders will revisit this long term strategy once there are more EVs to look at the benefits of load shifting, TOU or EV charging rate or any other program to influence EV deployment.
Renewable Energy Growth Program	•	• What happens if customer buys an EV and charges at home after they've already had solar installed under the REG Program?	•
Net Metering	•	• What happens if customer buys an EV and charges at home after they've already had solar installed under net metering?	•

Renewable Energy Standard	•	•	•
Long-Term Contracting Standard for Renewable Energy	•	•	•
Infrastructure, Safety, and Reliability Plan	•	• It is unclear the extent to which consideration of strategic electrification is being fully incorporated into the utility's long-range planning efforts • Practitioners are unfamiliar with considering electrification as a strategy	• Consider recommending scenario modeling of EV growth in distribution planning—also create a tracking mechanism where actual growth can be tracked and analyzed.
Standard Offer Supply Plan	• If SOS price goes down, the customer economics improve for those using EVs (e.g. more bill savings, shorter paybacks, etc.)	• More electric sales increases the amount of standard offer supply to be procured; if state peak is exacerbated, further electric costs could be created • If SOS price goes up, the customer economics deteriorate for those using EVs (e.g. fewer bill savings, longer paybacks, etc.)	•
Retail Choice	• Competitive providers can use EV services as a value-added service	• Competitive providers apparently have no incentive to motivate customers to choose EVs	• Take steps to specifically exempt charging station owner-operators from public utility regulations; this could improve the ability and ease for competitive providers to enter the marketplace for charging stations.
Ratemaking – Delivery Prices	•	• Time varying rates, not used in RI, will tend to promote the most valuable thermal electrification applications; other rate structures which base fixed charges on use will discourage strategic electrification • No existing structure to purchase stored energy from EVs • Lack of advanced metering infrastructure precludes time varying rates • Rules prohibiting resale of electricity prevent commercial charging stations from many product designs	• Longer-term item for when more EVs are in the marketplace ○ Explore the implications of allowing for the purchase of stored energy back from electric vehicle owners (vehicle-to-grid) and changes to rates and standards that would be needed. • Consider revising sale for resale rules to enable commercial charging services more flexibility in pricing.

Utility Financial Incentive	• Charging is a utility business opportunity	• Utility has no financial motivation to promote transportation electrification	• OER with stakeholders revisit this in conjunction with this long term strategy once there are more EVs to look at the benefit of TOU or EV charging rate or any other program to influence EV deployment.
Interconnection Standards	•	• Are there interconnection standards for electric vehicle charging stations?	•
Environmental Regulation	• Strategic electrification will help Rhode Island meet the Resilient RI emissions reduction targets, which are economy-wide targets	• Although strategic electrification will provide a benefit of lower overall emissions due to higher efficiency and different fuel sources, it will also shift energy consumption from the heating sector to the power sector, possibly raising RGGI allowance prices • Likewise, large-scale strategic electrification may make it more difficult than otherwise to comply with the Clean Power Plan, which solely addresses the power sector, if there is a controlling limitation on cost-effective clean power sector resources	•

Gaps Summary

1. Behavioral programs and benchmarking may unduly penalize those with EV.
2. No schedule or mapping of where EV is expected or how it will impact the grid.
3. Lack of rates to encourage load shifting for electric vehicles.
4. Lack of clear understanding of which drivers (no pun intended) influence move customers to adopt EVs, and where we are trying to insert ourselves into the EV ownership process.

Recommendations Summary

1. Change Home Energy Reports and benchmarking so that customers with EV are compared to other customers with EV.
2. Establish a procedure or schedule for forecasting loads as EVs are integrated into the system, including the impacts of charging on peak demand.
3. Longer-term recommendation for when there is a threshold level of EVs in place—identify rate-setting mechanisms, including time-variable rate design to encourage EV owners to switch demand.
4. Take steps to specifically exempt charging station owner-operators from public utility regulations; this could improve the ability and ease for competitive providers to enter the marketplace for charging stations.

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5. Active Load Management

Active load management (ALM) involves direct control of electric loads—by the utility, the customer, or a third party—in order to reduce demand during peak periods or balance the supply of electricity at other times. For the purposes of this discussion ALM can be thought of as a combination of rate design/price signals and new tools that enable customers to shape (or have their load managed) intelligently. Ultimately it could be a sophisticated management system that allows the utility to respond to savings opportunities in real time, using customer facilities.

Current Status: A pilot active load management strategy is used in the SRP Pilot in Tiverton and Little Compton. Demand response-capable Wi-Fi thermostats (in conjunction with plug load device equipment for customers with window AC units) allow National Grid to call demand response events during peak demand summer afternoons in the SRP Pilot area. In Rhode Island National Grid does not have "time of use" rate designs and does not offer critical peak pricing options.

Process	Synergies	Barriers	Recommendations
Energy Efficiency Program	• Clear mandate for demand response in LCP legislation[30] • There is a kW reduction goal currently in place for the EE programs • There are controllable devices that are deployed through EE, but not currently used for ALM, providing future potential ALM. Using these for ALM and selling into ISO market	• Rhode Island has very limited AMI infrastructure, and the general perception is that there may not be an appetite among all stakeholders or decision-makers to make the required investment. AMI is not required for all automated load management, but enables forms of ALM in use elsewhere, so its absence is limiting and thus is a barrier • As the Standards and cost-effectiveness tests are now structured in Rhode Island for LCP, the values of load reductions at critical times are not adequately identified or valued. That is, ALM as a strategy apparently does not produce enough kW/$ or kWh/$ to pass as a cost-effective strategy under the current TRC screening due to lack of costing information	• Obtain better value for super peak time period to enable screening of DR in EE plans. • Complete market assessment regarding potential for DR. For example, what is already being served by companies like

[30] RIGL 39-1027.7 (a) (1)(iii) Demand response, including, but not limited to, distributed generation, back-up generation and ***on-demand usage reduction***, which shall be designed to facilitate electric customer participation in regional demand response programs, including those administered by the independent service operator of New England ("ISO-NE") and/***or are designed to provide local system reliability benefits through load control or using on-site generating capability;*** (iv) To effectuate the purposes of this division, the commission may establish standards and/or rates (A) for qualifying distributed generation, ***demand response,*** and renewable energy resources; (B) for net-metering; (C) for back-up power and/or standby rates that reasonably facilitate the development of distributed generation; and (D) for such other matters as the commission may find necessary or appropriate. (2) Least-cost procurement, which shall include procurement of energy efficiency and energy conservation measures that are prudent and reliable and when such measures are lower cost than acquisition of additional supply, ***including supply for periods of high demand***. (***bolded italics*** added for emphasis)

	could provide an additional funding source for programs
	• Home Energy Reports provides a platform about their use that could be used for ALM
	• It is important to note that the underlying LCP legislation does not focus on EE to the exclusion of new forms of generation[31]
		• The underlying analysis of costs and benefits of load management has not been a focus of LCP to this point in Rhode Island. There is no information about potential levels of ALM, including potential benefits
		• ALM generates benefits and potentially cost savings by improving load factor, but is not likely to create many total electric kWh savings. Therefore, a focus on ALM under the present regulatory structure could:
		  ○ Inhibit achieving annual kWh and kW reduction goals around which the EE programs are structured, and
		  ○ Conflict the structure of Grid's current shareholder incentive, which is calculated primarily based on kWh savings achieved and also budget spend (i.e. ALM would reduce kWh savings/$ spent)
		• There are competing demands on the EE budget (i.e. resistance to increased spending for this cost-effective resource). Stated another way, ALM could require more funds, and we need to figure out how to pay for it
		• State policy to support ALM is unclear—including costs for meters and other costs
			EnerNOC and what initiative would provide the most benefit?
			• Assess utilizing Wi-Fi thermostats and communicating appliances for DR program.

System Reliability Procurement	• ALM in the form of demand response is used in the Pilot	• SRP does not currently use ALM other than in peak periods, for example, for balancing and large scale renewable integration at any time • No additional ALM projects have moved forward, possibly due to a barrier in screening criteria for NWAs to promote more projects under SRP. Findings from SRP effort need to be studied before DR efforts are scaled up	• Examine how to promote additional SRP projects or expand the current pilot to a other regions.
Renewable Energy Growth Program	• ALM might be able to identify new strategies to maximize benefits of this effort, increasing customer, and system benefits	• How would ALM potentially affect PBIs/bill credits? • More information is needed about ALM interaction with variable resources?	•
Net Metering	• ALM might be able to identify new strategies to maximize benefits of this effort, increasing customer, and system benefits	• How would ALM potentially affect net metering/credits?	•

[31] Title 39-1-27.7 (a) The commission shall establish not later than June 1, 2008, standards for system reliability and energy efficiency and conservation procurement, which shall include standards and guidelines for: (1) System reliability procurement, including but not limited to: (i) Procurement of energy supply from diverse sources, including, but not limited to, renewable energy resources as defined in chapter 26 of this title; (ii) Distributed generation, including, but not limited to, renewable energy resources and thermally leading combined heat and power systems, which is reliable and is cost-effective, with measurable, net system benefits;

Renewable Energy Standard	•	•	•
Long-Term Contracting Standard for Renewable Energy	•	•	•
Infrastructure, Safety, and Reliability Plan	•	• ALM might yield infrastructure savings, but these have not been systematically identified or quantified • It is unclear the extent to which consideration of ALM is being fully incorporated into the utility's long-range planning efforts • Many practitioners are unfamiliar with considering ALM as a strategy	• Review screening process with system planners to determine what the barriers are.
Standard Offer Supply Plan	• Reduced electric sales at high cost times decreases the cost of standard offer supply to be procured	• ALM might yield Standard Offer Supply cost savings, but these have not been systematically identified or quantified	• Gather information on costs and benefits of ALM.
Retail Choice	•	•	•
Ratemaking – Delivery Prices	•	• Time varying rates, not used in RI, will tend to promote ALM; other rate structures which base fixed charges on use will discourage ALM • Lack of advanced metering infrastructure precludes time varying rates, one mechanism for encouraging ALM	• Examine the potential for rate design that can promote ALM without meters.
Utility Financial Incentive	• In the EE Program, the utility receives an incentive for achieving kW savings.	Grid's shareholder incentive is calculated based off of % of kWh savings achieved relative to established targets. Currently ALM provides lower kWh savings for the same $ spent on most other EE measures. No explicit reward for better load management	•
Interconnection Standards	•	•	•
Environmental Regulation	• ALM will help Rhode Island meet the Resilient RI emissions reduction targets, which are economy-wide targets • ALM will help increase load factor and reduce peak demand, and thus emissions from higher-emitting oil/coal plants	•	•

Gaps Summary

1. Difficult to screen ALM under current EE TRC test.

2. Lack of knowledge in current DR marketplace.
3. No rates in place to promote load shifting in RI.
4. ALM is dynamic and most of what existing platforms address is static.

Recommendations Summary

1. Ensure EE programs do not miss opportunities to install controllable devices (e.g. Wi-Fi-connected thermostats, refrigerators, etc.).
2. Obtain value for super peak time period to enable screening of DR in EE plans.
3. Complete market assessment regarding potential for DR. For example, what is already being served by companies like EnerNOC and what initiative would provide the most benefit?
4. Examine the potential for a rate design or other pilot that can promote ALM without meters.
5. Assess whether the cost/benefit framework is reflecting the full net value of ALM.
6. In next round of LCP procurement 3-year planning, include assessment of DR and ALM potential costs and benefits in parallel with traditional EE savings. Include:
    a. A new kind of "potential study" that included ALM opportunities. This could include an assessment of potential new revenue by selling aggregated ALM into ISO markets.
    b. Recommendations for new ALM programs in 2016 (building on pilots in progress and other experience) which include target achievement levels for each program (not an aggregate ALM target for the utility).
    c. In Standards review process, re-draft standards to include guidance for screening and deploying ALM.
7. Consider design of underlying planning process, technologies and rate structures that would maximize benefits to customers, system, and environment of this approach.
8. Consider utility performance incentives that would reward activities that yield system and customer and environmental savings beyond just EE.

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Endnotes

[i] LCP statute: http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-1/39-1-27.7.HTM
[ii] 2015 EE Procurement Plan: http://www.ripuc.org/eventsactions/docket/4527page.html
[iii] PUC enabling statute: http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-1/39-1-1.HTM
[iv] Rate schedule statute: http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-3/39-3-10.HTM
[v] Last Rate Case (2012): http://www.ripuc.org/eventsactions/docket/4323page.html
[vi] Review of Rate Design Docket: http://www.ripuc.org/eventsactions/docket/4568page.html
[vii] Retail access statute: http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-1/39-1-27.3.HTM
[viii] Interconnection tariff: http://www.nationalgridus.com/non_html/RI_DG_Interconnection_Tariff.pdf
[ix] REG Program statute: http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-26.6/INDEX.HTM
[x] REG Program PUC filings: http://www.ripuc.org/eventsactions/docket/4536page.html
[xi] Net Metering statute: http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-26.4/INDEX.HTM
[xii] Net Metering tariff: http://www.ripuc.org/eventsactions/docket/4549page.html
[xiii] RES statute: http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-26/INDEX.HTM
[xiv] 2016 SOS/RES Procurement Plan: http://www.ripuc.org/eventsactions/docket/4556page.html
[xv] Long-Term Contracting Standard for Renewable Energy statute: http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-26.1/INDEX.HTM
[xvi] OER SRP Solar DG Pilot: http://www.energy.ri.gov/reliability/
[xvii] 2015 SRP Plan: http://www.ripuc.org/eventsactions/docket/4528page.html
[xviii] Decoupling ISR statute: http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-1/39-1-27.7.1.HTM
[xix] FY 2016 ISR Plan: http://www.ripuc.org/eventsactions/docket/4540page.html
[xx] FY 2015 Revenue Decoupling Mechanism Reconciliation Filing: http://www.ripuc.org/eventsactions/docket/4566page.html
[xxi] SOS statute: http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-1/39-1-27.8.HTM
[xxii] 2016 SOS/RES Procurement Plan: http://www.ripuc.org/eventsactions/docket/4556page.html
[xxiii] RGGI statute: http://webserver.rilin.state.ri.us/Statutes/TITLE23/23-82/INDEX.HTM
[xxiv] Resilient Rhode Island statute: http://webserver.rilin.state.ri.us/Statutes/TITLE42/42-6.2/INDEX.HTM

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